# PORT PELICAN

# APPLICATION

# DEEPWATER PORT LICENSE

Port Pelican LLC

Suite 2700
1111 Bagby
Houston, Texas 77002

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# for a Deepwater Port License
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# ABBREVIATIONS AND ACRONYMS

| Abbreviation/Acronym | Definition |
|---|---|
| ° | degrees |
| % | percent |
| AAA | American Automobile Association |
| ABS | ABS Consulting, Inc. |
| ABS | American Bureau of Shipping (app. Pg. 2-46) |
| ACHP | Advisory Council on Historic Preservation |
| AFB | Aquatic Filter Barriers |
| AFFF | Aqueous Film Forming Foam |
| AGO | Atmospheric Gas Oil |
| ANSI | American National Standards Institute |
| APB | Accounting Principles Board |
| APDEIS | Advanced Preliminary Draft Environmental Impact Statement |
| API | American Petroleum Institute |
| AQCR | Air Quality Control Regions |
| ASME | American Society of Mechanical Engineers |
| AWOIS | Automated Wreck and Obstruction Information System |
| AWS | American Welding Society |
| B.P. | Before Present |
| BACT | Best Available Control Technology |
| Bbbl | Billion barrels |
| bbl | barrel |
| bbl/day | barrel per day |
| BCFD | Billion cubic feet per day |
| BHP | brake horsepower |
| BOD | Biological Oxygen Demand |
| BML | Below the Mud Line |
| BOG | Boil-off Gas |
| BPSD | Barrels per stream day |
| Br | Bromine |
| BTA | Best Technology Available |
| BTU/cu.ft | British Thermal Units per cubic feet |
| CAA | Clean Air Act |
| CEI | Coastal Environments, Inc. |
| CEQ | Council on Environmental Quality |
| CERCLA | Comprehensive Environmental Response, Compensation, and Liability Act |
| CFCs | chlorofluorocarbons |
| CFR | Code of Federal Regulations |
| cfs | Cubic feet per second |
| CH | Critical Habitat |
| $CHBr_3$ | Bromoform |
| $CHClBr_2$ | Dibromochloromethane |
| $CHCl_2Br$ | Dichlorobromomethane |
| $CHCl_3$ | Chloroform |
| Chevron | Chevron Corporation |
| $CH_3NH_2$ | Methylamine |
| $CH_3NHCl$ | Chloromethylamine |

| Abbreviation/Acronym | Definition |
|---|---|
| $CHX_3$ | Trihalomethanes |
| CIA | Central Intelligence Agency |
| Cl | Chlorine |
| cm/s | centimeter per second |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| COD | Chemical Oxygen Demand |
| COE | U.S. Army Corps of Engineers |
| COTP | Captain of the Port |
| CPI | coalescing plate interceptor |
| CAN/CSA | Canada Standards |
| CTD | Conductivity, temperature and depth |
| CTS | Chevron Texaco Shipping |
| CUSA | Chevron USA, Inc. |
| CVX | ChevronTexaco Overseas Petroleum Corporation |
| CWA | Clean Water Act |
| CZMA | Coastal Zone Management Act |
| d/year | Days per year |
| dB | decibel |
| dBA | decibels on the A-weighted scale (human hearing frequency range) |
| DDT | d(ichloro)d(iphenyl)t(richloroethane) |
| DEIS | Draft Environmental Impact Statement |
| DEQ | Department of Environmental Quality |
| DNV | Det Norske Veritas |
| DO | Dissolved Oxygen |
| DOA | U.S. Department of Army |
| DOC | U.S. Department of Commerce |
| DOE | U.S. Department of Energy |
| DOI | U.S. Department of Interior |
| DOT | U.S. Department of Transportation |
| DWPA | Deepwater Port Act |
| dwt | dead weight |
| Dynegy | Dynegy Midstream Services, Limited Partnership |
| EEZ | Exclusive Economic Zone |
| EFH | Essential Fish Habitat |
| EIA | Energy Information Administration |
| EIQ | Emissions Inventory Questionnaire |
| EIS | Environmental Impact Statement |
| EP Energy Bridge | El Paso Energy Bridge |
| EPA | U.S. Environmental Protection Agency |
| EPCI | engineering, procurement, construction, and installation |
| Elba Island Terminal | Marine import terminal on Elba Island in Chatham County, Georgia |
| ER | Environmental Report |
| ESA | Endangered Species Act |
| F | Fahrenheit |
| FAA | Federal Aviation Agency |
| FCC | fluid catalytic cracking |
| FCMA | Magnuson-Stevens Fishery Conservation and Management Act |
| FEED | Front End Engineering Design |

| Abbreviation/Acronym | Definition |
|---|---|
| FEIS | Final Environmental Impact Statement |
| FERC | Federal Energy Regulatory Commission |
| FGT | Florida Gas Transmission |
| FIP | French Standards |
| fish/m | fish per meter |
| FMP | Fishery Management Plan |
| fps | feet per second |
| FPSO | Floating Production, Storage, and Offloading facilities |
| FR | Federal Register |
| FSRU | floating, storage and regas unit |
| ft | feet |
| $ft^3$/hr | cubic feet per hour |
| FWPCA | Federal Water Pollution Act |
| FWS | U.S. Fish and Wildlife Service |
| gal/person | gallons per person |
| gal/yr | gallons per year |
| GB124 | common block |
| GBS | Gravity Based Structure |
| GHG | Greenhouse Gas |
| GJ/hour | gigajoules per hour |
| GLO | General Land Office |
| GLOW | Gulf Long Term Weather |
| GMFMC | Gulf of Mexico Fishery Management Council |
| GOM | Gulf of Mexico |
| GPD | Gallons per day |
| GPM | Gallon per Minute |
| GROW | Global Reanalysis of Ocean Waves |
| GUMSHOE | Gulf of Mexico Storm Hindcast of Oceanographic Extremes |
| GWP | Global Warming Potential |
| $H_20$ | Water |
| ha | hectares |
| HAPs | Hazardous Air Pollutants |
| HAT | High Astronomical Tide |
| HAZOP | Hazardous Operations |
| HFGGS | Henry Floodway Gas Gathering System |
| HOCl | Hypochlorous acid |
| hp | horsepower |
| hPA | hectapascal |
| $H_s$ | Significant wave height |
| HS&E | Health, Safety and Environment |
| HVAC | High volume air conditioning |
| hz | hertz- a measurement of cycles per second |
| I | Iodine |
| IFV | Intermediate Fluid Vaporizer |
| IGT | Institute of Gas Technology |
| IMO | International Maritime Organization |
| ISO | International Standards Organization |
| ISA | Instrument Society of America |
| kips | English unit of force |

| Abbreviation/Acronym | Definition |
|---|---|
| kg | kilograms |
| km | kilometers |
| kts | knots |
| kV | Kilovolts |
| kW | kilowatt |
| LAT | Low Astronomical Tide |
| L $mol^{-1}$ $s^{-1}$ | Liter per mole per second |
| lb | pound |
| lb/day | Pounds per day |
| lb/$ft^3$ | Pounds per square foot |
| lb/hr | pounds per hour |
| l/mg/min | Liter per milligram per minute |
| $LC_{50}$ | Lethal Concentration that kills 50% of the test animals |
| LDEQ | Louisiana Department of Environmental Quality |
| Ldn | Day-night Sound Level |
| $Leq_{(24)}$ | 24-hour equivalent sound level |
| LIFO | Last-In, First-Out |
| LMAs | labor market areas |
| LNG | Liquefied Natural Gas |
| LNGC | Liquid Natural Gas Carrier |
| LOOP | Louisiana Offshore Oil Platform |
| LOTA | Louisiana Offshore Terminal Authority |
| LPG | Liquefied Petroleum Gas |
| LSU | Louisiana State University |
| LVGO | Light vacuum gas oil |
| µg/l | micrograms per liter |
| µmole/l | micromole per liter |
| µPA | micropascals |
| m | meter |
| m/sec | Meter per second |
| $m^3$ | Cubic meters |
| $m^3$/hr | cubic meters per hour |
| MACT | Maximum Achievable Control Technology |
| Magnuson Act | Magnuson-Stevens Fishery Conservation and Management Act |
| MAOP | maximum allowable operating pressure |
| MARSAT | Marine Satellite Telephone |
| MCC | motor control centers |
| MCF | Million Cubic Feet |
| MCFD | million cubic feet per day |
| metocean | meteorological and oceanographic |
| mg/l | milligrams per liter |
| mg/$m^3$ | Milligrams per cubic meters |
| MGD | million gallons per day |
| $mi^2$ | square miles |
| miles/second | Miles per second |
| MICC | Main Instrument Control Contractor |
| ml/l | milliliter per liter |
| MM | million |
| mm | millimeter |

| Abbreviation/Acronym | Definition |
|---|---|
| MMbbl | million barrels |
| MMBtu | Million British Thermal Units |
| MMBtu/hr | Million British Thermal Units per hour |
| MMCFD | million cubic feet per day |
| MMgal/yr | million gallons per year |
| MMO | modifications, maintenance and operations |
| MMPA | Marine Mammals Protection Act |
| MMS | Minerals Management Service |
| MODU | Mobile Offshore Drilling Units |
| MOU | Memorandum of Understanding |
| MPRSA | Marine Protection, Research, and Sanctuaries Act |
| MRFSS | Marine Recreational Fishery Statistics Survey |
| mS/cm | milli-Siemens per centimeter |
| mS/m | milli-Siemens per meter |
| MSL | Mean Sea Level |
| MSD | Marine Sanitation Device |
| MW | Megawatts |
| $N_2$ | Nitrogen |
| NA | Not Applicable |
| NAAQS | National Ambient Air Quality Standards |
| NAICS | North American Industry Classification System |
| NaOCl | Sodium hypochlorite or bleach |
| $NBr_3$ | Tribromamine |
| NBSIR | National Bureau of Standards Industrial Report |
| $NCl_3$ | Trichloramine |
| NEC | National Electric Code |
| NEPA | National Environmental Policy Act |
| NERL | National Environmental Research Laboratories |
| NESHAPs | National Emission Standards for Hazardous Air Pollutants |
| NF | Newfoundland |
| NFPA | National Fire Protection Association |
| NGA | Natural Gas Act |
| NHPA | National Historic Preservation Act |
| $NH_2Br$ | Monobromamine |
| NH2Cl | Monochloramine |
| $NHBr_2$ | Dibromamine |
| NHBrCl | Bromochloramine |
| $NHCl_2$ | Dichloramine |
| NM | nautical miles |
| nm | nanometer |
| NMFS | National Marine Fisheries Service |
| NMHC | Non-methane hydrocarbons |
| NMSA | National Marine Sanctuaries Act |
| $NO_2$ | Nitrogen Dioxide |
| NOAA | National Oceanic Atmospheric Administration |
| NOEC | No Observable Effect Concentration |
| NOI | Notice of Intent |
| NOS | National Ocean Service |
| $NO_x$ | Nitrogen Oxides |

| Abbreviation/Acronym | Definition |
|---|---|
| NPDES | National Pollutant Discharge Elimination System |
| NPS | National Park Service |
| NPSH | net positive suction head |
| NRC | National Research Council |
| NRHP | National Register of Historic Places |
| NSA | Noise Sensitive Area |
| NSPS | New Source Performance Standards |
| NSR | New Source Review |
| NTL | Notice to Lessees and Operators |
| NTU | Nephelometric Turbidity Units |
| NVTOC | Non Volatile Total Organic Carbon |
| NWI | National Wetland Inventory |
| $O_3$ | Ozone |
| OCIMF | Oil Companies International Marine Forum |
| OCS | Outer Continental Shelf |
| OCSLA | Outer Continental Shelf Lands Act |
| OCSPD | Outer Continental Shelf Petroleum Development |
| OOCR | Office of Ocean and Coastal Resources |
| OPA | Oil Pollution Act |
| OPR | Office of Pipeline Research |
| OPS | Office of Pipeline Safety |
| ORD | Office of Research and Development |
| ORV | Open Rack Vaporizer |
| Pb | Lead |
| PCBs | polychlorinated biphenyls |
| Pd | Period |
| PDEIS | Preliminary Draft Environmental Impact Statement |
| PIPL | Pelican Interconnector Pipeline |
| PLC | programmable logic controller |
| PM | Particulate Matter |
| $PM_x$ | Particulate matter smaller than x micron in diameter |
| POB | Personnel on board |
| Port Pelican | Port Pelican LLC |
| ppb | parts per billion |
| ppm | parts per million |
| ppt | parts per thousand |
| Project | Port Pelican Project |
| PSD | Prevention of Significant Deterioration |
| psf | pounds per square foot |
| psi | pounds per square inch |
| psig | pounds per square inch gauge |
| psu | practical salinity units |
| RACON | radar signaling |
| RO | Reverse Osmosis |
| ROVs | Remote Operated Vehicles |
| ROW | Right-Of-Way |
| RV | Recreational Vehicle |
| S/m | Siemens per meter |
| SC | Submerged Combustion |

| Abbreviation/Acronym | Definition |
|---|---|
| SCFD | standard cubic feet per day |
| SCFH | standard cubic feet per hour |
| sec | seconds |
| SHPO | State Historic Preservation Officer |
| SIGTTO | Society of International Gas Tanker and Terminal Operators |
| SL | Standard Length |
| SM | South Marsh Island |
| SMYS | specified minimum yield strength |
| $SO_2$ | Sulfur Dioxide |
| Southern Natural | Southern Natural Gas Company |
| SPB | Self-supporting Prismatic shape IMO type B |
| SPCC | Spill Prevention, Control, and Countermeasure Plan |
| SRV | Shuttle and regas vessel |
| SS | Stainless Steel |
| t | time |
| T&E | Threatened and endangered |
| TBD | To Be Determined |
| TCF | Trillion Cubic Feet |
| Terminal | Port  Pelican Terminal |
| TET | Texas Eastern Transmission |
| Texaco | Texaco Inc. |
| TGP | Tennessee Gas Pipeline |
| THM | Trihalomethanes |
| THMFP | Trihalomethanes formation potential |
| THPO | Tribal Historic Preservation Officer |
| Title V | Title V Operating Permits |
| TLP | Tension Leg Platform |
| TOC | total organic carbon |
| tons/hour | tons per hour |
| tons/year | tons per year |
| $T_p$ | Time peak |
| TPY | tons per year |
| TR | Topic Report |
| Transco | Transcontinental Pipe Line |
| TSP | Total Suspended Particulate |
| TTHM | Total Trihalomethane concentration |
| TWA | Time-weighted average |
| UBC | Uniform Building Code |
| UM3 | Three-dimensional Updated Merge |
| UPS | Uninterruptible Power Supply |
| U.S. | United States |
| USC | U.S. Code |
| USCG | U.S. Coast Guard |
| USDOC | U.S. Department of Commerce |
| UDOI | U.S. Department of Interior |
| USFWS | U.S. Fish and Wildlife Service |
| USGS | U.S. Geological Survey |
| UV | Ultraviolet |
| V | Volt |

| Abbreviation/Acronym | Definition |
|---|---|
| VAC | volts, alternating current |
| VOCs | Volatile organic compounds |
| VR | Vermilion |
| WINX | Winter Storm Extremes |
| WIS | Water Intake Structures |
| WMA | Wildlife Management Area |
| WT | Water |
| YPC | Yukon Pacific Corp. |
| yr | year |

## Common Conversion Equations

| Units | | Units |
|---|---|---|
| acres x 0.4047 | = | hectares |
| billion standard cubic feet per day (billion SCFD) x 0.0283 | = | billion standard cubic meter per day (billion SCMD) |
| billion standard cubic meter per day (billion SCMD) x 35.31 | = | billion standard cubic feet per day (billion G28SCFD) |
| British Thermal Unit (BTU) x 7.7816 x $10^2$ | = | Foot-pounds (ft-lbs) |
| $^0$C x 1.8 + 32 | = | 0F |
| centimeter (cm) x 3.937 x $10^{-1}$ | = | inch (in.) |
| cubic feet ($ft^3$) x 0.0283 | = | cubic meter (m3) |
| cubic feet per hour ($ft^2$/hr) x 0.0283 | = | cubic meters per hour (m3/hr) |
| cubic meter ($c^3$) x 35.31 | = | cubic feet (ft3) |
| cubic meters per hour ($m^3$/hr) x 35.31 | = | cubic feet per hour (ft2/hr) |
| feet (ft) x 0.3048 | = | meter (m) |
| feet per second (fps) x 0.1829 / 60 sec | = | meters per second (mps) |
| gallons (gal) x 3.785 | = | liters (L) |
| gallons per minute (gpm) x 0.06309 x 60 sec | = | liters per minute (Lpm) |
| hectares x 2.471 | = | acres |
| horsepower (hp) x 0.7457 | = | kilowatts (kw) |
| inch (in.) x 2.54 | = | centimeter (cm) |
| kgscm x 14.22 | = | psi |
| kilometer (km) x 0.6214 | = | mile (mi.) |
| kilowatts (kw) x 1.341 | = | horsepower (hp) |
| Liters (L) x 0.2642 | = | gallons (gal) |
| liters per minute (Lpm) x 0.26418 | = | gallons per minute (gpm) |
| meter (m) x 3.281 | = | feet (ft) |
| meters per second (mps) x 3.281 | = | feet per second (fps) |
| mile (mi.) x 1.609 | = | kilometer (km) |
| metric tons x 2.205 x $10^3$ | = | pounds (lbs) |
| million gallons per day (mgd) x 3.785 | = | million liters per day (mld) |
| million standard cubic feet per day (million SCFD) x 0.0283 | = | million standard cubic meter per day (million SCMD) |
| million standard cubic meter per day (million SCMD) x 35.31 | = | million standard cubic feet per day (SCFD) |
| nautical mile (nmi.) x 1.1516 | = | statute mile (smi.) |
| $^o$F x / 1.8 | = | oC |
| psi x 0.0703 | = | kgscm |
| statute mile (smi.) x 0.8684 | = | nautical mile (nmi.) |
| ton x 0.907185 | = | tonnes |
| tonnes x 1.10231 | = | ton |
| tonnes/hr x 1.10231 | = | tons/hr |
| tons/hr x 0.907185 | = | tonnes/hr |
| trillion cubic feet (tcf) x 0.0283 | = | trillion cubic meter (tcm) |
| trillion cubic meter (tcm) x 35.31 | = | trillion cubic feet (tcf) |

Section
1

# 1 Applicant Information

## Port Pelican LLC

## 1.1 Identity of Applicant and Affiliates

### *1.1.1 Name, Address and Principal Business Activity*

Applicant Name:

Port Pelican LLC, a wholly owned subsidiary of Chevron USA, Inc., a wholly owned subsidiary of

Mailing Address:

Port Pelican LLC
P.O. Box 1404
Houston, TX 77251-1404

Physical Address:

Port Pelican LLC
Suite 2700
1111 Bagby
Houston, TX 77002-2543

Port Pelican LLC (Port Pelican) was formed to engage in the business of operating a liquefied natural gas (LNG) facility to receive, store and vaporize LNG and deliver natural gas to existing natural gas infrastructure in the United States.

### *1.1.2 Corporate Officers and Directors*

Corporate officers of Port Pelican LLC are:

| | |
|---|---|
| George L. Kirkland | President |
| Sandy Cornelius | Vice President |
| Blake J. Koc | Vice President |
| Richard A. Lammons | Vice President |
| Edward B. Scott | Vice President |
| Audie P. Setters | Vice President |
| Walker C. Taylor | Secretary |
| Howard B. Sheppard | Treasurer |
| Warren J. Brechtel | Assistant Secretary |
| Yezdi N. Guzdar | Assistant Secretary |

Section
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| Howard B. Sheppard | Treasurer |
| Warren J. Brechtel | Assistant Secretary |
| Yezdi N. Guzdar | Assistant Secretary |

| | |
|---|---|
| John H. Jones, Jr. | Assistant Secretary |
| Anthony J. Knaapen | Assistant Secretary |
| Kimberley Crawford Schafer | Assistant Secretary |
| Frank G. Soler | Assistant Secretary |
| Gordon Tsuchiya | Assistant Secretary |
| Hongyan Xun | Assistant Secretary |
| Robert C. Gordan | Assistant Treasurer |
| Richard E. Lee | Assistant Treasurer |
| James D. Lyness | Assistant Treasurer |
| Steven H. Peth | Assistant Treasurer |

### *1.1.3 Relationship of Affiliates*

Chevron USA, Inc. (CUSA), is the parent company of Port Pelican LLC CUSA is a major subsidiary of ChevronTexaco Corporation. CUSA owns, manages and operates on its own behalf or on behalf of other ChevronTexaco subsidiaries, the U.S. integrated petroleum operations, excluding ChevronTexaco's investments in Equilon and Motiva (which were sold in February 2002), and most of the pipeline operations of ChevronTexaco. CUSA and its subsidiaries and affiliates manage and operate most of ChevronTexaco's U.S. businesses and assets related to the exploration and production of crude oil, natural gas and natural gas liquids and also those associated with refining, marketing, supply and distribution of products derived from petroleum, other than natural gas liquids. CUSA also holds ChevronTexaco's investment in CPChem.

Consolidated financial statements include the accounts of controlled subsidiary companies more than 50 percent owned. Investments in and advances to affiliates in which the company has a substantial ownership interest of approximately 20 percent to 50 percent, or for which the company exercises significant influence but not control over policy decisions are accounted for by the equity method, in accordance with Accounting Principles Board (APB) Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." Under this accounting, remaining unamortized cost is increased or decreased by the company's share of earnings or losses after dividends. Gains and losses that arise from the issuance of stock by an affiliate that results in changes in the company's proportionate share of the dollar amount of the affiliate's equity are recognized currently in income. Deferred income taxes are provided for these gains and losses.

### *1.1.4 Applicant's History, Citizenship, Incorporation, and Authority*

Port Pelican LLC was incorporated November 1, 2002, in Delaware and is a wholly owned subsidiary of Chevron U.S.A. Inc. Chevron U.S.A. Inc. is a major subsidiary of ChevronTexaco Corporation. Attachment 1 contain copies of the Incorporation Documents.

On October 9, 2001, Texaco Inc. (Texaco) became a wholly owned subsidiary of Chevron Corporation (Chevron) pursuant to a merger transaction, and Chevron changed its name to ChevronTexaco Corporation. The combination was accounted for as a pooling of interests. Certain Consolidated Financial Statements provided in this application give retroactive effect to the merger, with all periods presented as if Chevron and Texaco had always been combined. The Consolidated Financial Statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of significant intercompany accounts and transactions.

In preparing its Consolidated Financial Statements, the company follows accounting policies that are in accordance with accounting principles generally accepted in the United States. This requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. While the company uses its best estimates and judgments, actual results could differ

from these estimates as future confirming events occur. The nature of the company's operations and the many countries in which it operates subject it to changing economic, regulatory and political conditions. The company does not believe it is vulnerable to the risk of near-term severe impact as a result of any concentration of its activities.

Crude oil, petroleum products and chemicals are generally stated at cost, using a Last-In, First-Out (LIFO) method. In the aggregate, these costs are below market. Materials, supplies and other inventories generally are stated at average cost.

### *1.1.5 Lobbying Activities*

ChevronTexaco has a Government Relations office located at:

1401 Eye Street NW, Suite 1200
Washington, DC 20005.

There are 15 employees in the office, including nine registered lobbyists. ChevronTexaco has briefed various members of Congress and their staff and various Executive branch officials and their staff on our proposed Gulf of Mexico regasification facility. In addition the company has followed the Deep Water Port Act amendments (S 1214) giving the Coast Guard additional authority in the permitting of offshore natural gas facilities.

### *1.1.6 Terminal Operational Experience*

Port Pelican will be operated by experienced staff who have handled LNG at onshore ports and will be counseled by personnel experienced in offshore operations and maintenance. Liquid cargo transfer and storage and unloading of vessels containing liquefied natural gas (LNG) will be the primary activity at this port. The LNG will be regasified and delivered to customers using a conventional natural gas pipeline operation. No other commodities will be handled at this port.

The Applicant will be the operator of the facility. ChevronTexaco manages its investments in, and provides administrative, financial and management support to, U.S. and foreign subsidiaries and affiliates that engage in fully integrated petroleum operations, chemicals operations and coal mining activities.

Collectively, these companies operate in approximately 180 countries. Petroleum operations consist of exploring for, developing and producing crude oil and natural gas; refining crude oil into finished petroleum products; marketing crude oil, natural gas and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipelines, marine vessels, motor equipment and rail car. Chemicals operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses and fuel and lube oil additives.

## 1.2 Engineering Design Firm Information

### *1.2.1 Name, Address, Telephone, and Citizenship*

At this time, the firms listed in the table that follows are involved in the design of the Port Pelican Project. Additional specialized design firms will be required to complete the Project design. The Applicant will provide notification of additional engineering design firms performing future design work as they are engaged.

| Name | Address and Telephone | Citizenship | Responsibility |
|---|---|---|---|
| Mustang Engineering, L.P. | 16001 Park Ten Place<br>Houston, Texas 77084<br><br>(713) 215-8000 | United States | Overall project engineering and design |
| Black & Veatch Pritchard, Inc. | 11111 Richmond Ave.<br>Houston, TX 77082<br><br>(713) 260-0420 | United States | Design of regasification process equipment |
| SN Technigaz | SN Technigaz<br>Energies<br>1/7 avenue San Fernando<br>78884 Saint-Quentin-Yvelines<br>Cédex<br>FRANCE<br><br>33.1.61.37.89.73 | France | Construction of LNG storage tanks |
| Aker Kvaerner Technology, AS | Prof. Kohtsvei 5<br>N-1366 Lysaker<br>Norway<br><br>+47 6759 5050 | Norway | GBS unit design |
| Quest Consultants, Inc. | P.O. Box 721387<br>Norman, Oklahoma 73070<br><br>(405) 329-7475 | United States | Dispersion calculations and qualitative risk analysis for LNG spills |
| ABS Consulting, Inc. | 15600 San Pedro Ave Ste. 400<br>San Antonio, Texas 78232<br><br>(210) 495-5195 | United States | Energetics study for the GBS units |
| Sandwell Engineering Inc. | 700-1045 Howe Street,<br>Vancouver, B.C.V6Z 2A9 Canada<br><br>(604) 684-9311 | Canada | Wave and metocean studies, marine engineering |
| ENTRIX, Inc. | 5252 Westchester, Suite 250<br>Houston, Texas 77005<br><br>(713) 666-6223 | United States | Deepwater port license application preparation, NEPA studies, discharge modeling. |

## 1.3 Qualifications and Experience

### *1.3.1 Qualifications and Experience of the Applicant*

Although the Applicant is a newly created entity, it is a wholly owned affiliate of ChevronTexaco, which has been operating installations in offshore locations for more than 40 years. ChevronTexaco Corporation (NYSE: CVX), one of the world's largest integrated energy companies, is involved in every aspect of the energy industry, from oil and gas exploration and production to transportation, refining and retail marketing, as well as chemicals manufacturing and sales and power production. Active in more than 180 countries, ChevronTexaco employs more than 55,000 people worldwide.

ChevronTexaco has extensive experience in marine operations as well. ChevronTexaco Shipping (CTS) is one of ChevronTexaco's original operating entities. ChevronTexaco Shipping has two core businesses: Marine Transportation and Marine Services. CTS manages about 30 ChevronTexaco -owned or time chartered vessels around the world. CTS employs approximately 1,200 mariners and 150 shoreside support staff handling more than 600,000 barrels per day of crude oil into the United States.

### *1.3.2 Qualifications and Experience of Design Firms*

Mustang Engineering, L.P. is the contractor responsible for overall project engineering and design. Mustang was founded in 1987 to provide engineering design and project management for the oil and gas industry (domestic and international, onshore and offshore). As a key player in over 4,700 projects, serving over 300 clients, Mustang is one of the recognized experts in offshore oil production facilities, pipeline facilities, process plants facilities, and automation services. Examples of projects completed by Mustang include:

- BP Clair Development, North Sea, Front end engineering and detail design for Clair Field development on the UK continental shelf. A fixed platform in 500 feet of water with an outfitted operating deck weight of 10,000 tons. Flow rates are 60,000 bbl/day oil, 100,000 bbl/day water and 40 million SCFD gas lift compression. This is the first North Sea Platform to incorporate GOM, fit-for-purpose design, and is the North Seas's largest current new field development.

- Kerr-McGee Boomvang and Nansen, Gulf of Mexico, Topsides detailed design of these floating production facilities, located in 3,600-feet of water in the Gulf of Mexico. Nansen, the world's first Truss Spar, achieved first oil on January 28, 2002. Flow rates are 40,000 bbl/day oil, 80 million SCFD gas (200 million SCFD gas maximum), with up to eight wells connecting to the spar. Boomvang expected to achieve first oil during second quarter 2002.

- ExxonMobil, Diana Field Development, Gulf of Mexico. Topside facilities design and control systems integration for Deep Draft Caisson Vessel located in 4,950 feet of water in the Gulf of Mexico, a GOM record. Results include safety record seven times better than the industry standard; beat all quality objectives, e.g., "A nationally significant project." (MMS); "best inspection ever of an offshore facility" (USCG); cost more than $100 MM less than the funding estimate; wells initiated production on May 31st with no accidents or spills; one month ahead of schedule.

- BP Deepwater Development Program, Gulf of Mexico. Preliminary topsides design, project services and control systems integration for floating facilities on four major deepwater discoveries -- Thunder Horse, Holstein, Mad Dog and Atlantis. Mustang is providing support to BP for managing topsides fabrication, floating systems design and fabrication, facilities installation, pipeline design and installation and subsea systems design, fabrication and installation.

- Mobil Equatorial Guinea, Inc., Zafiro Producer FPSO, Offshore West Africa. Topsides facilities engineering for FPSO tanker conversion using 265,000 dwt VLCC. The Zafiro produces oil in 600 feet of water from up to 30 remote subsea wells in the Zafiro field. The trend-setting project achieved first production in less than 12 months from project sanction. The Phase II expansion was installed while the FPSO was in production, with production availability staying above 98 percent during expansion. Flow rates are 80,000 bbl/day oil, 45 million SCFD gas lift, 80 million SCFD flare gas and 35,000 bbl/day water.

- Deepwater FPSO, Offshore Nigeria. Conceptual design and cost estimate for field development in 4,800 feet. 24,500 metric tonnes topsides dry weight, comprising oil treating, gas compression, reinjection and water injection. This development has one of the largest flowrates in the world for its type -- 200,000 bbl/day oil, 300 million SCFD gas and up to 360,000 bbl/day water.

- BP Mica Pompano, Gulf of Mexico. Deepwater, remote sub-sea development project in 4,500 feet of water with a tieback to shallow water host platform. Flowrates are 12,000 bbl/day condensate, 15,000 bbl/day oil, 180 million SCFD gas and 2,000 bbl/day water. Mustang designed the addition of 2,200 ton modules/skids to the existing platform.

- Chevron Typhoon Mini-TLP, Gulf of Mexico. Topsides conceptual and detailed design for mini-TLP platform in 2,000 feet of water. Flowrates are 40,000 bbl/day oil, 60 million SCFD gas and 15,000 bbl/day water. First oil achieved July 29, 2001.

- Benguela - Belize Compliant Tower, Offshore Angola. Conceptual and costing studies and front end engineering design for compliant tower in 1,300 feet of water. Mustang was the winner of a five company design competition for FEED work. Mustang Engineering is the exclusive marketing agent for, and is authorized to grant licenses under, ExxonMobil Upstream Research Company's U.S. Patent Number 4,696,603 "Compliant Offshore Platform," and corresponding patents in other countries.

- ExxonMobil Kizomba, Offshore West Africa. Main Instrument Control Contractor (MICC) for this FPSO project. Mustang teamed with Fisher- Rosemount to provide front-end design and will participate in detail design, commissioning and start up for all the topsides, hull and subsea automation systems.

- NCRA Automation and Clean Fuels Project, McPherson, Kansas. Modernization of the instrumentation for the #1 Crude Unit in NCRA's refinery in Kansas. Mustang is also providing engineering and procurement services for a major Clean Fuels project producing desulfurized gasoline, diesel and gas oil. The refinery has a capacity of 35,000 bbl/day oil.

- Columbia Gulf, Stanton Horsepower Addition, Stanton, Kentucky. Detail design, procurement, construction management and survey for this 15,000 HP centrifugal facility. The facility includes eight gas storage injection pipelines. The flowrates are 80 million SCFD.

- Gaso Ducto, Lasmos Basin, Argentina. Construction management and inspection services for 20-inch gas transmission line between Argentina and Chile. The highest Gas Transmission Line in the world: 17,783 feet above sea level.

- Gulf Liquids New River Project LLC, New Pipeline Installation, Louisiana. Project management, detail design, procurement, survey, environmental permitting, construction craft inspection and environmental inspection of two 80-mile, 12-inch natural gas pipelines. This project requires virtually every type of pipeline construction method, including directional drill, conventional bore, open cut, push and conventional land lay.

- Tennessee Gas Pipeline, Stagecoach Lateral, Loop, Compressor Station and Uprate, Owego, New York to Wyalusing, Pennsylvania. The project, a FERC 7(c) regulated natural gas expansion project

involves 23 miles of greenfield 30-inch lateral. Project includes a 12,000 hp compressor station; 6.5 miles of 24-inch uprate replacement, 3.6 miles of uprate hydro testing; and 100 MMCFD meter station and meter station uprating.

- Troy Construction/Port of Houston, Houston Ship Channel. Engineering services for relocation or removal of 59 pipelines out of a total of 96. Some of the owners include Air Products, Coral Energy, ExxonMobil, Enterprise, Seadrift and Teppco. This project is in conjunction with the widening and deepening of the Houston Ship Channel.

- HOVENSA, St. Croix, Virgin Islands. Process study, process design, detailed engineering and procurement services for revamping the crude and vacuum units, offsite storage and transfer systems. Engineering and procurement services for multiple upgrade projects to support a new delayed coker at HOVENSA.

- Tesoro Refining, Alliance Engineer and Hydrocracker Expansion Project, Alaska. Has recently been selected as Tesoro's contractor for performing Front-End Loading Activities for capital projects at all Tesoro refineries. Previous work includes revamp of an existing Hydrocracker Unit to process 12,500 BPSD of mixed atmospheric gas oil (AGO) and light vacuum gas oil (LVGO) feeds jet selective DH- 32 catalyst.

- Coastal Aruba Refining Company, N.V., Refinery Expansion and Modifications, San Nicolas, Aruba. Engineering and procurement services for multiple refinery capacity expansion projects, including a crude unit, flare unit, distillate hydrotreater, hydrogen unit, etc.

- Celanese Ltd., Engineering Alliance Contract. Engineering and procurement services for six Celanese Texas sites in Bay City, Bishop, Clear Lake, Corpus Christi, Pampa and Pasadena. Mustang will execute Celanese projects on site through Mustang's Professional Services Group, in the Houston home office and at a high-value engineering office in Romania.

- Valero Refining Company, FCC Unit Upgrade, Texas City, Texas. Process engineering, definitive estimate, design and detail engineering, project management, construction management, field engineering support, vendor data approvals, and all design specifications required to increase the capacity of the FCC and Gas-Con Units from 55,000 bbl/day to 80,000 bbl/day.

Black & Veatch Pritchard is the contractor for design of the regasification process equipment. Black & Veatch Pritchard has been active in LNG projects since the early 1950s and was involved in one of the earliest baseload facilities at Camel, Algeria. Since that time the company has been involved with approximately 20 percent of the world market and 15 percent of the United States and Canadian market for liquefaction and revaporization plants. These plants have a capacity of 15 billion cubic meters per year worldwide and 55 million cubic feet per day in the United States and Canada. Along with the project development expertise, Black & Veatch Pritchard developed a proprietary mixed refrigerant process (PRICO®), which has been successfully used in both baseload and peak shaving applications.

Black & Veatch Pritchard has technical and mechanical design expertise in the following critical areas:

- Large compressors, including electric steam and gas turbine drivers

- Low temperature equipment and materials

- Heat exchange equipment

- Low temperature instrumentation

- Low temperature insulation
- Cryogenic piping
- LNG pumping
- LNG storage and loading facilities.

Black & Veatch Pritchard's LNG project experience covers projects ranging from four million SCFD to over 800 million SCFD in both domestic and foreign locations:

| Project Type | Company | Location | Throughput |
|---|---|---|---|
| Peak Shaving Facility | Northern Natural Gas | Wrenshall, MN | 16 million SCFD |
| Peak Shaving Facility | Northern Natural Gas | Ventura, IA | 11 million SCFD |
| Peak Shaving Facility | Atlanta Gas & Light Co. | Macon, GA | 10 million SCFD |
| Peak Shaving Facility | Chattanooga Gas Co. | Chattanooga, TN | 10 million SCFD |
| Peak Shaving Facility | Northern Indiana Public Service Co. | LaPorte, IN | 10 million SCFD |
| Peak Shaving Facility | Alabama Gas Co. | Pinson, AL | 12 million SCFD |
| Peak Shaving Facility | Bay State Gas & Light Co. | Ludlow, MA | 6 million SCFD |
| Peak Shaving Facility | North Carolina Natural Gas | Fayetteville, NC | 4 million SCFD |
| Peak Shaving Facility | Philadelphia Gas Works | Philadelphia, PA | 12 million SCFD |
| Peak Shaving Facility | Transcontinental Pipeline | Hackensack, NJ | 7 million SCFD |
| Peak Shaving Facility | Associated Natural Gas co. | Blytheville, AK | 1 million SCFD |
| Peak Shaving Facility | Memphis Light, Gas and Water Div. | Arlington, TN | 6 million SCFD |
| Base Load Facility | Mobil | Floating | 1.0 billion SCFD |
| Base Load Facility | Texaco/Sonangol | Angola | 800 million SCFD |

| Project Type | Company | Location | Throughput |
|---|---|---|---|
| Base Load Facility | Texaco | Nigeria | 450 million SCFD |
| Base Load Facility | BP Exploration | Confidential | 467 million SCFD |
| Base Load Facility | Sonatrach Units 5 & 6 | Skikda, Algeria | 360 million SCFD |
| Base Load Facility | Enron | Venezuela | 370 million SCFD |
| Base Load Facility | Sonatrach Unit 40 | Skikda, Algeria | 180 million SCFD |
| Base Load Facility | CAMEL (Technip/Pritchard) | Arzew, Algeria | 180 million SCFD |
| Terminal | Korea Electric Co. | Seoul, Korea | 682 million SCFD |
| Terminal | Williams Field Services | Mangalore, India | 340 million SCFD |
| Terminal | Dynegy Midstream Services | Lake Charles, LA | 1,500 million SCFD |
| Terminal | Calpine | Confidential | 500 million SCFD |
| Terminal | Penuelas Power Project | Puerto Rico | 200 million SCFD |

SN Technigaz is the contractor for construction of the Terminal LNG storage tanks. SN Technigaz is one of the world's leading suppliers of liquefied gas facilities. Examples of LNG projects performed by SN TECHNIGAZ include:

- Hazira FEED (India)
- Damietta LNG Tanks (Egypt)
- Huelva LNG Tank (Spain)
- Bilbao Liquefied Natural Gas Import Terminal (Spain)
- Revithoussa Liquefied Natural Gas Import Terminal (Greece)
- Suape LNG Receiving Terminal (Basic Design) (Brazil)

- Shanghai LNG Peak Shaving (People's Republic of China)
- Qatargas LNG Storage Tanks (Qatar)
- Marmara Ereglisi Liquefied Natural Gas Import Terminal (Turkey)
- Montoir-de-Bretagne Liquefied Natural Gas Storage Tanks (France)
- Pyeong Taek Liquefied Natural Gas Receiving Terminal (Korea)

Aker Kvaerner Technology, AS is the contractor for the design of the GBS units. Aker's involvement in the design of GBS's originated with concrete platform projects in the North Sea Aker's experience ranges from pre-conceptual studies through complete engineering, procurement, construction, and installation (EPCI) projects to removal of redundant platforms In addition to its work in the U.S., Akers has international project experience in the United Kingdom (UK), Canada, and Australia Examples of Aker's experience are provided in the table below.

| Client | Location | Description |
|---|---|---|
| Confidential | United States | Concept development of GBS based LNG receiving terminal for storage and regasification of LNG in Gulf of Mexico |
| Chevron Texaco | United States | Concept screening and development of alternative concepts (fixed and floating) for storage and regasification of LNG |
| Phillips / Bechtel | West Africa | Concept development to determine design viability of a GBS based LNG & LPG production plant with storage and offloading to LNG cargo carriers. Work included concepts screening, design development, construction methodology, schedule and cost estimation. |
| Statoil | West Africa | Concept development study of a turret moored concrete FPSO for LNG, LPG and condensate production. Construction methods and estimates based on local construction alternatively construction in Europe |
| IHI/BP | India | Development of an offshore GBS for LNG storage and regasification facility design in cooperation with IHI including construction methodology, schedule and cost. |
| Texaco | Confidential | Development of an offshore concrete GBS for storage and regasification of LNG for a preferred site outlining the storage system based on IHI SPB tanks, LNG carrier berthing and fendering arrangement for LNG carriers, and transport and assembly methods based on construction in different locations. Estimates of cost and schedule. |

| Client | Location | Description |
|---|---|---|
| Esso | Australia | Engineering and construction management support for the delivery of the GBS for West Tuna. Water depth: 61 m, Concrete: 18,000 m³. |
| Esso | Australia | Engineering and construction management support for the delivery of the GBS for Bream B. Water depth: 61 m, Concrete: 18,000 m³. |
| HMDC / Mobil | Grand Banks | Awarded the GBS Construction Management Contract and the marine operations for the execution of the Hibernia GBS project |
| BP | UKCS | Engineering and construction management support for the delivery of the oil storage and foundation structure for the Harding field. Installation by Aker under separate contract. Water depth: 106 m, Concrete: 35,000 m³. |
| Conoco | Norway (Halten-banken) | Engineering, procurement, construction and installation (EPCI) delivery of the concrete tension leg platform (TLP) for the Heidrun project including modifications, maintenance and operations (MMO); mooring foundations design; and marine operations. Water depth: 345 m, Concrete: 66,000 m³, Well slots: 58 |
| Shell | Norway (NCS) | EPCI delivery of the Condeep substructure for the Troll gas platform project including MMO and marine operations. Water depth: 303m, Concrete: 225,000 m³, Well slots: 40, The largest object moved by man |
| Saga | Norway (NCS) | EPCI delivery of the Concrete Foundations for the Snorre TLP including outfitting and installation. Water depth: 310 m, Concrete: 8,000 m³ |
| Shell | Norway (Halten-banken) | EPCI delivery of the Condeep substructure for the Draugen platform including MMO and marine operations. Water depth: 252 m, Concrete: 75,000 m³, Well slots: 10 |
| Statoil | Norway (NCS) | EPCI delivery of the Condeep substructure for the Sleipner A platform including marine operations. Water depth: 83m, Concrete: 75,000 m³, Well slots: 32 |
| Statoil | Norway (NCS) | EPCI delivery of the Condeep substructure for the Gullfaks C platform including MMO and marine operations. Water depth: 220 m, Concrete: 240,000 m³, Well slots: 42 |

Quest Consultants, Inc. is the contractor for dispersion calculations and qualitative risk analysis of LNG spills. Quest is an engineering firm specializing in process safety and risk management analysis for the petroleum and chemical industries. Examples of projects completed by Quest include:

- Vapor Dispersion and Fire Radiation Modeling:

  - Yung-An LNG Import Terminal; Taiwan Provided consulting services on all safety aspects during the design of this baseload receiving terminal. This included predicting the extent of hazard zones from potential LNG spills and fires.

  - Memphis Light, Gas, and Water; Memphis, Tennessee Calculated vapor dispersion and fire radiation hazard zones as part of a study of the feasibility of constructing another LNG storage tank at an existing peakshaving plant.

  - TransCanada Pipelines; Melford Point, Nova Scotia, and Gros Cacouna, Quebec, Canada Calculated vapor dispersion and fire radiation hazard zones as part of the site selection process for a proposed LNG receiving terminal.

  - ENEL; Montalto di Castro, Italy In charge of most safety aspects of this proposed baseload import terminal, including vapor dispersion and fire radiation modeling.

  - P.T. Badak Natural Gas Liquefaction Co.; Bontang, Indonesia In charge of most safety aspects of this large LNG facility during all expansion phases. This included initial and projected facility layout, flare placement, and predicting the extent of hazard zones from potential LNG spills and fires.

  - Trunkline LNG Import Terminal; Lake Charles, Louisiana Provided consulting services on all safety aspects during the design of this baseload receiving terminal. This included predicting the extent of hazard zones from potential LNG spills and fires.

  - Rim Gas Project (Petro-Canada); Bish Cove, British Columbia, Canada Calculated vapor cloud and fire radiation hazard zones for spills of LNG onto water.

  - Western LNG Associates; California and Alaska Provided consulting services on all safety aspects during the design of three baseload receiving terminals and one baseload liquefaction plant.

  - Phillips-Marathon; Kenai, Alaska Calculated vapor cloud and fire radiation hazard zones associated with proposed plant expansion.

  - Western LNG Project (Dome Petroleum); Grassy Point, British Columbia, Canada In charge of most safety aspects of this proposed liquefaction and export terminal, including vapor dispersion and fire radiation modeling.

  - Pritchard/KEPCO; Pyeong Taek, South Korea Calculated vapor cloud and fire radiation hazard zones during the siting and conceptual design phase of this baseload receiving terminal.

  - Southern Natural Gas Co.; Elba Island, Georgia Provided consulting services on all safety aspects during the design of this baseload receiving terminal. This included predicting the extent of hazard zones from potential LNG spills and fires.

- Bechtel/Phillips/Atlantic LNG; Point Fortin, Trinidad Calculated vapor cloud and fire radiation hazard zones during the siting and conceptual design phase of this LNG liquefaction plant and export terminal.

- Consumers' Gas Company Ltd.; Ontario, Canada In charge of most safety aspects of a proposed LNG peakshaving plant, including modeling of vapor dispersion and fire radiation hazard zones during the site selection process.

- Yukon Pacific Corp. (YPC); Anderson Bay, Alaska In charge of most safety aspects of this proposed baseload liquefaction and export terminal, including vapor dispersion and fire radiation modeling.

- Wisconsin Gas Company; Milwaukee, Wisconsin Calculated vapor cloud and fire radiation hazard zones during the siting phase of this proposed peakshaving plant.

- Dabhol Power Company; India Calculated vapor cloud and fire radiation hazard zones during the siting phase of this proposed receiving terminal.

- Bechtel/Phillips; Darwin, Australia Calculated vapor cloud and fire radiation hazard zones during the siting and conceptual design phase of a proposed LNG liquefaction plant and export terminal.

- Quantitative Risk Analyses:

  - LNG Import Terminal; East Coast of Mexico Quantitative risk analysis of proposed LNG import terminal to determine the risk potentially posed on workers and the public.

  - LNG Import Terminal; West Coast of Mexico Quantitative risk analysis of proposed LNG import terminal to determine the risk potentially posed on workers and the public.

ABS Consulting, Inc. is the contractor for the energetics study of the GBS units. ABS is a recognized expert in evaluating energetic events and analyzing structural performance of structures due to these events.

Sandwell Engineering, Inc. is the contractor for wave and Metocean studies and marine engineering. Sandwell has an international reputation in coastal and marine works. Sandwell's coastal and ocean engineering group is recognized world wide for providing engineering and management services specializes in the following areas:

- metocean studies;

- wave analysis, hindcasting and forecasting;

- wave force analysis;

- erosion and sedimentation studies;

- scour protection;

- vessel motion analysis;

- oceanography/metereologic analysis;

- breakwater and shoreline protection; and

- dredging and land reclamation.

Examples of projects completed by Sandwell involving the evaluation of metocean conditions and definition of design parameters for marine/offshore terminals include:

- Orlan Project. Exxon/Mobil gravity based structure
- Sakhalin Energy. PA-B and Lunskoye fields offloading marine structures
- Sakhalin Energy. Tanker loading unit
- Northstar Project, BP Amoco Company, Beaufort Sea, Alaska
- Funiwa LPT storage and offloading terminal validation, Texaco Inc. Nigeria
- Mobil, Chevron and PetroCanada, Whiffen Head Newfoundland
- Bontang Marine Terminal, Indonesia
- Antamina Marine Terminal, Peru,
- Talara marine Oil Terminal, Peru
- Pisco LPG Terminal, Peru
- LNG Receiving Terminal Study, New Brunswick, Canada
- NAWC LNG Terminal Study, Baja California, Mexico

ENTRIX, Inc. is the contractor responsible for preparation of the application for the deepwater port license, NEPA studies, and water discharge modeling. ENTRIX is a full-service environmental consulting firm providing expertise in the areas of environmental engineering, geosciences, and environmental sciences. ENTRIX staff includes environmental, mechanical, chemical, process, petroleum, and civil engineers; geologists, hydrologists, and oceanographers; marine, aquatic, and terrestrial biologists and ecologists; chemists; toxicologists; economists; planners; and regulatory experts.

Selected examples of ENTRIX project experience, with emphasis on offshore and pipeline system projects include:

- Calypso Pipeline Project — FERC Third-Party environmental impact statement (EIS) — Florida (offshore and onshore)
- Gulfstream Pipeline Project — FERC Third-Party EIS — Mississippi, Alabama, Gulf of Mexico, Florida
- Plains Resources. Point Arguello Platforms Grace and Gail — Environmental Review — offshore California
- Chevron Pipeline. Estero Marine Terminal — Benthic Biota Sampling — offshore California
- Plains All American Inc. Equilon Submarine Pipeline — EA — offshore California
- Trinidad Shell Exploration and Production B.V. Trinidad and Tobago offshore Block 25(a) — Offshore EIA — Trinidad

- Conoco U.K. Ltd. Barbados. Offshore Exploratory Drilling — EIA — Barbados
- Commonwealth of Puerto Rico. San Juan Harbor Oil Spill — Spill Response and NRDA Preparation, Puerto Rico
- ARCO Mozambique (Sofala) Ltd. Offshore Exploration Drilling — EIA — Mozambique
- Williams Gas Pipelines-Transco. Momentum Expansion Project — FERC Environmental Report and Applicant-Prepared Draft Environmental Assessment, Permitting — Mississippi, Alabama, Georgia, South Carolina, North Carolina
- Williams Gas Pipelines-Transco. Sundance Expansion Project — FERC Environmental Report, Permitting — Mississippi, Alabama, Georgia, North Carolina
- Coral Mexico Pipeline LLC Coral Mexico Pipeline — FERC Environmental Report, Permitting (including Internatinal Boundary and Water Commission application) — Texas
- Patriot Project — FERC Third-Party Environmental Impact Statement (EIS) — Tennessee, Virginia, North Carolina
- Greenbrier Pipeline Project — FERC Third-Party EIS — West Virginia, Virginia, North Carolina
- Florida Gas Transmission Phase IV Expansion Project — FERC Third-Party EIS — Mississippi, Alabama, Florida
- Kern River Gas Transmission. Kern River Expansion Project — FERC Environmental Report — Wyoming, Utah, Nevada, California
- Vector Pipeline Project — FERC Third-Party EIS — Illinois, Indiana, Michigan
- Great Lakes 300 Expansion Project — FERC Third-party EIS — Minnesota, Wisconsin, Illinois, Michigan
- Viking Voyageur Pipeline Project — FERC Third-party EIS — Minnesota, Wisconsin, Illinois
- California State Lands Commission. Southern Trails Pipeline Project — Mitigation Monitoring.
- INGAA (Interstate Natural Gas Association of America) Foundation — FERC Pre-Filing Coordination Study.
- INGAA Foundation — Report on Stakeholder Involvement
- INGAA Foundation — Study on Coordinating Federal Agency Reviews in the Environmental Approval Process
- Centennial Pipeline LLC Centennial Pipeline — Environmental Permitting — Louisiana, Arkansas, Mississippi, Kentucky, Tennessee, Illinois
- Yellowstone Pipe Line — EIS Consultant for Pipeline Reconnection and Repermitting Project — Montana
- El Paso Corporation, Pipeline Group — Environmental Compliance Handbook

- Great Lakes Gas Transmission, Colorado Interstate Gas, and ANR Pipeline — Environmental Compliance Manual

- Tenneco Energy. Compressor Stations — Water Management Systems — Texas, Louisiana, Mississippi, Ohio, New York, and Pennsylvania

- Transcontinental Gas Pipe Line Corporation. Compressor Stations — Wastewater and Stormwater Management — Gulf Coast and Eastern United States

- Texas Eastern Transmission Co. Compressor Stations — NPDES Permit Applications — Gulf Coast and Eastern United States

## 1.4 Address for Service of Documents

Port Pelican LLC
Suite 2700
1111 Bagby Street
Houston, TX 77002

Section
2

# 2 Deepwater Terminal Data

## 2.1 Terminal Location and Use

### *2.1.1 Location and Use*

Port Pelican Terminal will be located in the U.S Gulf of Mexico in approximately 83 feet of water.

The Port Pelican Project will deliver natural gas to the United States Gulf Coast using existing gas supply and gathering systems in the Gulf of Mexico and southern Louisiana. Gas will then be delivered to shippers using the national pipeline grid through interconnections with major interstate and intrastate pipelines. A significant volume of natural gas will be provided to the Louisiana market area as a result of this project, which will also improve the efficiency and flexibility of the existing pipeline infrastructure, and provide supply diversification while minimizing environmental impacts.

The Port Pelican Project (the Project) consists of the Port Pelican Terminal (the Terminal), a Liquefied Natural Gas (LNG) receiving, storage and regasification facility and the Pelican Interconnector Pipeline (PIPL) to transport the gas to the existing offshore gas gathering system.

Port Pelican Terminal will consist of two concrete gravity based structure (GBS) units fixed to the seabed, which will include integral LNG storage tanks, support deck mounted LNG receiving and vaporization equipment and utilities, berthing accommodations for LNG carriers, facilities for delivery of natural gas to a pipeline transportation system, and personnel accommodations.

The Terminal will be able to receive the largest LNG carriers in service or on order in 2002. LNG carrier arrival frequency will be planned to match specified terminal gas delivery rates. All marine systems, communications, navigational aids and equipment necessary to conduct safe LNG carrier operations and receiving of product during specified atmospheric and sea states will be provided at the port.

The regasification process consists of lifting the LNG from storage tanks, pumping the cold liquid to pipeline pressure, subsequent vaporization across heat exchanging equipment and finally, send out through custody transfer metering to the gas pipeline network. No gas conditioning is required for the Terminal since the incoming LNG will be pipeline quality.

A 42-inch diameter offshore Pelican Interconnector Pipeline traversing 37 nautical miles (NM) will be constructed as part of the Pelican Project. The PIPL will transport gas from the Terminal to a point near the Tiger Shoal Platform “A” where it will connect to the Henry-Floodway Gas Gathering System (HFGGS). The HFGGS will deliver the gas to the onshore U.S. gas pipeline network.

The Terminal will be constructed in two phases. Phase I includes the installation of two GBS structures with internal storage tanks and facilities for LNG offloading, send out and vaporization to deliver a peak 1.0 billion standard cubic feet per day (SCFD) of natural gas to pipeline. Additional

vaporization equipment and associated support equipment and facilities will be installed during Phase II to increase the facility vaporization and send out rate to 2.0 billion SCFD peak.

### *2.1.2 Lease Blocks Identification, Ownership Interests, and Use*

Port Pelican Terminal will be located in the U.S Gulf of Mexico. The proposed LNG carrier (LNGC) route and gas pipeline corridor are shown in Map 1 and Map 2. Existing structures in the vicinity of the Port Pelican Project are also shown on Map 1.

A total of 61 blocks will be involved in the Project. Of these blocks, MMS records obtained by the Applicant indicate that 34 blocks are not leased. The proposed use of the blocks is as follows[1]:

- Port Pelican Terminal; one block total, this block is not leased.
- LNGC route, safety zone, and anchorage; 41 blocks total, 28 blocks are not leased, 13 blocks are leased.
- PIPL; 23 blocks total, 11 blocks are not leased, 12 blocks are leased.

The lease blocks involved in the Project and the current leaseholders are identified in Table 2.1-1.

In addition to lease blocks crossed by the pipeline route for the PIPL identified in Table 2.1-1, other blocks could be involved in pipeline routing for the Project depending on the manner in which third parties are connected. Should third-party interconnects be made, additional pipelines might be installed by the Applicant to connect to third-party pipelines. Alternatively, a third-party might install an interconnecting pipeline that connects directly to a meter station at the Terminal. At this time, there are no firm interconnection plans other than the PIPL. A request will be submitted to the Commandant in the event that the Applicant wishes to install additional interconnecting pipelines.

The primary existing use of the Project area is for exploration and production of oil and gas. The concentration of leased blocks increases towards the coastline. As a result, there is a higher frequency of leased blocks along the PIPL corridor than along the proposed vessel route. No other economic mineral exploration or production has taken place on the blocks that will be part of this Project (Section 5.2.2.5, Potentially Important Uses). Limited ship traffic and fishing (commercial and/or sport fishing) may occur on some of the Project blocks (Section 5.2.4, Land Use and Coastal Zone Management).

### *2.1.3 Pipelines and Rights-of-Way Crossings*

A preliminary route survey and route selection was completed during preliminary engineering. Subsea hazards, pipeline and cable crossings, and other obstructions have been analyzed using reasonably and readily available existing data. The selected pipeline route was chosen on the basis of its constructability and its minimization of environmental impacts.

The PIPL will cross 13 existing pipelines (Map 2). Owners of the 13 existing pipelines are also liste on Map 2. Prior to initiating construction activities, a detailed pre-construction hazard survey will be executed to identify underwater hazards in the pipeline route and the exact location of subsea cable or pipeline crossings. Should a hazard be identified, it will be avoided. Remote Operated

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[1] Two blocks are counted more than once in the summary because they have more than one use for the project. Refer to Table 2.1-1 for the uses of these two blocks.

Vehicles (ROV's), as well as divers will be used to locate and monitor these pipeline crossings during construction of the PIPL.

## 2.2 Overall Site Plan

See Map 1 and Figure 1.1-21 for maps of the marine fairways and Port Pelican Terminal vicinity.

## 2.3 Site Plan for Marine components

### *2.3.1 Proposed Size and Location of Marine Components*

See Figure 1.1-3 for the proposed size and location of marine components for the Port Pelican Project.

### *2.3.2 Charted Water Depths*

Existing bathymetry at the Terminal site is limited to available nautical charts with 20 and 10 fathom contours given for the general area. NOAA Chart 11340 was the main chart used.

### *2.3.3 Reconnaissance Hydrographic Survey*

A reconnaissance hydrographic survey of the Terminal area (**CONFIDENTIAL–SENSITIVE INFORMATION**) utilized digital and analog echosounder records to assess bathymetry to a depth of plus or minus two feet. Water depth was found to range from about 79 feet in the north to 86 feet in the south. The sea floor is generally featureless, sloping south-southwest at a rate of 1.5 to 2.0 feet per mile. No evidence of surface fault scarps or significant slopes were found in the block during this study.

## 2.4 Soil Data

Soil characteristics in the Terminal area were investigated using geophysical instruments (echo sounder, side-scan sonar, magnetometer, sub-bottom profiler, and 2-D multi-channel airgun) along with piston coring (**CONFIDENTIAL–SENSITIVE INFORMATION**).

The sea floor in the Terminal area consists of less than one foot to five feet of Holocene sediments (sediments deposited in the last 10,000 years) deposited unconformably on a surface of older sediments that were highly dissected by erosion during an earlier low level sea stand. The near surface sediments are generally composed of a complex mixture of fine-grained shallow marine, estuarine, or overbank sediments (clays) and buried channels comprised of silts and sands.

The geological complexity of the sea floor sediments leads to a similar complexity in geotechnical characteristics throughout the block. Favorable conditions for siting of the Terminal were found at a number of locations within the lease block, which are dominated by horizontal clay strata that have not been subject to incision by channels. The less favorable areas do not appear to preclude siting of the Terminal. Data describing sediment characteristics found within the Terminal area can be found in TR-6 (Geological Resources) of the Environmental Report.

A detailed site investigation involving soil borings and in situ testing is planned for the Terminal site to delineate geotechnical conditions in more detail. These data will then be used to design the Terminal foundation.

## 2.5 Operational Information

### *2.5.1 LNG Carrier Data*

Typical design characteristics of current and anticipated future LNG carriers are listed in Table 2.5-1.

The construction of the typical vessels will be in conformity with the requirements of the IMO code for existing ships carrying liquefied gases in bulk.

The vessel characteristics presented in Table 2.5-1 do not necessarily represent those vessels that will eventually be used, since vessels will be chartered according to shipping requirements and availability on the world market. However, it will be the Terminal's duty to evaluate all vessels calling at the Terminal prior to entering into a commercial contract for LNG delivery. All LNG vessels using the Terminal will be required to meet the Terminal's standards to ensure the highest level of operational safety.

All LNG carriers arriving at the Terminal will be required to comply with current USCG anti-pollution regulations. LNG carriers unloading at the Terminal will be outfitted with either membrane or Moss® spherical cargo tank containment systems.

During offloading operations, all the cargo is discharged except for retained heel required for tank cooling during the return voyage. The resulting change in draft is typically very small.

LNG carriers outfitted with a membrane cargo tank system have a slight advantage during maneuvering operation because of less windage area than the Moss® tankers with large spherical cargo containment system. The impact of LNG carrier sail area during berthing and un-berthing will be reviewed during the maneuvering study and threshold limits determined accordingly.

### *2.5.2 Wind, Waves, and Currents Forecasting*

Wind and wave data for the Project area are detailed in a study prepared for this project (October 2001**CONFIDENTIAL–SENSITIVE INFORMATION**). These data are considered sufficient for conceptual design; however, site-specific data will be obtained for the final design.

A sustained wind velocity in excess of 22.5 knots is infrequent (less than 10 percent). Statistically, there are fewer than 29 days per year of winds exceeding 22.5 knots, with the worst months being January through March and August through September. The majority of winds exceeding 22.5 knots approach from the north sector during winter storms. Hurricanes would normally approach from the south or southeast direction and could result in winds and swell above statistical maxima.

Wave heights above two meters are exceeded 10 to 15 percent of the time. Peak wave periods are generally below 10 seconds with the majority between four to six seconds. Waves approach from all directions, with a slight prevalence from the south and southeast.

The extreme waves used as the design waves for structural analysis were taken from the ocean weather extreme wave data. The extreme wave climate at the LNG berth is shown in the tables

below. Extreme waves above two meters approach most predominantly from the north-northeast and south-southeast directions.

The 100-year design sea height (maximum run-up) would impact the south-southeast face of the LNG berth as a result of hurricane peak intensity. The resulting total run-up in elevation above Low Astronomical Tide (LAT) is estimated at 17.5 m. This is the maximum water surface elevation predicted. Further optimization of the Terminal deck elevation will be undertaken during design phase.

Currents in this area are expected to flow parallel to shore. The U.S. Coast Pilot 5 indicates that currents inside the 100-fathom contour from South West Pass to Sabine Pass are westerly (flow to the west) at approximately 0.25 knots. Currents increase with easterly winds and decrease (though rarely reverse) with westerly winds. Operational current data will be obtained to confirm this prediction. An analysis of extreme currents experienced during winter storms and hurricane events show the predominant wave direction towards the west at generally less than one knot (except during hurricanes).

The maximum tidal range for the area is approximately two feet (0.6 m).

### *2.5.3 Design Meteorological and Oceanographic Parameters*

| | |
|---|---|
| Temperature: | |
| Design Dry Bulb maximum, °F | 92 |
| Design Dry Bulb minimum, °F | 33 |
| Design Wet Bulb maximum, °F | 79 |
| Saline air | Yes |
| Rainfall: | |
| Rainfall, inches/hour | |
| 10 years | 3.5 |
| 25 years | 3.9 |
| 50 years | 4.3 |
| Rainy season | Summer |
| Seawater: | |
| Design Temperature at Surface | |
| Maximum | 87ºF |
| Mean | 74ºF |
| Minimum | 58ºF |
| Wind | |
| Maximum Design Wind Speed | 37.9 m/s (220 mph) for 100-year hurricane |
| Prevailing wind speed and direction | **CONFIDENTIAL–SENSITIVE INFORMATION** Gulf of Mexico LNG Receiving Terminal – Wave Climate Study ; Sandwell, Inc; October 2001 |

### *2.5.4 Operating Limits*

An “all bulletin” warning will be broadcast as soon as dates and times are known of LNG carrier movements. During actual transiting of the Fairways and corridor, a regular up-to-date location of the LNG carrier will be broadcast to all marine traffic in the area.

The operating limits for the Terminal will be verified by computer analysis and maneuvering simulator. The practical limits anticipated at this time are listed in the Tables 2.5-5 and 2.5-6.

Speed limits will be established based on detailed studies to be performed to ascertain the direction and optimum speed for the LNG carrier to approach the berth and assistance provided by three tugs. A speed limitation will be in place within the safety zone (within a 6,800-foot radius of the Terminal) to take into account the design energetics of the Terminal structure and protective features employed.

In preparing these studies, detailed Metocean data will be input for a real-time maneuvering simulation to ascertain a LNG carrier's approach and berthing operation. Although LNG carrier displacement will vary slightly, the cargo containment system, whether Moss® spherical or membrane type, will represent another factor because of the different wind areas. Various propulsion systems will also be considered (steam or diesel) and single- or twin-engine propulsion.

The proposed studies will be conducted with experienced marine pilots to confirm the safe approach speed, tug use, and optimum angles for different ship displacements, cargo tank arrangements and propulsion system. Confirmation of these results will be undertaken prior to project detailed design.

## *2.5.5 Fixed and Floating Offshore Components*

### ***2.5.5.1 Component Descriptions***

With the exception of floating tug mooring buoys, all offshore components of the Port Pelican Project will be fixed.

The Terminal will be comprised of two GBS units (Figure 2.3-4) with internal storage tanks and facilities for LNG offloading, send out, and vaporization to deliver a peak 1.0 billion SCFD of natural gas to pipeline. Additional vaporization equipment and associated support equipment and facilities will be installed during Phase II on the existing GBS units to increase the facility vaporization and send out rate to 2.0 billion SCFD peak.

The process at the Terminal will consist of offloading LNG from ocean going vessels to storage tanks, lifting the LNG from storage tanks, pumping the cold liquid to pipeline pressure, subsequent vaporization across heat exchanging equipment and finally, send out through custody transfer metering to the US gas pipeline network. Send out gas will enter the pipelines directly with no gas conditioning.

The Terminal is designed with facilities for 50 persons.

#### *2.5.5.1.1 Gravity Based Structures (GBS)*

The Terminal structure will be composed of two GBS units. The GBS units will be constructed of concrete, towed to the Terminal location, and sunk to rest on the ocean bottom. GBS units have been used to support offshore facilities for more than 30 years. Concrete construction is adaptable to extreme cold temperatures and will not be affected by contact with LNG.

The GBS units will be double-walled concrete structures, rectilinear in shape, and include integral LNG storage tanks, facilities for receiving LNG, vaporization equipment, electric power generation, water purification, nitrogen generation, sewage treatment, crew quarters, and maintenance facilities. Each GBS will be made of reinforced concrete, and will measure approximately 210 feet by 500 feet in plan view and 149 feet in height, with approximately 66 feet of freeboard. The GBS units will be located in a water depth of 83 feet.

An integrated LNG tank with gross storage capacity of 43,588,409 gallons (165,000 $m^3$) will be inside of each GBS. The GBS units are designed to resist 100-year hurricane environmental loads, a seismic load of 0.05 g and topside loads such as operational, vehicle loads, vessel collision, dropped objects, and explosion. Design parameters for the GBS units are provided Table 2.5-7.

The GBS units will be placed end to end with a minimum separation of 100 feet in order to provide adequate sheltering for the berthing of the largest LNG carrier. Two personnel bridges and one roadway bridge will span the space between the two GBS units. The personnel bridges are designed for a live load of 150 pounds per square foot (psf) with an impact factor of 1.5, while the roadway bridge is designed for the movement of a truck crane weighing 24 tons capable of carrying a load of 20 tons at a boom outreach of 3.5 m. The uniform design load over the roadway bridge is 300 psf and the impact factor is 1.5.

The personnel bridges will be at least 15 feet wide while the roadway bridge will be at least 30 feet wide (to accommodate the truck width). The roadway bridge will also have a personnel passage way for emergency movement.

The GBS units will be oriented perpendicular to the predominant wind and wave directions. An emergency flare will be located at one end of the Terminal and a quarters building will be located at the other end.

The freeboard of the GBS will be at least 66 feet. This will result in a topside elevation above the wave run up during an extreme storm or hurricane. If needed, a deflector will be installed to ensure that no wave or water spray can flood the topside.

The GBS units will be installed to rest on the ocean floor. The soil foundation will support the GBS units and will not allow them to slide, overturn or settle excessively over a long period, nor have excessive differential settlement. The base of the GBS units will be level. If the foundation is constructed separately from the main body of the GBS units, the mating mechanism will ensure that the mated structure performs as one monolithic structure during its operational life.

#### *2.5.5.1.2 LNG Carrier Offloading*

The Terminal's offloading facilities are designed to accommodate LNG carriers ranging in capacity from 100,000 $m^3$ to 160,000 $m^3$. Ships can be berthed and unloaded on either side of the Terminal. Two loading arm packages are provided, one on each side of the Terminal. Each package includes four 16 inch loading arms, two liquid arms, one vapor arm, and one arm that will normally be used for liquid, but can be used for vapor if the vapor arm is damaged. Using only two arms for liquid will result in a reduced offloading rate.

LNG carriers typically will be offloaded at a rate of 12,000 $m^3$/hr of LNG through the liquid loading arms and stored in the LNG storage tanks at a temperature of approximately minus 250°F. During offloading, most of the displaced vapor from the LNG storage tanks will be desuperheated by injection of a small amount of LNG and returned to the LNG carrier through the vapor arm to maintain LNG carrier pressure. The Terminal storage tanks will operate at slightly higher pressure than the LNG carriers to allow the return vapors to be pressured back to the LNG carrier without the use of a blower.

During the periods when LNG carriers are not being offloaded, LNG from the Terminal storage tanks will be circulated through the offloading piping system to keep it cool, and minimize the need for cool-down prior to LNG carrier arrival.

#### *2.5.5.1.3 LNG Storage*

The Terminal will have two integral LNG storage tanks. Each LNG tank will have a nominal capacity of 43,588,409 gallons (165,000 $m^3$). The tanks are designed to limit LNG boil off to less than 0.1 percent during steady state conditions. Each LNG storage tank will consist of an insulated, stainless steel or aluminum primary tank constructed within the concrete interior of the GBS, which provides secondary containment for the tanks. The storage technology for the primary LNG tanks will be a membrane design.

Cryogenic submerged pumps inside the tanks will transfer LNG from the storage tanks to the suction of the LNG send out pumps. The LNG tank pumps will be high-volume, low-head pumps, and provide sufficient net positive suction head (NPSH) for the deck-mounted, high-pressure LNG send out pumps. Each submerged pump is designed for 4,300 gallons per minute (GPM) with a differential head of 80 psi. This provides three 50 percent capacity pumps per tank initially and four 25 percent capacity pumps per tank when the Terminal reaches its planned design capacity.

#### *2.5.5.1.4 Boil-Off Gas Compression*

LNG is vaporized in the tank by heat picked up from the surroundings and by changes in the fluid composition when LNG is off loaded into the tank from LNG carriers. This vapor is referred to as boil-off gas. During steady state conditions, the boil-off gas rate is approximately four million SCFD. This rate rises to approximately 10 million SCFD during LNG carrier off loading. Boil-off gas will be:

- used to supply vapor to the LNG carrier to fill the void left when the liquid is pumped out;
- used for fuel gas; and
- compressed and condensed and combined with the LNG for vaporization.

Boil-off gas will be compressed to approximately 70 psig, and routed to the boil-off gas condenser. Compressed boil-off gas is condensed by mixing with a portion of the cold LNG being pumped out of the LNG storage tanks. The LNG leaving the bottom of the condenser is then combined with the main flow from the in-tank LNG pumps and flows to the suction of the LNG send out pumps.

Two 100 percent boil-off gas compressors will be provided so that a spare is always available.

#### *2.5.5.1.5 LNG Send Out/Vaporization*

Ultimately, two parallel trains, each with a peak capacity of 1.0 billion SCFD will be provided to vaporize the LNG and deliver natural gas to the pipeline at a pressure of up to 1,440 psig. One train will be installed in Phase I, and the second train installed during Phase II.

Each of the 1.0 billion SCFD trains will be comprised of six 200 million SCFD trains (one LNG send out pump, open rack vaporizer (ORV) and seawater lift pump in each 200 million SCFD train). For the peak send out rate, five of the six trains will be operating and one will be spare. For reliability, the 200 million SCFD trains will be configured so that one train can be taken offline for maintenance while the other units remain in operation.

Open rack vaporizers heat the LNG by exchanging heat with sea water. Sea water is pumped to the top of each ORV and flows down the outside of the panels. High pressure LNG flows upward through the tubes inside the panels and is warmed to approximately 35°F. In so doing, the sea water is cooled by approximately 20° F and returned to the Gulf, following aeration and chemical treatment (if necessary).

The LNG send out pumps will have a capacity of 1,725 GPM (200 million SCFD) per pump. Each ORV is capable of vaporizing 200 million SCFD of LNG. Each seawater lift pump has a capacity of 12,250 GPM to vaporize 200 million SCFD.

*2.5.5.1.6 Flare System*

Two flare systems will be provided at the terminal for the safe disposition of hydrocarbon relief streams. One system will handle high pressure relief sources and one system will handle low pressure relief sources. Each flare will be equipped with multiple pilots and electronic igniters. The flare headers will be continuously purged with nitrogen to prevent air infiltration through the flare tips.

The flares will be mounted on a flare tripod jacket located 300 feet away from the edge of the GBS. The flare will be approximately 175 feet above the elevation of the Terminal. A bridge designed for the required piping load and a live load of 150 psf will connect the flare tripod to the Terminal.

*2.5.5.1.7 Gas Metering*

Natural gas from the vaporizers will be metered before entering the gas pipeline. Each outgoing pipeline will have a custody transfer metering station. Metering capacity for each pipeline will be 1.0 billion SCFD for Phase I and 2.0 billion SCFD for Phase II.

*2.5.5.1.8 Sea Water for Vaporization*

Sea water will flow through intake screens to eliminate debris and marine life before being pumped to the vaporizers through strainers. To control biofouling, sodium hypochlorite will be injected into the pump suction to achieve a free chlorine concentration of 0.2 ppm. In addition, each pump will be shocked for 20 minutes three times per day at a level of 2.0 ppm free chlorine.

The treated sea water will flow through independent lines to the top of the Open Rack Vaporizers where it will be cooled approximately 20° F by exchanging heat with high pressure LNG from the send out pumps. The sea water will then flow from the bottom of the ORVs into a trench routed to the sea water outfall and returned to the Gulf of Mexico.

*2.5.5.1.9 Utility and Potable Water Systems*

Sea water for the utility and potable water systems will be supplied by two 100 percent electric motor driven utility seawater lift pumps. The seawater will enter the lift pumps through coarse intake strainers. Downstream of the pumps, the seawater will be strained with self-cleaning strainers. The seawater header pressure will supply a minimum of 30 psig at the highest point on the facility. The pumps will feed the hypochlorite system, potable water system, and utility stations.

Two 100 percent hypochlorite generators will supply hypochlorite injected at the suction of each seawater and fire water pump to control the growth of marine life in the pumps, piping, and downstream equipment. The hypochlorite generators will also furnish hypochlorite for treating sewage and for chlorination of potable water.

Two, 50 percent reverse osmosis type water makers will be used to produce potable water from seawater. Potable water will enter directly into the potable water tanks while reject water (approximately 70 to 80 percent of the inlet volume) will be returned overboard. The potable water will be chlorinated, sterilized and collected in one of two, 200-bbl storage tanks and distributed on demand from a potable water pressure set. The potable water system is sized based upon current and future manpower loading forecasts of the facility and other known and probable users of potable water. Intermittent users such as safety showers were not considered in the sizing of the continuous supply requirements.

At a minimum, potable water will meet the World Health Organization's standard for potable water. The system will be designed to prevent contamination of the potable water system. Any connections to non-sterilized systems will be via a backflow preventer to prevent contamination of the potable water system. Flushing connections for long runs of piping will be provided to allow replenishing the water in the line with newly sterilized water. Periodically one of the tanks will be taken out of service for cleaning.

Connections will be provided at the utility stations to provide wash down water for the facility. A portable pneumatic wash down unit will allow for high pressure wash down.

*2.5.5.1.10 Power Generation (Main, Emergency)*

Main electrical power for the Terminal will be generated at the 13.8 kV voltage level supplied by three, 50 percent gas turbine driven generators. Gas will be supplied by the Fuel Gas System (described below).

The emergency power service will be 480 VAC and supplied by two diesel engine driven generators. Each emergency generator will be equipped with a diesel day tank. The uninterruptible power supply (UPS) system will supply power to process control instrumentation, programmable logic controllers, computers, and communication equipment for up to 3.5 hours.

Power distribution will be at three voltage levels: 4160 VAC, 480 VAC and 208/120 VAC. Power will be distributed through switchgear and motor control centers (MCC) located in the switchgear/MCC building.

All electrical systems will be designed in accordance with ANSI standards and suitable for installation offshore.

*2.5.5.1.11 Instrument and Utility Air*

The instrument and utility air system will be a package consisting of:

- two 100 percent screw type air compressors operating on lead-lag demand to a common discharge;
- one dual set of Instrument Air Dryers (2 x 100 percent) supplying one "dry" Instrument Air Receiver; and
- one "Wet" Utility Air Receiver.

Utility air and instrument air will be separated into two separate systems after discharge from the compressors to users as required. Utility air will not be dried. Instrument air will meet the minimum standards of the Instrument Society of America (ISA) and will be distributed in the process and utility areas. Instrument air supply for air-drive users will include oilers at each location.

The compressed instrument and utility air system will be designed to operate during emergency shutdown conditions. This system will be shutdown only with operator approval; no system will automatically shut down the compressed instrument and utility air system.

*2.5.5.1.12 Nitrogen Generation and High Pressure Storage*

Nitrogen will be generated by removing oxygen from air. The nitrogen generation system will consist of:

- an air compressor and nitrogen generator; and

- a nitrogen storage tank assembly.

Nitrogen will be stored in DOT truck transport bottle racks or approved bulk tanks for distribution on demand.

Nitrogen will be used for LNG tank condition monitoring, flare header purge, and at utility stations. The generator is designed to deliver approximately 23,000 standard cubic feet per hour (SCFH) at the highest purity required by the users. Supply to critical services that depend on nitrogen will be separated from the normal user supply. Valving and controls will control the supply of nitrogen during upset conditions so that critical users have nitrogen for as long as possible.

*2.5.5.1.13 Fuel Gas System*

The primary source of fuel gas will be the vaporized product gas. Product gas pressure will be reduced to the pressure required by users. A fuel gas heater will be used to raise the gas temperature to the minimum required for the gas turbines. Fuel gas will be filtered at the turbines to meet turbine manufacturer requirements and will be metered to each user. The fuel gas system will be sized to provide fuel gas to all generators simultaneously.

During initial startup (commissioning of the Terminal), boil-off gas will be compressed with one electric motor driven fuel gas compressor to provide fuel gas for startup. A compressed natural gas barge will be used for startup situations where there is not sufficient boil-off gas available to get the plant running.

*2.5.5.1.14 Diesel Fuel*

The diesel fuel storage system will consist of:

- 750 bbl diesel storage tank with internal level gauge; and

- a diesel transfer skid (includes 2 x 100 percent pumps, 2 x 100 percent filters);

Diesel fuel will be supplied by boat. The vessels will pump the diesel into a storage tank on the Terminal through a diesel unloading hose and reel. Pneumatically driven diaphragm diesel transfer pumps will pump the diesel from the tank through high quality filters for the removal of water and particulates. The diesel will then flow through a totalizing meter and distribution piping to day tanks.

*2.5.5.1.15 Aviation Fuel*

The aviation fuel system will consist of:

- two, 700-gallon (approximate) aviation fuel storage tanks mounted on separate, transportable skid bases;

- aviation fuel transfer skid, complete with filtration and 2 x 100 percent JP-4 fuel transfer pumps, each rated at 50 GPM at 80 psi; and

- a separate aviation type refueling hose/reel station (dispenser unit), housed in a 316 stainless steel enclosure, shall be provided for installation on the helideck.

Aviation fuel will be available for refueling helicopters at the helideck. Portable IMO-type tanks containing aviation fuel will be transported to the Terminal on supply boats. The refueling system will consist of standard, packaged equipment manufactured for this special service.

One of the aviation fuel storage tanks will be at the Terminal while the other is sent to shore to be filled. The aviation fuel tanks and pumps skids will be located in the lay-down area on the quarters platform. These will include a pump and filter to deliver the fuel to a dispensing skid. The dispensing skid will be installed immediately adjacent to the helideck and include aviation hoses and meters. Fire control equipment will be provided for the fuel storage and pumping area as well as the fuel dispensing area.

*2.5.5.1.16 Buildings*

The Terminal will include three buildings:

- the quarters building (located on a separate structure);
- the control building (containing warehouse, shop, lab, control room and berthing observation deck); and
- the switchgear/motor control center (MCC) building.

*Quarters Building*

The living quarters will provide accommodation for 50-person occupancy. The building design will have four levels:

- Level One (the lowest level) will house the galley, kitchen and offices.
- Level Two will have bedrooms, laundry, linen storage, first aid and a mechanics room.
- Level Three will have bedrooms and a recreation area.
- Level Four (the top level) will have bedrooms, an exercise room, a communications room, an electrical workshop, HVAC, and a departure lounge.

A jib crane on the east side will be used for loading/offloading of stores and aviation fuel tanks. The helideck will be located on top of the quarters building and can accommodate one helicopter for a single landing and departure.

The living quarters will be supported by a four-pile jacket and will be located away from the Terminal at the opposite end from the flare system. A 183-foot bridge will connect the Terminal to a support tripod which will in turn connect to the quarters (at a right angle) via a 22-foot bridge.

*Control Building*

The Control Building will contain the:

- warehouse;
- shop;
- marine control room;
- process control room; and
- lab.

The warehouse section of the Control Building will house spare parts and operations and maintenance supplies, and will be the collection point for all materials and equipment for routine maintenance. Materials and equipment delivered from shore by supply boat are received at this location, warehoused and sent out for installation or use. The warehouse will be located at grade level. It will be two stories tall and approximately 20 feet x 40 feet.

A shop area including welding, electrical and an instrument shop will also be on the lower level or the Control Building. The shop area will be two stories tall, approximately 30 feet x 40 feet, and will include a 12 feet roll-up door for easy access for equipment repair. The building will include a 5-ton overhead crane. Items originating from the GBS deck areas are received into this building and are overhauled or removed onto a workboat for transport to shore.

The Process Control Room will be located above the warehouse/shop area. It will include all plant monitoring, safety and control equipment consoles. The room will be approximately 30 feet x 40 feet and include reinforced glass windows on three of its four sides. The lab will be along the east side of the control room and will be approximately 10 feet x 30 feet with reinforced windows along the sea side. Several control room to lab windows will be provided to allow a see-through from the control room to the outside east direction. An equipment room measuring approximately 10 feet x 20 feet will be located along the north side of the Process Control Room and lab.

The observation deck will be located above the control room and house the necessary equipment to properly control and monitor vessel berthing. The observation deck will be approximately 20 feet x 20 feet and include reinforced glass windows around the 360º perimeter.

*Switchgear/Motor Control Center (MCC) Building*

The two story Switchgear/Motor Control Center (MCC) building will house switchgears, motor control centers, panel boards, UPS, batteries and battery chargers, lighting transformers, PLC panels for switchgears, MCCs, and generator control panels for all process and utility users, lighting, emergency power distribution, etc. The building will measure 60 feet x 40 feet. Power distribution transformers will be located on the roof of the Switchgear/MCC Building.

*2.5.5.1.17 Material Handling*

The Terminal will use an onshore approach to material handling. The facilities will include:

- A 50-ton pedestal crane with a 100 feet lattice-work boom will be provided on the southeast corner of the east GBS. This crane will offload from boats onto the GBS laydown area, which is accessible by the material handling equipment on the GBS. The pedestal crane will also be used to offload from the laydown area to boats for transport to shore.

- A 20-ton mobile crane will include a telescopic boom and be capable of reaching most equipment and piping. Monorails will be used where necessary to move equipment to a location accessible by the crane. The crane will be powered by a diesel engine.

- A diesel powered fork lift will be provided to move small parts in the field. Capacity will be less than ½ ton.

- An electric motorized hand truck will be provided to move parts and packages in the warehouse area. The capacity will be approximately 500 pounds.

- Diesel-powered personnel vehicles will be used to transport parts and personnel from the control building and maintenance areas to the plant area. The vehicles' load capacity will be approximately one ton. They will include weather protection for personnel.

- A transport trailer will be provided to carry heavy equipment and parts from the maintenance shop or receiving area to the plant area.

The heat conductor panel from the Open Rack Vaporizers (ORV) may require removal for maintenance. This section is manufactured from aluminum alloy tubes mounted in a structural steel frame. Each section will weigh approximately 2,200 lbs, and has approximate dimensions of six feet x 22 feet high. In order to transport this item from the ORV to the warehouse/workshop, monorails with hoists will be mounted over each of the ORVs. This overhead monorail assembly will be used to pick up the panel, move it over to the side of the ORV skid and then down to the skid support level. From this point, the panel will rest on motorized hand trucks for transport along a defined corridor to the shop building.

The generator packages will include monorails as a part of the unit. The monorail will be capable of moving the gas turbine from its mounting brackets inside the engine enclosure to the open area adjacent to the unit. From there, it can be accessed with the mobile crane.

Equipment requiring routine handling, such as the cargo loading arms, will be operated hydraulically. The heaviest equipment unit or part that will be handled at the Terminal weighs under 20 tons. For major maintenance, refurbishment, or installation of parts weighing in excess of 20 tons, lifting equipment will be brought to the site from shore or provided on marine vessels.

*2.5.5.1.18 Tug Mooring Buoys*

Tug mooring buoys are the only floating components in the Port Pelican Project.

### *2.5.5.2 Component Design Criteria*

The project design criteria are defined in Port Pelican Engineering Design.

### *2.5.5.3 Design Standards and Codes*

Design standards and codes utilized in the design of the Project are as follows:

- US Code of Federal Regulations
  - 49 CFR Part 193, Liquefied Natural Gas Facilities: Federal Safety Standards
  - 33 CFR Part 127, Liquefied Natural Gas Waterfront Facilities
  - 33 CFR Part 322, Permits for Structures in or Affecting Navigable Waters of the US
  - 33 CFR Subchapter N, Outer Continental Shelf (OCS) Activities
  - 33 CFR Subchapter NN, Deepwater Ports
  - 33 CFR Subchapter O, Pollution
  - 33 CFR Subchapter P, Ports and Waterways Safety
  - 46 CFR Part 154, Safety Standard for Vessel Carrying Bulk Liquefied Gases
  - 46 CFR Chapter I Subchapter J, Electrical Engineering
  - 29 CFR 1910, Occupational Safety and Health Standards

- 40 CFR, Protection of Environment

- National Fire Protection Association (NFPA)
  - NFPA 59A, Standard for the Production, Storage and Handling of Liquefied Natural Gas (LNG)
  - NFPA 70, National Electric Code (NEC)
  - NFPA 72, National Fire Alarm Code
- American Bureau of Shipping (ABS)
  - Guidance Notes on Building and Classing Offshore LNG Terminals
  - Rules for Building and Classing Steel Vessels (used for SPB LNG Tanks)
- American Petroleum Institute (API)
  - API RP 500, Recommended Practice for Classification of Areas for Electrical Locations at Petroleum Facilities
  - API 620-Q, Design and Construction of Large, Welded Low Pressure Storage Tanks
  - API RP 2A – WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms – Working Stress Design
  - API RP 2A – LRFD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms – Load and Resistance Factor Design
  - API RP 2L, Recommended Practice for Planning, Designing & Constructing Heliports for Fixed Offshore Platforms
  - API RP 6D, Specifications for Pipeline Valves
  - API RP 14C, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Petroleum Platforms
  - API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems
  - API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities
  - API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms
  - API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities
  - API RP 75, Recommended Practice for Design and Operation of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities

- API RP 1111, Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines
- API RP 2510, Design and Construction of LPG Installations

- American Society of Mechanical Engineers (ASME)
  - ASME/ANSI B31.3, Process Piping
  - ASME/ANSI B31.4, Pipeline Transmission Systems for Liquid Hydrocarbons and Other Liquids
  - ASME/ANSI B31.5, Standards for Refrigeration Piping
  - ASME/ANSI B31.8, Gas Transmission and Distribution Systems
- American Welding Society (AWS)
  - AWS D1.1-98, Structural Welding Code: Steel
- International Maritime Organization (IMO)
  - IMO Gas Code, International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk, and amendments (Gas Code)
- American Concrete Institute
  - ACI 357R-84 (97), Guide for the Design and Construction of Fixed Offshore Concrete Structures
  - ACI 357.2R-88 (97), State-of-the-Art Report on Barge-Like Concrete Structures
  - ACI 318, Design of Concrete Structures
- Oil Companies International Marine Forum (OCIMF)
  - OCIMF 4, Design and Construction Specifications for Marine Loading Arms
  - OCIMF 20, Mooring Equipment Guidelines
  - OCIMF, Guidelines and Recommendations for the Safe Mooring of Large Ships at Piers and Sea Islands
- Society of International Gas Tanker and Terminal Operators (SIGTTO)
  - IP No. 14, Site Selection and Design for LNG Ports and Jetties
  - IP No. 15, A Listing of Design Guidelines of Liquefied Gas Terminals
  - SIGTTO, Prediction of Wind Loads on Large Liquefied Gas Carriers
  - SIGTTO, Liquefied Gas Handling Principles on Ships and in Terminals

- Det Norske Veritas
  - Rules for Classification of Fixed Offshore Installations (Part 3 Chapter 1 Structural Design, General)
  - Rules for the Design and Construction of Offshore Structures
  - Rules for Classification of Mobile Offshore Units
  - DNV RP 205, Impact Loads from Boats, technical notes DNV TNA 202
  - DNV TNA 101, Design Against Accidental Loads
- Norwegian Standard
  - NS 3473, Concrete Structures, Design Rules
- British Standards
  - BS 7777, Flat Bottomed, Vertical, Cylindrical Storage Tanks, For Low Temperature Service
  - BS 8110, Structural Use of Concrete
  - BS 4447, Specification for the Performance of Pre-stressing Anchorage for Post Tensioned Construction
  - BS 4449, Specification for Carbon Steel Bars for the Reinforcement of Concrete
- Canadian Standards
  - CAN/CSA S471-92, General Requirements, Design Criteria, The Environment & Loads
  - CAN/CSA S472-92, Foundation, Offshore Structures
  - CAN/CSA S474-92, Concrete Structures
- International Standards Organization (ISO)
  - ISO 13819, Offshore Concrete Structures
- European Standards
  - EN 1473, Installation and Equipment for Liquefied Natural Gas. Design of Onshore Installations.
- French Standards (FIP)
  - Recommendations for Acceptance of Post Tensioning Systems
  - Report of Methods of Assessment of the Fire Resistance of Concrete Structural Members

- Recommendations for Approval, Supply and Acceptance of Steel for Pre-stressing Tendons

#### *2.5.5.4 Installed Equipment*

##### *2.5.5.4.1 Navigational Lighting*

In addition to working deck lights for illumination of equipment and facilities on the Terminal, fixed navigation lights will be installed as required by USCG. Lights and beacons on the Terminal structure will include:

- Navigation warning lights on the Terminal mast mounted on the upper most deck of the accommodation block. Typically the lighting will be two white lights separated by a red light. These lights will be visible all round (360°) the horizon and have a range of at least ten NM.
- Searchlights on top of the accommodation block for scanning the approaches to the Terminal.
- Additional lights (flood) at regular intervals around the deck and berthing area such that all areas of the deck, equipment and regasification units are clearly illuminated. Flood lights will also be installed at deck level at each corner of the Terminal and in the berthing/manifold areas.
- Deck lighting around the accommodation block at walkways, ladders, and above all exit doors.
- A RACON beacon.

##### *2.5.5.4.2 Safety Equipment*

Safety equipment at the Terminal will include the following:

- A life vest will be installed at each bed on board. In addition, life vests totaling the same as beds onboard will be placed in lockers, port and starboard at the lifeboat stations.
- General alarms (push button type) will be placed in the Cargo Control Room and various locations in and around the Terminal.
- The lifeboat and emergency alarm buttons (fire/emergency) will also be placed in the Terminal Control Room and can only be actuated from this location.
- The Terminal will have a complete gas detection system with local and remote read-out in the Terminal Control Room. Visual alarms will also be displayed in areas having high noise levels. Gas Detection sensors will be installed in the following locations:
  - Each cargo tank compartment (4 per compartment)
  - Entrance to each passageway from outside
  - In the regasification unit and other location near the process equipment
  - Paint locker
  - Galley area
  - HVAC and ventilation intakes

- Cargo Loading Arm Area

A smoke detection system will be installed in the following locations:

- Cabins
- Storage locker spaces
- Offices
- Conference rooms
- Mess rooms and library
- Terminal Control Room
- Storage rooms,
- Hospital/medical room
- Safe Refuge Haven

Each sensor shall be fitted with an alarm into the passage way it serves with a remote read-out (including audio) in the Terminal Control Room.

Safety shower/eyewash stations will be provided in the shop/warehouse/lab area, near the Hypochlorite Generator, and in any other area where chemicals may be present. The water supply will be from the potable water system. The system will be configured to maintain an acceptable temperature for the water.

*2.5.5.4.3 Lifesaving Equipment*

A minimum of four, 40-man (4 at 50 percent), enclosed, davit launched, sealed escape capsules will be installed on the Terminal, They will be located remote from each other so that they will be available from all areas of the facility under emergency conditions. These lifeboats will be the primary means of egress from the structure. In addition to these escape capsules, life rafts and escape harnesses with life rings will be distributed around the facility. These life rafts and rings will be attached to the sides of the structure for quick release. They will be located to provide survival support for individuals whose access to the capsules may be blocked or compromised. The layout for the safety equipment will be based on a safety and risk analyses.

Two fast rescue safety launches will be installed on davits, allowing personnel to board the launches from the GBS deck for subsequent lowering to the sea surface. These boats can be used for man-overboard rescue duty, as well as periodic visual, sea level inspection of the structures, flare, quarters structures, overhung equipment, and mooring dolphins.

*2.5.5.4.4 Fire Fighting Equipment*

Firewater will be provided by four diesel-powered seawater fire pumps capable of pumping 3,000 GPM each at a discharge pressure of 165 psig. A sufficient number of fire pumps will be provided to assure 100 percent of the maximum fire water demand is available at all times. The pumps will be vertical lineshaft design with right angle gear, and will supply a firewater distribution system. The distribution system will be arranged to provide 100 percent of the maximum fire water demand with one of the legs of the distribution system impaired. A jockey pump will pump 50 GPM at 165 psig to maintain pressure in the distribution system.

High expansion foam protection will be provided to control the vaporization of released LNG and radiation from burning releases. High expansion protection will be provided at the troughs from the ORVs, the containment areas for releases from the loading arms, and the GBS manifold areas. Dry chemical systems will be provided to extinguish LNG fires.

Low expansion foam protection utilizing Aqueous Film Forming Foam (AFFF) will be provided for the helideck, the aviation fuel storage area, and areas where significant quantities of flammable or combustible liquids are stored or handled. These areas will include the diesel fuel storage and dispensing areas as an example.

Water spray fixed systems and hose and monitors, supplied from the fire water distribution system, will be provided to control vapor movement, control burning, and cool structures and equipment. These systems and equipment can also be used to provide heat for vaporizing pools of LNG when conditions warrant.

Carbon dioxide fire protection systems will be provided for enclosures where fires may occur and a clean fire extinguishing agent is needed for fire control. These areas may include MCC buildings and turbine enclosures.

Automatic sprinkler protection will be provided for specific buildings, such as the quarters. The sprinkler systems will be designed to discharge fresh water for the first ten minutes of operation. At the end of ten minutes if the system is still operating, sea water will be provided from the fire water supply and distribution systems.

A detection and control system will be provided to detect gas releases and fires. Combustible gas detectors will be located in areas where releases might occur. These areas include areas around the ORVs, LNG manifolds, and pumping areas. Low temperature detectors will be provided in areas where LNG pools may form should a release occur.

Fire detection will be provided in process areas and in areas normally occupied by personnel such as the accommodations building. The type of detection will be selected based on the analysis of the hazards in the area of detection. The detection system will be connected and report to a control system. The control system will accept the alarm signals, process them and sound alarms. The control system will also supervise the circuits between the detectors the fire control equipment and the alarm and process control systems. The fire control system will transmit signals to the process controls and the emergency shutdown system for processing.

*2.5.5.4.5 Pollution Prevention and Removal Equipment*

All equipment handling LNG will be provided with special drainage and containment. The containment and drainage system is provided to limit the spread of LNG releases from the process and direct them by the shortest route to overboard.

Equipment that has the potential to release hydrocarbons and that is not in a curbed area will be designed to be installed on skids. The skids will include drain pans designed to hold any potential hydrocarbon and rainwater.

The open drain system will collect any rainwater, wash water, or other fluids that might collect on the equipment skids. The drain fluids will flow to a CPI type separator. The capacity of the drain system will be designed to handle the expected maximum rainfall rate plus 500 GPM from the fire water system.

Inside the CPI separator, the hydrocarbon and water will be separated to meet the overboard discharge standards for the facility. Water from the separator will be continuously monitored for oil

content. Clean water will be discharged overboard while water that does not meet discharge standards will be recycled into the separator. Oil will be removed and stored in a waste oil holding tank for eventual transport to an onshore reclaiming station.

Open areas of the Terminal not subject to hydrocarbon spills will flow overboard. Facility maintenance procedures will address hydraulic and lube oil spill cleanup from vehicles and other mobile equipment.

Engine waste, including lube oil, hydraulic fluid, and engine coolant, will be collected and transferred to one of two portable waste tanks. One tank will be used for waste oil and hydraulic fluid. One tank will be used for waste engine coolant. When the tanks are full, they will be loaded on a supply or work boat and transported to shore for reclaiming or disposal.

Larger quantities of fluid, as with the main generator turbine engines, will be transferred to the appropriate tank using a portable waste transfer pump. The tanks will be transported to the appropriate engine via a Terminal transporation vehicle.

##### *2.5.5.4.6 Waste Treatment Equipment*

Black and gray water will be treated using a sewage treatment system. Waste outfall from the quarters building, control building and switchgear/MCC building will be treated by sewage treatment units prior to release overboard. A sanitary waste system consisting of a collection system and packaged sewage treatment units will be provided. The sewage treatment units will be of the chemical or biological treatment type.

## *2.5.6 Offshore Pipelines*

### ***2.5.6.1 Description and Preliminary Design Drawing***

A new pipeline (the Pelican Interconnector Pipeline) will be constructed to connect the Terminal to the existing Henry-Floodway Gas Gathering System (HFGGS) backbone. The Pelican Interconnector Pipeline (PIPL) will consist of a 42-inch outside diameter pipeline operating at 1,440 psi with a capacity of 2.0 billion SCFD. The pipeline will be located in water depths varying between 20 and 83 feet.

The PIPL will begin at the Terminal and end at Tiger Shoal “A” Platform. The PIPL will be 43 statute miles (37 NM) long.

The PIPL will be constructed of API 5L pipe having a specified minimum yield strength (SMYS) of 60,000 psi or greater. The pipeline will be constructed in accordance with the requirements of 49 CFR 192.327(g) and 192.612(b)(3) which requires all natural gas pipelines in the Gulf of Mexico to have a minimum of 36 inches of cover for normal excavation and 18 inches of cover for rock excavation. The pipeline will be coated with the appropriate weight concrete coating for undersea stability. The corrosion protection system will include a thin film external coating and sacrificial anodes.

Port Pelican’s control system will monitor discharge pressure and flow rate to protect the PIPL from significant pressure variations. Deliveries to the pipeline will be curtailed in the event of unexplained high or low excursions of these variables.

### ***2.5.6.2 Design Criteria, Standards, Codes and Recommended Engineering Practices***

The PIPL is designed to withstand stresses during installation, testing, and operations. The pipeline will be designed, constructed, tested, operated, and maintained in accordance with 49

CFR 192 and the standards incorporated by reference therein. Specific design standards, codes and recommended engineering practices to be followed include:

- American Petroleum Institute (API)
  - API RP 1111, Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines
  - API Spec 5L, Line Pipe
  - API Spec 6D, Pipeline Valves (Steel Gate, Plug, Ball, and Check Valves)
- American Society of Mechanical Engineers (ASME)
  - ASME/ANSI B31.8, Gas Transmission and Distribution Systems

#### *2.5.6.3 Metering System*

Natural gas from the vaporizers will be metered before entering the PIPL using a custody transfer metering station. Metering capacity will be 1.0 billion SCFD for Phase I and 2.0 billion SCFD for Phase II. Gas will be supplied at up to 1,440 psig.

#### *2.5.6.4 Pipeline Crossings*

A preliminary route survey and route selection was completed during preliminary engineering. Subsea hazards, pipeline and cable crossings, and other obstructions have been analyzed using reasonably and readily available existing data. The selected pipeline route was chosen on the basis of its constructability and its minimization of environmental impacts. Prior to initiating construction activities, a detailed pre-construction hazard survey will be executed to identify any underwater hazards in the path of placement and exact location of any additional subsea cable or pipeline crossings. Should a hazard be identified, it will be avoided.

The PIPL will cross 13 existing pipelines (Map 2). Remote Operated Vehicles (ROV's), as well as divers will be used to locate and monitor these pipeline crossings during construction of the PIPL.

The pipeline will be constructed in accordance with the requirements of 49 CFR 192.325 which mandates 12 inches of clearance from all other underground structures. The pipeline will be installed over the top of existing pipelines/cables. In some cases, it may be necessary to lower existing pipelines in order to achieve the required clearance between the PIPL and existing pipelines. Sandbags and/or concrete mats will be used to ensure 18 inches of separation between the PIPL and existing pipelines. In the event that the installation results in less than 36 inches of cover over the new pipeline, concrete mats will be used to provide an equivalent degree of protection.

Should any cables be found, industry standard protective crossing procedures, as agreed by cable owners when applicable, will be implemented. To the extent practicable, cables will be lowered to provide 36 inches of separation.

### *2.5.7 Onshore Components*

The Port Pelican Project consists of the Terminal and the PIPL, with the PIPL connecting the Terminal to the existing offshore Tiger Shoal “A” platform. The Project will have no onshore components.

## 2.5.8 Miscellaneous Components

### 2.5.8.1 Description of Communications Systems

The Terminal will be outfitted with up-to-date communication equipment capable of maintaining contact with the LNG carriers scheduled to offload at the Terminal and the stand-by tugs. The Terminal will use direct communication links to a shore base by means of microwave signals and Marine Satellite Telephone (MARSAT).

During the time a LNG carrier is alongside the Terminal (whether berthing, offloading or awaiting to depart), the Berthing Master will be the "point of contact" between the Terminal and the LNG carrier. The Berthing Master will be in continuous contact with the Terminal operating staff located in the Marine Control Room using the Terminal communications equipment, rather than the LNG carrier's communications equipment. A cable connected fiber-optic "hot line" will be fitted to permit direct communications between the LNG carrier cargo control room and the Terminal control room. Back up communications will be provided by UHF and VHF radios.

### 2.5.8.2 Description of Radar Navigation System

At least two radars will be installed on the mast above the accommodation block. One radar will be capable of covering the medium to short ranges 12 miles down to one mile and the second unit for long to medium range, 30 miles to 12 miles.

The small range radar will monitor all vessels operating and/or transiting in the near vicinity of the Terminal. This unit is operating and continuously monitoring for suspicious vessels in the safety zone. It will also monitor all marine traffic in the area advising as necessary the approaching LNG carrier for berthing or anchoring.

The larger range radar will monitor all marine vessels within a 30 mile radius, if necessary advising the approaching or departing LNG carriers of other marine traffic and deviations from the fairways and corridor approaches to the GBS.

### 2.5.8.3 Mooring of Vessels

Typical mooring scenario will require two tugs to be secured alongside, fore and aft and third tug astern to control the forward speed of the LNG carrier. The LNG carrier will approach the berth with a speed and angle appropriate for the weather and wave conditions. When the bow of the LNG carrier is close to abeam of the forward mooring hooks, a messenger line is transferred from the GBS deck to the LNG carrier bow mooring station. The LNG carrier hawsers are connected to the messenger line and then retrieved by the GBS mooring crew. As soon as the hawser(s) are connected to the mooring hooks, the LNG carrier will proceed to pull in the slack hawser and with maneuvering of the tugs push the LNG carrier alongside the berth. Other bow, amidships and stern mooring lines will be passed to the GBS as soon as possible. The fendering system is designed to absorb energy from a landing speed of 0.6 m/s for the largest LNG carrier.

The Mooring Master will board the incoming LNG carrier at the "Pilot onboard-POB" position approximately three miles from the Pelican Terminal. He may transfer from one of the attending mooring tugs. The LNG carrier will not be permitted to berth without a Mooring Master onboard and tugs in attendance. The Mooring Master will advise the captain of the LNG carrier on operational and ship control matters that are peculiar to the specific GBS terminal such as navigational aids, depth of water and current characteristics of the maneuvering area, mooring equipment and procedures, tugs, and port's vessel traffic control procedures.

In addition to assisting in berthing the LNG carrier, he will be responsible to ensure the vessel is securely moored to the terminal and in correct position for the connecting the cargo loading (receive) arms to the LNG carrier manifold.

An Assistant Berthing Master will be assigned and located at the selected Terminal berth to supervise the mooring crew, cargo manifold connection, and liaise with the Mooring Master and LNG carrier captain.

After the LNG carrier is moored, two tugs will be released, leaving one on stand-by at the Terminal. One tug will be recalled to assist the stand-by tug during the un-berthing of the LNG carrier. Mooring points for off duty tugs will be provided on both sides of the berth structure.

Each tug will be outfitted for "open" water service with large fendering system all round and capable of working as far as practical in the sea states for the area. Preliminary estimates indicate these tugs will have a bollard pull of about 60 to 70 tons with an estimated horsepower of about 5,000 to 6,000. Tugs will be of the traction type with the Voith Schneider propulsion system capable of pushing, berthing and towing the largest LNG carrier calling at the Terminal.

#### *2.5.8.4 Support and Servicing Vessels*

A rescue/support boat will be installed at the East end of the Terminal. This boat is USCG-approved boat powered by an inboard diesel engine and is capable of carrying six persons. This boat will be launched and recovered by a davit and fast recovery winch. This boat may be used as a guard boat, for line handling, or as a maintenance workboat. It will also be outfitted to deploy light containment boom in the event of a small oil spill.

#### *2.5.8.5 Shorebased Support Facilities for Support and Servicing Vessels*

A shore base will be used to facilitate the movement of personnel, equipment, supplies, and disposable materials between the Terminal and shore. An existing office/warehouse approximately three to six acres in area with a bulkhead will be leased for this purpose. The location of the shore base has not been determined at this time.

### *2.5.9 Aids to Navigation*

The navigation aids presently installed along established fairways to be used by the LNG vessels are generally adequate. Additional navigational aids will be used to mark the proposed new vessel route. One buoy will be installed marking the junction of the new vessel route and the existing fairway and two additional buoys will be located at mile intervals beginning at the safety zone leading to the Terminal maneuvering area and a RACON (radar signaling) device installed on the GBS. A study of navigational aids on existing structures will be undertaken to optimize their use for transit along the approach corridor. US Coast Pilot 5, 29th Edition 2002 is the primary reference for review of the navigation plan for the area.

The Terminal will have a minimum of four mechanical foghorns. Two will be mounted on the forward area of the structure and two at the after end of the second structure. Each will have a distinct sequence of blasts as required by USCG rules for fixed facilities in the Gulf of Mexico. Hand held fog horns will be stored onboard in the event of a power failure.

## 2.6 Operations Manual

### *2.6.1 Draft Marine Operations Manual*

A draft copy of the Marine Operations Manual is included in the Port Pelican Engineering Design. The manual will be finalized after the detailed Terminal design is completed and the results of several operations and safety studies are completed.

Section
3

# 3 Financial Information

## 3.1 Annual financial statements

The Applicant (Port Pelican LLC) was incorporated on November 1, 2002. No historical annual financial statements exist for the Applicant.

Chevron USA, Inc. (CUSA), is the parent company of the Applicant and is a wholly owned subsidiary of the ChevronTexaco Corporation. Summarized financial information for CUSA and its consolidated subsidiaries is presented below (all amounts are in millions of dollars). More detailed financial statements for CUSA are provided in Attachment 2.

| | Year ended December 31 | | |
|---|---|---|---|
| | 2001 | 2000* | 1999* |
| Sales and other operating revenues | **$37,033** | $40,729 | $28,957 |
| Total costs and other deductions | **34,771** | 38,047 | 28,644 |
| Net income | **1,802** | 2,336 | 885 |

*Certain reclassifications were made to conform to the 2001 presentation.

| | At December 31 | |
|---|---|---|
| | 2001 | 2000 |
| Current assets | **$ 2,888** | $ 4,396 |
| Other assets | **20,795** | 20,738 |
| Current liabilities | **4,344** | 4,094 |
| Other liabilities | **9,797** | 10,251 |
| Net equity | **9,542** | 10,789 |
| Memo: Total Debt | **$6,272** | $6,728 |

## 3.2 Interim Income Statements and Balance Sheets

The Applicant (Port Pelican LLC) was incorporated on November 1, 2002. No interim income statements or balance sheets exist for the Applicant.

Chevron USA, Inc. (CUSA), is the parent company of the Applicant. Income statements and balance sheets for CUSA and its consolidated subsidiaries are provided in Attachment 2.

## 3.3 Annualized Projections or Estimates

The Project will be constructed and operated on the basis of a take-or-pay tariff contract with Third Parties (capacity holders). This structure is a "Tolling" arrangement in which the Terminal is a service provider.

The tariff structure under a tolling agreement combines a capacity fee and a usage fee. The capacity payment will be sized to cover operating and maintenance costs, capital depreciation, income tax, and a reasonable return on the capital investment. The usage (or commodity) fee is charged when LNG is processed through the terminal and generally amounts to incremental operating expenses. The Third Party (toller) is obligated to pay the capacity fee payment to the terminal, whether or not the toller requires the terminal to process the gas.

Annualized projections or estimates for the Project are provided in the Confidential–Sensitive Information document.

At this time, no contracts for the receipt of LNG are in place.

## 3.4 Management and Financing

Capital contributions from the Parent Company of the Applicant will provide the equity necessary for the construction of Port Pelican. Presently, no agreements concerning the management and financing of the deepwater port, including agreements relating to throughputs, capital contributions, loans, guarantees, commitments, charters, and leases have been executed by the Applicant.

## 3.5 Total Capacity and Demand

The Port Pelican Project will receive, store and vaporize LNG to produce natural gas, which will then be delivered through the PIPL and HFGGS to U.S. gas markets. Storage volumes are designed to provide offloading of the LNG carriers with immediate regasification. No long-term storage of LNG (a service typically provided by onshore LNG receiving terminals) will be provided by the Project.

LNG receipt is estimated at 800 million SCFD annual average for the first two years of operation. In subsequent years, the annual average LNG receipt is estimated at 1.6 billion SCFD.

Annualized projections or estimates of LNG deliveries and operational expenses for the Project are provided in the Confidential–Sensitive Information document.

Natural gas demand in the United States is forecast to grow significantly in the next 20 years. The Energy Information Administration forecasts annual U.S. natural gas demand will reach 30 trillion cubic feet (Tcf) by the year 2010, and 35 Tcf by the year 2020. This represents an increase of over 30 percent from current consumption levels.

Electric generation is a major reason for the projected increase in demand for natural gas in the United States. In recent years, most of the increase in power generation capacity resulted from the introduction of new power plants fired by natural gas. Natural gas is becoming a preferred fuel in the United States energy market because it produces fewer pollutants when combusted compared to other hydrocarbon fuels.

A significant volume of natural gas will be provided to the natural gas distribution market by this Project, improving the efficiency and flexibility of the existing pipeline infrastructure, and providing supply diversification while minimizing environmental impacts. This Project will increase the supply of natural gas available throughout the southeastern United States, particularly in Louisiana and the Gulf Coast region.

No refinery runs, or other hydrocarbon products or services will be provided by this Project.

Section
4

# 4 Engineering and Construction Costs, Contracts, and Studies

## 4.1 Construction Costs

The Port Pelican Project will have an initial peak capacity 1.0 billion SCFD during Phase I. Phase 2 will have 2.0 billion SCFD capacity after the installation of additional vaporization facilities. Construction costs for the Project are presented in the Confidential–Sensitive Information document.

## 4.2 Completion Dates

First deliveries of LNG to the Port Pelican Terminal are scheduled for 2006. Phase 2 is expected to be complete by 2008. Completion dates for the Project are presented in the Confidential–Sensitive Information document.

## 4.3 Contract Copies

The applicant will not enter into contracts for the construction or operation of the Project until the Permit requested by this Application has been approved. Construction contracts will be submitted by the Applicant as they are completed.

## 4.4 Contract Studies

Studies completed showing the engineering planning or design approach for the Project are listed in Table 4.4-1. **All of these studies are CONFIDENTIAL SENSITIVE INFORMATION.**

## 4.5 Construction Procedures

### *4.5.1 Port Pelican*

The GBS units that will comprise Port Pelican will be fabricated on-land, floated into place, and sunk in approximately 83 feet of water, thus avoiding construction impacts to marine physical and biological resources that would be associated with in-place construction of the Terminal. Equipment for the Terminal will be transported to the GBS units by boat or barge and lifted into place on the GBS units. Jackets to support other Terminal structures will be installed.

### *4.5.2 Pelican Interconnector Pipeline (PIPL)*

A 42-inch diameter gas pipeline (the Pelican Interconnector Pipeline (PIPL)) will depart the Terminal and deliver natural gas to the Tiger Shoal A platform (Map 2). The PIPL will extend approximately 37 NM and will operate at 1,440 psi. with a capacity of two billion SCFD. The pipeline will be located in water depths varying between 20 and 83 feet and will be covered to meet regulatory standards of an equivalent three feet of cover. The PIPL will cross through the lease blocks identified in Table 1.1-1.

After all right-of-way easements, grants, and required permits and clearances have been obtained, construction will begin. The PIPL portion of the Port Pelican Project will take approximately 60 to 75 days to complete. The pipeline will be installed using shallow draft lay barges and a crew drawn from the region.

The pipe will be located in shallow water (less than 200 feet depth) and will be installed using an "S" lay configuration. This configuration involves the use of two barges. The first barge (lay barge) has a stinger on the rear side, which is used to keep the pipe from bending when it is laid into the water. The crew on the first barge will weld the 40-foot joints of pipe together; the pipe is then laid into the water off the rear of the barge as the barge moves forward. The pipeline will have a controlled, unsupported span from the barge stern to seabed during installation. This span will be maintained in proper configuration controlled with the stinger connected to the lay barge stern, and tension will be applied to the pipeline by tension equipment on the lay barge. The second barge (jetting/trenching barge) cuts the trenches and then covers the pipe with the required cover, (generally three to four feet of sediment).

Emergency procedures will be developed to provide for the safety of construction crews and the pipeline during installation operations during adverse weather conditions or other difficult installation situations.

The pipeline will be laid dry and then free-flooded with approximately 375,000 barrels of seawater to enable tie-in to the riser piping. The free-flood intake rate will be limited to approximately 2,000 GPM.

After completion of the pipeline installation, pigging operations will be undertaken to ensure the pipeline has been properly installed. A multi-train pig run will be made to remove loose debris and confirm that there are no dents/buckles in the pipeline. During these pig runs, the initial line fill water will be discharged and replaced with a second line fill used for hydrostatic testing. Water for the second fill will be drafted through jet pumps and injected into the pipeline at the Port Pelican scraper trap while initial fill water is discharged overboard through the Tiger Shoal “A” scraper trap. Intake and discharge rates will be limited to approximately 2,000 GPM.

The pipeline will then be hydrostatically tested in accordance with the requirements of 49 CFR 192.503, 192.505, and 192.619(a)(2)(ii). The pipeline and risers are designed for a maximum allowable operating pressure (MAOP) of 1,440 psig. The hydrostatic test will be conducted using seawater as the test medium with the minimum test pressures being held for eight hours. The risers will be tested to a minimum of 2,160 psig (i.e., 1.5 x 1,440 psig) and the pipeline will be tested to a minimum of 1,800 psig (i.e., 1.25 x 1,440 psig).

Hydrostatic testing of the pipeline will involve approximately 375,000 barrels of seawater drawn from and returned to the Gulf of Mexico. The intake and discharge sites will be Port Pelican and Tiger Shoal “A” respectively. Upon successful completion of the hydrostatic test, the pipeline will be purged using air to drive a pig from Port Pelican to Tiger Shoal “A”. The discharge of hydrostatic test water will be made in accordance with the terms of the general discharge permit

governing operations of this type in the Gulf of Mexico. The discharge rate will be limited to approximately 2,000 GPM.

No decision has been made regarding the use of corrosion inhibitors in the test water. A batch of biocide will be run through the pipe after dewatering, but it would not be discharged into the Gulf of Mexico. Instead, the biocide will be routed to the HFGGS via the existing infrastructure and disposed of there in accordance with standard operating procedures and applicable regulations.

## 4.6 Estimated Decommissioning Cost

The estimated cost for decommissioning of the Terminal is 15 percent of the initial development cost. This estimate is based on industry experience for decommissioning of other offshore structures. A detailed analysis of decommissioning, including possible alternatives for continued use, will be provided at a later date.

Section
5

# 5 Environmental Report

The information in this section of the application summarizes more detailed information contained in Topic Reports in the Environmental Report in:

- TR 01, Project Description
- TR 02, Water Use and Quality
- TR 03, Biological Resources
- TR 04, Cultural Resources
- TR 05, Socioeconomics
- TR 06, Geological Resources
- TR 08, Land Use, Recreation, and Aesthetics
- TR 09, Air and Noise Quality
- TR 10, Alternatives

## 5.1 Alternatives Analysis (see Topic Report 10)

The Port Pelican Project has been designed to avoid or minimize adverse impacts to the biological, physical, and socioeconomic environment. By locating the Project offshore and making use of existing near shore infrastructure, the project will avoid substantial environmental impacts typically associated with large land based LNG facilities and minimize associated offshore pipeline expansions.

### *5.1.1 Project Objectives*

The objective of the Port Pelican Project is to receive and vaporize LNG, and to send natural gas through the PIPL to the HFGGS for the US gas market. Project criteria for the Port Pelican Project include:

- regasification operations 365 days per year;
- LNG storage capacity of 330,000 cubic meters;
- send out/vaporization average annual capacity of 800 million SCFD and peak capacity of one billion SCFD in Phase I of the Project, with a doubling of that capacity in Phase II;
- pipeline quality natural gas requiring no gas processing;

- pipeline pressure of 1,440 psig; and
- 2006 terminal in-service date.

### 5.1.2 No-Action and Postponed Action Alternative

The no-action alternative would avoid the environmental impacts immediately associated with the Port Pelican Project. However, since the Project would be unavailable to meet anticipated growth in energy demand in the U.S. market, LNG handling capacity not provided by the Port Pelican Project would need to be provided by other alternatives. Other impacts would likely occur as a result of the following:

- Construction of other new LNG handling facilities.
- Expansion of existing LNG handling facilities.
- Imbalance between LNG supply and demand that would lead to higher natural gas prices and substitution of other energy sources (e.g., coal, oil, nuclear). Depending on market conditions and availability of substitute energy sources, the substitute fuels might not be as clean burning as natural gas.
- Overseas exploration has developed significant natural gas resources. Much of this gas has no local market due to lack of demand, infrastructure, and/or ability to pay for gas. Without access to export markets, this gas is effectively stranded.

A postponed action alternative would defer construction-related effects to a future date. This might encourage other LNG terminal projects with potentially more adverse environmental impacts than the Port Pelican Project.

### 5.1.3 System Alternatives

System alternatives are alternatives that would meet the objectives of the project by using an alternative LNG import terminal or pipeline system or a different configuration of facilities. System alternatives could include the use of existing offshore projects and/or existing onshore facilities.

#### *5.1.3.1 Alternative Offshore Projects*

There are no existing offshore natural gas projects receiving LNG. Proposed offshore projects have been considered by industry and three alternative concepts were examined by the Pelican Project as discussed in Section 5.1.5. Other concepts located at alternative sites could be used for offshore LNG terminals. Based upon our studies for the Port Pelican Project, the alternatives would not meet Project objectives and/or would incur greater environmental impact.

#### *5.1.3.2 Alternative Onshore Projects*

Existing or proposed onshore facilities are considered as alternatives to the import and delivery capacity that would be provided by the Port Pelican Project:

- Elba Island Terminal;
- Cove Point Terminal;
- Hackberry Terminal;

- Everett LNG Terminal; and
- CMS Lake Charles Terminal.

The Elba Island Terminal recommisioning project has been proposed by Southern LNG and was recently approved by the Federal Energy Regulatory Commission (FERC) in Docket Nos. CP99-579-000 and CP99-580-000. The project involves recommisioning the existing LNG terminal on Elba Island in Chatham County, Georgia for open-access contract service to shippers. The Elba Island Terminal recommisioning project would not be able to meet the objectives of the Port Pelican Project because it has a smaller design capacity (540 million SCFD peak send out rate) than the Project. In addition, the Elba Island Terminal's existing capacity is committed to existing contracts, and thus would not meet Project objectives without significant expansion.

The Cove Point project is the recommisioning and expansion of an existing shore-based LNG facility located on the western shore of the Chesapeake Bay near Cove Point, in Calvert County, Maryland. The project was recently approved by the FERC (Docket No. CP01-76-000). The Cove Point project would not be able to meet Port Pelican Project objectives without substantial expansion because 100 percent of the additional capacity will be dedicated to meeting long-term binding contracts with shippers.

Hackberry LNG Terminal LLC, a subsidiary of Dynegy Midstream Services, Limited Partnership, filed an application with the FERC (Docket No. CP-02-374-000) to build and operate LNG terminal facilities in Hackberry, Louisiana. The Hackberry Terminal project involves conversion of an existing liquefied petroleum gas (LPG) terminal site to make it capable of handling LNG. The Hackberry Terminal project would not be able to meet Port Pelican Project objectives because it is not designed to provide the send out capacity available with the Phase II expansion of Port Pelican Terminal.

The Everett LNG Terminal Project, located in Boston, MA, was reactivated in 1998 to receive LNG after being shut down in 1987. The Terminal receives LNG under long-term contracts from Algeria and Trinidad, where its affiliate Cabot LNG has a 10% share in the Atlantic LNG project. The Everett facility would not meet the objectives of the Port Pelican Project because it has an average design natural gas send out rate less than the Port Pelican Project. In addition, Everett Terminal's capacity is fully committed to existing contracts.

The CMS Lake Charles Project is a proposed expansion from 700 million SCFD to 1.2 billion SCFD with additional storage from 6.3 to 9.0 BSF by CMS Enerby. The project involves expansion of existing facilities in Calcasieu Parish, LA for open access contract to shippers. The CMS Lake Charles Project would not meet the objectives of the Port Pelican Project. In addition, its existing and expansion capacity is fully committed to existing contracts.

Other onshore sites along the Gulf Coast could be alternatives to the Port Pelican Project, including existing ship unloading sites suitable for conversion to a LNG terminal (such as an idle refinery or liquids terminal); or other undeveloped sites. Currently, there are no known suitable refinery sites or new land sites. Environmental impacts of offshore alternatives would be fewer than those of onshore alternatives. Onshore facilities would need to have access to ports capable of receiving LNG carriers, and would likely be located on coastal wetlands. Other potential environmental impacts, including impacts to waterbodies, forest lands, and residences could occur from construction of the pipelines needed to interconnect onshore terminals with existing interstate natural gas pipeline systems.

### *5.1.4 Alternative Natural Gas Pipeline Systems (see Topic Report 10, Section 10.2.4)*

Alternative natural gas pipeline systems are pipelines that could replace all or part of those that would be used to transport gas from the Port Pelican Terminal to onshore market hubs and connection to

interstate pipelines. Althought the following major interstate natural gas pipeline systems, pass within proximity to Port Pelican Terminal, curent contracted volumes through these lines will not allow capacity for Port Pelican gas volumes:

- Sea Robin (CMS Energy);
- Columbia Gulf;
- Williams/Transco; and
- Tennessee Gas.

### *5.1.5 Alternative LNG Terminal Technology (see Topic Report 10, Section 10.3)*

Port Pelican Terminal will utilize GBS units with integral LNG storage and onboard open rack vaporizers (ORVs) for regasification of LNG. Alternative LNG Terminal technologies are:

- Floating Storage and Regas Unit (FSRU); and
- Shuttle and Regas Vessel (SRV).

FSRUs would be located in water depth of approximately 165 feet. Offloading of an LNG vessel would be side-by-side or end-to-end along the FSRU via one berth and loading arm, which would provide 85 percent berth availability. Regasification would take place on the FSRU and the natural gas would then be transported to the Tiger Shoal Platform "A" platform via lateral pipeline.

Despite some of the advantages of FSRUs, they were not chosen for use in the Pelican Terminal Project because:

- The potential for reduced berth operability due to shut-down during severe weather conditions.
- The FSRU would require two mooring points and a larger safety zone to accommodate LNG carrier swing circles.
- Periodic scheduled dry-docking of the FSRU for maintenance would be required.
- An FSRU would have limited deck space and restricted layout flexibility. This would cause incremental regas capacity to be smaller than what is possible on a GBS.
- Expandability would only be possible by adding another FSRU. This would require a larger safety zone, a proportional increase in operations personnel, and would significantly increase both operational and capital expenditures.
- The deeper water depth requirements for siting an FSRU may result in a substantially longer pipeline than would be needed for the Port Pelican Terminal GBS site.
- The FSRU would require an on-deck flare rather than a flare with a separate support structure, and this would increase safety risks.
- There is no proven technology for floating offshore LNG storage with regasification. FSRU technology is new for the Gulf of Mexico.

A shuttle and regas vessel (SRV) is a dedicated LNG carrier with regas equipment on board, calling to a receiving terminal with no permanent storage. This technology was not chosen for use in the Pelican Terminal Project because:

- SRVs are effectively a dedicated LNG fleet, with regasification equipment on all vessels.
- SRVs would consume a significantly larger volume of fuel with attendant emissions.
- Expandability is limited to the installation of duplicate terminals.
- The SRV mooring and offloading system would require deeper water and may result in a longer pipeline length, with proportionally greater environmental impacts.
- SRVs would have limited deck space with restricted layout flexibility. The SRV would require an on-deck flare and may require a booster station to attain desired delivery rates.
- Compared to a GBS terminal, SRVs would have reduced berth operability due to necessary shut-down for adverse weather conditions.
- Because SRVs would require a dedicated fleet, which is more costly, and a longer pipeline to the Tiger Shoal Platform "A" Lateral, SRVs might not be commercially viable.

GBS units are massive, concrete structures that are pre-fabricated at an on-shore facility. The structures are then floated and towed to the installation location, where they are flooded and sunk to rest on a foundation on the sea floor. The deck of the GBS unit is located at an elevation above the sea surface that provides sufficient freeboard for sea states that will be encountered at the location.

GBS technology was selected for use on this Project because a terminal design based on GBS units will provide more benefits and fewer environmental impacts than FSRUs or SRVs from safety, operability, availability and environmental perspectives. Advantages of using GBS units include:

- A large volume for internal LNG storage tanks with excellent protection and containment provided by the concrete GBS structure.
- There is a long history of safe and successful use of GBS units in the North Sea, Australia, and Canada. It is expected that the ability of GBS units to operate in environments with highly energetic sea states like the North Sea will lead to extremely high reliability and safety when GBS units are used in the Gulf of Mexico.
- Better shelter for LNG carriers during LNG transfer operations. This translates into higher operability and reliability (berthing utilization estimated at 95 percent for a GBS terminal).
- The larger scale of the GBS allows for a larger thoughput facility design, reducing cost. In addition, the larger deck area of a GBS allows for more flexibility and safety in arrangement of equipment.
- The potential for future expandability at a lower cost than other technologies considered.
- Higher safety for the facility and crew. Crew quarters are located on a separate structure and the flare tower is a separate structure at some distance from the Terminal and berthed LNG carriers.
- Depth of water in which the GBS would be placed is moderate, allowing the GBS to be located in a location that will optimize distance to shipping lanes and pipeline construction distance.

- The GBS location can be placed sufficiently far offshore to avoid existing areas of vessel congestion and the creation of new areas of vessel congestion.

### *5.1.6 Alternative Regasification Technologies (see Topic Report 10, Section 10.5)*

Five different regasification technologies for vaporizing LNG were evaluated:

- Open Rack Vaporizer (ORV);
- Submerged Combustion Vaporizer (SC);
- Intermediate Fluid Vaporizer (IFV) with Glycol/Water intermediate fluid;
- IFV with Rankine Cycle power recovery;
- IFV with boiling and condensing intermediate.

Each of these technologies is a proven process for LNG vaporization. The processes were evaluated for the Port Pelican Project using the following criteria:

- safety during marine and terminal operations, and during lng processing and gas send out;
- commercial viability (based on multiple 200 million SCFD process trains);
- operability/maintainability;
- space required and suitability for offshore GBS; and
- environmental impacts.

ORV was selected as the technology for the Port Pelican Project for the following reasons:

- ORV is a widely used, highly proven technology.
- ORV is a simple process, giving it very high reliability.
- The weight of ORVs is much lower than the alternatives.
- Fuel usage is low, reducing operating costs and lowering environmental impacts (air emissions).

### 5.1.7 Alternative Construction Methods

The GBS units will be fabricated on-land, floated into place, and installed in approximately 83 feet of water, thus avoiding construction impacts to marine physical and biological resources that would be associated with in-place construction of the Terminal. Impacts on marine resources from GBS installation will be avoided to the extent possible, but there will be some unavoidable permanent impacts within the GBS footprint. Short- and long-term impacts to biota will occur at the perimeter of the GBS and along the PIPL construction right-of-way. No other means for transporting the GBS units to the Terminal site are available.

#### *5.1.7.1 Alternative Offshore Pipeline Installation Methods*

Conventional, S-lay pipeline installation methods will be employed for the Port Pelican Project. Pipeline burial or trenching will be required. There are many commercially available offshore trenching methods. These methods may be classified into four main groups: dredging, jetting, plowing and blasting.

Dredging involves repositioning seabed material or transporting it to the surface in sold form. Dredging is a pre-pipelay technique and must be complemented by a backfilling operation. Various types of dredging equipment exist such as draglines, clamshells, dippers, bucket-wheel/ladders, jet-suctions, cutter suctions, and trailing suction hoppers. Use of these methods results in either a relatively large seabed impact if material is simply repositioned or logistical challenges associated with handling the spoil if it is brought to the surface.

Jetting is post-pipelay technique that uses water jets to break up, remove, or liquefy the soil immediately under a marine pipeline and allow the pipeline to settle to the desired elevation below the prevailing seabed. Jetting is typically done by using either a towed or self-propelled sled that moves along the in-place pipeline and employs high pressure water jets to cut and remove the soil from beneath the pipeline. Towed jet sleds have pontoons that slide along the seabed close to the pipeline while self propelled units have wheels that rest directly on the pipeline and use the pipeline for traction. In either case, seabed impacts are limited to a relatively narrow corridor immediately adjacent to the pipeline.

Plowing is a post pipelay technique that employs a towed plow to cut a trench and lower the pipeline to the desired elevation below the prevailing seabed. Wheels on the plow rest directly on the pipe and serve to guide it along the route. Seabed impacts are limited to a relatively narrow corridor immediately adjacent to the pipeline, but multiple plow runs must be made when dealing with large diameter pipe.

Blasting is a pre-pieplay technique involving the use of explosives to break up materials that are too hard to be removed by other methods. This is a slow, costly method, and it can have significant seabed impacts. This method is used only when other methods will not work.

### 5.1.8 Siting (see Topic Report 10, Section 10.4)

#### *5.1.8.1 Site Selection*

Initial site selection screening criteria included:

- location within 50 miles of Tiger Shoal Platform “A” Lateral,
- water depth of 65 to 100 feet,
- general accessibility,
- on an not leased Minerals Management Service (MMS) block,

- adjacent blocks also not leased, and
- access to third- party pipelines.

Four possible sites were considered acceptable for the proposed location of Port Pelican. The site selected provides the safest routing for an LNG carrier approaching from the Gulf of Mexico and the shortest distance for the new pipeline from the Terminal to the existing pipeline connection.

Important factors considered in the final selection were:

- the safety of navigation between the various offshore platforms and structures with special considerations due to departure in adverse weather;
- the maneuvering area available and proximity to a safe anchorage for the LNG carrier in the event of delay in berthing.

## 5.2 Net Environmental Impacts and Mitigation

### *5.2.1 Sea Bottom Characteristics (see Topic Report 6)*

The proposed project area for both the Port Pelican Terminal and the Pelican Interconnector Pipeline is located on the continental shelf of the Gulf of Mexico. This area is largely a Mesozoic-Cenozoic basin, with various Cenozoic depocenters located seaward and a Pleistocene depocenter at the shelf edge. Underlying the shelf is a thick sequence of offlapping sedimentary wedges that have been deformed by the movement of salt and overpressured shale.

Potential geologic hazards that may occur on the continental shelf include active faulting, shallow gas in seafloor sediments, and seafloor instability.

According to API RP2A-LRFD – "Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms – Loads and Resistance Factor Design (1993)", the Gulf of Mexico is situated in a seismic risk zone of category zero. This implies that the horizontal ground acceleration is less than 0.05 g. According to Section C.4.1.3 of the recommended practice, "No earthquake analysis is required since the design for environmental loading other than earthquake will provide sufficient resistance against potential effects from seismically active zones".

A preliminary study of the Terminal area utilized digital and analog echosounder records to assess bathymetry to a depth of plus or minus two feet. The sea floor of the block was found to be relatively featureless, sloping south southwest at a rate of 1.5 to 2.0 feet per mile. No evidence of surface fault scarps or significant slopes were found in the block during this study.

During the geological assessment the Terminal area, a number of areas where gas might be present in sediments were identified by geophysical methods. The stratigraphic horizon where most instances of potential gas-containing sediments were found was at a depth of 105 to 115 feet below the sea bottom. Sediments that might contain gas were not laterally continuous, although they extended for distances up to 1,000 feet. It is believed that the gas in these sediments is biogenic and recent, originating from the decay of organic material in the sediments. No gas vents or indicators of gas escaping from the sea floor were found. There is no evidence that the gas originates from the migration of deeper sources of petrogenic gas.

### 5.2.2 Natural Environment

#### 5.2.2.1 Biota (see Topic Report 3)

Port Pelican Project will be located in shallow water habitats (less than 200 feet deep) in the Gulf of Mexico. The major benthic habitat of the northern Gulf of Mexico is comprised of a soft muddy bottom, which are void of vegetation and dominated by polychaetes. Organisms in this habitat type include spaghetti worms and other burrowing marine organisms as well as crustaceans and mollusks.

Potential major impacts on biota and biotic environment that have the potential to occur during installation of the Terminal and the PIPL include:

- temporary reduction in primary productivity due to turbidity caused by installation of the GBS units;
- displacement of pelagic and soft bottom demersal fishes from the GBS footprint; and
- displacement and/or loss of benthic organisms within the GBS footprint.
- Potential major impacts on biota and biotic environment that have the potential to occur during Terminal and PIPL operation include:
- impingement of marine organisms during seawater intake;
- reduction in primary production due to turbidity caused by water discharge from the Terminal;
- loss of marine organisms from temperature effects from discharge of cooled seawater, discharge of chlorine from the anti-biofouling agent used to control marine growth on ORVs, sewage and oily discharge from the Terminal; and
- displacement or behavioral changes due to noise.

Mitigation techniques have been included into Project design to address the impacts, and continuing consultation with resource agencies will further investigate options for mitigation and avoidance of environmental impacts. To minimize impingement of marine organisms, seawater will be drawn through screens at a velocity of less than 0.5 feet per second for use in the LNG regasification process. Optimum screen size to minimize impingement at ORV seawater intakes will be determined through discussions with resource agencies. The discharge pathway will be designed to minimize turbidity. Cooled seawater discharge, residual chlorine, oil and sewage discharge, and noise are expected to have negligible impacts on biota.

#### 5.2.2.2 Littoral Processes, Currents, and Wave Patterns (see Topic Report 2)

Because the Terminal will be located approximately 32 NM offshore, there will be no effect on natural littoral processes. Sedimentation and erosion along the shoreline will not be effected by the Terminal.

The scale of the Terminal structure will produce only localized effects on current and wave patterns. None of the effects will approach the extent of the 1.12-NM radius safety zone around the Terminal.

#### 5.2.2.3 Sea Bottom Sediments and Features (see Topic Report 6, Section 6.4)

Most of the major impacts to the sea bottom sediments and features will take place during construction. Structures anchored disturb the sea bottom beneath the structure and some seabottom adjacent to the

structure. Impacts from bottom area disturbance are of concern near sensitive areas such as topographic features, chemosynthetic communities, and archaeological sites.

Jetting of sea bottom sediments for pipeline trenching and terminal construction activities will cause sediment displacement (resuspension of sediments). Approximately 6,540 cubic yards (5,000 m3) of sediment will be resuspended for every 3,280 feet (one km) of pipeline trenched.

Sediment displacement is also expected to occur during pipe laying activities. Pipe laying barges use an array of eight 9.9 ton (9,000 kg) anchors to position the barge and to move it forward along the pipeline route. These anchors are continually moved as the pipe laying operation proceeds. The area affected by these anchors depends on water depth, wind, currents, chain length, and the size of the anchor and chain. Pipeline installation also disturbs some surrounding areas where anchors are set to hold the support vessels in place.

Mooring buoys may be placed near drilling rigs or platforms so that service vessels need not anchor, especially in deeper water. These temporarily installed anchors will most likely be smaller and lighter than those used for vessel anchoring and, thus, will have less impact on the sea bottom. Moreover, installing one buoy will preclude the need for numerous individual vessel-anchoring incidents. Service vessel anchoring is expected to occur only occasionally in shallow waters.

#### *5.2.2.4 Infrastructure Considerations*

The Port Pelican Project is designed to make maximum use of existing infrastructure, including:

- existing onshore fabrication yards will be used for the fabrication of major Terminal components;
- the PIPL will connect to existing offshore gas gathering lines to transport gas to the U.S. natural gas pipeline system; and
- existing onshore support facilities will be used for support of Terminal operations.

The only new infrastructure to be created by this project is the Terminal itself and PIPL connecting the Terminal to the existing gas gathering infrastructure. The Terminal site has been selected to minimize environmental impacts and to ensure safe operation.

#### *5.2.2.5 Potentially Important Uses (see Topic Report 6, Section 6.2)*

Louisiana's economic offshore geologic resources include phosphate, sulphur, salt, oyster-shell, limestone, sand and gravel, magnesia, oil, and gas. Most of the mapped potential offshore sand sources occur within Louisiana's state waters. Currently, there are two producing sulphur operations offshore, both on the outer continental shelf (OCS). The Main Pass Sulphur Mine, with sulphur reserves that exceed all of the other remaining U.S. reserves combined, and the Caminada Mine are both located east of the Mississippi River delta. Additionally, salt mining from diapiric structures beneath the OCS may be possible.

The OCS of the Gulf of Mexico is a very active area oil and gas exploration and production. The large amounts of sediment carried by the Mississippi River over the past 20 million years have created a major sedimentary basin with optimum characteristics for the successful formation and accumulation of oil and gas.

No mineral resources will be affected by the proposed project. The proposed Pelican Terminal will be located in a block that is currently not leased. The PIPL will cross leased blocks, but will not impact oil or

natural gas production, any active or inactive sand mining areas, sulphur mines or any other areas where commercially exploitable mineral resources are currently being exploited.

Commercial and recreational uses associated with fisheries are of the Project area discussed in Section 5.2.4.

#### *5.2.2.6 Sediment Quality Considerations (see Topic Report 2)*

Most studies of offshore Gulf of Mexico sediments report metal concentrations that are not elevated compared to natural concentrations. Exceptions are in areas within one to three kilometers of production platforms, where high concentrations of drill cuttings and drilling mud are found. In these areas, barium and chromium, (components of drilling mud cuttings) and nickel and vanadium (associated with product oils) can be elevated. Hydrocarbons in sediments from the Gulf of Mexico are a mixture of terrigenous, petroleum, and planktonic hydrocarbons. Measurable petroleum inputs, due to natural seepage, have been found at all sites sampled in the Gulf of Mexico

The Port Pelican Project will not be in proximity to any offshore oil and gas production or exploration locations. As a result, no contaminated sediments are expected in the project area. Jetting of sediments to excavate the sea floor for GBS placement and pipeline installation will utilize sea water and will not introduce contaminants into the sea floor sediments.

#### *5.2.2.7 Groundwater Resources (see Topic Report 2, Section 2.1)*

Groundwater in the Port Pelican Project area consists of a single aquifer, the Coastal Lowlands Aquifer. Although the aquifer extends to the edge of the continental shelf in the Gulf of Mexico, mixing with sea water in offshore areas causes the aquifer to be saline and unsuitable as a freshwater resource.

The Port Pelican Project will not utilize any groundwater resources and has little or no potential to contaminate groundwater. Since the aquifer slopes towards the Gulf of Mexico, any contaminants introduced into the aquifer in the Project area would move away from usable onshore groundwater resources.

#### *5.2.2.8 Cultural Resources (see Topic Report 4)*

A high resolution geophysical survey of the Terminal area was made from aboard the R/*V Seis Surveyor* August 25 through 29, 2002. Data collected from the survey were assessed for evidence of shipwrecks and high probability areas for prehistoric archeological sites associated with formerly subaerially exposed landforms. The results of this survey indicate that the Project will have no effect on historic or prehistoric resources.

A survey of the PIPL will be made during Qtr. 1, 2003. Once completed results will be forwarded to Commandant and MMS. Should anomalies be found and not satisfactorily evaluated the area would be avoided.

### *5.2.3 Design, Construction and Operation*

#### *5.2.3.1 Effluents, Air Emissions, and Noise*

##### *5.2.3.1.1 Effluents and Water Quality (see Topic Report 2)*

Operational sources of effluent will be as follows:

- Open rack vaporizers (ORV) will discharge sea water used in the ORVs that has been treated with sodium hypochlorite. At the point of discharge, the ORV water will be approximately 20° F cooler

than the ambient sea water. The water temperature will be within 2° F of ambient 200 feet from the discharge point. The estimated chlorine concentration at the edge of the mixing zone after discharge is 0.01 ppm.

- Gray and black water from the quarters building, maintenance/control room, lab, warehouse building, and electrical building will be treated in a chemical or biological sanitary waste system prior to discharge in accordance with NPDES permit parameters.

- Drainage water from the deck consisting of rainwater and wash water will be treated in an oily water treatment system that includes a CPI separator before being discharged. The resulting discharge will contain less than 20 ppm of oil.

- Brine water from the reverse osmosis freshwater supply plant will be neutralized with hydrochloric acid with hydroxide or lime. The salinity of the discharged water will be higher than the salinity of the ambient water. However, there will be no significant impact from this discharge due to its small quantity (30 gallons per month discharged intermittently).

During construction, potential sources of impacts on water quality will be as follows:

- Placement of the gravity based structures (GBS units) comprising the Port Pelican Terminal will produce turbidity due to disturbance of bottom sediments. Pipeline trenching to install the Pelican Interconnector Pipeline will also produce turbidity along the pipeline corridor. Water quality will return to normal within minutes to hours without mitigation.

- Hydrostatic testing of the Pelican Interconnector Pipeline will be conducted to ensure integrity of the new pipeline prior to beginning operations. Sea water without chemical additives will be used for testing. The water will be discharged back to the Gulf of Mexico when testing is complete. No impact on water quality is expected from this discharge.

#### *5.2.3.2 Air Emissions and Air Quality (see Topic Report 9)*

During construction, the pipe laying barge and other barges and vessels working offshore will produce air emissions. Most emissions will result from fuel combustion in the barge and support boat engines, and would consist of $NO_x$, and CO, and small amounts of VOC, $PM_{10}$ and $SO_2$. Since construction does not occur at a single location for any significant length of time, the impact of these emissions at any single location would be minor and short-term. Offshore equipment emissions would be transient due to weather conditions and extremely variable in intensity. The emissions from construction equipment should have an insignificant impact on the air quality of the region.

It is expected that construction of the proposed facilities would increase noise levels in the vicinity of the project areas, but no onshore Noise Sensitive Areas would be affected since the Project would be located 32 NM offshore. Pipeline construction will proceed at a rate of about several hundred feet per day. Due to the assembly-line method of construction, activities in one area could last from several weeks to several months intermittently. Construction equipment will be maintained in accordance with manufacturer's specifications to minimize noise impacts.

Operational sources of air emissions are summarized in Table 5.2-1. The most significant sources of air emissions will be from the turbine generators, which will be fueled by pipeline-quality LNG boil-off gas. Each turbine will emit an estimated 486 tons per year (TPY) of priority pollutant emissions (973 TPY total). Application of Best Available Control Technology (BACT) will result in emissions per turbine of carbon monoxide (189 TPY), nitrogen dioxide (295 TPY), particulate materials (0 TPY), sulfur dioxide (0 TPY), volatile organic compounds (2.0 TPY), based on MMS Form 139 calculations.

LNG boil-off gas from the Terminal storage tanks and from working losses during LNG carrier offloading and LNG send off will be recovered using a vapor recovery system to the extent possible. The remainder of LNG boil-off gas will be used to fuel the turbine generators or sent to the flare. The flare will be continuously purged with nitrogen to prevent air infiltration through the flare tip and promote complete combustion of hydrocarbons.

The fuel gas compressor, boil-off gas compressor, various pumps, heaters, scrubbers, and utility equipment will be electric powered. No air emissions will be generated by this equipment.

#### *5.2.3.3 Noise (see Topic Report 9)*

The equipment at the Port Pelican Terminal will operate at a noise level of about 85 to 120 decibels (dB). Noise abatement features include sound enclosures and acoustic walls. The pipeline will be buried beneath the sea floor and its operation would not be a significant source of noise to the surrounding environment. Equipment and layout at the Terminal is designed so noise levels will not exceed a time-weighted average (TWA) of 85 dBA (A-weighted decibels) in order to reduce the potential for noise-induced hearing loss.

#### *5.2.3.4 Spills and Releases (see Topic Report 2)*

Potential sources of spills and releases from Terminal operations will be as follows:

- Spills of LNG, lubricants or fuels (primarily diesel) from operational equipment.
- Spills of diesel, aviation fuel, or waste oil during transfer operations or from tank failure.
- Spills of LNG during transfer operations or from failure of storage tanks.

By far the primary hydrocarbon at the Terminal will be LNG. The LNG is received at the Terminal in a liquid state at a temperature of approximately -255°F. At ambient temperature, spilled LNG will undergo a rapid phase transition from liquid to gas. When the phase transition is complete, the LNG will be completely vaporized, leaving no residue or water quality impact.

The process areas of the Terminal will be curbed for containment of spills per the requirements of NFPA 59A. Equipment that has the potential to release hydrocarbons outside of curbed area is designed to be installed on skids with drain pans designed to hold any potential hydrocarbon and rainwater.

Spills, wash water, and rainwater within curbed areas and from equipment skids will drain to impoundment basins. The fluids will then flow to a corrugated plate interceptor (CPI) separator which will separate hydrocarbons from water. The hydrocarbons will be collected in a waste oil tank and the water will be discharged in accordance with NPDES permit requirements.

Facility maintenance procedures will address hydraulic and lube oil spill cleanup from vehicles and other mobile equipment in areas of the Terminal that are not curbed.

The 250-bbl diesel tank will be located within a secondary containment area. The tank will have an automatic level control to prevent overfilling. Two, 700-gallon portable tanks will be used for storage of aviation fuel, and two, portable tanks will be used for storage of waste oil. Each portable tank will be skid-mounted with an integrated pan for containment of minor spills or leaks. Procedural controls will be implemented to ensure that spills do not occur during transfer operations. Because of the relatively small quantities of diesel, aviation fuel, and waste oil being stored at the Terminal, any spill of these materials is likely to be small.

The integral LNG storage tanks in the Terminal structure will consist of an insulated, stainless steel or aluminum primary tank constructed within the concrete interior of the GBS, which provides secondary containment for the tanks. The GBS units are protected from vessel impacts by a system of mooring and breasting dolphins. Procedural controls will be implemented to ensure that spills do not occur during LNG transfer operations. LNG spills will undergo rapid phase transition from liquid to gas, leaving no residue or water quality impacts.

The Terminal will be equipped with an appropriate supply of spill containment and response equipment and personnel will be trained in emergency response procedures. A rescue/support boat capable of carrying six persons will be outfitted to deploy light containment boom in the event of a small oil spill.

#### *5.2.3.5 Waste, Spoil and Refuse Material Generation and Management*

No dredging will be performed during the construction of the Port Pelican Project. Jetting of sea bottom sediments will be used to install the GBS units and the PIPL. No maintenance dredging around the Terminal will be required.

Solid wastes will be generated by the following activities taking place at the Terminal:

- Maintenance wastes (metal turnings, sand blast waste, oily rags, etc.) will be generated intermittently.
- Garbage (paper waste, packaging wastes, etc) will be generated at a rate of 250 lb/day (50 persons at five lb/day per person).
- Waste solvent drums, paint cans, hazardous solids, etc. will be generated intermittently.

All solid waste from the Terminal will be collected and periodically brought to the shore facility for disposal at permitted solid waste facilities. Waste shipments from the Terminal will be manifested and disposed in accordance with applicable regulations.

The Terminal design will include the necessary secure storage buildings, paint lockers, transfer dollies, etc. for safe storage of hazardous materials and the safe transport of hazardous wastes to shore for final disposal. Hazardous wastes will be minimized by using the following techniques:

- standardized lubricants, solvents, and hazardous materials will be used where appropriate;
- non-hazardous materials will be substituted for hazardous materials where possible; and
- solvents and hazardous materials will be recycled, reused, or regenerated where possible.

### *5.2.4 Land Use and Coastal Zone Management (see Topic Report 8)*

The Terminal will be fabricated at existing shore facilities, then transported to the Terminal location for final assembly and installation. The GBS units, pipe segments, and other materials required for construction of the offshore portion of the pipeline will be transferred directly from delivery vessels to offshore construction barges. Project-dedicated onshore pipeyards or contractor yards will not be required, eliminating the need for additional permitting of onshore sites.

Fabrication activities necessary to build the Port Pelican Terminal structures are similar to the kinds of activities already being conducted at the four fabrication sites under consideration. No extra space would be required for either fabrication or construction purposes. No extra land or yard will be required for the operation. Incremental increases in vessel traffic, helicopters, and shuttle tankering would

produce the potential for increased conflicts with other uses of surface, airspace, and underwater areas, but these impacts are expected to be negligible.

The Port Pelican Terminal will be located approximately 32 NM offshore of Louisiana in the Gulf of Mexico. This area of the Gulf of Mexico is extensively developed for offshore oil and gas production. No areas are reserved for military exercises in this part of the Gulf of Mexico.

There is limited ship traffic in the area of the Port Pelican Project and along the proposed vessel route from Sabine Fairway to the Terminal. Impacts to shipping and navigation routes in the Gulf include increases in vessel traffic, increase in probability of vessel collisions, blockage of navigation channels, and the potential of the pipeline itself being damaged by ships or anchors. Use of best industry practices would minimize the probability of damage, and the Terminal location has been selected to avoid shipping lanes and navigation channels.

Offshore marine recreational fishing and diving are major recreational activities occurring on the outer continental shelf. Most of the offshore recreational fishing in the Central Gulf of Mexico Planning Area is directly associated with oil and gas structures. At least 46 different fish species are caught by recreational anglers fishing near oil and gas platforms in the central Gulf of Mexico. It is expected that the Terminal will provide similar enhanced artificial habitat. However, fishing will not be allowed in proximity to the Terminal because of safety and security considerations.

Potential negative impacts to recreation from the Terminal would include reduced fish catches, or disturbed fish habitats (both commercial and recreational) or impacts to visual aesthetics. Construction activities, because they are short-term and localized, are typically temporary and not significant. Fish would likely avoid areas during construction activity, but would likely recolonize the areas following construction. The Terminal safety zone might present a potential navigational barrier for deep-sea fishers.

No significant long-term impacts on recreational and aesthetic resources have been identified or projected as a result of construction or operation of the Terminal.

Section
6

# 6 Regulatory Compliance and Federal Authorizations

## 6.1 Sections 5 and 6 of the Deepwater Port Act of 1974 (amended, 2002)

This Application is being submitted in compliance with Sections 5 and 6 of the Deepwater Port Act of 1974 as amended in 2002. This application was prepared in accordance with 33 CFR Parts 148, 149, and 150 (Proposed Rules, Federal Register, Volume 67, No. 104, May 30, 2002).

A cross reference between this Application and the proposed rules is provided in the Table of Contents.

## 6.2 National Environmental Policy Act

The National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321 et seq.) is the foundation of modern American environmental protection in the United States and its commonwealths, territories, and possessions. NEPA requires that Federal agency decision makers consider all reasonably foreseeable environmental effects of their proposed actions and to involve and inform the public in the decision making process.

This application provides environmental information pursuant to 33 CFR Parts 148, 149 and 150 (Proposed Rules, Federal Register, Volume 67, No. 104, May 30, 2002). The Applicant is supportive of the USCG need to comply with NEPA. The Environmental Report (Volume II) is presented to aid in conducting this review. The Applicant is in the process of developing outreach programs for use in seeking public input during the review of this Application. This information will be made available upon request.

## 6.3 Federal Water Pollution Control Act (Clean Water Act)

Although the Port Pelican Project is considered a “new source” for purposes of the Federal Water Pollution Act, the EPA has not promulgated performance standards for deepwater ports. Therefore, the Terminal is not subject to new source performance standards under the Federal Water Pollution Control Act.

### 6.3.1 Section 401(a)(1) Certification

The Environmental Protection Agency (EPA) has jurisdiction for this Project because the Project is located outside state waters. The EPA staff coordination with State of Louisiana Department of Environmental Quality is expected to be informal.

### 6.3.2 NPDES Short Form D Information

A pre-filing draft of the NPDES application is included in the Confidential–Sensitive Information document. The application will be completed and expected to be filed in Qtr. 1, 2003.

## 6.4 Coastal Zone Management Act

### 6.4.1 Section 307 Certification

The Pelican Terminal will be located approximately 32 NM off the coast of Louisiana and is therefore not subject to the Coastal Zone Management Act.

## 6.5 Dredge and Fill Data

### 6.5.1 U.S. Army Permit Requirements

Regulatory jurisdiction for this Project has not been clearly defined at this time. Navigation topics are being addressed by the U.S. Coast Guard. Dredge and fill requirements do not appear to be applicable because of the offshore location for this Project.

## 6.6 Clean Air Act

Regulations at 30 CFR Part 250.303 empower MMS to conduct a review of onshore air impacts which result from an offshore facility, to ensure that the National Ambient Air Quality Standards are not exceeded (Title 1 of Clean Air Act). MMS has informed Port Pelican LLC that it will consult with the EPA to determine jurisdiction.

The Port Pelican Project is considered a “new source” for purposes of the Clean Air Act. As a new source, the Terminal will be subject to New Source Review (NSR) regulations under the Act. The NSR program is designed to ensure that new facilities will not threaten air quality while allowing for economic growth. The NSR program has been in effect since1980.

There are two parts of NSR program; “non-attainment area review” and “Prevention of Significant Deterioration” (PSD) or its equivalent (PSD is an EPA term, not found in the MMS regulations; however, MMS analyses are relatively equivalent to those of EPA). The Terminal will not be located in a non-attainment area. Therefore, the non-attainment review criteria are not applicable.

The air impacts analysis will require modeling of the Terminal emissions with a view toward effects on coastal air quality. It is not anticipated that emissions from the Terminal will have any effect on coastal air quality within the meaning of the Clean Air Act.

## 6.7 Marine Protection, Research and Sanctuaries Act

The Marine Protection, Research, and Sanctuaries Act (MPRSA) regulates the ocean dumping of waste, provides for a research program on ocean dumping, and provides for the designation and regulation of marine sanctuaries. Often known as the Ocean Dumping Act, this act regulates the ocean dumping of all material beyond the territorial limit (three miles from shore) and prevents or strictly limits dumping material that "would adversely affect human health, welfare, or amenities, or the marine environment, ecological systems, or economic potentialities." Material includes, but is not limited to dredged material; solid waste; incinerator residue; garbage; sewage; sewage sludge; munitions; chemical and biological warfare agents; radioactive materials; chemicals; biological and laboratory waste; wrecked or discarded equipment; rocks; sand; excavation debris; and industrial, municipal, agricultural, and other waste. The term does not include sewage from vessels or oil, unless the oil is transported via a vessel or aircraft for the purpose of dumping. Disposal by means of a pipe, regardless of how far at sea the discharge occurs, is regulated by the Clean Water Act, through the NPDES permit process.

Port Pelican will comply with this Act through compliance with the Clean Water Act. In addition, facility management practices are designed to prevent wastes from being discharged without proper treatment.

## 6.8 Endangered Species Act

The Endangered Species Act provides a program for the conservation of threatened and endangered plants and animals and the habitats in which they are found. The law prohibits any action, administrative or real, that results in a "taking" of a listed species, or adversely affects habitat. Likewise, import, export, interstate, and foreign commerce of listed species are all prohibited.

The installation of the Terminal may create short term “harassment” conditions to sensitive species. Consultation with National Marine Fisheries Services staff will be done during preparation of the detailed design. Necessary approvals or permits will be obtained if required before installation.

## 6.9 Marine Mammal Protection Act

Under the MMPA, the Secretary of Commerce is responsible for the conservation and management of pinnipeds (other than walruses) and cetaceans. The Secretary of the Interior is responsible for walruses, sea and marine otters, polar bears, manatees and dugongs. The Secretary of Commerce delegated MMPA authority to National Marine Fisheries Service. Part of the responsibility that NMFS has under the MMPA involves monitoring populations of marine mammals to make sure that they stay at optimum levels. If a population falls below its optimum level, it is designated as "depleted," and a conservation plan is developed to guide research and management actions to restore the population to healthy levels.

This project is not expected to impact populations of marine mammals to the point of developing a conservation plan for populations in the vicinity of the Terminal. Port Pelican LLC will consult with NMFS regarding marine mammals and implement appropriate mitigations measures as necessary.

## 6.10 National Historic Preservation Act

Section 106 of the National Historic Preservation Act, as amended, requires agencies to take into account the effect of their undertakings on properties in or eligible for listing in the National Register of Historic Places (NRHP) and to afford the Advisory Council on Historic Preservation (ACHP) an opportunity to comment on the undertaking. ChevronTexaco, as a non-federal party, is assisting the lead agency in meeting its obligations under Section 106 and the implementing regulations of 36 CFR 800, Executive Order 11593.

If evidence of prehistoric or historic cultural remains is encountered during installation of the Terminal or the PIPL, all activity in that area will be halted, and an avoidance zone for further work in that area will be established. The archeologists at the U.S. Department of the Interior Minerals Management Service in New Orleans will be notified immediately to ascertain the possible cultural significance of the feature encountered.

## 6.11 Comprehensive Environmental Response, Compensation, and Liabilities Act (CERCLA)

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund, was enacted by Congress on December 11, 1980. This law created a tax on the chemical and petroleum industries and provided broad Federal authority to respond directly to releases or threatened releases of hazardous substances that may endanger public health or the environment.

The Applicant, through sound engineering design of the Terminal and proper operation of the Terminal seeks to avoid situations where the application of CERCLA mandated provisions would be implemented by the USCG.

## 6.12 Natural Gas Act

Under Section 3 of the Natural Gas Act as amended, the importation of natural gas into the US requires approval from the Department of Energy (DOE). DOE is responsible for issuing licenses to import natural gas and LNG from foreign countries. The Office of Fossil Energy (DOE) has been delegated the authority to issue import licenses in a timely manner. Importation regulations are found at 10 CFR Part 590.

Since LNG will be received at Port Pelican from foreign sources, it is conceivable that an import license may be required at some point in the future. Port Pelican does not anticipate applying for an import license at this time. The LNG importer will apply for an import license at the appropriate time.

The Maritime Security Act of 2002 contains provisions that affect the applicability of the Natural Gas to deepwater ports. It states that the Act applies to the acceptance, transport, storage, regassification, or conveyance of natural gas at or through a deepwater port, to the exclusion of the

Natural Gas Act or any regulation issued under the NGA. Applicant anticipates that license requirements will be imposed on the importation of LNG by the appropriate federal agency.

## 6.13 Outer Continental Shelf Lands Act

Under the Outer Continental Shelf Lands Act, the Secretary of the Department of the Interior (DOI) is responsible for managing the exploration and production of mineral resources underlying the Outer Continental Shelf (OCS). This responsibility has been delegated to the Minerals Management Service (MMS).

Regulatory processes and jurisdictional authority concerning pipelines on the OCS and in coastal areas are shared by several federal agencies, including DOI, the Department of Transportation (DOT), U.S. Army Corps of Engineers (COE), the Federal Energy Regulatory Commission (FERC), and U.S. Coast Guard (USCG). In addition to regulating pipelines, these agencies have the responsibility of overseeing and regulating the following areas: the placement of structures on the OCS and pipelines in areas that affect navigation; the certification of proposed projects involving the transportation or sale of interstate natural gas, including OCS gas; and the right of eminent domain exercised by pipeline companies. In addition, the Office of Pipeline Safety (DOT) is responsible for promulgating and enforcing safety regulations for the transportation in or affecting interstate commerce of natural gas, liquefied natural gas (LNG), and hazardous liquids by pipeline. The regulations are contained in 49 CFR 191-193 and 195.

With the passage of the Maritime Transportation Security Act of 2002, the Secretary of the Department of Transportation has been designated as having the authority to grant a license for the siting, construction, and operation of a Deepwater Port. The US Coast Guard has been designated as the responsible agency under the Act. They in turn will issue regulations for the construction and operation of Port Pelican, including any appurtenant pipelines.

Section

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# 7 Certification Statement

## 7.1 Statement of Veracity

~~DISTRICT OF COLUMBIA~~ State of Maryland

ss:

Richard A. Lammons, being first duly sworn on his oath disposes and says that he is Vice President of Port Pelican LLC, that he has read the foregoing submittal and is familiar with the contents thereof, that all the statements and matters contained therein are true and correct to the best of his information, knowledge and belief, and that he is authorized to execute and file the same with the United States ~~Coast~~ Guard.

Richard A. Lammons
Vice President
Port Pelican LLC

Sworn to and subscribed before me this 25th day of November, 2002.

Notary Public

In and For State of Maryland County of Montgomery

My Commission Expires:

08/01/05

# Attachment 1
# Incorporation Documents

# Delaware



*The First State*

I, HARRIET SMITH WINDSOR, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF FORMATION OF "PORT PELICAN LLC", FILED IN THIS OFFICE ON THE FIRST DAY OF NOVEMBER, A.D. 2002, AT 9 O'CLOCK A.M.

Harriet Smith Windsor

Harriet Smith Windsor, Secretary of State

3586937 8100

020678222

AUTHENTICATION: 2069499

DATE: 11-04-02

CERTIFICATE OF FORMATION
OF
PORT PELICAN LLC
* * * * * * * *

THE UNDERSIGNED, an authorized natural person, for the purpose of forming a limited liability company, under the provisions and subject to the requirements of the State of Delaware (particularly Chapter 18, Title 6 of the Delaware Code and the acts amendatory thereof and supplemental thereto, and known, identified and referred to as the "Delaware Limited Liability Company Act"), hereby certify that:

1. The name of the limited liability company is

Port Pelican LLC

2. The address of its registered office in the State of Delaware is 2711 Centerville Road, Suite 400, in the City of Wilmington, County of New Castle. The name of its registered agent at such address is Corporation Service Company.

IN WITNESS WHEREOF, the undersigned has executed this Certificate of Formation of Port Pelican LLC this 1st day of November, 2002.

Kimberley C. Schafer

# LIMITED LIABILITY COMPANY AGREEMENT OF PORT PELICAN LLC

THE UNDERSIGNED is executing this Limited Liability Company Agreement ("Agreement") for the purpose of forming and operating a limited liability company (the "Company") pursuant to the provisions of the Delaware Limited Liability Company Act, 6 *Del. Code* § 18-101 *et seq.* (the "LLC Act"), and does hereby certify and agree as follows:

1. **Name; Organization**. The name of the Company shall be **PORT PELICAN LLC**, or such other name as the Board of Directors may from time to time hereafter designate. The Company was formed on November 1, 2002, upon the execution and filing of a certificate of formation of the Company with the Secretary of State of the State of Delaware setting forth the information required by section 18-201 of the LLC Act.

2. **Definitions**. In addition to terms otherwise defined herein, the following terms are used herein as defined below:

"Board of Directors" means the Board of Directors designated in Section 7 hereof.

"By-Laws" shall mean the By-Laws of the Company as amended from time to time which By-Laws are expressly incorporated herein by reference as part of this Agreement. The initial By-Laws of the Company are attached hereto as Exhibit A and are hereby adopted and approved by the Member.

"Corporate Servant" means any natural person who is or was a director, officer, employee or agent of the Company, or is or was serving at the request of the Company as a director, officer, manager, partner, trustee, employee or agent of another corporation, partnership, joint venture, trust or other organization or enterprise, nonprofit or otherwise, including an employee benefit plan;

"Director" means a member of the Board of Directors as designated in, or selected pursuant to, Section 7 hereof, and shall be deemed in all respects to be a "manager" as set forth in section 18-101(10) of the LLC Act.

"indemnify" means to hold harmless against expenses (including attorneys' fees), judgments, fines (including excise taxes assessed with respect to an employee benefit plan) and amounts paid in settlement actually and reasonably incurred by the Corporate Servant in connection with a Proceeding;

"Interest" means the ownership interest of the Member in the Company (which shall be considered personal property for all purposes), consisting of (i) the Member's Percentage Interest in profits, losses, allocations, and distributions, (ii) the Member's right to vote or grant or withhold consents with respect to Company matters as provided herein or in the LLC Act and (iii) the Member's other rights and privileges as herein provided.

"Member" means **CHEVRON U.S.A. INC.**, a Pennsylvania corporation.

"Percentage Interest" means the Member's share of the profits and losses of the Company and the Member's percentage right to receive distributions of the Company's assets. The Percentage Interest of the Member shall be 100%.

"Proceeding" means any threatened, pending or completed action, suit or proceeding, whether civil, criminal or administrative.

3. **Purpose**. The purpose of the Company shall be to engage in any lawful business that may be engaged in by a limited liability company organized under the LLC Act, as such business activities may be determined by the Board of Directors from time to time.

4. **Offices**.

(a) The principal office of the Company, and such additional offices as the Board of Directors may determine to establish, shall be located at such place or places inside or outside the State of Delaware as the Board of Directors may designate from time to time.

(b) The registered office of the Company in the State of Delaware is located at 2711 Centerville Road, City of Wilmington, County of New Castle, Delaware. The registered agent of the Company for service of process at such address is CSC The United States Corporation Company.

5. **Members**. The Company shall have one Member. The name and address of the sole Member is **Chevron U.S.A. Inc.**, 575 Market Street, San Francisco, California 94105.

6. **Term**. The Company shall continue until dissolved and terminated in accordance with Section 10 of this Agreement.

7. **Management of the Company**.

(a) Subject to the delegation of rights and powers as provided for herein and in the By-Laws, the Board of Directors shall have the sole right to manage the business of the Company and shall have all powers and rights necessary, appropriate or advisable to effectuate and carry out the purposes and business of the Company. The Member, by reason of its status as such, shall not have any authority to act for or bind the Company but shall have only the right to vote on or approve the actions herein specified to be voted on or approved by the Member.

(b) The officers of the Company shall be elected, removed, and perform such functions as are provided in the By-Laws. The Board of Directors may appoint, employ or otherwise contract with such other persons or entities for the transaction of the business of the Company or the performance of services for or on behalf of the Company as it shall determine in its sole discretion. The Board of Directors may delegate to any officer of the Company or to any such other person or entity such authority to act on behalf of the Company as the Board of Directors may from time to time deem appropriate in its sole discretion.

(c) Except as otherwise provided by the Board of Directors or in the By-Laws, when the taking of such action has been authorized by the Board of Directors, any Director, any officer of the Company or any other person specifically authorized by the Board of Directors, may execute any contract or other agreement or document on behalf of the Company and may execute and file on behalf of the Company with the Secretary of State of the State of Delaware any certificates of correction of, or certificates of amendment to, the Company's certificate of organization, one or more restated certificates of organization and certificates of merger or consolidation and, upon the dissolution and completion of winding up of the Company, as provided in the LLC Act, a certificate of cancellation canceling the Company's certificate of formation.

(d) The Board of Directors shall have between one and six Directors or such other number as the Board of Directors shall determine. The Board of Directors shall initially be composed of the following individual:

Kimberley C. Schafer

(e) Vacancies on the Board of Directors from whatever cause shall be filled in the manner provided in the By-Laws. Determinations to be made by the Board of Directors in connection with the conduct of the business of the Company shall be made in the manner provided in the By-Laws, unless otherwise specifically provided herein.

8. **Capital Contributions; Administrative Matters**.

(a) The Member has contributed to the Company one hundred dollars ($100) in cash. The Member shall have no obligation to make any further capital contributions to the Company.

(b) The Company hereby designates the Member as "Tax Matters Partner" for the purposes of the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder.

9. **Distributions**. Distributions of cash or other assets of the Company shall be made at such times and in such amounts as the Board of Directors may determine.

10. **Dissolution**. The Company shall be dissolved and its affairs wound up and terminated upon the first to occur of the following:

(a) The consent of the Member to dissolve the Company; or

(b) Any other event causing a dissolution of the Company under the LLC Act.

11. **Liquidation**. If the Company shall be dissolved by reason of the occurrence of any of the circumstances described in Section 10, no further business shall be conducted by the Company except for the taking of such action as shall be necessary for the winding up of the Company's affairs and the distribution of the Company's assets to the Member. Upon such

dissolution, the Member shall act as liquidator or, if it is unable or unwilling to do so, the Member shall select a liquidator. The Member or the liquidator selected by the Member, as the case may be, shall have full authority to wind up the affairs of the Company, to make a final distribution to the Member and to file a certificate of cancellation pursuant to section 18-203 of the LLC Act upon completion of the winding up of the Company.

12. **Reorganizations and Restructurings**. The Company shall have the right and authority, with the consent of the Member, to reorganize and restructure as needed.

13. **Limitation on Liability**. The debts, obligations, and liabilities of the Company, whether arising in contract, tort, or otherwise, shall be solely the debts, obligations, and liabilities of the Company, and no Member, Director, or officer of the Company shall be obligated personally for any such debt, obligation, or liability of the Company solely by reason of being a Member, Director, and/or officer.

14. **Standard of Care; Indemnification of Directors, Officers, Employees, and Agents**.

(a) Each Director of the Company shall stand in a fiduciary relation to the Company and shall perform his or her duties as a director, including his or her duties as a member of any committee of the Board of Directors upon which he or she may serve, in good faith, in a manner he or she reasonably believes to be in the best interests of the Company and with such care, including reasonable inquiry, skill and diligence, as a person of ordinary prudence would use under similar circumstances.

(b) The Member shall have no duties to the Company solely by reason of acting in its capacity as a member.

(c) A Director of the Company shall not be liable to the Company or its Member for monetary damages for breach of fiduciary duty as a director, except for liability (a) for any breach of the director's duty of loyalty to the Company or its Member; (b) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law; or (c) for any transaction from which the Director derived an improper personal benefit.

(d) To the fullest extent authorized by the LLC Act, the Company shall indemnify any Corporate Servant who was or is a party or is threatened to be made a party to and proceeding by reason of the fact that such person was or is a Corporate Servant.

(e) In serving or continuing to serve the Company, a Corporate Servant is entitled to rely and shall be presumed to have relied on the rights granted pursuant to the foregoing provisions of this Section 14, which shall be enforceable as contract rights and inure to the benefit of the heirs, executors and administrators of the Corporate Servant; and no repeal or modification of the foregoing provisions of this Section 14 shall adversely affect any right existing at the time of such repeal or modification.

(f) The Board is authorized, to the extent permitted by the Section 14 to cause the

Company to pay expenses incurred by Corporate Servants in defending Proceedings and to purchase and maintain insurance on their behalf whether or not the Company would have the power to indemnify them under the provisions of this Section 14 or otherwise.

(g) Any right or privilege conferred by or pursuant to the provision of this Section 14 shall not be exclusive of any other rights to which any Corporate Servant may otherwise be entitled.

(h) The contract rights to indemnification and to the advancement of expenses conferred in this Section 13 shall not be exclusive of any other right that any person may have or hereafter acquire under any statute, agreement, vote of the Directors or otherwise.

15. **Qualifications**. The Board of Directors shall have the authority to qualify the Company to do business in any foreign jurisdiction in which the conduct of the Company's business or the Company's ownership or leasing of property requires such qualification.

16. **Amendments**. This Agreement may be amended only upon the written consent of the Member.

17. **Governing Law**. This Agreement shall be governed by and construed in accordance with the domestic laws of the State of Delaware without giving effect to any choice of law or conflict of law provision or rule (whether of the State of Delaware or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of Delaware.

18. **Construction**. Words used herein, regardless of the number and gender used, shall be deemed and construed to include any other number, singular or plural, and any other gender, masculine, feminine, or neuter, as the context requires, and, as used herein, unless the context clearly requires otherwise, the words "hereof," "herein," and "hereunder" and words of similar import shall refer to this Agreement as a whole and not to any particular provisions hereof.

IN WITNESS WHEREOF, the undersigned Member has duly executed this Agreement as of the 6th day of November, 2002.

**CHEVRON U.S.A. INC.**

By: Kimberley C Schafer
Assistant Secretary

PORT PELICAN LLC

* * * * *

# MINUTES

# OF

# FIRST MEETING OF THE BOARD OF DIRECTORS

* * * * *

The first meeting of the board of directors of PORT PELICAN LLC (the "Company"), was held at 575 Market Street, San Francisco, California, on November 6, 2002, at 9:10 a.m.

There was present at the meeting: Kimberley C. Schafer.

With quorum established, the meeting was called to order.

## 1. APPROVAL OF COMPANY SEAL

RESOLVED: That the Secretary of this Company is hereby authorized to create a company seal bearing the words "PORT PELICAN LLC, Delaware, November 1, 2002", said seal to be adopted as the seal of the Company.

## 2. REGISTRATION TO DO BUSINESS

RESOLVED: That for the purpose of authorizing the Company to do business in any state, territory or dependency of the United States or any foreign country in which it is necessary or expedient for this Company to transact business, the proper officers of this Company are hereby authorized to appoint and substitute all necessary agents or attorneys for service of process, to designate and change the location of all necessary statutory offices and, under the company seal, to make and file all necessary certificates, reports, powers of attorney and other instruments as may be required by the laws of such state, territory, dependency or country to authorize the Company to transact business therein and whenever it is expedient for the Company to cease doing business therein and withdraw therefrom, to revoke any appointment of agent or attorney for service of process, and to file such certificates, reports, revocation of appointment, or surrender of authority as may be necessary to terminate the authority of the Company to do business in any such state, territory, dependency or country.

## 3. CAPITAL INVESTMENT

RESOLVED: That the offer of Chevron U.S.A. Inc., a Pennsylvania corporation, to contribute one hundred dollars (U.S. $100) in cash is accepted; and be it further

RESOLVED: That the proper officers of this Company be and they hereby are authorized to accept a capital contribution from Chevron U.S.A. Inc. in the amount of one hundred dollars (U.S. $100.00).

## 4. AGENT FOR SERVICE OF PROCESS

RESOLVED: That Corporation Service Company is engaged to furnish this Company with statutory representation services in each jurisdiction within the United States in which this Company is incorporated or qualified to do business (the "Applicable Jurisdictions"); and be it further

RESOLVED: That the designations and appointments of the person or persons presently furnishing statutory representation services to this Company in each Applicable Jurisdiction are revoked; and be it further

RESOLVED: That the appropriate officers of this Company are authorized and directed to cause to be prepared and filed and/or recorded with the appropriate authorities of each Applicable Jurisdiction any and all documents necessary for the appointment and designation of Corporation Service Company, its agents and/or representatives, as provider of statutory representation services; and be it further

RESOLVED: That Corporation Service Company is designated the Company's registered agent in the State of Delaware, and the following address is designated the Company's registered office in the State of Delaware: 2711 Centerville Road, Wilmington, New Castle County, Delaware 19805; and be it further

RESOLVED: That pursuant to the aforementioned engagement, Corporation Service Company, its agents and/or representatives, are authorized to accept on behalf of this Company any legal process, orders, demands, notices, and other legal documents which may be served upon this Company in each Applicable Jurisdiction; and be it further

RESOLVED: That in each Applicable Jurisdiction, the resolutions herein set forth shall take effect with respect to this Company at the effective time and date of the requisite documents in each Applicable Jurisdiction.

## 5. APPOINTMENT OF OFFICERS

The following persons are hereby appointed as officers of the Company to take effect at the close of this meeting, to serve until their respective successors are chosen and qualify:

| | |
|---|---|
| President | George L. Kirkland |
| Vice-President | Audie P. Setters |
| Vice-President | Edward B. Scott |
| Vice-President | Sandy Cornelius |
| Vice-President | Blake J. Koc |
| Vice-President | Richard A. Lammons |
| Secretary | Walker C. Taylor |
| Treasurer | Howard B. Sheppard |
| Assistant Secretary | Warren J. Brechtel |
| Assistant Secretary | Yezdi Guzdar |
| Assistant Secretary | John H. Jones, Jr. |

| | |
|---|---|
| Assistant Secretary | Anthony J. Knaapen |
| Assistant Secretary | Kimberley C. Schafer |
| Assistant Secretary | Frank G. Soler |
| Assistant Secretary | Gordon Tsuchiya |
| Assistant Secretary | Hongyan Xun |
| Assistant Treasurer | Robert C. Gordan |
| Assistant Treasurer | Richard E. Lee |
| Assistant Treasurer | James D. Lyness |
| Assistant Treasurer | Stephen H. Peth |

## 6. GENERAL AUTHORITY RESOLUTIONS

RESOLVED: That any officer of this Company or any division thereof is empowered in such capacity to execute for and on behalf of this Company (without the necessity of affixing the company seal) all papers requiring execution in the name of this Company, except no authority is conferred by this resolution for execution of any of the following:

(a) leases to others covering oil, gas or other hydrocarbon or nonhydrocarbon minerals underlying fee lands of this Company, or deeds or conveyances to others, covering fee lands of this Company, other than rights of way and similar easements, where either book value or sale price exceeds $500,000;

(b) documents, instruments or promissory notes in support of any borrowings, provided, however, that the promissory notes and other documents given as consideration for the acquisition of real or personal property shall not be deemed to constitute a borrowing;

(c) documents or agreements establishing bank accounts in the name of this Company, or withdrawing of funds or closing of any bank accounts of this Company, and be it further

RESOLVED: That each party empowered by this resolution is authorized to affix the seal of this Company to such papers as require a seal and to acknowledge and deliver any such papers as fully as if special authority were granted in each particular instance; and be it further

RESOLVED: That any officer of this Company or any division thereof is empowered on behalf of this Company to appoint any person or persons whom they or any one of them may deem proper as Agents or Attorneys-in-Fact of this Company with the powers to do those things that the person making such appointment may lawfully do by virtue of the authority herein granted to them.

## 7. BANKING RESOLUTIONS

RESOLVED: That any two persons holding the following positions with this Company:

The President
Any Vice-President
The Treasurer
Any Assistant Treasurer

(collectively, "Authorizing Officers")

are authorized to:

(A) By written authorization, open, maintain, and close accounts with banks and other financial institutions; and

(B) By written authorization, designate officer(s) or other employee(s) of this Company or officer(s) or employee(s) of ChevronTexaco Corporation who shall have authority manually or by facsimile to sign and countersign checks, drafts, or other orders of payment, drawn on bank accounts of this Company; and

(C) By written authorization, request, authorize, and direct the designated depositaries of this Company (including their correspondent banks of such depositaries) to honor all checks or other items in this Company's name on its accounts designated in such authorization, when bearing the facsimile signature of any such person(s) named in such authorization. The designated depositaries (including their correspondent banks) shall be authorized to honor and to charge this Company's accounts at such depositaries for all such checks, regardless of by whom or by what means the facsimile signature or signatures thereon may have been affixed thereto, if such facsimile signature or signatures resemble the facsimile specimens from time to time filed with depositaries by any two of the Authorizing Officers of this Company; and

(D) By written authorization, designate the officer(s) or employee(s) of this Company or officer(s) or employee(s) of ChevronTexaco Corporation who shall have authority to issue instructions directing such banks and other financial institutions to transfer funds from accounts of this Company through various means including but not limited to transfers by check, draft, wire transfer, or automated clearing house; and

(E) By written authorization, designate officer(s) or other employee(s) of this Company or officer(s) or employee(s) of ChevronTexaco Corporation who shall have authority to (i) enter into contracts for purchase and/or sale of foreign exchange, either spot or forward, with any bank or other financial institution; (ii) execute and deliver any and all agreements or instruments evidencing such contracts; and (iii) execute renewals or extensions of such contracts on behalf of this Company; and be it further

RESOLVED: That, by written authorization, an Authorizing Officer may appoint a deputy to act as an Authorizing Officer in exercising any of the authorities described in paragraphs A, B and C of the preceding resolution; and be it further

RESOLVED: That any two of the Authorizing Officers are authorized and empowered in the name of and on behalf of this Company to cause letters of credit or guarantees to be issued in favor of third parties by such banks or other financial institutions, in such amounts as they may deem advisable and to execute applications for and other agreements and instruments related to such letters of credit as they may approve in form and substance, such approval to be conclusively evidenced by the execution and delivery thereof.

8. **INVESTMENT RESOLUTION**

RESOLVED: That any two persons holding the following positions with the Company:

The President
Any Vice-President
The Treasurer
Any Assistant Treasurer
(the "Authorizing Officers")

are authorized and empowered, in the name of and on behalf of this Company to enter into general agreements with any of ChevronTexaco Corporation's direct or indirect, wholly owned subsidiaries setting forth the terms and conditions on which such subsidiary will invest the excess funds of this Company and arrange for safekeeping for its securities by a custodian in connection with such investment transactions.

9. **ANNUAL MEETING RESOLUTION**

RESOLVED: That, the annual meeting of stockholders of this Company be set for the first Tuesday in November at 10:00 a.m. to be held at a location determined by the directors, provided that should said date fall upon a legal holiday, the annual meeting of stockholders shall be held at the same hour on the next day following that shall not be a legal holiday.

10. **BOARD MEETING RESOLUTION**

RESOLVED: That a regular meeting of the Board of Directors is set for each and every business day at 9:00 a.m. at such location as a quorum of Directors may choose.

11. **APPROVAL OF BY-LAWS**

RESOLVED: That the By-laws of PORT PELICAN LLC, a Delaware limited liability company, presented to this meeting and annexed to these minutes be approved and adopted as the By-laws of this Company.

12. **TAX RESOLUTIONS**

RESOLVED: That the General Tax Counsel of ChevronTexaco Corporation, as attorney-in-fact, is authorized to execute and deliver waivers, extensions, claims for refunds, returns and reports, file and prosecute protests, appeals and lawsuits, appear for, negotiate, compromise and settle on behalf of, represent, and bind this Company in all matters pertaining to federal windfall profit taxes, federal income taxes, partnership returns, realty and personal property taxes, state and local income, franchise, gross receipts, sales, use and profits taxes, customs duties, state and federal excise taxes, and all other similar taxes, duties and fees; and be it further

RESOLVED: That the General Tax Counsel of ChevronTexaco Corporation, as attorney-in-fact may delegate all or any portion of the authority granted in the foregoing resolution to such additional persons as he may deem desirable to carry out the provisions of the foregoing resolution and may sign certificates of authority to that effect.

13. **FISCAL YEAR**

RESOLVED: That the fiscal year of the Company shall be from January 1 to December 31.

14. **NUMBER OF DIRECTORS**

RESOLVED: That the number of the directors of the Company be and the same hereby is fixed at five.

15. **APPOINTMENT OF DIRECTORS**

The following persons were thereupon duly appointed as directors of the Company to take office as of the close of this meeting:

Darry W. Callahan
George L. Kirkland
Blake J. Koc
Edward B. Scott
Audie P. Setters

16. **CHEVRON POLICIES**

RESOLVED: That this Company adopt all the policies and practices of ChevronTexaco Corporation, a Delaware corporation.

17. **CAPITAL CONTRIBUTIONS**

RESOLVED: That any Officer of this Company is hereby authorized to execute any document and take any legal action required or necessary to effect any recommendation from the Internal Finance Committee of ChevronTexaco Corporation with regard to contributions to the capital of any subsidiary or affiliate of this Company.

Kimberley C Schafer
Kimberley C. Schafer

**Adopted November 6, 2002**

**Port Pelican LLC,**
**a Delaware limited liability company**

# BY-LAWS

## Preamble

These By-Laws shall be subject to the Limited Liability Company Agreement, as from time to time in effect (the "Agreement"), of **Port Pelican LLC**, a Delaware limited liability company (the "Company"). In the event of any inconsistency between the terms hereof and the terms of the Agreement, the terms of the Agreement shall control.

Capitalized terms used herein and not defined herein are used as defined in the Agreement.

## I.

## The Board of Directors

1. Authority of Board. The business and affairs of the Company shall be managed by or under the direction of the Board of Directors (the "Board") or, if authorized by the Board, by or under the direction of one or more committees thereof, to the extent permitted by law and by the Board. The Board or any such authorized committee may delegate management responsibility to the extent permitted by law and as deemed appropriate by the Board or such committee. Except as may be otherwise provided by law or these By-Laws or, in the case of a committee of the Board, by applicable resolution of the Board or such committee, the Board or any committee thereof may act by unanimous written consent or, at an authorized meeting at which a quorum is present, by the vote of the majority of the Directors present at the meeting. Except as may be otherwise provided by law, the Board shall have power to determine from time to time whether, and if allowed, when and under what conditions and regulations any of the accounts and books of the Company shall be open to inspection. The Board shall not be required to distribute an annual report to the Member of the Company.

2. Number of Directors; Vacancies; Removal. The authorized number of Directors who shall constitute the Board shall be fixed from time to time by resolution of the Board. Whenever there shall be fewer Directors in office than the authorized number of Directors, the Board may, by resolution approved by a majority of the Directors then in office, reduce the authorized number of Directors or choose one or more additional Directors, each of whom shall hold office until the next annual meeting of the Member or until his or her successor is duly elected. A Director may be removed at any time by the Member, with or without cause.

3. Authorized Meetings of the Board. The Board shall have authority to hold annual, regular and special meetings. An annual meeting of the Board may be held immediately following the annual meeting of the Member of the Company, at such place as may be determined by resolution of the Board. Regular meetings of the Board may be held at such times and places and may be determined from time to time by resolution of the Board. Special

meetings of the Board may be held at such times and places as may be called by the President or by at least one-third of the members of the Board.

Both annual and regular meetings of the Board may be held without notice thereof. However, a special meeting of the Board shall be an authorized meeting only if actual or constructive notice of the time and place thereof has been given to each Director, or all Directors waive notice thereof. Such notice for any Director may be given orally in person or by telephone by any officer of the Company, or delivered by hand or transmitted electronically by the Company to the Director's business address. Such notice shall be given not less than one hour before the hour fixed for the special meeting. If the notice does not state the place of the meeting, the meeting shall be held at the office of the Secretary of the Company.

A majority of the authorized number of Directors shall constitute a quorum at any Board meeting. If any meeting of the Board shall lack a quorum, a majority of the Directors present may adjourn the meeting from time to time, without notice, until a quorum is obtained. Every act or decision taken by the affirmative vote of a majority of the Directors present at a meeting duly held at which a quorum is present shall be regarded as the act of the Directors, except to the extent that the vote of a greater number of Directors is required by the Agreement, these By-Laws or applicable law.

4. Action by Consent. Unless otherwise restricted by the Agreement, these By-Laws or applicable law, any action required or permitted to be taken at any meeting of the Board or of any committee thereof may be taken without a meeting, if all members of the Board or committee, as the case may be, consent thereto in writing, and the writing or writings are filed with the minutes of proceedings of the Board or committee.

5. Committees. The Board may, by resolution approved by at least a majority of the authorized number of Directors, provide for one or more committees of the Board with such powers, duties and rules of procedure as may be provided by, or established in accordance with the direction of, the Board. Except as may be established to the contrary by applicable resolution of the Board, at any meeting of any such committee of the Board, the member or members thereof who are present and not disqualified from voting, whether or not constituting a quorum, may unanimously appoint another Director to act in the place of any absent or disqualified member Director.

## II.

## Officers

1. Designated Officers. The officers of the Company shall consist of a President, one or more Vice-Presidents, a Secretary, one or more Assistant Secretaries, a Treasurer, one or more Assistant Treasurers, and such other officers as may be appointed to hold such offices as may from time to time be created by resolution of the Board. The Treasurer shall be the chief financial officer of the Company unless the Board designates another officer as such.

2. Appointment and Removal of Officers. The President shall from time to time be appointed by, and serve at the pleasure of, the Board. The Board or the President may appoint

other designated officers to serve at the pleasure of the Board and the President. The Board or the President may remove any officer, with or without cause.

3. Resignation of Officers. Any officer may also resign at any time by giving written notice to the Board, the President or the Secretary.

4. President. The President shall preside at all meetings of the Member and the Board, shall be the chief executive officer of the Company, and shall perform all other duties as may from time to time be assigned to him or her by, or be in accordance with the direction of, the Board. The President shall also act as Reporting Unit Head, as that term is defined in Policy 190 of the Chevron Corporation, as in effect from time to time.

5. Vice-Presidents. In the event of the absence or disability of the President, one of the Vice-Presidents may be designated by the Board or the President to exercise his or her power and perform his or her duties, and the Vice-Presidents shall perform all other duties as may from time to time be assigned to them by the Board or the President, or otherwise be in accordance with the direction of the Board.

6. Secretary. The Secretary shall keep full and complete records of the proceedings of the Board and committees thereof and of the meetings of the Member; keep the seal of the Company, and affix the same to all instruments which may require it; have custody of and maintain the Company's records of Interests; and perform all other duties as may from time to time be assigned to him or her by the Board or the President, or otherwise be in accordance with the direction of the Board.

7. Assistant Secretaries. The Assistant Secretaries shall assist the Secretary in the performance of his or her duties and perform all other duties as may from time to time be assigned to them by the Board or the President, or otherwise be in accordance with the direction of the Board.

8. Treasurer. The Treasurer shall have custody of the funds of the Company, and deposit and pay out such funds, from time to time, in such manner as may be prescribed by, or be in accordance with the direction of, the Board, and shall perform all other duties as may from time to time be assigned to him or her by the Board or the President, or otherwise be in accordance with the direction of the Board.

9. Assistant Treasurers. The Assistant Treasurers shall assist the Treasurer in the performance of his or her duty and generally perform all other duties as may from time to time be assigned to them by the Board or the President, or otherwise be in accordance with the direction of the Board.

10. Reporting Officer. The Reporting Officer shall have such responsibility and authority as is set forth in Policy 190 of the Chevron Corporation, as in effect from time to time.

11. Other Officers. Any other elected officer shall have such powers and perform such duties as may from time to time be assigned to him or her by the Board or the President, or otherwise be in accordance with the direction of the Board.

12. Powers of Attorney. Whenever an applicable statute, decree, rule or regulation requires a document to be subscribed by a particular officer of the Company, such document may be signed on behalf of such officer by a duly appointed attorney-in-fact, except as otherwise directed by the Board or the President or limited by law.

III.

**Offices**

The Company shall have offices at such place or places as the Board or the President may from time to time determine.

IV.

**Records and Reports**

1. Maintenance and Inspection of Member Register. The Company shall maintain at its principal place of business a record of its Member, giving the name and address of the Member.

2. Maintenance and Inspection of By-Laws. The Company shall keep at its principal place of business the original or a copy of these By-Laws as amended to date, which shall be open to inspection by the Member at all reasonable times during business hours.

3. Maintenance and Inspection of Other Records. The accounting books and records, minutes of proceedings of the Member and the Board and any committees or delegates of the Board, and all other information pertaining to the Company that is required to be made available to the Member under the LLC Act shall be kept at such place or places designated by the Board or in the absence of such designation, at the principal place of business of the Company. The minutes shall be kept in written form and the accounting books and records and other information shall be kept either in written form or in any other form capable of being converted into written form. The books of account and records of the Company shall be maintained in accordance with generally accepted accounting principles consistently applied during the term of the Company, wherein all transactions, matters, and things relating to the business and properties of the Company shall be currently entered. Subject to such reasonable standards (including standards governing what information and documents are to be furnished and at whose expense) as may be established by the Board from time to time, minutes, accounting books and records, and other information shall be open to inspection upon the written demand of the Member at any reasonable time during usual business hours for a purpose reasonably related to the Member's interests as a Member. Any such inspection may be made in person or by an agent or attorney and shall include the right to copy and make extracts.

4. Inspection by Directors. Every Director shall have the right at any reasonable time to inspect all books, records, and documents of every kind and the physical properties of the Company for a purpose reasonably related to his or her position as Director. This inspection by a Director may be made in person or by an agent or attorney and the right of inspection includes

the right to copy and make extracts of documents.

V.

## General Matters

1. Checks, Drafts, Evidence of Indebtedness. All checks, drafts, or other orders for payment of money, notes, or other evidence of indebtedness issued in the name of or payable to the Company shall be signed or endorsed in such manner and by such person or persons as shall be designated from time to time in accordance with the resolution of the Board.

2. Contracts and Instruments; How Executed. The Board, except as otherwise provided in the Agreement or these By-Laws, may authorize any Director, Directors, officer, officers, agent or agents to enter into any contract or execute any instrument in the name of and on behalf of the Company and this authority may be general or confined to specific instances; and unless so authorized or ratified by the Directors or within the agency power of an officer (or otherwise specified in the Agreement or these By-Laws), no officer, agent, or employee shall have any power or authority to bind the company by any contract or engagement or to pledge its credit or to render it liable for any purpose or for any amount.

3. Representation of Shares of Other Entities Held by the Company. Any officer or any other person authorized by the Board or by any of the officers, is authorized to vote or represent on behalf of the Company any and all shares of any corporation, partnership, trust, or other entity, foreign or domestic, standing in the name of the Company. The authority granted may be exercised in person or by a proxy duly executed by such designated person.

VI.

## Meetings of the Member

1. Annual Meeting of Member. An annual meeting of the Member in the Company shall be held on a date and at a time designated by resolution of the Board of Directors. At the annual meeting, Directors shall be elected to serve for the ensuing year and until their successors are elected. Any other proper business may also be transacted at the annual meeting.

2. Special Meeting of Member. Special meetings of the Member may be called at any time by the Board, the President, or by the Member, to be held not less than ten nor more than sixty days after the request therefor.

3. Places of Meetings. The Board may determine where each meeting of the Member shall be held, but in the absence of any designation by the Board of the meeting place, meetings of the Member shall be held at the office of the Secretary of the Company.

4. Notices of Meetings. Written notice of all meetings of the Member stating the place, date and hour of the meeting, shall be mailed, postage prepaid, or delivered, not less than ten nor more than sixty days before such meeting to the Member.

5. Quorum for Action by Member Elections. Except as may otherwise be provided by law, all elections shall be held and all questions decided by the vote at a meeting or written consent in lieu of a meeting of the Member.

6. Proxies. At any meeting of the Member, the Member may be represented and have its Percentage Interest voted by a proxy or proxies appointed by an instrument in writing executed by the Member.

7. Adjournments. Any meeting of the Member (whether annual or special), may be adjourned from time to time and from place to place by vote of the Member, without notice other than announcement at such meeting of the time and place at which the meeting is to be resumed—such adjournment and the reasons therefor being recorded in the journal of proceedings of the meeting. At any meeting so resumed after such adjournment, provided the Member shall then be represented, any business may be transacted which might have been transacted at the meeting as originally scheduled.

## VII.

## Corporate Seal

The seal of the Company shall have the name of the Company inscribed thereon, together with the date and state of organization.

## VIII.

## Amendments

1. Any of these By-Laws may be altered, amended or repealed by the vote or consent of the Member, or any of these By-Laws may be altered, amended or repealed by resolution of the Board approved by at least a majority of the Directors then in office.

2. These By-Laws and any amendments hereto shall be deemed incorporated by reference into the Agreement.

# Attachment 2
# Detailed Financial Information

**CHEVRONTEXACO CORP filed this 10-K405 on 03/27/2002.**

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2001**

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number 1-368-2

# ChevronTexaco Corporation

(Exact name of registrant as specified in its charter)

| Delaware | 94-0890210 | 575 Market Street, San Francisco, California 94105 |
|---|---|---|
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification Number) | (Address of principal executive offices) (Zip Code) |

Registrant's telephone number, including area code (415) 894-7700

NONE

(Former name or former address, if changed since last report.)

Securities registered pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common stock par value $.75 per share<br>Preferred stock purchase rights | New York Stock Exchange, Inc.<br>Pacific Exchange |

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Aggregate market value of the voting stock held by nonaffiliates of the Registrant
As of February 28, 2002 – $89,318,940,000

Number of Shares of Common Stock outstanding as of February 28, 2002 – 1,067,200,937

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2002 Annual Meeting and 2002 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, as amended, in connection with the company's 2002 Annual Meeting of Stockholders (in Part III)

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## PART I

### Item 1. Business

#### (a) General Development of Business

**Summary Description of ChevronTexaco**

ChevronTexaco Corporation[1], a Delaware corporation, manages its investments in subsidiaries and affiliates, and provides administrative, financial and management support to, U.S. and foreign subsidiaries that engage in fully integrated petroleum operations, chemicals operations, coal mining, power and energy services. The company operates in the United States and approximately 180 other countries. Petroleum operations consist of exploring for, developing and producing crude oil and natural gas; refining crude oil into finished petroleum products; marketing crude oil, natural gas and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipelines, marine vessels, motor equipment and rail car. Chemicals operations include the manufacture and marketing, by an affiliate, of commodity petrochemicals and plastics for industrial uses, and the manufacture and marketing, by a consolidated subsidiary, of fuel and lubricating oil additives.

In this report, exploration and production of crude oil, natural gas liquids and natural gas may be referred to as “E&P” or “upstream” activities. Refining, marketing and transportation may be referred to as “RM&T” or “downstream” activities. A list of the company’s major subsidiaries is presented on page E-2 of this Annual Report on Form 10-K. As of December 31, 2001, ChevronTexaco had 55,763 employees (excluding 11,806 service station employees), down about 1,600 from year-end 2000. Included in this net change between periods was an addition of about 1,000 employees who had previously been classified as contractors in certain international operations. Approximately 32,000, or 47 percent, of the company’s employees, including service station employees, were employed in U.S. operations, of which approximately 4,500 were unionized.

**CAUTIONARY STATEMENTS RELEVANT TO FORWARD-LOOKING INFORMATION FOR THE PURPOSE OF “SAFE HARBOR” PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995**

This annual report on Form 10-K of ChevronTexaco Corporation contains forward-looking statements relating to ChevronTexaco’s operations that are based on management’s current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as “anticipates,” “expects,” “intends,” “plans,” “targets,” “projects,” “believes,” “seeks,” “estimates” and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, ChevronTexaco undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the factors that could cause actual results to differ materially are crude oil and natural gas prices; refining margins and marketing margins; chemicals prices and competitive conditions affecting supply and demand for aromatics, olefins and additives products; actions of competitors; the competitiveness of alternate energy sources or product substitutes; technological developments; inability of the company’s joint-venture partners to fund their share of operations and development activities; potential failure to achieve expected production from existing and future oil and gas development projects; potential delays in the development, construction or start-up of planned projects; the successful integration of the former Chevron, Texaco and Caltex businesses; potential disruption or interruption of the company’s production or manufacturing facilities due to accidents or political events; potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental regulations (including, particularly, regulations and litigation dealing with gasoline composition and characteristics); and potential liability resulting from pending or future litigation. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed herein also could have material adverse effects on forward-looking statements.

[1] Incorporated in Delaware in 1926 as Standard Oil Company of California, the company adopted the name Chevron Corporation in 1984 and ChevronTexaco Corporation in 2001. As used in this report, the term “ChevronTexaco” and such terms as “the company,” “the corporation,” “our,” “we,” and “us” may refer to ChevronTexaco Corporation, one or more of its consolidated subsidiaries, or to all of them taken as a whole, but unless it is stated otherwise, does not include “affiliates” of ChevronTexaco – i.e., those companies accounted for by the equity method (generally owned 50 percent or less), or investments accounted for by the cost method. All of these terms are used for convenience only, and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

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**Overview of Petroleum Industry**
Petroleum industry operations and profitability are influenced by many factors, over some of which individual petroleum companies have little control. Governmental policies, particularly in the areas of taxation, energy and the environment, have a significant impact on petroleum activities, regulating where and how companies conduct their operations and formulate their products and, in some cases, limiting their profits directly. Prices for crude oil and natural gas, petroleum products and petrochemicals are determined by supply and demand for these commodities. The members of the Organization of Petroleum Exporting Countries (OPEC) are typically the world's swing producers of crude oil, and their production levels are a major factor in determining worldwide supply. Demand for crude oil and its products and natural gas is largely driven by the conditions of local, national and worldwide economies, although weather patterns and taxation relative to other energy sources also play a significant part. Natural gas is generally produced and consumed on a country or regional basis.

**Operating Environment**
Refer to page FS-2 of this Annual Report on Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion on the company's current business environment and outlook.

**Texaco Merger Transaction**
On October 9, 2001, Texaco Inc. (Texaco) became a wholly owned subsidiary of Chevron Corporation (Chevron) pursuant to a merger transaction, and Chevron changed its name to ChevronTexaco Corporation. The combination was accounted for as a pooling of interests, and each share of Texaco common stock was converted on a tax-free basis into the right to receive 0.77 shares of ChevronTexaco common stock. In the merger, ChevronTexaco issued approximately 425 million shares of common stock, representing about 40 percent of the outstanding ChevronTexaco common stock after the merger. Further discussion of the Texaco merger transaction, including merger-related expenses and synergy savings, is contained on pages FS-2 and FS-3 of this Annual Report on Form 10-K.

**ChevronTexaco Strategic Direction**
ChevronTexaco's primary strategic objective is to achieve the highest total stockholder return in its peer group for the five-year period 2000 - 2004. British Petroleum, ExxonMobil and Royal Dutch Shell are the primary competition where ChevronTexaco operates and comprise the company's competitor peer group. The company had the highest total stockholder return in its peer group for the 2000 - 2001 period.

As a foundation for attaining this goal, the company has established four key priorities:

- Operational excellence through safe, reliable, efficient and environmentally sound operations;

- Cost reduction by lowering unit costs through innovation and technology;

- Capital stewardship by investing in the best project opportunities and executing them successfully (safer, faster, at lower cost); and

- Profitable growth through leadership in developing new business opportunities in both existing and new markets.

Supporting these four priorities is a continued and improved focus on:

- Organizational Capability: The company has developed strategies to build capability systems to achieve top performance in the four priorities described above.

**(b) Description of Business and Properties**

The company's largest business segments are exploration and production, and refining, marketing and transportation. Chemicals is also a significant operation, conducted mainly by the company's affiliate – Chevron Phillips Chemical Company LLC (CPChem). The petroleum activities of the company are

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widely dispersed geographically. The company has petroleum operations in North America, South America, Europe, Africa, Middle East, Central and Far East Asia, and Australia.

CPChem has operations in the United States, Belgium, China, South Korea, Singapore, Saudi Arabia, Qatar and Mexico. The company's wholly owned Oronite additives business has operations in the United States, France, Netherlands, Singapore, Japan and Brazil.

An affiliate, Dynegy Inc. (Dynegy), is one of the leading marketers of energy products and services in the United States with customers in the United States, Canada, the United Kingdom (U.K.) and other European countries. Its business activities include energy marketing; independent power generation; gathering, processing, selling and transportation of natural gas and natural gas liquids; and broadband trading.

Tabulations of segment sales and other operating revenues, earnings, income taxes and assets, by United States and International geographic areas, for the years 1999 to 2001, may be found in Note 11 to the consolidated financial statements beginning on page FS-28 of this Annual Report on Form 10-K. In addition, similar comparative data for the company's investments in and income from equity affiliates and property, plant and equipment are contained in Notes 14 and 15 on pages FS-31 to FS-33.

The company's worldwide operations can be affected significantly by changing economic, tax, regulatory and political environments in the various countries in which it operates, including the United States. Environmental regulations and government policies concerning economic development, energy and taxation may have a significant effect on the company's operations. Management evaluates the economic and political risk of initiating, maintaining or expanding operations in any geographical area. The company monitors political events worldwide and the possible threat these may pose to its activities – particularly the company's oil and gas exploration and production operations – and the safety of the company's employees.

The company attempts to avoid unnecessary involvement in partisan politics in the communities in which it operates, but participates in the political process to safeguard its assets and to ensure that the community benefits from its operations and remains receptive to its continued presence.

**Capital and Exploratory Expenditures**

A discussion of the company's capital and exploratory expenditures is contained on page FS-10 of this Annual Report on Form 10-K.

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**Petroleum – Exploration and Production**

**Liquids and Natural Gas Production**
The following table summarizes the company's and affiliates' net production of crude oil and natural gas liquids, and natural gas for 2001 and 2000.

**Net Production[1] Of Crude Oil And Natural Gas Liquids And Natural Gas**

| | Crude Oil & Natural Gas Liquids (Thousands of Barrels per Day) | | Natural Gas (Millions of Cubic Feet per Day) | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| **United States:** | | | | |
| California | 249 | 266 | 116 | 118 |
| Gulf of Mexico | 187 | 179 | 1,023 | 1,130 |
| Texas | 87 | 110 | 598 | 660 |
| Wyoming | 11 | 15 | 220 | 225 |
| Other States | 80 | 97 | 749 | 777 |
| Total United States | 614 | 667 | 2,706 | 2,910 |
| **Africa:** | | | | |
| Angola | 168 | 169 | 1 | 1 |
| Nigeria | 158 | 155 | 43 | 47 |
| Republic of Congo | 20 | 25 | — | — |
| Democratic Republic of Congo | 9 | 8 | — | — |
| **Asia-Pacific:** | | | | |
| Indonesia | 304 | 319 | 134 | 133 |
| Partitioned Neutral Zone (PNZ)[2] | 144 | 139 | 10 | 11 |
| Australia | 45 | 48 | 235 | 225 |
| Kazakhstan | 17 | 17 | 67 | 83 |
| Thailand | 16 | 14 | 75 | 70 |
| Papua New Guinea | 7 | 11 | — | — |
| Philippines | 1 | — | 9 | — |
| China | 24 | 28 | — | — |
| **Other International:** | | | | |
| United Kingdom (North Sea) | 115 | 117 | 350 | 342 |
| Canada | 64 | 66 | 167 | 146 |
| Argentina | 57 | 51 | 56 | 51 |
| Denmark | 39 | 39 | 100 | 98 |
| Norway | 17 | 15 | 4 | 1 |
| Venezuela | 4 | 4 | 4 | — |
| Colombia | — | 1 | 203 | 194 |
| Trinidad | — | 8 | 100 | 65 |
| Netherlands | — | — | 1 | 1 |
| Total International | 1,209 | 1,234 | 1,559 | 1,468 |
| Total Consolidated Operations | 1,823 | 1,901 | 4,265 | 4,378 |
| Equity in Affiliates | 136 | 96 | 152 | 88 |
| Total Including Affiliates | 1,959 | 1,997 | 4,417 | 4,466 |

[1] Net production excludes royalty interests owned by others.

[2] Located between the Kingdom of Saudi Arabia and the State of Kuwait.

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In 2001, ChevronTexaco conducted its worldwide exploration and production operations in the United States and approximately 25 other countries. Worldwide net crude oil and natural gas liquids production, including that of affiliates but excluding volumes produced under operating service agreements, decreased by about 2 percent from the 2000 levels. Net worldwide production of natural gas, including affiliates, fell 1 percent in 2001. Net liquids and natural gas production in the United States was down about 8 percent and 7 percent, respectively. The lower production reflected normal field declines and asset sales, partially offset by new and enhanced production in the deepwater and other areas of the Gulf of Mexico. International net liquids production, including affiliates, increased about 1 percent, while net natural gas production rose 10 percent from 2000. The increase in gas production occurred primarily in Trinidad, Canada and the company's Tengizchevroil (TCO) affiliate in Kazakhstan.

While worldwide oil-equivalent production in 2001 was down less than 2 percent from 2000 levels, the company has targeted an oil-equivalent production growth rate over the next five years of 2.5 to 3 percent annually. However, 2002 production is expected to increase only about 1 percent because of OPEC-related constraints.

**Acreage**

At December 31, 2001, the company owned or had under lease or similar agreements undeveloped and developed oil and gas properties located throughout the world. The geographical distribution of the company's acreage is shown in the next table.

**Acreage[1] At December 31, 2001**
(Thousands of Acres)

| | Undeveloped[2] | | Developed[2] | | Developed and Undeveloped | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| United States | 10,457 | 7,462 | 8,508 | 4,152 | 18,965 | 11,614 |
| Africa | 25,556 | 8,751 | 411 | 116 | 25,967 | 8,867 |
| Asia-Pacific | 53,619 | 25,384 | 1,683 | 590 | 55,302 | 25,974 |
| Other International | 51,545 | 27,132 | 2,400 | 859 | 53,945 | 27,991 |
| Total International | 130,720 | 61,267 | 4,494 | 1,565 | 135,214 | 62,832 |
| Total Consolidated Companies | 141,177 | 68,729 | 13,002 | 5,717 | 154,179 | 74,446 |
| Equity in Affiliates | 927 | 464 | 57 | 28 | 984 | 492 |
| Total Including Affiliates | 142,104 | 69,193 | 13,059 | 5,745 | 155,163 | 74,938 |

1 Gross acreage includes the total number of acres in all tracts in which the company has an interest. Net acreage is the sum of the company's fractional interests in gross acreage.

2 Developed acreage is spaced or assignable to productive wells. Undeveloped acreage is acreage where wells have not been drilled or completed to permit commercial production, and may contain undeveloped proved reserves.

Refer to Table IV on page FS-48 of this Annual Report on Form 10-K for data about the company's average sales price per unit of oil and gas produced, as well as the average production cost per

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unit for 2001, 2000 and 1999. The following table summarizes gross and net productive wells at year-end 2001 for the company and its affiliates.

**Productive Oil And Gas Wells At December 31, 2001**

| | Productive[1] Oil Wells | | Productive[1] Gas Wells | |
|---|---|---|---|---|
| | Gross[2] | Net[2] | Gross[2] | Net[2] |
| United States | 43,368 | 26,868 | 11,075 | 5,533 |
| Africa | 1,386 | 544 | 5 | 2 |
| Asia-Pacific | 8,396 | 7,537 | 269 | 141 |
| Other International | 2,248 | 1,400 | 382 | 171 |
| Total International | 12,030 | 9,481 | 656 | 314 |
| Total Consolidated Companies | 55,398 | 36,349 | 11,731 | 5,847 |
| Equity in Affiliates | 106 | 43 | — | — |
| Total Including Affiliates | 55,504 | 36,392 | 11,731 | 5,847 |
| Multiple completion wells included above: | 617 | 338 | 350 | 218 |

1 Includes wells producing or capable of producing and injection wells temporarily functioning as producing wells. Wells that produce both oil and gas are classified as oil wells.

2 Gross wells include the total number of wells in which the company has an interest. Net wells are the sum of the company's fractional interests in gross wells.

**Reserves and Contract Obligations**

Table V on pages FS-48 and FS-49 of this Annual Report on Form 10-K sets forth the company's net proved oil and gas reserves, by geographic area, as of December 31, 2001, 2000 and 1999. During 2002, the company will file estimates of oil and gas reserves with the Department of Energy, Energy Information Agency. Those estimates are consistent with the reserve data reported on page FS-49 of this Annual Report on Form 10-K.

In 2001, ChevronTexaco's worldwide oil and equivalent-gas (BOE) barrels of net proved reserves additions exceeded production, with a replacement rate of 127 percent of net production, including sales and acquisitions. Excluding sales and acquisitions, the replacement rate was 112 percent of net production. In the United States, the reserves replacement rate was impacted by a significant downward revision in proved crude oil reserve quantities for the Midway Sunset Field in California's San Joaquin Valley. The revision was the result of a determination of lower-than-projected oil recovery from the field's steam

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injection process. The following table summarizes the company's net additions to net proved reserves of crude oil and natural gas liquids and natural gas, compared with net production during 2001.

**Reserves Replacement – 2001**

| | Additions to Reserves | | Net Production | | BOE Reserves Replacement % | Memo: Replacement % Including Sales and Acquisitions |
|---|---|---|---|---|---|---|
| | Liquids (mmbbls)[1] | Gas (bcf)[2] | Liquids (mmbbls)[1] | Gas (bcf)[2] | | |
| United States | (89) | 452 | 224 | 988 | 5% | (3)% |
| Africa | 168 | 1,116 | 129 | 16 | 268% | 268% |
| Asia-Pacific | 216 | 511 | 204 | 194 | 126% | 127% |
| Other international[3] | 424 | 1,100 | 157 | 415 | 190% | 269% |
| Total Worldwide | 719 | 3,179 | 714 | 1,613 | 112% | 127% |

1 mmbbls = millions of barrels

2 bcf = billions of cubic feet

3 Includes equity in affiliates

The company sells crude oil and natural gas from its producing operations under a variety of contractual arrangements. Most contracts generally commit the company to sell quantities based on production from specified properties but certain gas sales contracts specify delivery of fixed and determinable quantities. Dynegy and ChevronTexaco have entered into long-term strategic alliances whereby Dynegy purchases substantially all natural gas and natural gas liquids produced by legacy Chevron in the United States, excluding Alaska, and supplies natural gas and natural gas liquids feedstocks to the company's U.S. refineries and chemical plants. In March 2002, the company reached agreement with Dynegy to expand those contracts to include substantially all of legacy Texaco's U.S. natural gas and natural gas liquids production. Outside the United States, the company is contractually committed to deliver approximately 110 billion cubic feet of natural gas through 2004 from both Australian and U.K. reserves, and approximately 335 billion cubic feet of natural gas post-2004 through 2020 from Australian reserves only. The company believes it can satisfy these contracts from quantities available from production of the company's proved developed Australian and U.K. natural gas reserves. Substantially all of the contracts discussed above include variable-pricing terms.

**Development Activities**

Details of the company's development expenditures and costs of proved property acquisitions for 2001, 2000 and 1999 are presented in Table I on page FS-45 of this Annual Report on Form 10-K.

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The table below summarizes the company's net interest in productive and dry development wells completed in each of the past three years and the status of the company's development wells drilling at December 31, 2001. A "development well" is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. "Wells drilling" include wells temporarily suspended.

**Development Well Activity**

| | Wells Drilling At 12/31/01 | | Net Wells Completed[1] | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | 2001 | | 2000 | | 1999 | |
| | Gross[2] | Net[2] | Prod. | Dry | Prod. | Dry | Prod. | Dry |
| United States | 373 | 137 | 866 | 21 | 919 | 14 | 857 | 14 |
| Africa | 33 | 13 | 22 | — | 39 | — | 19 | — |
| Asia-Pacific | 16 | 11 | 555 | — | 501 | 1 | 530 | 1 |
| Other International | 32 | 19 | 109 | 2 | 113 | — | 30 | — |
| Total International | 81 | 43 | 686 | 2 | 653 | 1 | 579 | 1 |
| Total Consolidated Companies | 454 | 180 | 1,552 | 23 | 1,572 | 15 | 1,436 | 15 |
| Equity in Affiliates | 37 | 18 | 17 | — | 33 | — | 1 | — |
| Total Including Affiliates | 491 | 198 | 1,569 | 23 | 1,605 | 15 | 1,437 | 15 |

1 Indicates the number of wells completed during the year regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of oil or gas or, in the case of a dry well, the reporting of abandonment to the appropriate agency.

2 Gross wells include the total number of wells in which the company has an interest. Net wells are the sum of the company's fractional interests in gross wells.

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**Exploration Activities**
The following table summarizes the company's net interests in productive and dry exploratory wells completed in each of the last three years and the number of exploratory wells drilling at December 31, 2001.

**Exploratory Well Activity**

| | Wells Drilling At 12/31/01 | | Net Wells Completed[1] | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | 2001 | | 2000 | | 1999 | |
| | Gross[2] | Net[2] | Prod. | Dry | Prod. | Dry | Prod. | Dry |
| United States | 42 | 28 | 101 | 32 | 69 | 30 | 90 | 40 |
| Africa | 4 | 1 | 8 | 2 | 2 | 4 | 2 | 2 |
| Asia-Pacific | 10 | 4 | 31 | 8 | 15 | 11 | 6 | 12 |
| Other International | 12 | 8 | 6 | 10 | 7 | 7 | 8 | 5 |
| Total International | 26 | 13 | 45 | 20 | 24 | 22 | 16 | 19 |
| Total Consolidated Companies | 68 | 41 | 146 | 52 | 93 | 52 | 106 | 59 |
| Equity in Affiliates | 1 | — | 14 | — | — | — | — | — |
| Total Including Affiliates | 69 | 41 | 160 | 52 | 93 | 52 | 106 | 59 |

1 Indicates the number of wells completed during the year regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of oil or gas or, in the case of a dry well, the reporting of abandonment to the appropriate agency.

2 Gross wells include the total number of wells in which the company has an interest. Net wells are the sum of the company's fractional interests in gross wells.

"Exploratory wells" are wells drilled to find and produce oil or gas in unproved areas and include delineation wells, which are wells drilled to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir beyond the proved area. "Wells drilling" include wells temporarily suspended. The company had $783 million of suspended exploratory wells included in properties, plant and equipment at year-end 2001, a decrease of $87 million from 2000. Decreases in the United States, United Kingdom, Australia and Angola were partially offset by increases in Nigeria, Brazil and China. The wells are suspended pending a final determination of the commercial potential of the related oil and gas fields. The ultimate disposition of these well costs is dependent on: (1) decisions on additional major capital expenditures, (2) the results of additional exploratory drilling that is underway or firmly planned, and in some cases, (3) securing final regulatory approvals for development.

Details of the company's exploration expenditures and costs of unproved property acquisitions for 2001, 2000 and 1999 are presented in Table I on page FS-45 of this Annual Report on Form 10-K.

**Review of Ongoing Exploration and Production Activities in Key Areas**
ChevronTexaco's 2001 key upstream activities not discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations beginning on page FS-2 of this Annual Report on Form 10-K are presented below. The comments include reference to "net production," which excludes partner shares and royalty interests. "Total production" includes these components. In addition to the activities discussed, ChevronTexaco was active in other geographic areas, but these activities were less significant.

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**Consolidated Operations**

**A) United States**

United States exploration and production activities are concentrated in nearly 850 fields located mainly in the Gulf of Mexico, Texas, New Mexico, the Rocky Mountains, California and Alaska.

**Gulf of Mexico:** In the Gulf of Mexico Shelf, the company maintained average net production rates of 142,000 barrels of oil, 1.237 billion cubic feet of gas, and 14,200 barrels of natural gas liquids per day.

In the Gulf of Mexico deepwater, ChevronTexaco has interests in three significant developments. The company operates and has a 57 percent interest in Genesis, which averaged net daily oil-equivalent production of 33,000 barrels during the year. Production began in July 2001 at a second development, Typhoon, in which the company has a 50 percent interest. Net daily production averaged nearly 18,000 barrels of oil-equivalent during the fourth quarter 2001. ChevronTexaco has a 50 percent interest in a third deepwater development, Petronius, which averaged net oil-equivalent production of 27,000 barrels per day during 2001. Exploration programs resulted in discoveries at Trident, Boris and Blind Faith, and confirmation of the 2000 Champlain discovery. The Trident appraisal is ongoing.

**Mid-Continent/ Permian Basin:** Onshore operations in the mid-continent United States are located in Utah, Texas, and Wyoming. Net natural gas production averaged 921 million cubic feet per day, while net production of crude oil and natural gas liquids averaged 31,000 barrels per day. Capital spending was focused on natural gas development and coalbed methane activity, located in northeast Utah. Permian Basin operations are located primarily in New Mexico. In 2001, net daily production averaged 117,500 barrels of crude oil and natural gas liquids and 275 million cubic feet of natural gas.

**California:** During 2001, average net daily production from the company's San Joaquin Valley fields was 245,100 barrels of crude oil, 116 million cubic feet of natural gas and 3,900 barrels of natural gas liquids. Approximately 210,000 barrels per day of the crude oil production was heavy oil.

**Offshore Florida:** Development of the Destin Dome area of the Norphlet trend offshore Florida continues to be hampered by delays in obtaining regulatory approvals. A draft environmental impact statement was issued in August 1999 by the governing agencies indicating no significant environmental impacts from the project. In July 2000, ChevronTexaco and its partners in the Destin Dome development filed a lawsuit against the federal government to recover exploration expense and future lost profits following continuing delays in obtaining the necessary development permits. The company has filed a motion for summary judgement, which could decide the liability portion of the case and leave the amount of damages to be decided later.

**B) Africa**

**Nigeria:** ChevronTexaco's principal subsidiary in Nigeria, Chevron Nigeria Limited (CNL), operates and holds a 40 percent interest in 11 concessions, predominantly in the swamp and near-offshore regions of the Niger Delta. CNL operates under a joint venture arrangement with the Nigerian National Petroleum Corporation (NNPC), which owns the remaining 60 percent interest. ChevronTexaco's subsidiaries Chevron Oil Company Nigeria Limited (COCNL) and Texaco Overseas Nigeria Petroleum Company Unlimited (TOPCON) each hold a 20 percent interest in six concessions. TOPCON operates these concessions under a joint venture agreement with NNPC, which owns the remaining 60 percent interest.

In 2001, daily net production from the 33 CNL-operated fields averaged 143,000 barrels of oil and 2,700 barrels of liquefied petroleum gas (LPG). During 2001, net production from the six TOPCON-operated fields averaged approximately 12,000 barrels of oil per day.

Phase 2 of the Escravos gas project was completed in the first quarter 2001. As a result, processing capacity at the plant increased to 285 million cubic feet per day. Preliminary design for Phase 3, which includes adding a second gas plant and expanding processing capacity to 680 million cubic feet per day,

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started in the third quarter of 2001 and is targeted for completion in 2005. ChevronTexaco holds a 40 percent working interest in the Escravos gas project.

Feasibility engineering and preliminary technical evaluations have been completed for a proposed gas-to-liquids (GTL) plant at Escravos. Front-end engineering and design started in March 2001. The proposed 33,000 barrels-per-day (12,000 barrels per day net) GTL project is the first to use the Sasol Chevron Global Joint Venture's technology and operational expertise. Project start-up is expected to be in 2005. ChevronTexaco holds a 37.5 percent interest.

**Angola:** ChevronTexaco is the largest producer in Angola and the first to produce in the deepwater. Cabinda Gulf Oil Company Limited (CABGOC), a wholly owned subsidiary of ChevronTexaco, is operator of two concessions, Blocks 0 and 14, off the coast of Angola's Cabinda enclave. Block 0, in which CABGOC has a 39 percent interest, is a 2,100-square-mile concession adjacent to the Cabinda coastline. Block 14, in which CABGOC has a 31 percent interest, is a 1,560-square-mile deepwater concession located west of Block 0.

In Block 0, the company operates in 3 areas – A, B and C. Area A, containing 15 fields currently producing, averaged net production of approximately 96,000 barrels of crude oil per day in 2001. Area B, with 3 fields producing, averaged net production of 32,500 barrels of crude oil per day. Area C averaged net production of 10,500 barrels of crude oil per day from 7 fields. Major development projects during 2001 included phase 1 of a waterflood project in Area A and a production and gas injection platform in the Area B North Nemba Field.

In Block 14, net production in 2001 from the Kuito Field, Angola's first deepwater producing area, averaged approximately 19,000 barrels of crude oil per day. Development plans are under way for other fields within the Block.

Texaco Panama Angola Inc., a subsidiary of ChevronTexaco, is operator of and has a 20 percent interest in Block 2, a 160-square-mile concession adjacent to the northwestern part of Angola's coast. Average net daily production from Block 2 was about 7,000 barrels of crude oil in 2001.

The company operates and has a 40 percent interest in offshore exploration Blocks, 9 and 22, which encompass approximately 2,000-square-miles each and are located south of Luanda, Angola's capital.

**Republic of Congo:** ChevronTexaco has interests in two license areas, Haute Mer and Kitina/ Sounda, in offshore Congo and adjacent to the company's concessions in Cabinda. ChevronTexaco has a 30 percent interest in the Haute Mer exploration permit and a 29 percent interest in the Kitina/ Sounda exploitation permits. The company's interest in the deepwater Mer Profonde Sud license area was relinquished in 2001. Net production from ChevronTexaco's concessions in the Republic of Congo averaged 20,000 barrels per day in 2001. Field development studies continue for the deepwater Moho and Bilondo discoveries in Haute Mer. Appraisal drilling was underway in early 2002.

**Chad-Cameroon:** ChevronTexaco is a 25 percent partner in a project that will develop landlocked oil fields in southern Chad and transport crude oil by pipeline to the coast of Cameroon for export to world markets. Project financing was secured during the second quarter 2001. At the end of 2001, the overall development project was about one-third complete. Pipeline construction began in the fourth quarter and drilling initiated in the first quarter 2002. First production is expected in 2004.

**Equatorial Guinea:** ChevronTexaco is a 65 percent partner and operator of the L Block offshore the Republic of Equatorial Guinea. The initial 3D seismic survey was completed in 2001 and is presently being analyzed.

**C) Asia-Pacific**

**Indonesia:** ChevronTexaco's interests in Indonesia are managed by two wholly owned subsidiaries, PT Caltex Pacific Indonesia (CPI) and Amoseas Indonesia (AI). CPI accounts for approximately 50 percent of Indonesia's total crude oil output and holds an interest in six production-sharing contracts. AI is a power generation company that operates the Darajat geothermal contract area in West Java and a

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cogeneration facility in support of CPI's operation in North Duri. ChevronTexaco's net share of production during 2001 averaged about 320,000 barrels of crude oil and condensate per day. CPI continues to implement enhanced oil recovery projects to extract more oil from its existing reservoirs. The Duri Field in the Rokan Block, under steamflood since 1985, is the largest steamflood project in the world. Currently 9 of 13 areas are under steam injection, with total production averaging about 260,000 barrels of oil per day during 2001. Area 10 is currently under development and will be placed on injection in the second quarter of 2002. CPI was awarded a new production-sharing contract for the Kisaran Block in 2001. The block is located in a gas prospective basin adjacent to the Rokan Block. A seismic review is planned for 2002.

**Thailand:** The company operates Block B8/32 in the Gulf of Thailand with a 52 percent interest. The company holds a 33 percent interest in adjacent exploration Blocks 7, 8 and 9, which are currently inactive pending resolution of border issues between Thailand and Cambodia. Block B8/32 produces oil and natural gas from three fields: Tantawan, Maliwan, and Benchamas. Initial production from the Maliwan Field occurred in October 2001. Net average daily production during 2001 from the company's interests in Thailand was 75 million cubic feet of natural gas and 16,000 barrels of crude oil. In 2002, the Benchamas Field will go through a major processing upgrade to bring total field production levels up to 60,000 barrels of oil per day. Development of the Maliwan Field will continue with production from multiple platforms expected to begin in 2005. Nine of the 11 exploration wells drilled in 2001 were successful, extending the productive areas in Block B8/32 significantly. During 2002, an exploration program is planned to evaluate the remaining portions of the concession.

**Australia:** ChevronTexaco has a one-sixth interest in the North West Shelf (NWS) Project in offshore Western Australia. Average daily net production from the NWS Project during 2001 was 230 million cubic feet of natural gas and 16,000 barrels per day of condensate. Net crude oil production from the NWS Project averaged approximately 17,000 barrels per day and total LPG production averaged about 4,000 barrels per day. Approximately 68 percent of the natural gas was sold, primarily under long-term contracts, in the form of liquefied natural gas (LNG) to major utilities in Japan. The remaining gas was sold to the Western Australia domestic gas market. In 2001, ChevronTexaco approved the development of the Train 4 LNG expansion project, which is planned to increase LNG capacity by about 50 percent in 2004. The North West Shelf Venture LNG sellers have secured LNG Sales and Purchase Agreements and Letters of Intent with several Japanese customers, for a total volume equal to the capacity of the new LNG Train.

The company is operator and has a 57 percent interest in the undeveloped Gorgon area gas field offshore north-west Australia. ChevronTexaco is actively pursuing long-term gas sales from Gorgon to Australian industrial customers and in international LNG markets including China, Korea, and the west coast of North America.

**Philippines:** ChevronTexaco holds a 45 percent interest in the Malampaya gas field located about 50 miles offshore of the Palawan Island. The Malampaya gas-to-power project represents the first offshore production of natural gas in the Philippines. In September 2001 production commenced. The gas will be delivered to three power plants under Gas Sales and Purchase Agreements. Gas sales are projected to increase throughout 2002 as the power plants are commissioned and brought into commercial operation.

**Middle East:** ChevronTexaco holds a concession with the Kingdom of Saudi Arabia to produce onshore crude oil from the Partitioned Neutral Zone (PNZ). The Kingdom of Saudi Arabia and the State of Kuwait each own 50 percent of the hydrocarbon resources. ChevronTexaco is entitled to 50 percent of the gross field production, for which it pays a royalty and other taxes to the Kingdom of Saudi Arabia. During 2001, record production was achieved from the four producing fields – averaging 144,000 net barrels of crude oil per day. Planned development drilling, workover, and facilities enhancement programs during the next few years are expected to maintain production at similar levels. The company also has exploration agreements in Bahrain and Qatar.

**Caspian Region:** The company holds a 20 percent equity interest in the Karachaganak Field located in northwest Kazakhstan. Net daily production for 2001 was 14,300 barrels of condensate and 67 million cubic feet of gas from the existing production facilities. The current phase of the Karachaganak

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development includes the building of processing and liquid export facilities to be completed by the end of 2003.

**D) Other International Areas**

**Europe:** The company holds producing interests in 24 fields in Denmark, Norway and the United Kingdom. The combined net average daily production during 2001 was 171,000 barrels of crude oil and condensate and 454 million cubic feet of natural gas. The Alba Field in the United Kingdom North Sea, where ChevronTexaco is operator and holds a 21 percent equity interest, produced a net average of 17,000 net barrels of crude oil and 2.8 million cubic feet of natural gas per day. Development of the Alba Extreme South project, which is expected to begin production in late 2002, will maintain the Alba Field's total production of 80,000 barrels of crude oil per day. ChevronTexaco holds an approximate 32 percent interest in the Britannia Field and shares operatorship. Net production averaged 9,600 barrels of crude oil and condensate per day and 208 million cubic feet of natural gas per day. The Captain Field net daily production averaged 49,000 barrels of crude oil during 2001. ChevronTexaco is operator and holds an 85 percent interest.

In Denmark, ChevronTexaco holds a 15 percent interest in the Danish Underground Consortium (DUC) currently producing crude oil and natural gas from 14 fields in the Danish North Sea. The DUC also holds nine exploration licenses with company interests ranging from 12 to 27 percent.

**Canada:** Total production from the Hibernia Field offshore Newfoundland, in which ChevronTexaco holds an interest of about 27 percent, averaged approximately 151,000 barrels of crude oil per day. Average net daily production from the company's onshore Canadian operations was 52,000 barrels of oil equivalent during 2001.

**Venezuela:** The company operates the onshore Boscan Field, located near the city of Maracaibo, under an Operating Services Agreement and receives operating expense reimbursement and capital recovery, plus interest and an incentive fee. Development drilling continued in 2001. Boscan crude oil production, subject to Venezuela's OPEC production restrictions, averaged 104,800 barrels per day during 2001. The company is also the operator and has a 27 percent interest in the LL-652 Field in Lake Maracaibo. Net production from LL-652 during 2001 averaged 4,900 barrels of oil per day, up from 4,000 barrels of oil per day in 2000. Field performance during 2001 indicated slower than anticipated re-pressurization of the reservoir by water injection and a reduction in the projected volumes of crude oil recoverable during the company's remaining contract period of operations. As a result the company wrote down proved crude oil reserve quantities at LL-652 in 2001.

**Argentina:** ChevronTexaco operates in Argentina as Chevron San Jorge S.R.L. Chevron San Jorge holds more than 6.1 million exploration and production acres in the Neuquén and Austral basins of Argentina, with working interest shares ranging from 18 to 100 percent in operated license areas. In addition, the company holds a 14 percent interest in Oleoductos del Valle S.A. (Oldeval), a major oil export pipeline from the Neuquén producing area to the Atlantic coast. Daily net production during 2001 in the Neuquén and Austral areas averaged over 66,000 net barrels of oil-equivalent, an increase of over 11 percent from 2000 production levels.

**Brazil:** ChevronTexaco holds working interests ranging from 20 to 50 percent in nine deepwater blocks offshore Brazil totaling approximately 9.2 million acres. Deepwater exploration is concentrated in the Campos, Santos, and Espirito Santo basins. During 2001, the company drilled two successful appraisal wells in the Frade Field in Block BC-4 of the Campos Basin. ChevronTexaco's interest in the Frade Block is approximately 43 percent. In the non-operated Block BS-4, where ChevronTexaco holds a 20 percent interest, two exploratory wells were drilled during 2001. One well resulted in a discovery.

**Affiliate operations**

**Caspian Region:** The Tengizchevroil (TCO) partnership, formed in 1993, includes the Tengiz and Korolev oil fields located in western Kazakhstan. In January 2001, the company acquired an additional

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5 percent stake in TCO, increasing its ownership interest to 50 percent. In 2001, total crude oil production from TCO increased for the eighth consecutive year, averaging 268,000 barrels of oil per day. Engineering for TCO's next major expansion, expected to come on-line during 2005, is under way. Production at Korolev, located near Tengiz, began in November 2001. Crude oil from the field is very similar to crude produced from Tengiz and is routed to existing facilities at TCO through an extension of an existing gathering system.

**Venezuela:** ChevronTexaco has a 30 percent interest in the Hamaca integrated oil production and upgrading project located in Venezuela's Orinoco Belt. Development drilling and major facility construction at Hamaca continued throughout 2001. Early production was established in October 2001, at a net rate of 9,000 barrels of crude oil per day. At the completion of the crude oil upgrading facilities in the first half of 2004, field production will increase to 190,000 barrels of crude oil per day and will be lighter, high-value crude.

**Petroleum – Natural Gas Liquids**

The company sells natural gas liquids from its producing operations under a variety of contractual arrangements. In the United States, the majority of sales are to the company's affiliate, Dynegy. Dynegy and ChevronTexaco have entered into long-term strategic alliances whereby Dynegy purchases substantially all natural gas and natural gas liquids produced by legacy Chevron in the United States, excluding Alaska, and supplies natural gas and natural gas liquids feedstocks to the company's U.S. refineries and chemical plants. In March 2002, the company reached agreement with Dynegy to expand those contracts to include substantially all of legacy Texaco's U.S. natural gas and natural gas liquids production. Outside the United States, natural gas liquids sales take place in the company's Canadian upstream operations, with lower sales levels in Africa, Australia and Europe.

Refer to "Selected Operating Data" on page FS-7 of this Annual Report on Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations for further information on the company's natural gas liquids sales volumes.

**Petroleum – Refining**

Distillation operating capacity utilization in 2001, adjusted for sales and closures, averaged 88 percent in the United States (including asphalt plants) and 87 percent worldwide (including affiliates), compared with 88 percent in the United States and worldwide in the prior year. ChevronTexaco's capacity utilization at its U.S. fuels refineries averaged 90 percent in 2001, compared with 91 percent in 2000. ChevronTexaco's capacity utilization of its wholly-owned U.S. cracking and coking facilities, which are the primary facilities used to convert heavier products to gasoline and other light products, averaged 84 percent in 2001, up from 80 percent in the year earlier. The company processed imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for 68 percent of ChevronTexaco's U.S. refinery inputs in 2001.

Prior to October 2001, the company had interests in eight U.S. refineries with a combined capacity of about 1.3 million barrels per day through its investments in the Equilon and Motiva affiliates. These investments were placed in trust in October 2001, and sold, as required by the U.S. Federal Trade Commission, in February 2002.

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The daily refinery inputs over the last three years for the company and affiliate refineries are shown in the following table:

**Petroleum Refineries: Locations, Capacities And Inputs**
(Inputs and Capacities are in Thousands of Barrels Per Day)

| Locations | | December 31, 2001 | | Refinery Inputs | | |
|---|---|---|---|---|---|---|
| | | Number | Operable Capacity | 2001 | 2000 | 1999 |
| Pascagoula | Mississippi | 1 | 295 | 332 | 313 | 328 |
| El Segundo | California | 1 | 260 | 213 | 219 | 211 |
| Richmond | California | 1 | 225 | 229 | 203 | 207 |
| El Paso[1] | Texas | 1 | 65 | 61 | 60 | 65 |
| Honolulu | Hawaii | 1 | 54 | 54 | 51 | 51 |
| Salt Lake City | Utah | 1 | 45 | 44 | 44 | 43 |
| Other[2] | | 2 | 96 | 50 | 53 | 50 |
| **Total Consolidated Companies – United States** | | **8** | **1,040** | **983** | **943** | **955** |
| Equity in Affiliates[3] | Various Locations | — | — | 353 | 447 | 579 |
| **Total Including Affiliates – United States** | | **8** | **1,040** | **1,336** | **1,390** | **1,534** |
| Pembroke | United Kingdom | 1 | 210 | 202 | 215 | 195 |
| Cape Town | South Africa | 1 | 112 | 71 | 65 | 73 |
| Batangas | Philippines | 1 | 76 | 65 | 65 | 70 |
| Colón[4] | Panama | 1 | 60 | 54 | 44 | 49 |
| Burnaby, B.C., | Canada | 1 | 52 | 52 | 51 | 52 |
| Escuintla | Guatemala | 1 | 17 | 16 | 16 | 17 |
| **Total Consolidated Companies – International** | | **6** | **527** | **460** | **456** | **456** |
| Equity in Affiliates[5] | Various Locations | 11 | 781 | 676 | 694 | 779 |
| **Total Including Affiliates – International** | | **17** | **1,308** | **1,136** | **1,150** | **1,235** |
| **Total Including Affiliates – Worldwide** | | **25** | **2,348** | **2,472** | **2,540** | **2,769** |

1 Capacity and input amounts for El Paso represent ChevronTexaco's share.

2 Refineries in Perth Amboy, New Jersey and Portland, Oregon, which are primarily asphalt plants.

3 Represents ChevronTexaco interests in Equilon and Motiva refineries, which were placed in trust on October 9, 2001, as required by the US Federal Trade Commission, prior to disposition in February 2002.

4 ChevronTexaco is negotiating with the Panamanian government in order to cease refining operations and convert these facilities to terminal operations in 2002.

5 1999 inputs include Koa Oil Co. Ltd. refineries. Interests sold in 1999.

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**Petroleum – Refined Products Marketing**

**Product Sales:** The company markets petroleum products throughout much of the world. The principal brands for identifying these products are "Chevron," "Texaco" and "Caltex."

The following table shows the company's and its affiliates' refined product sales volumes, excluding intercompany sales, over the past three years.

**Refined Products Sales Volumes[1,2]**
(Thousands of Barrels Per Day)

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| United States | | | |
| Gasolines | 1,246 | 1,320 | 1,266 |
| Jet Fuel | 481 | 481 | 451 |
| Gas Oils and Kerosene | 419 | 419 | 410 |
| Residual Fuel Oil | 228 | 179 | 227 |
| Other Petroleum Products[3] | 203 | 268 | 269 |
| Total United States | 2,577 | 2,667 | 2,623 |
| International | | | |
| Gasolines | 410 | 455 | 481 |
| Jet Fuel | 136 | 156 | 145 |
| Gas Oils and Kerosene | 925 | 629 | 647 |
| Residual Fuel Oil | 475 | 573 | 567 |
| Other Petroleum Products[3] | 549 | 708 | 781 |
| Total International | 2,495 | 2,521 | 2,621 |
| Total Worldwide | 5,072 | 5,188 | 5,244 |

[1] Includes equity in affiliates

[2] Includes Equilon and Motiva pre-merger

[3] Principally naphtha, lubricants, asphalt and coke

In the United States, the company supplies, directly or through dealers and jobbers, more than 8,200 motor vehicle retail outlets, of which about 1,300 are company-owned or -leased stations. The company's gasoline market area is concentrated in the southern, southwestern and western states. According to the *Lundberg Share of Market Report*, ChevronTexaco ranks among the top three gasoline marketers in 16 states. The company's former affiliates, Equilon and Motiva, operated through approximately 22,000 retail outlets in the United States. ChevronTexaco sold its investments in Equilon and Motiva in February 2002.

In Canada – primarily British Columbia – the company's branded products are sold in approximately 170 stations (mainly owned or leased).

ChevronTexaco operates a network of over 8,000 service stations and 650 convenience stores in more than 30 countries that cover the Asia-Pacific region, Southern and East Africa, and the Middle East. ChevronTexaco will continue to use the Caltex brand name in these areas.

In Europe, the company has marketing operations in the United Kingdom, Ireland, Netherlands, Belgium, Luxembourg and the Scandinavian countries. In West Africa, the company operates in Cameroon, the

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Canary Islands, Cote d'Ivoire, Nigeria, Togo and Benin. In these regions, the company mainly uses the Texaco brand name.

ChevronTexaco operates in approximately 40 countries across the Caribbean, Central America, and South America, with a significant presence in Brazil. In this region, the company uses the Texaco brand name.

In addition to the above activities, the company manages other marketing businesses globally. In global aviation fuel marketing, the company markets more than 400,000 barrels per day of aviation fuel in about 75 countries, representing a worldwide market share of about 12 percent. The company is the leading marketer of jet fuels in North America and ranks third in the Asia-Pacific region, Latin America, and the Caribbean. ChevronTexaco markets residual fuel oils and marine lubricants in over 100 countries, and motor lubricants in nearly 200 countries.

**Petroleum – Transportation**

**Pipelines:** ChevronTexaco owns and operates an extensive system of crude oil, refined products, chemicals, natural gas liquids and natural gas pipelines in the United States. The company also has direct or indirect interests in other U.S. and international pipelines. The company's ownership interests in pipelines are summarized in the following table:

**Pipeline Mileage At December 31, 2001**

| | Wholly Owned | Partially Owned[1] | Total |
|---|---|---|---|
| United States: | | | |
| Crude oil[2] | 1,876 | 458 | 2,334 |
| Natural gas | 1,403 | 1,872 | 3,275 |
| Petroleum products | 3,624 | 1,869 | 5,493 |
| Total United States | 6,903 | 4,199 | 11,102 |
| International: | | | |
| Crude oil[2] | — | 694 | 694 |
| Natural gas | — | 184 | 184 |
| Petroleum products | 4 | 547 | 551 |
| Total International | 4 | 1,425 | 1,429 |
| Worldwide | 6,907 | 5,624 | 12,531 |

1 Reflects equity interest in pipelines, except for those owned by Dynegy Inc.

2 Includes gathering lines related to the transportation function. Excludes gathering lines related to the U.S. and international production activities.

The Caspian Pipeline Consortium (CPC) was formed to build a crude oil export pipeline from the Tengiz Field to the Russian Black Sea port of Novorossiysk. The company has a 15 percent ownership interest in CPC. The first delivery of Tengizchevroil crude oil from the CPC terminal occurred in October 2001. When the construction project, including the pipeline, pump stations and terminal, is essentially complete, by the second quarter of 2002, the CPC system capacity will be 600,000 barrels of oil per day. Additional capacity will be possible with additional pump stations and tankage.

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**Tankers:** ChevronTexaco's controlled seagoing fleet at December 31, 2001, is summarized in the following table. All controlled tankers were utilized in 2001. In addition, at any given time, the company has 30 to 40 vessels under charter on a term or voyage basis.

**Controlled Tankers At December 31, 2001**

| | U.S. Flag | | Foreign Flag | |
|---|---|---|---|---|
| | Number | Cargo Capacity (Millions of Barrels) | Number | Cargo Capacity (Millions of Barrels) |
| Owned | 3 | 0.8 | 8 | 10.4 |
| Bareboat Charter | — | — | 15 | 21.2 |
| Time-Charter | — | — | 4 | 2.2 |
| Total | 3 | 0.8 | 27 | 33.8 |

Federal law requires that cargo transported between U.S. ports be carried in ships built and registered in the United States, owned and operated by U.S. entities and manned by U.S. crews. At year-end 2001, the company's U.S. flag fleet was engaged primarily in transporting crude oil from Alaska to refineries on the West Coast and Hawaii, refined products between the Gulf Coast and East Coast, and refined products from California refineries to terminals on the West Coast, Alaska and Hawaii.

The Federal Oil Pollution Act of 1990 requires the scheduled phase-out, by year-end 2010, of all single hull tankers trading to U.S. ports or transferring cargo in waters within the U.S. Exclusive Economic Zone. This has resulted in the utilization of more costly double-hull tankers. By the end of 2001, ChevronTexaco was operating a total of 16 double-hull tankers. ChevronTexaco expects to take delivery of two additional double-hull tankers in 2003, also to be operated under long-term bareboat charters. The company is a member of many oil-spill response cooperatives in areas in which it operates around the world.

At year-end 2001, two of the company's controlled international flag vessels continued to be used as floating storage vessels in its upstream operations offshore Cabinda Province, Angola. The remaining international flag vessels were engaged primarily in transporting crude oil from the Middle East, Indonesia, Mexico and West Africa to ports in the United States, Europe, and Asia. Refined products also were transported by tanker worldwide.

**Energy Marketing and Services – Dynegy**

ChevronTexaco owns an approximate 26 percent equity share of Dynegy Inc. (Dynegy), which is one of the world's leading energy merchants. Dynegy reported record net income of $648 million in 2001, a 29 percent increase compared with 2000. ChevronTexaco invested a total of $1.7 billion in Dynegy in 2001 and January 2002. Dynegy's equity market value at December 31, 2001, was $8.6 billion. Through a global physical network of assets and marketing, logistics and risk management capabilities, Dynegy provides energy and communications solutions to customers in North America, the United Kingdom and continental Europe. Dynegy's activity extends across the entire convergence value chain, from power generation, wholesale and direct commercial and industrial marketing and trading of power, natural gas, coal, emission allowances, weather derivatives, and broadband to transportation, gathering and processing of natural gas liquids.

Dynegy is one of the leading natural gas marketers in North America, with sales of more than 13 billion cubic feet per day, and a leading natural gas liquids marketer, with worldwide sales in excess of 557,000 barrels per day. Dynegy is also one of the largest processors of natural gas in North America, with production of more than 84,000 barrels of natural gas liquids per day. As of January 1, 2002, Dynegy

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operates or controls 19,100 gross megawatts of power generation capacity and plans to add over 1,400 gross megawatts in 2002.

Dynegy and ChevronTexaco formed a long-term strategic alliance in 1996 whereby Dynegy purchases essentially all natural gas and natural gas liquids produced or controlled by the legacy Chevron operations in the United States (excluding Alaska) and supplies natural gas and natural gas liquids feedstocks to most of ChevronTexaco's U.S. refineries and chemical plants. In March 2002, the company reached agreement with Dynegy to expand those contracts to include substantially all of legacy Texaco's undedicated U.S. natural gas and natural gas liquids production.

**Chemicals**

Chevron Phillips Chemical Company (CPChem) is a 50-50 joint venture with Phillips Petroleum Company formed in July 2000, when both companies combined most of their petrochemicals operations. CPChem owns or has joint venture interests in 34 manufacturing facilities and five research and technical centers in the United States, Puerto Rico, Belgium, China, Mexico, Saudi Arabia, Singapore, and South Korea.

In December 2001, commercial production of K-Resin resumed with the completion of Phase I of the rebuild at the Houston Chemical Complex, shut down since an explosion and fire that occurred in March 2000. Restoration of the remaining K-Resin capacity will be completed in 2002, bringing annual production capacity to 335 million pounds.

An olefins and polyolefins complex in Qatar is under construction and expected to start production in late 2002. Annual production capabilities at the complex include 1.1 billion pounds of ethylene, 1 billion pounds of polyethylene, and 100 million pounds of hexene-1. The complex is owned and will be operated by Qatar Chemical Company, Ltd. a joint venture between CPChem, with a 49 percent interest, and Qatar General Petroleum, which owns the remaining 51 percent.

A 50-50 joint venture with BP Solvay to build a new high-density polyethylene (HDPE) facility at a CPChem site in the Houston area is on track for start-up in late 2002. The jointly owned 700-million-pounds-per-year HDPE facility will be the largest of its kind in the world and will use CPChem proprietary manufacturing technology.

ChevronTexaco retained its "Oronite" fuel and lubricant additives business. Oronite is a leading developer, manufacturer and marketer of performance additives for fuels and lubricating oils. The company owns and operates five manufacturing facilities in the United States, France, Singapore, Japan and Brazil and has equity interests in facilities in India and Mexico.

**Coal**

The company's coal mining and marketing subsidiary, The Pittsburg & Midway Coal Mining Co. (P&M), owned and operated two surface mines and one underground mine at year-end 2001. P&M also owns an approximate 30 percent interest in Inter-American Coal Holding N.V., which has interests in mining operations in Venezuela.

Sales and other operating revenues in 2001 were $353 million, an increase of 19 percent from 2000. Sales of coal from P&M's wholly owned mines and from its affiliates were 16.2 million tons, an increase of 17 percent from 2000. At year-end 2001, P&M controlled approximately 196 million tons of developed and undeveloped coal reserves, including significant reserves of environmentally desirable low-sulfur fuel.

**Other Activities – Synthetic Crude Oil**

In Canada, ChevronTexaco has a 20 percent interest in the Athabasca Oil Sands Project. The project is expected to begin bitumen production in late 2002 and reach 155,000 barrels of bitumen per day at peak production. The bitumen will be upgraded into high quality synthetic oil using hydroprocessing technology at a synthetic crude unit, which will start up by late 2002 or early 2003.

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**Power and Gasification**

ChevronTexaco participates in its power and gasification business through ownership, equity investments with others and licensing of proprietary technology. The company's electrical power business includes conventional power generation projects, as well as cogeneration facilities. Cogeneration produces thermal energy, such as steam, and electric power. ChevronTexaco has used steam produced in cogeneration in its upstream operations in onshore California and Indonesia. ChevronTexaco uses its proprietary gasification technology to convert a wide variety of hydrocarbon feedstocks into a clean synthesis gas. The synthetic gas can be used to generate electricity in low-emission power plants. ChevronTexaco licenses this technology, operates owned gasification facilities and invests in projects using the technology. With licenses and partners, the company has interests in over 70 gasification facilities operating or being developed worldwide.

**Research and Technology**

The company's core hydrocarbon technology efforts support the upstream, downstream and power and gasification businesses, aimed at developing and applying these technologies to create increased value. These activities include heavy oil recovery and upgrading, deepwater exploration and production, shallow water production operations, gas-to-liquids processing, hydrocarbon gasification to power, and new and improved refinery processes.

Additionally, ChevronTexaco's Technology Ventures Company focuses upon the identification, growth, and commercialization of emerging technologies for new energy applications. The range of business spans early-stage venture capital investing in emerging technologies to developing joint venture companies in new energy systems such as advanced batteries for distributed power and transportation systems, fuel cells and hydrogen fuel storage.

The company is building an information technology infrastructure encompassing computing, data management, security, and connectivity of partners, suppliers, and employees. The architecture, known as "Net Ready," is designed to provide the foundation for the company to rapidly integrate advances in computing and network-based technology.

ChevronTexaco's research and development expenses were $209 million, $211 million and $226 million for the years 2001, 2000 and 1999, respectively.

Because some of the investments the company makes in the areas described above are in new or unproven technologies and business processes, ultimate success is not always certain. Although not all initiatives may prove to be economically viable, the company's overall investment in this area is not significant to the company's consolidated financial position.

**Environmental Protection**

Virtually all aspects of the company's businesses are subject to various federal, state and local environmental, health and safety laws and regulations. These regulatory requirements continue to change and increase in both number and complexity, and govern not only the manner in which the company conducts its operations, but also the products it sells. ChevronTexaco expects more environmental-related regulations in the countries where it has operations. Most of the costs of complying with the myriad laws and regulations pertaining to its operations are embedded in the normal costs of conducting its business.

In 2001, the company's U.S. capitalized environmental expenditures were $220 million, representing approximately 4 percent of the company's total consolidated U.S. capital and exploratory expenditures. These environmental expenditures include capital outlays to retrofit existing facilities, as well as those associated with new facilities. The expenditures are predominantly in the petroleum segment and relate mostly to air and water quality projects and activities at the company's refineries, oil and gas producing facilities and marketing facilities. For 2002, the company estimates U.S. capital expenditures for environmental control facilities will be $370 million. The future annual capital costs of fulfilling this

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commitment are uncertain and will be governed by several factors, including future changes to regulatory requirements.

Further information on environmental matters and their impact on ChevronTexaco, and the company's 2001 environmental expenditures, remediation provisions and year-end environmental reserves are contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages FS-10 and FS-11 of this Annual Report on Form 10-K.

**Item 2. Properties**

The location and character of the company's oil, natural gas and coal properties and its refining, marketing, transportation and chemicals facilities are described above under Item 1. Business. Information required by the Securities Exchange Act Industry Guide No. 2 ("Disclosure of Oil and Gas Operations") is also contained in Item 1 and in Tables I through VII on pages FS-45 to FS-51 of this Annual Report on Form 10-K. Note 15, "Properties, Plant and Equipment," to the company's financial statements is on page FS-33 of this Annual Report on Form 10-K.

**Item 3. Legal Proceedings**

A. Texaco Exploration and Production Inc. – Aneth Producing Unit and Gas Plant – Clean Air Act Enforcement Action

Texaco Exploration and Production Inc. ("TEPI") has agreed to pay a civil penalty of $243,725 to settle an enforcement action brought by the United States Environmental Protection Agency involving alleged Clean Air Act violations at TEPI's Aneth Producing Unit and Gas Plant, located on the Navajo Nation in Utah. In addition, TEPI has agreed to a supplemental environmental project wherein it will provide a local fire department in Montezuma Creek, Utah with $51,275 in emergency response equipment and hazardous materials training. The alleged violations include: 1) a claim that TEPI's Aneth Producing Unit failed to provide notice to emergency response authorities of releases of sulfur dioxide in December 1997 as required by section 304 of the Emergency Planning and Community Right-to-Know Act; and 2) non-compliance with Clean Air Act regulations at the Aneth Gas Plant near Montezuma Creek, Utah, resulting from a 1991 renovation of the facility and the cleanup of asbestos-containing materials following a 1997 explosion.

B. Texaco Exploration and Production Inc. – Aneth Producing Unit – Clean Water Act Enforcement Action

Texaco Exploration and Production Inc. ("TEPI") has agreed to a civil penalty of $370,000 to settle an enforcement action brought by the United States Environmental Protection Agency involving alleged Clean Water Act violations at TEPI's Aneth Producing Unit located on the Navajo Nation in Utah. In addition to the civil penalty, TEPI agreed to fund a $479,000 supplemental environmental project. The alleged violations include: 1) a claim that TEPI did not report releases of pollutants as required by law and 2) unlawful releases of pollutants into Waters of the United States.

C. Texaco Chemical Company – Clean Water Act Enforcement Action

Texaco Chemical Company ("TCC") has agreed to pay a $300,000 civil penalty to settle an administrative enforcement action initiated by the United States Environmental Protection Agency. This enforcement action, which involved two separate proceedings initiated in 1992 and subsequently consolidated, alleged violations of the Texas State Implementation Plan; hazardous waste laws; Polychlorinated Biphenyl (PCB) regulations; and release notification and requirements at the TCC facility located in Port Neches, Texas. The stock of TCC was sold to Huntsman in 1994 and ChevronTexaco has no current relationship with the Port Neches facility.

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**Item 4. Submission of Matters to a Vote of Security Holders**

The following matters were submitted to a vote of Chevron Corporation stockholders at a special meeting on October 9, 2001.

Voters approved the issuance of common stock to Texaco Inc. stockholders at a ratio of 0.77 shares of ChevronTexaco common stock for each share of Texaco common stock, by a vote of 442,294,614 votes (98.9 percent) for and 4,754,183 (1.1 percent) against. There were 4,926,109 abstentions.

Voters approved the amendment of the Restated Certificate of Incorporation to change the name of Chevron Corporation to "ChevronTexaco Corporation," by a vote of 438,925,583 votes (97.9 percent) for and 9,456,781 (2.1 percent) against. There were 3,594,154 abstentions.

**Executive Officers of the Registrant at March 1, 2002**

| Name and Age | | Executive Office Held | Major Area of Responsibility |
|---|---|---|---|
| D. J. O'Reilly | 55 | Chairman of the Board since 2000<br>Director since 1998<br>Vice-Chairman from 1998 to 2000<br>President of Chevron Products Company from 1994 to 1998<br>Executive Committee Member since 1994 | Chief Executive Officer |
| P. J. Robertson | 55 | Vice-Chairman of the Board since 2002<br>Vice-President since 1994<br>President of Chevron Overseas Petroleum Inc. from 2000 to 2002<br>Executive Committee Member since 1997 | Office of the Chairman<br>Worldwide Exploration and Production Activities |
| G. F. Tilton | 53 | Vice-Chairman of the Board since 2001<br>Director since 2001<br>Chairman of the Board and Chief Executive Officer, Texaco Inc., 2001<br>President of Global Business Unit, Texaco Inc. from 1997 to 2001<br>Executive Committee Member since 2001 | Office of the Chairman |
| D. W. Callahan | 59 | Executive Vice-President since 2000<br>Vice-President since 1999<br>President of Chevron Chemical Company from 1999 to 2000<br>Executive Committee Member since 1999 | Chemicals, Coal,<br>Human Resources, Technology |
| H. D. Hinman | 61 | Vice-President and General Counsel since 1993<br>Executive Committee Member since 1993 | Law |
| G. L. Kirkland | 51 | President of ChevronTexaco Overseas Petroleum Inc. since 2002<br>Vice-President since 2002<br>President of Chevron U.S.A. Production Company<br>from 2000 to 2002<br>Executive Committee Member from 2000 to 2001 | Overseas<br>Exploration and<br>Production |
| J. S. Watson | 45 | Vice-President and Chief Financial Officer since 2000 | Finance |

Vice-President since 1998
Executive Committee Member since 2000

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**Executive Officers of the Registrant at March 1, 2002 — (continued)**

| Name and Age | | Executive Office Held | Major Area of Responsibility |
|---|---|---|---|
| **R. I. Wilcox** | **56** | **President, North America Exploration and Production since 2002<br>Vice President since 2002** | **North American Exploration and Production** |
| **P. A. Woertz** | **48** | **Executive Vice President since 2001<br>Vice-President since 1998<br>President of Chevron Products Company From 1998 to 2001<br>Executive Committee Member since 1998** | **Worldwide Refining, Marketing and Transportation Activities** |

The Executive Officers of the Corporation consist of the Chairman of the Board, the Vice-Chairman of the Board, and such other officers of the Corporation who are either Directors or members of the Executive Committee, or who are chief executive officers of principal business units. Except as noted below, all of the Corporation's Executive Officers have held one or more of such positions for more than five years.

| | |
|---|---|
| D. W. Callahan | - Senior Vice President, Chevron Chemical Company – 1991<br>- President, Chevron Chemical Company – 1999 |
| G. L. Kirkland | - General Manager, Asset Management, Chevron Nigeria Limited – 1996<br>- Chairman and Managing Director, Chevron Nigeria Limited – 1996<br>- President, Chevron USA Production Company – 2000 |
| P. J. Robertson | - Executive Vice-President of Chevron U.S.A. Production Company – 1996<br>- Vice-President, Chevron Corporation and President of Chevron U.S.A. Production Company – 1997<br>- President of Chevron Overseas Petroleum Inc. since 2000 |
| G. F. Tilton | - President of Texaco USA – 1995<br>- President of Global Businesses, Texaco Inc. – 1997 |
| J. S. Watson | - President, Chevron Canada Limited – 1996<br>- Vice-President, Strategic Planning, Chevron Corporation – 1998<br>- Vice-President and Chief Financial Officer, Chevron Corporation – 2000 |
| R. I. Wilcox | - Vice President and General Manager, Marine Transportation, Chevron Shipping Company – 1996<br>- General Manager, Asset Management, Chevron Nigeria Limited – 1999<br>- Chairman and Managing Director, Chevron Nigeria Limited – 2000<br>- Corporate Vice President and President, North America Exploration and Production – 2002 |
| P. A. Woertz | - President, Chevron International Oil Company – 1996<br>- Vice President, Logistics and Trading, Chevron Products Company – 1996<br>- President, Chevron Products Company – 1998 |

## PART II

### Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters

The information on ChevronTexaco's common stock market prices, dividends, principal exchanges on which the stock is traded and number of stockholders of record is contained in the Quarterly Results and Stock Market Data tabulations, on page FS-43 of this Annual Report on Form 10-K.

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**Item 6. Selected Financial Data**

The selected financial data for years 1997 through 2001 are presented on page FS-44 of this Annual Report on Form 10-K.

**Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**

The index to Management's Discussion and Analysis, Consolidated Financial Statements and Supplementary Data is presented on page FS-1 of this Annual Report on Form 10-K.

**Item 7A. Quantitative and Qualitative Disclosures About Market Risk**

The company's discussion of interest rate, foreign currency and commodity price market risk is contained on pages FS-9 and FS-10. Management's Discussion and Analysis of Financial Condition and Results of Operations – "Financial Instruments" and Note 10 to the Consolidated Financial Statements – "Financial and Derivative Instruments" beginning on page FS-27.

**Item 8. Financial Statements and Supplementary Data**

The index to Management's Discussion and Analysis, Consolidated Financial Statements and Supplementary Data is presented on page FS-1 of this Annual Report on Form 10-K.

**Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

None.

## PART III

**Item 10. Directors and Executive Officers of the Registrant**

The information on Directors appearing under the heading "Nominees For Directors" in the Notice of the 2002 Annual Meeting of Stockholders and 2002 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, as amended, in connection with the company's 2002 Annual Meeting of Stockholders, is incorporated herein by reference in this Annual Report on Form 10-K. See Executive Officers of the Registrant on pages 22 and 23 of this Annual Report on Form 10-K for information about Executive Officers of the company.

The information contained under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Notice of the 2002 Annual Meeting of Stockholders and 2002 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, as amended, in connection with the company's 2002 Annual Meeting of Stockholders, is incorporated herein by reference in this Annual Report on Form 10-K. ChevronTexaco believes all filing requirements were complied with during 2001.

**Item 11. Executive Compensation**

The information appearing under the heading "Executive Compensation," including the subheadings "Summary Compensation Table," "Long-Term Incentive Plan – 2001 Performance Units Awards Table," "Option Grants in Last Fiscal Year Table," "G. F. Tilton's Option Grants in Last Fiscal Year Table," "Aggregated Option Exercises in Last Fiscal Year and Fiscal Year-end Option Values Table," "Pension Plan Table," "Termination of Employment and Change-in-Control Arrangements" and "Summary of Glenn F. Tilton's Employment Agreement" and in the Notice of the 2002 Annual Meeting of Stockholders and 2002 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, as amended, in connection with the company's 2002 Annual Meeting of Stockholders, is incorporated herein by reference in this Annual Report on Form 10-K.

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**Item 12. Security Ownership of Certain Beneficial Owners and Management**

The information appearing under the heading "Directors' and Executive Officers' Stock Ownership" in the Notice of the 2002 Annual Meeting of Stockholders and 2002 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, as amended, in connection with the company's 2002 Annual Meeting of Stockholders, is incorporated herein by reference in this Annual Report on Form 10-K.

**Item 13. Certain Relationships and Related Transactions**

The information appearing under the heading "Transactions with Directors and Officers" in the Notice of the 2002 Annual Meeting of Stockholders and 2002 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, as amended, in connection with the company's 2002 Annual Meeting of Stockholders, is incorporated herein by reference in this Annual Report on Form 10-K.

**PART IV**

**Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K**

**(a) The following documents are filed as part of this report:**

**(1) Financial Statements:**

| | Page(s) |
|---|---|
| Report of Independent Accountants – PricewaterhouseCoopers LLP | FS-15 |
| Report of Independent Public Accountants – Arthur Andersen LLP | FS-15 |
| Consolidated Statement of Income for the three years ended December 31, 2001 | FS-16 |
| Consolidated Statement of Comprehensive Income for the three years ended December 31, 2001 | FS-17 |
| Consolidated Balance Sheet at December 31, 2001 and 2000 | FS-18 |
| Consolidated Statement of Cash Flows for the three years ended December 31, 2001 | FS-19 |
| Consolidated Statement of Stockholders' Equity for the three years ended December 31, 2001 | FS-20 to FS-21 |
| Notes to Consolidated Financial Statements | FS-22 to FS-42 |

**(2) Financial Statement Schedules:**

We have included on page 26 of this Annual report on Form 10-K, Financial Statement Schedule II – Valuation and Qualifying Accounts.

**(3) Exhibits:**

The Exhibit Index on pages E-1 and E-2 of this Annual Report on Form 10-K lists the exhibits that are filed as part of this report.

**(b) Reports on Form 8-K:**

(1) A Current Report on Form 8-K was filed by the company on November 19, 2001. In this report, ChevronTexaco

filed the following financial information:

- Review of Operations 1998-2000
- Audited Supplemental Combined Financial Statements 1998-2000
- Supplemental Information on Oil and Gas Producing Activities 1998-2000
- Financial Summary 1996-2000
- Audited Schedule II – Valuation and Qualifying Accounts

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**SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS ($ MILLIONS)**

| | Year ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| **Employee Termination Benefits:** | | | |
| Balance at January 1 | $ 1 | $ 130 | $ 156 |
| Additions charged to expense | 763 | 15 | 291 |
| Payments | (105) | (144) | (317) |
| **Balance at December 31*** | **$ 659** | **$ 1** | **$ 130** |

*$275 is reported as "Deferred Credits and Other Noncurrent Obligations" on the Consolidated Balance Sheet

| | | | |
|---|---|---|---|
| **Other Merger-related Expenses:** | | | |
| Balance at January 1 | $ — | $ — | $ — |
| Additions charged to expense | 128 | — | — |
| Payments | (1) | — | — |
| **Balance at December 31** | **$ 127** | **$ —** | **$ —** |
| **Allowance for Doubtful Accounts:** | | | |
| Balance at January 1 | $ 136 | $ 113 | $ 90 |
| Additions charged to expense | 116 | 74 | 97 |
| Bad debt write-offs | (69) | (51) | (74) |
| **Balance at December 31** | **$ 183** | **$ 136** | **$ 113** |
| **Deferred Income Tax Valuation Allowance:*** | | | |
| Balance at January 1 | $1,574 | $1,588 | $1,295 |
| Additions charged to deferred income tax expense | 258 | 326 | 381 |
| Deductions credited to deferred income tax expense | (401) | (340) | (88) |
| **Balance at December 31** | **$1,431** | **$1,574** | **$1,588** |

*See also Note 16 to the consolidated financial statements on page FS-34

| | | | |
|---|---|---|---|
| **Inventory Valuation Allowance:** | | | |
| Balance at January 1 | $ 4 | $ — | $ 170 |
| Additions | — | 4 | — |
| Deductions | (4) | — | (170) |
| **Balance at December 31** | **$ —** | **$ 4** | **$ —** |

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**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 27th day of March 2002.

ChevronTexaco Corporation

By DAVID J. O'REILLY*

David J. O'Reilly, Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 27th day of March 2002.

**Principal Executive Officers (And Directors)**

DAVID J. O'REILLY*

David J. O'Reilly, Chairman of the Board

PETER J. ROBERTSON*

Peter J. Robertson, Vice-Chairman of the Board

GLENN F. TILTON*

Glenn F. Tilton, Vice-Chairman of the Board

**Principal Financial Officer**

JOHN S. WATSON*

John S. Watson, Vice-President, Finance and Chief Financial Officer

**Principal Accounting Officer**

STEPHEN J. CROWE*

Stephen J. Crowe, Vice-President and Comptroller

*By: /s/ LYDIA I. BEEBE

Lydia I. Beebe, Attorney-in-Fact

**Directors**

SAMUEL H. ARMACOST*

Samuel H. Armacost

ROBERT J. EATON*

Robert J. Eaton

SAM GINN*

Sam Ginn

CARLA A. HILLS*

Carla A. Hills

FRANKLYN G. JENIFER*

Franklyn G. Jenifer

J. BENNETT JOHNSTON*

J. Bennett Johnston

SAM NUNN*

Sam Nunn

CHARLES R. SHOEMATE*

Charles R. Shoemate

FRANK A. SHRONTZ*

Frank A. Shrontz

THOMAS A. VANDERSLICE*

Thomas A. Vanderslice

CARL WARE*

Carl Ware

JOHN A. YOUNG*

John A. Young

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**INDEX TO MANAGEMENT'S DISCUSSION AND ANALYSIS**
**CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**


| | Page(s) |
|---|---|
| Management's Discussion and Analysis | FS-2 to FS-14 |
| Report of Independent Accountants | FS-15 |
| Report of Independent Public Accountants | FS-15 |
| Consolidated Statement of Income | FS-16 |
| Report of Management | FS-16 |
| Consolidated Statement of Comprehensive Income | FS-17 |
| Consolidated Balance Sheet | FS-18 |
| Consolidated Statement of Cash Flows | FS-19 |
| Consolidated Statement of Stockholders' Equity | FS-20 to FS-21 |
| Notes to Consolidated Financial Statements | FS-22 to FS-42 |
| Quarterly Results and Stock Market Data | FS-43 |
| Five-Year Financial Summary | FS-44 |
| Supplemental Information on Oil and Gas Producing Activities | FS-44 to FS-51 |

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## Management's Discussion and Analysis of Financial Condition and Results of Operations

**TEXACO MERGER TRANSACTION**

On October 9, 2001, Texaco Inc. (Texaco) became a wholly owned subsidiary of Chevron Corporation (Chevron) pursuant to a merger transaction, and Chevron changed its name to ChevronTexaco Corporation. The combination was accounted for as a pooling of interests, and each share of Texaco common stock was converted on a tax-free basis into the right to receive 0.77 shares of ChevronTexaco common stock. In the merger, ChevronTexaco issued approximately 425 million shares of common stock, representing about 40 percent of the outstanding ChevronTexaco common stock after the merger.

In accordance with pooling-of-interests accounting, the accompanying audited consolidated financial statements give retroactive effect to the merger, with all periods presented as if Chevron and Texaco had always been combined.

As a result of the merger, the accounts of certain operations that were jointly owned by the combining companies are consolidated in the accompanying financial statements. These operations are primarily those of the Caltex Group of Companies, which was previously owned 50 percent each by Chevron and Texaco.

**KEY FINANCIAL RESULTS**

| Millions of dollars, except per-share amounts | **2001** | 2000 | 1999 |
|---|---|---|---|
| Net Income | **$ 3,288** | $ 7,727 | $ 3,247 |
| Special Items and Merger Effects Included in Net Income | **(3,522)** | (378) | (191) |
| Earnings Excluding Special Items and Merger Effects | **$ 6,810** | $ 8,105 | $ 3,438 |
| Per Share: | | | |
| Net Income – Basic | **$ 3.10** | $ 7.23 | $ 3.01 |
| – Diluted | **$ 3.09** | $ 7.21 | $ 3.00 |
| Earnings Excluding Special Items and Merger Effects – Basic | **$ 6.42** | $ 7.58 | $ 3.19 |
| – Diluted | **$ 6.41** | $ 7.57 | $ 3.18 |
| Dividends* | **$ 2.65** | $ 2.60 | $ 2.48 |
| Sales and Other Operating Revenues | **$104,409** | $117,095 | $84,004 |
| Return on: | | | |
| Average Capital Employed | **7.8%** | 17.3% | 8.5% |
| Average Stockholders' Equity | **9.8%** | 24.5% | 11.1% |

* Chevron divided pre-merger.

ChevronTexaco's net income of $3.288 billion was down significantly from 2000 but was slightly higher than 1999. Net income for 2001 included net charges of $1.743 billion for special items and $1.779 billion for merger effects, for a combined total of $3.522 billion. Special items included asset write-downs of $1.709 billion, primarily for exploration and production (upstream) properties as a result of downward revisions in estimated proved crude oil reserves. Merger effects represented merger-related expenses of $1.136 billion and net losses on merger-related asset dispositions of $643 million. In 2000 and 1999, net special charges were $378 million and $191 million, respectively.

Net income and special items for the individual business segments are discussed in the Results of Operations section beginning on page FS-4.

**NET INCOME BY MAJOR OPERATING AREA[1]**

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| Exploration and Production | | | |
| United States | **$ 1,779** | $3,453 | $1,133 |
| International | **2,533** | 3,702 | 1,450 |
| Total Exploration and Production | **4,312** | 7,155 | 2,583 |
| Refining, Marketing and Transportation | | | |
| United States | **1,254** | 721 | 551 |
| International | **560** | 414 | 546 |
| Total Refining, Marketing and Transportation | **1,814** | 1,135 | 1,097 |
| Chemicals | **(128)** | 40 | 109 |
| All Other | **(2,710)** | (603) | (542) |
| Net Income[2] | **$ 3,288** | $7,727 | $3,247 |

[1] 1999 and 2000 conformed to the 2001 presentation

[2] Includes Foreign Currency Gains (Losses): **$ 191** $ 182 $ (15)

**EARNINGS BY MAJOR OPERATING AREA, EXCLUDING SPECIAL ITEMS AND MERGER EFFECTS[1]**

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| Exploration and Production | | | |
| United States | **$ 2,890** | $3,736 | $1,390 |
| International | **2,905** | 3,622 | 1,520 |
| Total Exploration and Production | **5,795** | 7,358 | 2,910 |
| Refining, Marketing and Transportation | | | |
| United States | **1,332** | 974 | 638 |
| International | **598** | 526 | 615 |
| Total Refining, Marketing and Transportation | **1,930** | 1,500 | 1,253 |
| Chemicals | **(32)** | 130 | 174 |
| All Other | **(883)** | (883) | (899) |
| **Earnings Excluding Special Items and Merger Effects[2]** | **6,810** | 8,105 | 3,438 |
| Special Items and Merger Effects[2] | **(3,522)** | (378) | (191) |
| **Net Income[2]** | **$ 3,288** | $7,727 | $3,247 |

[1] 1999 and 2000 conformed to the 2001 presentation

[2] Includes Foreign Currency Gains (Losses): **$ 191** $ 182 $ (15)

**BUSINESS ENVIRONMENT AND OUTLOOK**

ChevronTexaco's overall operating earnings depend largely on the profitability of its upstream – exploration and production – and downstream – refining, marketing and transportation – businesses.

Upstream operating earnings align most closely with industry price levels for crude oil and natural gas. The decline in the company's upstream operating earnings during 2001 tracked the downward slide in prices for these commodities. The price trend for crude oil was largely caused by reduced demand in weakened economies worldwide and the relative oversupply by OPEC and certain other oil-producing countries.

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The average spot price during 2001 for West Texas Intermediate (WTI), a benchmark crude oil, was about $26 per barrel – down from an average of about $30 in 2000 – and ended the year under $20. A similar trend existed for certain natural gas prices, which are more sensitive to regional supply-demand balances. In the United States, the company's average natural gas sales realization started 2001 at about $10.00 per thousand cubic feet. By the end of the year, the average realization had dropped below $3.00. Into early 2002, the WTI crude oil price moved above $20 per barrel, but the company's U.S. average natural gas realization remained below $3.00 per thousand cubic feet. Earnings during 2001 were also dampened by slightly lower oil-equivalent production – down less than 2 percent from 2000 levels. However, the company anticipates an oil-equivalent production growth rate over the next five years of 2.5 to 3 percent annually, although 2002 production is expected to increase only about 1 percent because of OPEC-related constraints.

Downstream operating earnings are most closely tied to refining and marketing margins, which can vary among the geographic areas in which the company operates. Although world-wide demand for refined products weakened overall during 2001,margins fluctuated on regional supply-demand balances. For example, margins improved in North America over the prior year and sales volumes increased for all higher-value products. Margins also improved in most of the Asia, Middle East and eastern Africa operating areas. However, in Europe, Latin America and certain western African countries, changes in product prices were not able to keep pace with feedstock costs, and margins suffered. Early in 2002, profitability was weak in all geographic areas and is not expected to rebound in earnest until the world economies and product demand improve.

The company's chemical segment was not profitable during 2001, and significant improvement for certain commodity chemicals is not expected until demand more closely matches industry capacity.

**MERGER EFFECTS**

Within 18 months of the merger, ChevronTexaco expects to realize pre-tax savings of approximately $1.8 billion annually through operating efficiencies and the elimination of redundant facilities and operations.

Significant one-time expenses are being incurred in connection with the merger. Total before-tax merger-related expenses, from the time of the merger announcement in October 2000 through the end of 2003, are estimated at $2 billion. Major expenses include employee severance payments; incremental pension and medical plan costs associated with work-force reductions; legal, accounting, SEC filing and investment banker fees; employee and office relocations; and costs for the elimination of redundant facilities and operations. During 2001, $1.563 billion of before-tax ($1.136 billion after tax) merger-related expenses were recorded. Included were accruals of $891 million for employee termination benefits for approximately 4,500 employees, and other merger-related expenses that will not benefit future operations. Payments against the accruals were $105 million. Approximately 1,400 employees were terminated after the merger during 2001. The year-end 2001 accrual balance of $786 million is expected to be nearly extinguished by early 2003, as certain terminating employees are eligible to delay separation payments for one year or more.

As a condition of approving the merger, the U.S. Federal Trade Commission (FTC) required the disposition of certain Texaco assets, including investments in Equilon and Motiva – joint ventures engaged in U.S. refining, marketing and transportation businesses. The interests in these joint ventures were placed in trust at the time of the merger, and ChevronTexaco no longer exercised control over the joint ventures. Accordingly, the method of accounting for these investments was changed in the fourth quarter 2001 from equity to cost basis. Based on the terms of the sale that closed in February 2002, the company recorded an after-tax charge of $564 million in 2001 for the anticipated loss. Cash proceeds from the sale received in 2002 were $2.2 billion. Indemnification by ChevronTexaco against certain Equilon and Motiva contingent liabilities at the date of sale are discussed in the "On- and off-balance-sheet arrangements" section on page FS-8.

Additional after-tax charges of $79 million were recorded in 2001 for other merger-related asset dispositions, which are expected to result in proceeds of approximately $75 million. Including the loss for the Equilon and Motiva sale, total charges for merger-related asset dispositions of $643 million were recorded in 2001 and classified as an "Extraordinary item" on the Consolidated Statement of Income in accordance with pooling-of-interests reporting requirements of Accounting Principles Board (APB) Opinion No. 16, "Business Combinations." The net book value of these asset sales that were not completed at year-end 2001 was $2.181 billion and was classified as "Assets held for sale – merger related" in the "Current Assets" section of the Consolidated Balance Sheet. Net income during 2001 for all merger-related assets that are being sold was approximately $375 million.

**OPERATING HIGHLIGHTS AND DEVELOPMENTS**

Key operating highlights and events during 2001 and early 2002 included:

**Worldwide oil and gas reserves** The company added approximately 1.2 billion barrels of oil-equivalent reserves during 2001. These additions equated to 127 percent of production for the year. Included were slightly more than 100 million barrels each for the Tengiz Field in Kazakhstan and the Hamaca project in Venezuela as a result of drilling activities. Almost 200 million oil-equivalent barrels were added for natural gas reserves for several fields in Nigeria. About 160 million barrels of the additions during the year were the result of successful discoveries in areas that included Latin America, the North Sea and West Africa. Also, approximately 175 million equivalent-barrels were acquired early in 2001 through the purchase of an additional 5 percent interest in Tengizchevroil, the company's 50 percent-owned affiliate in Kazakhstan that operates the Tengiz and Korolev fields.

**Angola** Approximately 30,000 barrels per day of total crude oil production began at the company-operated Phase 1C development in the deepwater Kuito Field in Block 14, where the company holds a 31 percent interest. In Block 0, the North Nemba production and gas injection platform was installed in March 2001. At year-end, total oil production exceeded 30,000 barrels per day. Continuation of the North Nemba development program in 2002 will result in average production of about 40,000 barrels per day. The company is the operator and holds a 39 percent interest.

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**Nigeria** The Escravos Gas Project successfully completed Phase 2 development in 2001, increasing processing capacity to 285 million cubic feet of gas per day. Upon completion of Phase 3 in 2005,capacity is expected to increase to 680 million cubic feet per day. The company holds a 40 percent working interest in the Escravos project. Front-end engineering and design started in March 2001 on the gas-to-liquids project at Escravos. This is the first project to use the Sasol Chevron Global Joint Venture technologies. The company holds a 38 percent interest in the project.

**Chad-Cameroon** The Doba oil field development — a $3.5 billion project, including a 650-mile pipeline — reached one-third completion at the end of 2001. Initial total production of 225,000 barrels of crude oil per day is expected in 2004. The company holds a 25 percent interest in the project.

**Kazakhstan** Tengizchevroil (TCO) increased its total production for the eighth straight year, averaging 268,000 barrels per day of crude oil. Engineering for the next major expansion is under way and it is expected to come on line in 2005. The company holds a 50 percent interest in TCO. In October, the first tankers were loaded with crude oil from the Caspian Pipeline Consortium (CPC) facilities near the Black Sea port of Novorossiysk. CPC's pipeline connects the Tengiz Field in western Kazakhstan to Novorossiysk, enabling full access to world market prices for Tengiz oil, and greatly reduces transportation costs. CPC is owned 15 percent by ChevronTexaco.

**U.K. North Sea** In December 2001, ChevronTexaco received government approval to develop the company-operated Alba Extreme South and Caledonia projects in the North Sea. Both are located in the company's central North Sea core area, which includes the producing Alba and Britannia fields. frFirst oil production from the Alba Extreme South project is scheduled for the fourth quarter 2002 and will help maintain Alba's total field production at about 80,000 barrels of crude oil per day. Chevron-Texaco operates the field and holds a 21 percent ownership. First oil from Caledonia is expected late in the third quarter of 2002, and peak field production is anticipated at about 13,000 barrels per day. The company holds a 27 percent interest.

**Philippines** Gas production commenced in October from the Malampaya Field offshore the Philippine island of Palawan. ChevronTexaco has a 45 percent interest in the landmark gas-to-power project – the largest single foreign investment and the first-ever offshore production of natural gas in the Philippines.

**Australia** The company made two significant natural gas discoveries offshore Western Australia. Both are located in permit area WA-267-P, where the company operates and holds a 50 percent interest. During 2001, the company approved development of the $1.6 billion LNG expansion project by the North West Shelf venture. A mid-2004 start-up will increase gross liquefied natural gas capacity by about 50 percent. The company holds a one-sixth interest.

**China** During 2001, an average of about 18,000 barrels per day total of low-sulfur crude oil is being produced after an October start-up at the QHD 32-6 Field in China's Bohai Bay where ChevronTexaco holds a 24.5 percent interest.

**Bangladesh** In April 2001, ChevronTexaco was awarded a 60 percent interest in the 1.7 million-acre onshore tract, Block 9, in Bangladesh, east of Dhaka. Block 9 surrounds the Bakhrabad gas field and is adjacent to other major gas-producing areas. Seismic studies are planned in 2002 with initial drilling to commence in late 2002 or early 2003.

**Venezuela** The company holds a 30 percent interest in the Hamaca integrated oil project, located in Venezuela's Orinoco Belt. Early production was established during October 2001.After completion of crude oil upgrading facilities in 2004, Hamaca total production is expected to increase to 190,000 barrels per day.

**U.S. Gulf of Mexico** Typhoon, a deepwater development project, was completed below budget and production commenced in July 2001, two months ahead of schedule. Daily total production averaged about 39,000 oil-equivalent barrels through the end of the year. ChevronTexaco is the operator with a 50 percent interest.

**U.S. Refining** In December, the company approved a $150 million project at its Pascagoula, Mississippi, refinery to produce low-sulfur gasoline that meets anticipated new U.S. Environmental Protection Agency standards. Regulatory permits have been secured and the activities will commence during 2002. The project is expected to take a year to complete.

**Chevron Phillips Chemical Company (CPChem)** The company's 50 percent-owned CPChem affiliate is engaged in a joint venture with BP Solvay to build a new high-density polyethylene (HDPE) facility at CPChem's Cedar Bayou, Texas, facility that is on track for a start-up in late 2002. The 700 million pounds-per-year HDPE facility will be the largest of its

kind in the world. A world-scale olefins and polyolefins complex in Qatar also is expected to start production in late 2002. The facility will be owned and operated by Qatar Chemical Company, a joint venture between CPChem, with a 49 percent interest, and Qatar General Petroleum.

**Dynegy Inc.** In November 2001, ChevronTexaco acquired $1.5 billion in redeemable, convertible preferred shares of its Dynegy affiliate. In early 2002, ChevronTexaco purchased approximately $200 million of additional Dynegy common shares to maintain its 26.5 percent ownership interest following Dynegy's public equity offering in December 2001.

**RESULTS OF OPERATIONS**

Sales and other operating revenues were $104 billion in 2001, compared with $117 billion in 2000 and $84 billion in 1999. Revenues in 2001 declined on lower average realizations for crude oil and refined products. The increase in 2000 from 1999 was primarily the result of sharply higher prices for crude oil, natural gas and refined products. The effect of higher prices in 2000 was partially offset by the absence of chemicals revenues in the second half of the year due to the July 1, 2000, formation of CPChem, which is accounted for under the equity method.

**Income from equity affiliates** totaled $1.1 billion in 2001, $1.1 billion in 2000 and $0.9 billion in 1999. Equity income increased marginally in 2001 on the strength of improved earnings for Equilon, Motiva and Dynegy, partially offset by lower earnings for Tengizchevroil and LG-Caltex and by larger losses from CPChem. In 2000, increases in earnings from Tengiz-chevroil and Motiva were partially offset by lower earnings from Equilon and LG-Caltex and losses from CPChem.

**Other income** totaled $0.7 billion in 2001, $1.0 billion in 2000 and $0.8 billion in 1999. The fluctuations between years were the result of changes in net gains and losses from asset sales and interest income from investments.

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**Purchased crude oil and products** costs of $60.5 billion in 2001 were lower than the $69.8 billion in 2000 – primarily due to lower crude oil prices – but about 30 percent higher than the $46.3 billion in 1999 when average crude oil prices were recovering from 20-year lows that occurred in 1998. Offsetting some of the effect of higher prices since 1999 was the absence of such costs associated with the chemicals operations contributed to CPChem in July 2000.

**Operating, selling, general and administrative expenses,** excluding the effects of special items, were about the same at $11.5 billion in 2001 and 2000. Similar expenses in 1999 were $10.8 billion, reflecting mainly higher fuel costs for the company's plants and facilities. Mitigating this effect since mid-2000 was the absence of expenses associated with the chemicals operations contributed to CPChem.

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| Operating Expenses | **$ 7,650** | $ 8,323 | $ 7,773 |
| Selling, General and Administrative Expenses | **3,984** | 3,626 | 3,222 |
| Total Operating Expenses | **11,634** | 11,949 | 10,995 |
| Less: Special Charges, Before Tax | **164** | 488 | 199 |
| Adjusted Total Operating Expenses | **$11,470** | $11,461 | $10,796 |

**Exploration expenses** were $1.0 billion in 2001, compared with $0.9 billion in 2000 and $1.1 billion in 1999. In 2001, well write-offs were $184 million higher compared with 2000 – which more than offset declines in other exploration expenses. The increased write-offs reflected, in part, a reprioritization of development opportunities post-merger.

**Depreciation, depletion and amortization** expense was $7.1 billion in 2001, compared with $5.3 billion in 2000 and $4.9 billion in 1999. Depreciation expense associated with asset impairments was $2.3 billion in 2001, compared with $0.7 billion in 2000 and $0.4 billion in 1999. After adjusting for the effect of impairments, the expense amounts were $4.8 billion in 2001, $4.6 billion in 2000 and $4.5 billion in 1999. Higher expense in 2001 on this adjusted basis resulted from higher capital spending, reserve revisions and additional abandonment provisions, while 2000 was higher than 1999 because production between years increased. The expense in 2000 also reflected lower depreciation in chemicals, resulting from the CPChem joint venture formation.

**Income tax expenses** were $4.4 billion in 2001, $6.3 billion in 2000 and $2.6 billion in 1999, reflecting effective income tax rates of 53 percent, 45 percent and 44 percent for each of the three years, respectively.

The increase in the 2001 effective tax rate was primarily due to U.S. before-tax income (generally subject to a lower tax rate) being a significantly smaller percentage of overall before-tax income in 2001 compared with 2000. The decline in the U.S. before-tax income arose primarily because substantially all of the 2001 merger-related expenses were associated with operations in the United States.

**Foreign currency gains** in 2001 were $191 million, compared with gains of $182 million in 2000 and losses of $15 million in 1999. Approximately $150 million of the gains in 2001 were attributable to the devaluation of the Argentine peso late in the year. Excluding this impact, currency gains were lower than in 2000 primarily due to fluctuations of the Netherlands and Australian currencies. The losses in 1999 were primarily in Australia.

*U.S. Exploration and Production*

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| Earnings Excluding Special Items | **$ 2,890** | $3,736 | $1,390 |
| Asset Write-Offs and Revaluations | **(1,168)** | (176) | (204) |
| Asset Dispositions | **49** | (107) | – |
| Prior-Year Tax Adjustments | **8** | – | – |

| | | | |
|---|---|---|---|
| Restructurings and Reorganizations | **–** | – | (53) |
| Total Special Items | **(1,111)** | (283) | (257) |
| Segment Income | **$ 1,779** | $3,453 | $1,133 |

**U.S. exploration and production** earnings, excluding special items, declined in 2001 primarily because of significantly lower crude oil prices. Oil-equivalent production was also down 8 percent. Higher earnings in 2000, compared with 1999, were mainly the result of increased prices for crude oil and natural gas. Partially offsetting the benefit of higher prices was a decline in oil-equivalent production of 7 percent between years.

The company's average 2001 U.S. crude oil realization was $21.70 per barrel, compared with $26.69 in 2000 and $15.50 in 1999. The average U.S. natural gas realization was $4.38 per thousand cubic feet in 2001, compared with $3.87 and $2.12 in 2000 and 1999, respectively.

Net liquids production for 2001 averaged 614,000 barrels per day, down 8 percent from 2000 and 14 percent from 1999. Net natural gas production averaged 2.7 billion cubic feet per day in 2000,down 7 percent from 2000 and 14 percent from 1999. The lower oil-equivalent production reflected normal field declines and asset sales, partially offset by new and enhanced production in the deep water and other areas of the Gulf of Mexico.

Special items in 2001 included a $1.0 billion impairment of the Midway Sunset Field in California's San Joaquin Valley. The impairment was a result of the write-down in proved crude oil reserve quantities, upon determination of lower-than-projected oil recovery from the field's steam injection process.

*International Exploration and Production*

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| Earnings Excluding Special Items* | **$2,905** | $3,622 | $1,520 |
| Asset Write-Offs and Revaluations | **(247)** | – | – |
| Asset Dispositions– | | 80 | – |
| Prior-Year Tax Adjustments | **(125)** | – | (47) |
| Restructurings and Reorganizations | **–** | – | (23) |
| Total Special Items | **(372)** | 80 | (70) |
| Segment Income* | **$2,533** | $3,702 | $1,450 |
| *Includes Foreign Currency Gains: | **$ 181** | $ 97 | $ 9 |

**International exploration and production** earnings, excluding special items, declined in 2001 primarily on lower average crude oil prices. Partially offsetting this effect was an increase of about 3 percent in oil-equivalent production and higher natural gas prices. Earnings in 2000 improved from 1999 on significantly higher crude oil and natural gas prices; oil-equivalent production between years was flat.

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The average liquids realization, including equity affiliates, was $22.17 per barrel in 2001, compared with $26.04 in 2000 and $16.57 in 1999. The average natural gas realization was $2.36 per thousand cubic feet in 2001, compared with $2.09 in 2000 and $1.66 in 1999.

Daily net liquids production of 1.345 million barrels in 2001 increased about 1 percent from 1.330 million barrels in 2000 and 1.337 million barrels in 1999. Production increases in Kazakhstan during 2001 more than offset lower volumes from Indonesia. In 2000, increases in Argentina, Kazakhstan, Kuwait and Thailand did not offset declines in Indonesia and the United Kingdom.

Net natural gas production of 1.711 billion cubic feet per day in 2001 was up 10 percent from 2000 and more than 13 percent from 1999. Most notable among the geographic areas with production increases were Kazakhstan, Trinidad and Canada. In 2000, production increases were primarily in Argentina, Colombia, Kazakhstan and Thailand, partially offset by lower production from normal declines in mature fields in Canada and the United Kingdom.

Special items in 2001 included a $247 million impairment of the LL-652 Field in Venezuela – as slower-than-expected reservoir repressurization resulted in a reduction in the projected volumes of oil recoverable during the company's remaining contract period of operation.

*U.S. Refining, Marketing and Transportation*

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| Earnings Excluding Special Items | **$1,332** | $ 974 | $638 |
| Asset Write-Offs and Revaluations | **–** | – | (76) |
| Asset Dispositions | **–** | – | 75 |
| Environmental Remediation Provisions | **(78)** | (191) | (40) |
| Restructurings and Reorganizations | **–** | – | (46) |
| Litigation and Regulatory | **–** | (62) | – |
| Total Special Items | **(78)** | (253) | (87) |
| Segment Income | **$1,254** | $ 721 | $551 |

**U.S. refining, marketing and transportation** earnings in 2001, excluding special items, increased 37 percent to $1.332 billion and more than doubled 1999 earnings of $638 million. Amounts included the company's share of equity income for the Equilon and Motiva joint ventures until the October 2001 merger, when these interests were placed in trust. Post-merger, the investments were accounted for on the cost basis, and earnings included dividend income, a component of other income, rather than the equity income as was recognized pre-merger.

Earnings increases in 2001 reflected significantly higher gasoline sales margins – especially early in the year – partially offset by weaker distillate sales margins and higher operating expense. Higher sales volumes across all major product lines also contributed to the improvement. Earnings in 2000 improved from 1999, particularly on the East and Gulf coasts. Earnings in 1999 suffered from lower sales margins and operational problems at the company's California refineries.

Refined products sales volumes of 2.577 million barrels per day in 2001 decreased about 3 percent from 2000 and 2 percent from 1999. The 2001 sales volumes reflected pre-merger sales only for Equilon and Motiva. Sales in 2000 suffered from the effect of 1999 year-end stockpiling by customers in anticipation of possible Year 2000-related interruptions. The average U.S. refined products sales realization of $30.45 per barrel in 2001 was down 25 percent from the 2000 average of $40.75, but up 19 percent from depressed levels in 1999.

*International Refining, Marketing and Transportation*

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Earnings Excluding Special Items* | **$598** | $ 526 | $ 615 |
| Asset Write-Offs and Revaluations | **(46)** | (112) | – |
| Asset Dispositions | **–** | – | (111) |
| Prior-Year Tax Adjustments | **8** | – | 114 |
| Restructurings and Reorganizations | **–** | – | (72) |
| Total Special Items | **(38)** | (112) | (69) |
| Segment Income* | **$560** | $ 414 | $ 546 |
| *Includes Foreign Currency Gains (Losses): | **$ 23** | $ 107 | $ (27) |

**International refining, marketing and transportation** earnings include results of the company's consolidated refining and marketing businesses, international marine operations, international supply and trading activities, and equity earnings of primarily Asia-Pacific affiliates. Excluding special items, 2001 earnings of $598 million were up 14 percent from 2000, but about 3 percent lower than in 1999.

Earnings in most of Asia, the Middle East and eastern Africa and South Africa operating areas improved significantly in 2001 because of improved marketing margins, particularly early in the year. Partially offsetting the marketing improvement were higher costs and somewhat lower refining margins. Earnings decreased in 2000, compared with 1999, on lower marketing margins and refined products sales volumes. The region suffered from a very competitive operating environment, including excess refinery capacity.

European operations suffered from low marketing and refining margins and lower sales volumes in 2001 compared with prior years, primarily due to weaker economic conditions. Latin American earnings were nearly level with 2000,with improved refining margins almost offsetting the declining sales volumes and marketing margins. In 2000, weaker margins in Latin America and West Africa resulted in lower earnings compared with 1999. These were partially offset by increased earnings in Europe, driven by higher margins in the United Kingdom and the Netherlands.

International refined products sales volumes were 2.495 million barrels per day in 2001, down about 1 percent from 2.521 million in 2000 and about 5 percent lower than 2.621 million in 1999. Weaker economic conditions, particularly in Europe, dampened demand in 2001. Lower trading volumes and the third quarter 1999 sale of the company's equity interest in Koa Oil Company Limited in Japan were responsible for the decline in sales volumes in 2000.

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*Chemicals*

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| (Loss) Earnings Excluding Special Items* | **$ (32)** | $130 | $174 |
| Asset Write-Offs and Revaluations | **(96)** | (90) | (43) |
| Restructurings and Reorganizations | **–** | – | (22) |
| Total Special Items | **(96)** | (90) | (65) |
| Segment (Loss) Income* | **$(128)** | $ 40 | $109 |
| *Includes Foreign Currency (Losses) Gains: | **$ (3)** | $ (2) | $ 3 |

**Chemicals** earnings include results from the company's Oronite division, the company's petrochemicals business prior to its contribution to CPChem in July 2000, and equity earnings in CPChem from that date. After excluding the effect of special items, the segment recorded a loss of $32 million in 2001, compared with earnings of $130 million in 2000 and $174 million in 1999. Results for all years reflected a protracted period of generally weak demand for commodity chemicals and industry over-capacity.

Special items in 2001 and 2000 include write-downs in the CPChem operations in Puerto Rico.

**SELECTED OPERATING DATA**

| | **2001** | 2000 | 1999 |
|---|---|---|---|
| **U.S. Exploration and Production** | | | |
| Net Crude Oil and Natural Gas Liquids Production (MBPD) | **614** | 667 | 712 |
| Net Natural Gas Production (MMCFPD) | **2,706** | 2,910 | 3,145 |
| Natural Gas Sales (MMCFPD)[1] | **7,830** | 7,302 | 6,534 |
| Natural Gas Liquids Sales (MBPD)[1] | **340** | 373 | 415 |
| Revenues from Net Production | | | |
| Crude Oil ($/Bbl) | **$21.70** | $26.69 | $15.50 |
| Natural Gas ($/MCF) | **$ 4.38** | $ 3.87 | $ 2.12 |
| **International Exploration and Production[1]** | | | |
| Net Crude Oil and Natural Gas Liquids Production (MBPD) | **1,345** | 1,330 | 1,337 |
| Net Natural Gas Production (MMCFPD) | **1,711** | 1,556 | 1,512 |
| Natural Gas Sales (MMCFPD) | **2,675** | 2,398 | 2,342 |
| Natural Gas Liquids Sales (MBPD) | **90** | 67 | 58 |
| Revenues from Liftings | | | |
| Liquids ($/Bbl) | **$22.17** | $26.04 | $16.57 |
| Natural Gas ($/MCF) | **$ 2.36** | $ 2.09 | $ 1.66 |
| Other Produced Volumes (MBPD)[3] | **105** | 123 | 96 |
| **U.S. Refining, Marketing and Transportation[1,2]** | | | |

| | | | |
|---|---|---|---|
| Gasoline Sales (MBPD) | **1,246** | 1,320 | 1,266 |
| Other Refined Products Sales (MBPD) | **1,331** | 1,347 | 1,357 |
| Refinery Input (MBPD) | **1,286** | 1,337 | 1,484 |
| Average Refined Products Sales Price ($/Bbl) | **$30.45** | $40.75 | $25.50 |
| **International Refining, Marketing and Transportation[1]** | | | |
| Refined Products Sales (MBPD) | **2,495** | 2,521 | 2,621 |
| Refinery Input (MBPD) | **1,136** | 1,150 | 1,235 |

MBPD = Thousands of barrels per day; MMCFPD = Millions of cubic feet per day; Bbl = Barrel; MCF = Thousands of cubic feet.

[1] Includes equity in affiliates.

[2] Includes Equilon and Motiva pre-merger.

[3] Represents total field production under the Boscan operating service agreement in Venezuela, and in 2000 included a Colombian operating service agreement.

*All Other*

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| Net Charges Excluding Special Items* | **$ (883)** | $(883) | $(899) |
| Asset Write-Offs and Revaluations | **(152)** | – | (54) |
| Asset Dispositions | **–** | 99 | 147 |
| Prior-Year Tax Adjustments | **104** | 107 | 161 |
| Environmental Remediation | **–** | (73) | – |
| Restructurings and Reorganizations | **–** | – | (41) |
| Litigation and Regulatory | **–** | – | 104 |
| Other | **–** | 147 | 40 |
| Total Special Items | **(48)** | 280 | 357 |
| Merger Effects | **(1,779)** | – | – |
| Segment Charges* | **$(2,710)** | $(603) | $(542) |
| *Includes Foreign Currency Losses: | $ (10) | $ (20) | $ – |

**All Other** consists of coal mining operations, the company's equity interest in Dynegy Inc. – a gatherer, processor, transporter and marketer of energy products – corporate administrative costs, worldwide cash management and debt financing activities, power and gasification ventures, technology investments and real estate and insurance activities.

Earnings, excluding special items, for coal operations were $19 million in 2001 compared with $1 million in 2000 and $34 million in 1999. The improved earnings in 2001 resulted from increased sales volumes, productivity improvements and the absence of a work stoppage that in 2000 lasted several months.

The company's share of Dynegy earnings before special items in 2001 was $175 million, up from $119 million in 2000 and $44 million in 1999. Significantly higher prices for natural gas and natural gas liquids and an increase in earnings from power generation activities were the primary reasons for the improved results in 2001 from the previous periods.

Net charges for the balance of the All Other segment, excluding special items, were $1.077 billion in 2001, $1.003 billion in 2000 and $977 million in 1999. Increases in various corporate expenses essentially offset the benefits of lower interest expense and higher interest income in 2001 and 2000.

Merger effects in 2001 represented the sum of $1.136 billion for merger-related expenses and $643 million for losses on merger-related asset dispositions.

**LIQUIDITY AND CAPITAL RESOURCES**

**Cash, cash equivalents and marketable securities** were approximately $3.2 billion at the end of both 2001 and 2000. Cash provided by operating activities in 2001 was $11.5 billion, compared with $13.5 billion in 2000 and $7.8 billion in 1999. Cash provided by asset sales was $0.3 billion in 2001, $1.2 billion in 2000 and $1.6 billion in 1999. During 2001, the company's overall debt levels increased to $17.4 billion at December 31, 2001, compared with $15.9 billion at December 31, 2000. Improved cash flows in 2000 permitted the company to reduce overall debt levels by $3.2 billion and repurchase $1.5 billion of the company's common shares, net of sales. In addition, the company received a cash distribution of $835 million in 2000 from CPChem after the joint venture obtained debt financing. In 1999, a payment of $775 million was made to Occidental Petroleum in settlement of the Cities Service lawsuit.

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In February 2002, the company completed the sale of its investments in Equilon and Motiva to Shell and Saudi Refining Inc. for proceeds of $2.2 billion.

**Dividends** ChevronTexaco paid common stock dividends of $2,733 million, $2,664 million and $2,589 million in 2001, 2000 and 1999, respectively. Dividends on Texaco preferred shares were $6 million, $15 million and $28 million in 2001, 2000 and 1999, respectively. In addition, dividends of $119 million, $110 million and $55 million were paid for the three years to stockholders who hold minority interests in ChevronTexaco subsidiary companies.

**Debt, lease and minority interest obligations** ChevronTexaco's total debt and capital lease obligations were $17.4 billion at December 31, 2001, up from $15.9 billion at year-end 2000. In addition, at December 31, 2001, the company had minority interest obligations of $283 million, down from $746 million at December 31, 2000. In 2001, net repayments of $2.4 billion in long-term debt were more than offset by proceeds of $3.8 billion from new short-term debt. Changes in long-term debt during 2001 included a non-cash reduction of $100 million of ESOP debt. In addition to the repayments of long-term debt during 2001, $463 million of Monthly Income Preferred shares, which were accounted for as minority interest, and $300 million of Texaco Market Auction Preferred Shares were redeemed.

At year-end 2001, ChevronTexaco had $3.2 billion in committed credit facilities with various major banks, which permit the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and also can be used for general credit requirements. No borrowings were outstanding under these facilities during the year or at year-end 2001. In addition, ChevronTexaco has three existing "shelf" registrations on file with the Securities and Exchange Commission that together would permit registered offerings of up to $2.8 billion of debt securities. Additionally, at December 31, 2001, the company had lines of credit available for short-term financing totaling $500 million, of which $210 million had not been utilized.

The company's debt due within 12 months, consisting primarily of commercial paper and the current portion of long-term debt, totaled $11.6 billion at December 31, 2001, up from $8.2 billion at December 31, 2000. Of this total short-term debt, $3.2 billion was reclassified to long-term at year-end 2001. Settlement of these obligations was not expected to require the use of working capital in 2002, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis. The company's practice has been to continually refinance its commercial paper, maintaining levels it believes to be appropriate.

The company's future debt level is dependent primarily on its results of operations, its capital-spending program and cash that may be generated from asset dispositions. The company believes it has substantial borrowing capacity to meet unanticipated cash requirements. In periods of sustained low crude oil and natural gas prices (below levels of approximately $20 per barrel for West Texas Intermediate benchmark crude oil and $2.50 per thousand cubic feet for Henry Hub benchmark natural gas) and narrow refined products margins, cash provided by operating activities and asset sales may not be sufficient to fund the company's investing activities and may result in increased borrowings or a reduction in overall cash levels. ChevronTexaco's senior debt is rated AA by Standard and Poor's Corporation and Aa2 by Moody's Investor Service, except for senior debt of Texaco Inc. which is rated Aa3. ChevronTexaco's U.S. commercial paper is rated A-1+ by Standard and Poor's and Prime 1 by Moody's, and the company's Canadian commercial paper is rated R-1 (middle) by Dominion Bond Rating Service. All of these ratings denote high-quality, investment-grade securities.

**Share repurchase programs** In December 1997, Chevron's Board of Directors approved the repurchase of up to $2 billion of the company's outstanding common stock for use in its employee stock option programs. Total repurchases from the program's inception through the end of 2000 were 23.3 million shares at a cost of $1.9 billion. The program was formally terminated in September 2001.

In March 1998, Texaco's Board of Directors approved the repurchase of up to $1 billion of Texaco's outstanding common stock. This program was suspended in October 2000, prior to the announcement of the planned merger with Chevron. At that time, 11.4 million shares had been acquired at a cost of $643 million.

**On- and off-balance-sheet arrangements** The following tables summarize the company's material on- and off-balance-sheet obligations at year-end 2001.

*Contractual Obligations*

| Millions of dollars | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | 2002 | 2003–2005 | 2006 | After 2006 |
| On balance sheet: | | | | | |
| Long-term debt[1] | $6,599 | $1,095 | $1,963 | $195 | $3,346 |
| Short-term debt[2] | 3,200 | – | – | – | 3,200 |
| Noncancelable capital lease obligations | 954 | 80 | 214 | 47 | 613 |
| Redemption of subsidiary's preferred shares | 199 | – | 199 | – | – |
| Off balance sheet: | | | | | |
| Noncancelable operating lease obligations | 2,541 | 692 | 881 | 237 | 731 |
| Unconditional purchase obligations | 5,598 | 1,157 | 3,231 | 861 | 349 |
| Through-put and take-or-pay agreements | 2,060 | 213 | 652 | 233 | 962 |

[1] Includes guarantee of $535 of ESOP debt, $100 due in 2002, $85 during 2003 – 2005 and $350 due after 2006.

[2] Continually refinanced on a long-term basis.

*Commercial Commitments (Off Balance Sheet)*

| Millions of dollars | Commitment Expiration by Period | | | | |
|---|---|---|---|---|---|
| | Total | 2002 | 2003 – 2005 | 2006 | After 2006 |
| Guarantees of non-consolidated affiliates or joint venture obligations* | $686 | $211 | $ 33 | $ – | $442 |
| Guarantees of obligations of unrelated parties | 742 | 141 | 225 | 34 | 342 |

* Excludes $432 related to Equilon and Motiva. See Note 22.

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ChevronTexaco provided certain indemnities for contingent liabilities of Equilon and Motiva to Shell Oil and Saudi Refining Inc. as part of the agreement for the sale of the company's interests in those investments. Generally, the indemnities provided are limited to contingent liabilities that may mature within 18 months of the sale of the company's interests and are reduced by any reserves that were established prior to the sale. Excluding environmental liabilities, the company's financial exposure related to those indemnities is contractually limited to $300 million. Additionally, the company has provided indemnities for certain environmental liabilities arising out of conditions that existed prior to the formation of Equilon and Motiva and during the periods of ChevronTexaco's ownership interest in those entities as well as for customary representation and warranties within the agreements.

In other off-balance-sheet arrangements, the company securitizes certain accounts receivable in its downstream business through the use of qualifying special purpose entities (SPEs). At December 31, 2001, approximately $850 million, representing about 10 percent of ChevronTexaco's total current accounts receivable balance, were securitized. ChevronTexaco's total estimated financial exposure under these arrangements at December 31, 2001, was approximately $50 million. These arrangements have the effect of accelerating ChevronTexaco's collection of the securitized amounts. In the event of the SPEs experiencing major defaults in the collection of receivables, ChevronTexaco would have no loss exposure connected with third-party investments in these securitization arrangements.

The above information should also be read in conjunction with Note 22 to the Consolidated Financial Statements – Other Contingencies and Commitments on page FS-40.

**FINANCIAL RATIOS**

The year-end **current ratio** is the ratio of current assets to current liabilities. Generally, two items adversely affected ChevronTexaco's current ratio, but in the company's opinion do not affect its liquidity. First, current assets in all years included inventories valued on a LIFO basis, which at year-end 2001 were lower than replacement costs, based on average acquisition costs during the year, by nearly $1.6 billion. Also, because the company carries a larger percentage of short-term debt, it benefits from lower interest cost by continually refinancing its commercial paper.

The **interest coverage ratio** is defined as income before income tax expense, plus interest and debt expense and amortization of capitalized interest, divided by before-tax interest costs. ChevronTexaco's interest coverage ratio was lower in 2001, primarily due to lower before-tax income partially offset by lower interest expense as a result of replacing long-term debt with lower interest rate commercial paper obligations. The company's **debt ratio** (total debt divided by total debt plus equity) increased to 33.9 percent in 2001, due to an increase in total debt for the year.

*Financial Ratios*

| | **2001** | 2000 | 1999 |
|---|---|---|---|
| Current Ratio | **0.9** | 1.1 | 1.0 |
| Interest Coverage Ratio | **9.6** | 12.5 | 6.0 |
| Total Debt/Total Debt Plus Equity | **33.9%** | 32.3% | 39.2% |

**FINANCIAL AND DERIVATIVE INSTRUMENTS**

**Commodity Derivative Instruments** ChevronTexaco is exposed to market risks related to the volatility of crude oil, refined products, natural gas and refinery feedstock prices. The company uses derivative commodity instruments to manage its exposure to price volatility on a small portion of its activity, including: firm commitments and anticipated transactions for the purchase or sale of crude oil, feedstock purchases for company refineries, crude oil and refined products inventories, and fixed-price contracts to sell natural gas and natural gas liquids.

ChevronTexaco also uses derivative commodity instruments for trading purposes, and the results of this activity are not material to the company's financial position, net income or cash flows.

The company's positions are monitored and managed on a daily basis by a risk control group to ensure compliance with the company's stated risk management policy that has been approved by the company's Board of Directors.

The derivative instruments used in the company's risk management and trading activities consist mainly of futures

contracts traded on the New York Mercantile Exchange and the International Petroleum Exchange, crude oil and natural gas swap contracts, options and other derivative products entered into principally with major financial institutions and other oil and gas companies. Virtually all derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from market quotes and other independent third-party quotes.

The aggregate effect of a hypothetical 15 percent change in prices for natural gas, crude oil and petroleum products would not be material to the company's financial position, net income or cash flows. The hypothetical loss on the related commodity contracts was estimated by calculating the cash value of the contracts as the difference between the hypothetical and contract delivery prices, multiplied by the contract amounts.

**Foreign Currency** The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

The aggregate effect of a hypothetical adverse change of 10 percent to year-end exchange rates (a weakening of the U.S. dollar) would not be material to the company's financial position, net income or cash flows.

**Interest Rates** The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps hedging a portion of the company's fixed-rate debt are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. During 2001, no new swaps were initiated in connection with debt

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issues in the year. At year-end 2001, the weighted average maturity of interest rate swaps was approximately five years.

A hypothetical 10 percent increase in interest rates upon the interest rate swaps would cause the fair value of the "receive fixed" swaps to decline and the "receive floating" swaps to increase. The aggregate effect of these changes would not be material to the company's financial position, net income or cash flows.

The company's $1.5 billion investment in redeemable, convertible preferred stock of Dynegy is carried at fair value.

**TRANSACTIONS WITH RELATED PARTIES**

ChevronTexaco enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements. In the United States, there are long-term agreements in place with Dynegy for the purchase of substantially all natural gas and natural gas liquids produced by legacy Chevron in the United States, excluding Alaska, and the supply of natural gas and natural gas liquids feedstocks to the company's U.S. refineries and chemicals plants. In early 2002, the company was negotiating to expand these agreements to include substantially all legacy Texaco U.S. production of natural gas and natural gas liquids. Internationally, there are long-term purchase agreements in place with the company's refining affiliate in Thailand. Management believes the foregoing agreements and others have been negotiated on terms consistent with those that would have been negotiated with an unrelated third party.

**CAPITAL AND EXPLORATORY EXPENDITURES**

Worldwide capital and exploratory expenditures for 2001 totaled $12.0 billion,including the company's equity share of affiliates' expenditures. Capital and exploratory expenditures were $9.5 billion in 2000 and $10.1 billion in 1999. Expenditures for exploration and production activities represented 59 percent of total outlays in 2001, compared with 65 percent in 2000 and 72 percent in 1999. International exploration and production spending was 66 percent of worldwide exploration and production expenditures in 2001, compared with 62 percent in 2000 and 75 percent in 1999, reflecting the company's continuing focus on international exploration and production activities. Expenditures in 2001 included additional investments in Tengizchevroil and the purchase of $1.5 billion of redeemable, convertible preferred shares of Dynegy stock. Expenditures in the All Other segment in 2000 included an additional investment of approximately $300 million in Dynegy Inc. Included in 1999 were expenditures of about $1.7 billion – mainly cash and assumption of debt – for the acquisition of Rutherford-Moran Oil Corporation and Petrolera Argentina San Jorge S.A., exploration and production businesses in Thailand and Argentina, respectively.

The company estimates 2002 capital and exploratory expenditures at $9.4 billion, including ChevronTexaco's share of spending by affiliates. Excluding the 2001 amounts for the increased investment in Tengizchevroil and the Dynegy redeemable, convertible preferred stock, spending between years is expected to be about 9 percent lower in 2002. About $6.1 billion,or 65 percent of the total, is targeted for exploration and production activities, with $1.8 billion of that in the United States. Worldwide downstream spending is estimated at $1.7 billion,and investments in chemicals are budgeted at $400 million. Budgeted expenditures for power and related businesses are $800 million. The remaining $400 million is primarily targeted for emerging technologies and information technology infrastructure.

**PRE-MERGER EMPLOYEE TERMINATION BENEFITS AND OTHER RESTRUCTURING COSTS**

Chevron recorded before-tax charges of $235 million in 1999 for employee termination benefits and other restructuring costs as part of a 3,500-employee reduction program in all its operating segments across several business functions. Employees affected were primarily U.S.-based, and all employee terminations were completed by December 2000. Termination benefits for approximately 3,100 of the 3,500 employees were paid from the assets of Chevron's U.S. and Canadian pension plans.

In the fourth quarter 1998, Texaco recorded $115 million before tax for a corporatewide reorganization affecting 1,400 employees. During the second quarter 1999, the program was expanded by about 1,200 employees and an additional $48 million before-tax was accrued. By the end of the third quarter 2000, the employee reductions were met and all termination payments were made.

During the first quarter of 2000, Texaco recorded $17 million before tax for the termination of an additional 200 employees. Terminations and payments were completed by the end of the first quarter 2001.

Caltex recorded charges of $37 million in 1999 for restructuring activities that included severance and other termination benefits of $23 million for 200 employees. By December 2000, all work force reductions and separation payments were completed.

**ENVIRONMENTAL MATTERS**

Virtually all aspects of the businesses in which the company engages are subject to various federal, state and local environmental, health and safety laws and regulations. These regulatory requirements continue to increase in both number and complexity over time and govern not only the manner in which the

| *Capital and Exploratory Expenditures* | **2001** | | | 2000 | | | 1999 | | |
|---|---|---|---|---|---|---|---|---|---|
| Millions of dollars | **U.S.** | **Inter-national** | **Total** | U.S. | Inter-national | Total | U.S. | Inter-national | Total |
| Exploration and Production | **$ 2,420** | **$ 4,709** | **$ 7,129** | $ 2,354 | $ 3,897 | $ 6,251 | $ 1,811 | $ 5,479 | $ 7,290 |
| Refining, Marketing and Transportation | **873** | **1,271** | **2,144** | 919 | 1,121 | 2,040 | 946 | 1,003 | 1,949 |
| Chemicals | **145** | **34** | **179** | 135 | 51 | 186 | 326 | 136 | 462 |
| All Other | **2,570** | **6** | **2,576** | 891 | 152 | 1,043 | 311 | 125 | 436 |
| Total | **$ 6,008** | **$ 6,020** | **$ 12,028** | $ 4,299 | $ 5,221 | $ 9,520 | $ 3,394 | $ 6,743 | $ 10,137 |
| Total, Excluding Equity in Affiliates | **$ 4,934** | **$ 5,382** | **$ 10,316** | $ 3,594 | $ 4,697 | $ 8,291 | $ 2,871 | $ 6,161 | $ 9,032 |

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company conducts its operations, but also the products it sells. Most of the costs of complying with laws and regulations pertaining to company operations and products are embedded in the normal costs of doing business.

Accidental leaks and spills requiring cleanup may occur in the ordinary course of business. In addition to the costs for environmental protection associated with its ongoing operations and products, the company may incur expenses for corrective actions at various owned and previously owned facilities and at third-party owned waste-disposal sites used by the company. An obligation may arise when operations are closed or sold or at non-ChevronTexaco sites where company products have been handled or disposed of. Most of the expenditures to fulfill these obligations relate to facilities and sites where past operations followed practices and procedures that were considered acceptable at the time but now require investigative and/or remedial work to meet current standards.

Using definitions and guidelines established by the American Petroleum Institute, ChevronTexaco estimated its world-wide environmental spending in 2001 at $1.246 billion for its consolidated companies. Included in these expenditures were $323 million of environmental capital expenditures and $923 million of costs associated with the control and abatement of hazardous substances and pollutants from ongoing operations. For 2002, total worldwide environmental capital expenditures are estimated at $495 million. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

The following table analyzes the annual changes to the company's before-tax environmental remediation reserves, including those for Superfund sites. For 2001, the company recorded additional provisions for estimated remediation costs at refined products marketing sites and various producing properties in the United States.

| Millions of dollars | **2001** | 2000 | 1999 |
|---|---|---|---|
| Balance at January 1 | **$1,234** | $1,079 | $1,132 |
| Expense Provisions | **216** | 429 | 275 |
| Expenditures | **(290)** | (274) | (328) |
| Balance at December 31 | **$1,160** | $1,234 | $1,079 |

Under provisions of the Superfund law, the Environmental Protection Agency (EPA) has designated ChevronTexaco a potentially responsible party, or has otherwise involved the company, in the remediation of 413 hazardous waste sites. The company made provisions or payments in 2001 and prior years for approximately 287 of these sites. No single site is expected to result in a material liability for the company. For the remaining sites, investigations are not yet at a stage where the company is able to quantify a probable liability or determine a range of reasonably possible exposures. The Superfund law provides for joint and several liability for all responsible parties. Any future actions by the EPA and other regulatory agencies to require ChevronTexaco to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's consolidated financial position or liquidity. Remediation reserves at year-end 2001, 2000 and 1999 for Superfund sites were $62 million, $73 million and $79 million, respectively.

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are indeterminable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties and the extent to which such costs are recoverable from third parties. While the amount of future costs may be material to the company's results of operations in the period in which they are recognized, the company does not expect these costs will have a material adverse effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other petroleum or chemicals companies.

The company maintains additional reserves for dismantlement, abandonment and restoration of its worldwide oil and gas and coal properties at the end of their productive lives. Many of these costs are related to environmental issues. Expense provisions are recognized on a unit-of-production basis. The reserves balance at year-end 2001 was $2.2 billion and is included in "Accumulated depreciation, depletion and amortization" in the company's Consolidated Balance Sheet.

For the company's other ongoing operating assets, such as refineries and chemicals facilities, no provisions are made for exit or cleanup costs that may be required when such assets reach the end of their useful lives, unless a decision to sell or otherwise abandon the facility has been made.

**LITIGATION AND OTHER UNCERTAINTIES**

Chevron, Texaco and four other oil companies (refiners) filed suit in 1995 contesting the validity of a patent granted to Unocal Corporation (Unocal) for reformulated gasoline, which ChevronTexaco sells in California in certain months of the year. In March 2000, the U.S. Court of Appeals for the Federal Circuit upheld a September 1998 District Court decision that Unocal's patent was valid and enforceable and assessed damages of 5.75 cents per gallon for gasoline produced in infringement of the patent. In May 2000, the Federal Circuit Court denied a petition for rehearing with the U.S. Court of Appeals for the Federal Circuit filed by the refiners in this case. The refiners petitioned the U.S. Supreme Court, and in February 2001, the Supreme Court denied the petition to review the lower court's ruling, and the case was remanded to the District Court for an accounting of all infringing gasoline produced from August 1, 1996, to September 30, 2000. The District Court granted Unocal's motion for summary judgment requesting an accounting and denied the refiners' motion to stay the proceedings and vacate the accounting order. However, the judge presiding over this case recused himself before entering a final judgment and a new judge was assigned. Additionally, in May 2001, the U.S. Patent Office (USPO) granted the refiners'petition to reexamine the validity of Unocal's patent and in February 2002, the USPO ruled the patent invalid. Unocal has two months to respond to the USPO ruling. The Federal Trade Commission also announced that it was investigating whether Unocal's failure to disclose to the California Air Resources Board that it had filed a patent application was unfair competition, which may make Unocal's patent unenforceable.

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If Unocal's patent ultimately is upheld and is enforceable, the company's financial exposure includes royalties, plus interest, for production of gasoline that is proven to have infringed the patent. Chevron and Texaco, as well as Texaco's former affiliates Equilon and Motiva, have been accruing in the normal course of business any future estimated liability for potential infringement of the patent covered by the trial court's ruling. In 2000, Chevron and Texaco made payments to Unocal totaling approximately $28 million for the original court ruling, including interest and fees.

Unocal obtained additional patents for alternate formulations that could affect a larger share of U.S. gasoline production. ChevronTexaco believes these additional patents are invalid and unenforceable. However, if such patents are ultimately upheld, the competitive and financial effects on the company's refining and marketing operations, while presently indeterminable, could be material.

Another issue involving the company is the petroleum industry's use of methyl tertiary-butyl ether (MTBE) as a gasoline additive and its potential environmental impact through seepage into groundwater. Along with other oil companies, the company is a party to lawsuits and claims related to the use of the chemical MTBE in certain oxygenated gasolines. These actions may require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. Total costs to the company related to these lawsuits and claims are not currently determinable. ChevronTexaco continues the use of MTBE in gasoline it sells in certain areas. The state of California had directed that MTBE be phased out of the manufacturing process by the end of 2002. In March 2002, the governor of California postponed the phase out of MTBE in California until the end of 2003.

The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites including, but not limited to: Superfund sites and refineries, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold.

See "Environmental Matters" on page FS-10 for comments related to uncertainties connected with environmental cost estimates and financial exposures.

At year-end 2001, the projected benefit obligations exceeded the value of the assets in the company's combined U.S. pension plans by $780 million. If investment returns are insufficient to offset increases in the plan's obligations, pension expense may increase and additional funding may be required.

The U.S. federal income tax liabilities have been settled through 1993 for Chevron and Caltex and through 1991 for Texaco. California franchise tax liabilities have been settled through 1991 for Chevron and through 1987 for Texaco. Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

The company's operations, particularly exploration and production, can be affected by other changing economic, regulatory and political environments in the various countries in which it operates, including the United States. In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated oil and gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for ChevronTexaco's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills in California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range of estimates exist for a possible net settlement amount for the four zones. ChevronTexaco currently estimates its maximum possible net before-tax liability at less than $400 million. At the same time, a possible maximum net amount that could be owed to ChevronTexaco is estimated at more than $200 million. The timing of the settlement and the exact amount within this range

of estimates are uncertain.

Areas in which the company and its affiliates have major operations include the United States of America, Canada, Australia, the United Kingdom, Norway, Denmark, Kuwait, Republic of Congo, Angola, Nigeria, Chad, Equatorial Guinea, Democratic Republic of Congo, Indonesia, Papua New Guinea, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad, Korea, the Philippines, Singapore and South Africa. The company's Tengizchevroil affiliate operates in Kazakhstan. The company's CPChem affiliate manufactures and markets a wide range of petrochemicals and plastics on a worldwide basis, with manufacturing facilities in existence or under construction in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium. The company's Dynegy affiliate has operations in the United States, Canada, the United Kingdom and other European countries.

ChevronTexaco receives claims from, and submits claims to, customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and may take lengthy periods to resolve.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

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**CRITICAL ACCOUNTING POLICIES**

In December 2001, the Securities and Exchange Commission (SEC) issued a statement addressing selection and disclosure by public companies of "critical accounting policies and practices." In the statement, the SEC encouraged inclusion in Management's Discussion and Analysis (MD&A) commentary as to "the likelihood of materially different reported results if different assumptions or conditions were to prevail" in the application of these critical accounting policies.

The accompanying ChevronTexaco consolidated financial statements and supplementary information were prepared in accordance with accounting principles generally accepted in the United States (GAAP). Significant accounting policies are discussed in Note 1 to the Consolidated Financial Statements. Inherent in the application of many of these accounting policies is the need for management to make estimates and judgments in the determination of certain revenues, expenses, assets and liabilities. As such, materially different financial results can occur as circumstances change and additional information becomes known. Differences have occurred in the past with respect to a few critical accounting policies, as follows:

**Successful Efforts Method of Oil and Gas Accounting** Among other things, this accounting principle requires that capitalized costs for producing properties be amortized on the basis of crude oil and natural gas reserve quantities. The reserve estimates are determined in accordance with earth science and petroleum engineering principles and practices – and can vary as a result of changes in such factors as forecasted oil and gas prices, reservoir performance and oil field technology.

Downward revision in reserve estimates (on a field basis in North America; by concession or country in other producing areas) can result in either: (a) higher depreciation and depletion expense per barrel in future periods, or (b) an immediate write-down of the asset's book value in accordance with accounting rules for the impairment of properties. The latter condition would result if the downward revisions were so significant that the estimated future cash flows from the remaining reserves in the field were insufficient to recover the unamortized capitalized costs. Conversely, if the oil and gas reserve quantities were revised upward, future per-barrel depreciation and depletion expense would be lower.

The application of successful efforts accounting can also cause material fluctuations between periods in exploration expense if drilling results are different than expected or if the company changes its exploration and development plans. The determination that exploratory drilling was unsuccessful in finding economically producible reserves requires the immediate expensing of previously capitalized drilling costs.

**Impairment of Long-Lived Assets** In addition to oil and gas assets that could become impaired under the application of successful efforts accounting, other assets could become impaired and require write-down if circumstances warrant. Conditions that could cause an asset to become impaired include lower-than-forecasted commodity sales prices, changes in the company's business plans or a significant adverse change in the local or national business climate. The amount of an impairment charge would be based on estimates of an asset's fair value compared with its book value.

**Environmental Remediation and Litigation Reserve Estimation** Management also makes judgments and estimates in recording liabilities for environmental cleanup and litigation. Liabilities for environmental remediation are subject to change because of matters such as changes in laws, regulations and their interpretation; the determination of additional information on the extent and nature of site contamination; and improvements in technology. Likewise, actual litigation costs can vary from estimates based on the facts and circumstance and application of laws in individual cases.

**Income Tax Accounting** The computation of the company's income tax expense requires the interpretation of complex tax laws and regulations in many taxing jurisdictions around the world; the determination of expected outcomes from pending litigation; and the assessment of audit findings that are performed by numerous taxing authorities. Actual income tax expense can differ significantly from management's estimates.

The above assessment of critical accounting policies is not meant to be an all-inclusive discussion of the uncertainties to financial results that can occur from the application of the full range of the company's accounting policies. Materially different financial results could occur in the application of other accounting policies as well. Likewise, materially different results can occur upon the adoption of new accounting standards promulgated by the various rule-making bodies.

Other contingencies are discussed in Note 22 to the Consolidated Financial Statements. The status of pending litigation and other information is included in Note 12 to the Consolidated Financial Statements. Information on

contingencies and litigation is also addressed on page FS-11.

**NEW ACCOUNTING STANDARDS**

The company adopted the Financial Accounting Standards Board (FASB) Statement No. 133, “Accounting for Derivative Instruments and Hedging Activities” (FAS 133), as amended by FAS 138, “Accounting for Certain Derivative Instruments and Certain Hedging Activities – an amendment of FASB Statement No. 133,” effective January 1, 2001. The adoption of FAS 133 and FAS 138 did not have a significant impact on the company’s results of operations, financial position or liquidity.

Recent interpretations of FAS 133 and FAS 138 by the FASB Derivatives Implementation Group prescribe mark-to-market accounting for certain natural gas sales contracts. Some of these interpretations became effective January 1, 2002. Adoption at that time did not result in a material effect to earnings. The effect of subsequent changes in the contracts’ fair values is uncertain.

In September 2000, the FASB issued Statement No. 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities – A Replacement of FASB Statement No. 125” (FAS 140). FAS 140 is effective for transfers occurring after March 31, 2001, and for disclosures relating to securitization transactions and collateral for fiscal years ending after December 15, 2000. Adoption of FAS 140 had no significant effect on ChevronTexaco’s accounting or disclosures for the types of transactions in the scope of the new standard.

In June 2001, the FASB issued Statement No. 141, “Business Combinations” (FAS 141), Statement No. 142, “Goodwill and Other Intangible Assets” (FAS 142) and Statement No. 143,

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"Accounting for Asset Retirement Obligations" (FAS 143). FAS 141 is effective for all business combinations initiated after June 30, 2001, and for all business combinations accounted for using the purchase method for which the date of acquisition is July 1, 2001, or later. FAS 142 is effective for fiscal years beginning after December 15, 2001, except for goodwill and intangible assets acquired after June 30, 2001, which were immediately subject to the amortization and nonamortization provisions of the Statement. FAS 143 is effective for fiscal years beginning after June 15, 2002. Adoption of FAS 141 will have no effect on the company's pooling-of-interests method of accounting for the Texaco merger transaction, but will affect future transactions. Similarly, adoption of FAS 142 may affect future transactions, but is not expected to have an effect on the company's prior business combinations. FAS 143 differs in several significant respects from current accounting for asset retirement obligations under FAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." Adoption of FAS 143 will affect future accounting and reporting of the assets, liabilities and expenses related to these obligations. The magnitude of the effect has not yet been determined.

In August 2001, the FASB issued Statement No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144). FAS 144 is effective for fiscal years beginning after December 15, 2001, with initial application effective as of the beginning of the fiscal year adopted. Adoption of FAS 144 will not affect assets classified as held for disposal as a result of disposal activities that were initiated prior to its initial application, but may affect future disposals.

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**REPORT OF INDEPENDENT ACCOUNTANTS**
**TO THE STOCKHOLDERS AND THE BOARD OF DIRECTORS OF CHEVRONTEXACO CORPORATION**

In our opinion, based on our audits and the report of other auditors, the consolidated financial statements listed in the index appearing under Item 14 (a)(1) on page 25 present fairly, in all material respects, the financial position of ChevronTexaco Corporation and its subsidiaries at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. In addition, based on our audits and the report of other auditors, the financial statement schedule listed in the index appearing under Item 14(a)(2) on page 25 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. The consolidated financial statements give retroactive effect to the merger of Texaco Inc. on October 9, 2001, in a transaction accounted for as a pooling of interests, as described in Note 2 to the consolidated financial statements. We did not audit the financial statements or financial statement schedule of Texaco Inc., which statements reflect total assets of $30,867 million as of December 31, 2000, and total revenues of $51,130 million and $35,691 million for each of the two years in the period ended December 31, 2000. Those statements and schedule were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included for Texaco Inc., is based solely on the report of the other auditors. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
San Francisco, California
March 8, 2002

**REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS**

**To Shareholders, Texaco Inc.:**

We have audited the consolidated balance sheet of Texaco Inc. (a Delaware corporation) and subsidiary companies as of December 31, 2000 and 1999, and the related consolidated statements of income, stockholders' equity, comprehensive income and cash flows for each of the two years in the period ended December 31, 2000. These financial statements (not presented separately herein) are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above (not presented separately herein) present fairly, in all material respects, the financial position of Texaco Inc. and subsidiary companies as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States.

Our audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The

schedule listed in Item 14 on Texaco Inc.'s 2000 Form 10-K (not presented separately herein) is the responsibility of the Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

ARTHUR ANDERSEN LLP

February 22, 2001
New York, New York

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## Consolidated Statement of Income[1]

| Millions of dollars, except per-share amounts | Year ended December 31 2001 | 2000 | 1999 |
|---|---|---|---|
| **REVENUES AND OTHER INCOME** | | | |
| Sales and other operating revenues[2] | **$104,409** | $117,095 | $84,004 |
| Income from equity affiliates | **1,144** | 1,077 | 896 |
| Other income | **692** | 958 | 813 |
| **TOTAL REVENUES AND OTHER INCOME** | **106,245** | 119,130 | 85,713 |
| **COSTS AND OTHER DEDUCTIONS** | | | |
| Purchased crude oil and products | **60,549** | 69,814 | 46,256 |
| Operating expenses | **7,650** | 8,323 | 7,773 |
| Selling, general and administrative expenses | **3,984** | 3,626 | 3,222 |
| Exploration expenses | **1,039** | 949 | 1,072 |
| Depreciation, depletion and amortization | **7,059** | 5,321 | 4,934 |
| Merger-related expenses | **1,563** | — | — |
| Interest and debt expense | **833** | 1,110 | 1,132 |
| Taxes other than on income[2] | **15,156** | 15,827 | 15,441 |
| Minority interests | **121** | 111 | 71 |
| **TOTAL COSTS AND OTHER DEDUCTIONS** | **97,954** | 105,081 | 79,901 |
| **INCOME BEFORE INCOME TAX EXPENSE** | **8,291** | 14,049 | 5,812 |
| **INCOME TAX EXPENSE** | **4,360** | 6,322 | 2,565 |
| **NET INCOME BEFORE EXTRAORDINARY ITEM** | **$ 3,931** | $ 7,727 | $ 3,247 |
| Extraordinary loss, net of income tax | **(643)** | — | — |
| **NET INCOME** | **$ 3,288** | $ 7,727 | $ 3,247 |
| **PER-SHARE AMOUNTS** | | | |
| **NET INCOME BEFORE EXTRAORDINARY ITEM – BASIC** | **$ 3.71** | $ 7.23 | $ 3.01 |
| **– DILUTED** | **$ 3.70** | $ 7.21 | $ 3.00 |
| **NET INCOME – BASIC** | **$ 3.10** | $ 7.23 | $ 3.01 |
| **– DILUTED** | **$ 3.09** | $ 7.21 | $ 3.00 |

[1] 2000 and 1999 include certain reclassifications to conform to 2001 presentation

[2] Includes consumer excise taxes: **$ 6,546** $ 6,601 $ 6,029

See accompanying Notes to Consolidated Financial Statements.

**REPORT OF MANAGEMENT**
**TO THE STOCKHOLDERS OF CHEVRONTEXACO CORPORATION**

Management of ChevronTexaco is responsible for preparing the accompanying financial statements and for ensuring their integrity and objectivity. The statements were prepared in accordance with accounting principles generally accepted in the United States of America and fairly represent the transactions and financial position of the company. The financial statements include amounts that are based on management's best estimates and judgments.

The company's statements have been audited by PricewaterhouseCoopers LLP, independent accountants, selected by the Audit Committee and approved by the stockholders. Management has made available to PricewaterhouseCoopers LLP all the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

Management of the company has established and maintains a system of internal accounting controls that is designed to provide reasonable assurance that assets are safeguarded, transactions are properly recorded and executed in accordance with management's authorization, and the books and records accurately reflect the disposition of assets. The system of internal controls includes appropriate division of responsibility. The company maintains an internal audit department that conducts an extensive program of internal audits and independently assesses the effectiveness of the internal controls.

The Audit Committee is composed of directors who are not officers or employees of the company. It meets regularly with members of management, the internal auditors and the independent accountants to discuss the adequacy of the company's internal controls, its financial statements, and the nature, extent and results of the audit effort. Both the internal auditors and the independent accountants have free and direct access to the Audit Committee without the presence of management.

| | | |
|---|---|---|
| /s/ David J. O'Reilly | /s/ John S. Watson | /s/ Stephen J. Crowe |
| **DAVID J. O'REILLY** | **JOHN S. WATSON** | **STEPHEN J. CROWE** |
| Chairman of the Board | Vice President | Vice President |
| and Chief Executive Officer | and Chief Financial Officer | and Comptroller |

March 8, 2002

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## Consolidated Statement of Comprehensive Income

| Millions of dollars | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| **NET INCOME** | **$3,288** | $7,727 | $3,247 |
| Unrealized holding gain on securities | | | |
| Net gain arising during period | | | |
| Before income taxes | **3** | 87 | 72 |
| Income taxes | **—** | (30) | (33) |
| Reclassification to net income of net realized gain | | | |
| Before income taxes | **—** | (154) | (48) |
| Income taxes | **—** | 54 | 11 |
| Total | **3** | (43) | 2 |
| Net derivatives gain on hedge transactions | **3** | — | — |
| Minimum pension liability adjustment | | | |
| Before income taxes | **14** | (28) | (15) |
| Income taxes | **(5)** | 9 | 5 |
| Total | **9** | (19) | (10) |
| Currency translation adjustment | | | |
| Unrealized net change arising during period | **(11)** | (14) | (21) |
| Reclassification adjustment to net income for sale of investment in affiliate | **—** | — | (14) |
| Total | **(11)** | (14) | (35) |
| **OTHER COMPREHENSIVE GAIN (LOSS), NET OF TAX** | **4** | (76) | (43) |
| **COMPREHENSIVE INCOME** | **$3,292** | $7,651 | $3,204 |

See accompanying notes to Consolidated Financial Statements.

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## Consolidated Balance Sheet

| Millions of dollars, except per-share amounts | At December 31 2001 | 2000 |
|---|---|---|
| **ASSETS** | | |
| Cash and cash equivalents | **$ 2,117** | $ 2,328 |
| Marketable securities | **1,033** | 913 |
| Accounts and notes receivable (less allowance: 2001 - $152; 2000 - $116) | **8,279** | 10,763 |
| Inventories: | | |
| Crude oil and petroleum products | **2,207** | 1,969 |
| Chemicals | **209** | 200 |
| Materials, supplies and other | **532** | 485 |
| | **2,948** | 2,654 |
| Prepaid expenses and other current assets | **1,769** | 1,255 |
| Assets held for sale – merger related | **2,181** | — |
| **TOTAL CURRENT ASSETS** | **18,327** | 17,913 |
| Long-term receivables, net | **1,225** | 1,218 |
| Investments and advances | **12,252** | 11,764 |
| Properties, plant and equipment, at cost | **99,943** | 95,568 |
| Less: accumulated depreciation, depletion and amortization | **56,710** | 51,249 |
| | **43,233** | 44,319 |
| Deferred charges and other assets | **2,535** | 2,407 |
| **TOTAL ASSETS** | **$77,572** | $77,621 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Short-term debt | **$ 8,429** | $ 3,094 |
| Accounts payable | **6,427** | 7,563 |
| Accrued liabilities | **3,399** | 3,014 |
| Federal and other taxes on income | **1,398** | 1,864 |
| Other taxes payable | **1,001** | 1,126 |
| **TOTAL CURRENT LIABILITIES** | **20,654** | 16,661 |
| Long-term debt | **8,704** | 12,494 |
| Capital lease obligations | **285** | 327 |
| Deferred credits and other noncurrent obligations | **4,394** | 4,303 |
| Noncurrent deferred income taxes | **6,132** | 6,687 |
| Reserves for employee benefit plans | **3,162** | 3,034 |
| Minority interests | **283** | 746 |
| **TOTAL LIABILITIES** | **43,614** | 44,252 |
| Preferred stock (authorized 100,000,000 shares, $1.00 par value, none issued) | **—** | — |
| Market Auction Preferred Shares (authorized 30,000,000 shares, $1.00 par value, 1,200 issued, liquidation preference of $250,000 per share) | **—** | 300 |
| Common stock (authorized 4,000,000,000 shares, $0.75 par value; 1,137,021,057 shares issued at December 31, 2001; 1,149,520,976 shares issued at December 31, 2000) | **853** | 862 |

| | | |
|---|---|---|
| Capital in excess of par value | **4,811** | 5,505 |
| Retained earnings | **32,767** | 32,206 |
| Accumulated other comprehensive loss | **(306)** | (310) |
| Deferred compensation and benefit plan trust | **(752)** | (921) |
| Treasury stock, at cost (2001 - 69,800,315 shares; 2000 - 84,835,000 shares) | **(3,415)** | (4,273) |
| **TOTAL STOCKHOLDERS' EQUITY** | **33,958** | 33,369 |
| **TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY** | **$77,572** | $77,621 |

See accompanying notes to Consolidated Financial Statements.

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## Consolidated Statement of Cash Flows

| Millions of dollars | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| **OPERATING ACTIVITIES** | | | |
| Net income | **$ 3,288** | $ 7,727 | $ 3,247 |
| Adjustments | | | |
| Depreciation, depletion and amortization | **7,059** | 5,321 | 4,934 |
| Dry hole expense | **646** | 462 | 583 |
| Distributions less than income from equity affiliates | **(489)** | (26) | (288) |
| Net before-tax gains on asset retirements and sales | **(116)** | (371) | (542) |
| Net foreign currency (gains) losses | **(122)** | (130) | 58 |
| Deferred income tax (credits) charges | **(768)** | 521 | 23 |
| Extraordinary before-tax loss on merger-related asset dispositions | **787** | — | — |
| Net decrease in operating working capital | **643** | 91 | 266 |
| Minority interest in net income | **121** | 111 | 68 |
| Decrease in Cities Service provision | **—** | — | (149) |
| Cash settlement of Cities Service litigation | **—** | — | (775) |
| Other, net | **408** | (239) | 346 |
| **NET CASH PROVIDED BY OPERATING ACTIVITIES** | **11,457** | 13,467 | 7,771 |
| **INVESTING ACTIVITIES** | | | |
| Capital expenditures | **(9,713)** | (7,629) | (7,895) |
| Proceeds from asset sales | **298** | 1,229 | 1,578 |
| Net (purchases) sales of marketable securities | **(183)** | 80 | 597 |
| Net sales (purchases) of other short-term investments | **56** | (84) | — |
| Collection of note/formation payments from U.S. affiliate | **—** | — | 101 |
| Distribution from Chevron Phillips Chemical Company LLC | **—** | 835 | — |
| Other, net | **—** | (73) | 9 |
| **NET CASH USED FOR INVESTING ACTIVITIES** | **(9,542)** | (5,642) | (5,610) |
| **FINANCING ACTIVITIES** | | | |
| Net borrowings (repayments) of short-term obligations | **3,830** | (3,254) | 542 |
| Proceeds from issuances of long-term debt | **412** | 1,293 | 2,383 |
| Repayments of long-term debt and other financing obligations | **(2,856)** | (1,241) | (1,491) |
| Redemption of Market Auction Preferred Shares | **(300)** | — | — |
| Redemption of subsidiary preferred stock | **(463)** | — | — |
| Issuance of preferred stock by subsidiaries | **12** | — | — |
| Dividends paid | | | |
| Common stock | **(2,733)** | (2,664) | (2,589) |
| Preferred stock | **(6)** | (15) | (28) |
| Dividends paid to minority interests | **(119)** | (110) | (55) |
| Net sales (purchases) of treasury shares | **128** | (1,498) | 108 |
| **NET CASH USED FOR FINANCING ACTIVITIES** | **(2,095)** | (7,489) | (1,130) |

| | | | |
|---|---|---|---|
| **EFFECT OF FOREIGN CURRENCY EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS** | **(31)** | (5) | (30) |
| **NET CHANGE IN CASH AND CASH EQUIVALENTS** | **(211)** | 331 | 1,001 |
| **CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR** | **2,328** | 1,997 | 996 |
| **CASH AND CASH EQUIVALENTS AT YEAR – END** | **$ 2,117** | $ 2,328 | $ 1,997 |

See accompanying Notes to Consolidated Financial Statements

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## Consolidated Statement of Stockholders' Equity

| | 2001 | | 2000 | | 1999 | |
|---|---|---|---|---|---|---|
| Shares in thousands; amounts in millions of dollars | **Shares** | **Amount** | Shares | Amount | Shares | Amount |
| **PREFERRED STOCK** | **—** | **$ —** | — | $ — | — | $ — |
| **MARKET AUCTION PREFERRED SHARES** | | | | | | |
| Balance at January 1 | **1** | **$ 300** | — | $ — | — | $ — |
| Redemptions | **(1)** | **(300)** | — | — | — | — |
| **BALANCE AT DECEMBER 31** | **—** | **$ —** | 1 | $ 300 | 1 | $ 300 |
| **SERIES B ESOP CONVERTIBLE PREFERRED STOCK** | | | | | | |
| Balance at January 1 | **—** | **$ —** | — | $ — | 649 | $ 389 |
| Redemptions | **—** | **—** | — | — | (587) | (352) |
| Retirements | **—** | **—** | — | — | (62) | (37) |
| **BALANCE AT DECEMBER 31** | **—** | **$ —** | — | $ — | — | $ — |
| **SERIES F ESOP CONVERTIBLE PREFERRED STOCK** | | | | | | |
| Balance at January 1 | **—** | **$ —** | — | $ — | 53 | $ 39 |
| Redemptions | **—** | **—** | — | — | (53) | (39) |
| Retirements | **—** | **—** | — | — | — | — |
| **BALANCE AT DECEMBER 31** | **—** | **$ —** | — | $ — | — | $ — |
| **COMMON STOCK** | | | | | | |
| Balance at January 1 | **1,149,521** | **$ 862** | 1,149,521 | $ 1,724 | 1,149,544 | $ 1,724 |
| Retirement of Texaco treasury stock | **(12,500)** | **(9)** | — | — | — | — |
| Change in par value | **—** | **—** | — | (862) | — | — |
| Monterey Resources acquisition adjustment | **—** | **—** | — | — | (23) | — |
| **BALANCE AT DECEMBER 31** | **1,137,021** | **$ 853** | 1,149,521 | $ 862 | 1,149,521 | $ 1,724 |
| **CAPITAL IN EXCESS OF PAR** | | | | | | |
| Balance at January 1 | | **$ 5,505** | | $ 4,621 | | $ 4,856 |
| Retirement of Texaco treasury stock | | **(739)** | | — | | — |
| Change in common stock par value | | **—** | | 862 | | — |
| Redemption of Texaco Series B and Series F ESOP convertible preferred stock | | **—** | | — | | (308) |
| Monterey Resources acquisition adjustment | | **—** | | — | | (2) |
| Treasury stock transactions | | **45** | | 22 | | 75 |
| **BALANCE AT DECEMBER 31** | | **$ 4,811** | | $ 5,505 | | $ 4,621 |
| **RETAINED EARNINGS** | | | | | | |
| Balance at January 1 | | **$32,206** | | $27,148 | | $26,503 |
| Net income | | **3,288** | | 7,727 | | 3,247 |
| Cash dividends | | | | | | |

| | | | |
|---|---|---|---|
| Common stock | **(2,733)** | (2,664) | (2,589) |
| Preferred stock | | | |
| Texaco Series B ESOP convertible preferred stock | **—** | — | (17) |
| Texaco Series F ESOP convertible preferred stock | **—** | — | (2) |
| Market Auction Preferred Shares | **(6)** | (17) | (9) |
| Tax benefit from dividends paid on unallocated ESOP shares and other | **12** | 12 | 15 |
| **BALANCE AT DECEMBER 31** | **$32,767** | $32,206 | $27,148 |

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## Consolidated Statement of Stockholders' Equity – Continued

| | 2001 | | 2000 | | 1999 | |
|---|---|---|---|---|---|---|
| Shares in thousands; amounts in millions of dollars | **Shares** | **Amount** | Shares | Amount | Shares | Amount |
| **ACCUMULATED OTHER COMPREHENSIVE LOSS** | | | | | | |
| Currency translation adjustment | | | | | | |
| Balance at January 1 | | **$ (212)** | | $ (198) | | $ (163) |
| Change during year | | **(11)** | | (14) | | (35) |
| Balance at December 31 | | **$ (223)** | | $ (212) | | $ (198) |
| Minimum pension liability adjustment | | | | | | |
| Balance at January 1 | | **$ (100)** | | $ (81) | | $ (71) |
| Change during year | | **9** | | (19) | | (10) |
| Balance at December 31 | | **$ (91)** | | $ (100) | | $ (81) |
| Unrealized net holding gain on securities | | | | | | |
| Balance at January 1 | | **$ 2** | | $ 45 | | $ 43 |
| Change during year | | **3** | | (43) | | 2 |
| Balance at December 31 | | **$ 5** | | $ 2 | | $ 45 |
| Net derivatives gain on hedge transactions | | | | | | |
| Balance at January 1 | | **$ —** | | $ — | | $ — |
| Change during year | | **3** | | — | | — |
| Balance at December 31 | | **$ 3** | | $ — | | $ — |
| **BALANCE AT DECEMBER 31** | | **$ (306)** | | $ (310) | | $ (234) |
| **DEFERRED COMPENSATION AND BENEFIT PLAN TRUST** | | | | | | |
| **DEFERRED COMPENSATION** | | | | | | |
| Balance at January 1 | | **$ (681)** | | $ (712) | | $ (785) |
| Net reduction of ESOP debt and other | | **106** | | 35 | | 45 |
| Restricted stock Awards | | **(35)** | | (30) | | (18) |
| Amortization and other | | **12** | | 26 | | 46 |
| Vesting upon merger | | **86** | | — | | — |
| **BALANCE AT DECEMBER 31** | | **(512)** | | (681) | | (712) |
| **BENEFIT PLAN TRUST (COMMON STOCK)** | **7,084** | **(240)** | 7,084 | (240) | 7,084 | (240) |
| **BALANCE AT DECEMBER 31** | **7,084** | **$ (752)** | 7,084 | $ (921) | 7,084 | $ (952) |
| **TREASURY STOCK AT COST** | | | | | | |
| Balance at January 1 | **84,835** | **$ (4,273)** | 67,282 | $ (2,816) | 84,853 | $ (3,728) |
| Purchases | **141** | **(9)** | 19,517 | (1,580) | 56 | (5) |
| Retirement of Texaco treasury stock | **(12,500)** | **748** | — | — | — | — |
| Redemption of Texaco Series B and Series F ESOP convertible stock | **—** | **—** | — | — | (12,459) | 699 |
| Other — mainly employee benefit plans | **(2,676)** | **119** | (1,964) | 123 | (5,168) | 218 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **BALANCE AT DECEMBER 31** | **69,800** | **$ (3,415)** | 84,835 | $ (4,273) | 67,282 | $ (2,816) |
| **TOTAL STOCKHOLDERS' EQUITY AT DECEMBER 31** | | **$33,958** | | $33,369 | | $29,791 |

See accompanying notes to Consolidated Financial Statements.

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## Notes to Consolidated Financial Statements

Millions of dollars, except per-share amounts

**NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

**Basis of Presentation – Merger of Chevron and Texaco** On October 9, 2001, Texaco Inc. (Texaco) became a wholly owned subsidiary of Chevron Corporation (Chevron) pursuant to a merger transaction, and Chevron changed its name to ChevronTexaco Corporation. The combination was accounted for as a pooling of interests.

These Consolidated Financial Statements give retroactive effect to the merger, with all periods presented as if Chevron and Texaco had always been combined. Certain reclassifications have been made to conform the separate presentations of Chevron and Texaco. The reclassifications had no impact on the amount of net income or stockholders' equity.

The Consolidated Financial Statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of significant intercompany accounts and transactions. Included in the consolidation are the accounts of the Caltex Group of Companies (Caltex) – a joint venture, owned 50 percent each by Chevron and Texaco prior to the merger and accounted for under the equity method by both companies.

**General** ChevronTexaco manages its investments in, and provides administrative, financial and management support to, U.S. and foreign subsidiaries and affiliates that engage in fully integrated petroleum operations, chemicals operations and coal mining activities. In addition, ChevronTexaco holds investments in power generation and gasification businesses. Collectively, these companies operate in approximately 180 countries. Petroleum operations consist of exploring for, developing and producing crude oil and natural gas; refining crude oil into finished petroleum products; marketing crude oil, natural gas and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipelines, marine vessels, motor equipment and rail car. Chemicals operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses and fuel and lube oil additives.

In preparing its Consolidated Financial Statements, the company follows accounting policies that are in accordance with accounting principles generally accepted in the United States. This requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. While the company uses its best estimates and judgments, actual results could differ from these estimates as future confirming events occur.

The nature of the company's operations and the many countries in which it operates subject it to changing economic, regulatory and political conditions. The company does not believe it is vulnerable to the risk of near-term severe impact as a result of any concentration of its activities.

**Subsidiary and Affiliated Companies** The consolidated financial statements include the accounts of controlled subsidiary companies more than 50 percent owned. Investments in and advances to affiliates in which the company has a substantial ownership interest of approximately 20 percent to 50 percent, or for which the company exercises significant influence but not control over policy decisions are accounted for by the equity method, in accordance with Accounting Principles Board (APB) Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." Under this accounting, remaining unamortized cost is increased or decreased by the company's share of earnings or losses after dividends. Gains and losses that arise from the issuance of stock by an affiliate that results in changes in the company's proportionate share of the dollar amount of the affiliate's equity are recognized currently in income. Deferred income taxes are provided for these gains and losses.

**Derivatives** The majority of the company's activity in commodity derivative instruments is intended to manage the price risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts and their limited use, the company has elected not to apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's trading activity, gains and losses from the derivative instruments are reported in current income. For derivative instruments relating to foreign currency exposures, gains and losses are reported in current income. Interest rate

swaps – hedging a portion of the company's fixed rate debt – are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

**Short-Term Investments** All short-term investments are classified as available for sale and are in highly liquid debt or equity securities. Those investments that are part of the company's cash management portfolio with original maturities of three months or less are reported as "Cash equivalents." The balance of the short-term investments is reported as "Marketable securities." Short-term investments are marked-to-market with any unrealized gains or losses included in other comprehensive income.

**Inventories** Crude oil, petroleum products and chemicals are generally stated at cost, using a Last-In, First-Out (LIFO) method. In the aggregate, these costs are below market. Materials, supplies and other inventories generally are stated at average cost.

**Properties, Plant and Equipment** The successful efforts method is used for oil and gas exploration and production activities. All costs for development wells, related plant and equipment, and proved mineral interests in oil and gas properties are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs also are capitalized for wells that find commercially producible reserves that cannot be classified as proved, pending one or more of the following: (1) decisions on additional major capital expenditures, (2) the results of additional

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**NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES** – Continued

exploratory wells that are under way or firmly planned, and (3) securing final regulatory approvals for development. Otherwise, well costs are expensed if a determination as to whether proved reserves were found cannot be made within one year following completion of drilling. All other exploratory wells and costs are expensed.

Long-lived assets, including proved oil and gas properties, are assessed for possible impairment by comparing their carrying values with the undiscounted future net before-tax cash flows. Impaired assets are written down to their estimated fair values, generally their discounted future net before-tax cash flows. For proved oil and gas properties in the United States, the company generally performs the impairment review on an individual field basis. Outside the United States, reviews are performed on a country or concession basis. Impairment amounts are recorded as incremental depreciation expense in the period in which the event occurs.

Depreciation and depletion (including provisions for future abandonment and restoration costs) of all capitalized costs of proved oil and gas producing properties, except mineral interests, are expensed using the unit-of-production method by individual field as the proved developed reserves are produced. Depletion expenses for capitalized costs of proved mineral interests are recognized using the unit-of-production method by individual fields as the related proved reserves are produced. Periodic valuation provisions for impairment of capitalized costs of unproved mineral interests are expensed.

Depreciation and depletion expenses for coal are determined using the unit-of-production method as the proved reserves are produced. The capitalized costs of all other plant and equipment are depreciated or amortized over their estimated useful lives. In general, the declining-balance method is used to depreciate plant and equipment in the United States; the straight-line method generally is used to depreciate international plant and equipment and to amortize all capitalized leased assets.

Gains or losses are not recognized for normal retirements of properties, plant and equipment subject to composite group amortization or depreciation. Gains or losses from abnormal retirements are recorded as expenses and from sales as Other income.

Expenditures for maintenance, repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

**Environmental Expenditures** Environmental expenditures that relate to ongoing operations or to conditions caused by past operations are expensed. Expenditures that create future benefits or contribute to future revenue generation are capitalized.

Liabilities related to future remediation costs are recorded when environmental assessments and/or cleanups are probable and the costs can be reasonably estimated. Other than for assessments, the timing and magnitude of these accruals are generally based on the company’s commitment to a formal plan of action, such as an approved remediation plan or the sale or disposal of an asset. For the company’s U.S. and Canadian marketing facilities, the accrual is based on the probability that a future remediation commitment will be required. For oil, gas and coal producing properties, a provision is made through depreciation expense for anticipated abandonment and restoration costs at the end of a property’s useful life.

For Superfund sites, the company records a liability for its share of costs when it has been named as a Potentially Responsible Party (PRP) and when an assessment or cleanup plan has been developed. This liability includes the company’s own portion of the costs and also the company’s portion of amounts for other PRPs when it is probable that they will not be able to pay their share of the cleanup obligation.

The company records the gross amount of its liability based on its best estimate of future costs using currently available technology and applying current regulations as well as the company’s own internal environmental policies. Future amounts are not discounted. Recoveries or reimbursements are recorded as assets when receipt is reasonably assured.

**Currency Translation** The U.S. dollar is the functional currency for substantially all of the company’s consolidated operations and those of its equity affiliates. For those operations, all gains or losses from currency translations are currently included in income. The cumulative translation effects for those few entities, both consolidated and affiliated, using functional currencies other than the U.S. dollar are included in the currency translation adjustment in stockholders’ equity.

**Revenue Recognition** Revenues associated with sales of crude oil, natural gas, coal, petroleum and chemicals products and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which ChevronTexaco has an interest with other producers are generally recognized on the basis of the company's net working interest (entitlement method).

**Stock Compensation** The company applies Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for stock options, and presents in Note 21 pro forma net income and earnings per share data as if the accounting prescribed by FAS No. 123, "Accounting for Stock-Based Compensation," had been applied.

**NOTE 2. TEXACO MERGER TRANSACTION**

The following table presents summarized financial data for the combined company for periods prior to the merger.

| | Nine months ended September 30 | Year ended December 31 | |
|---|---|---|---|
| Millions of dollars | **2001** | 2000 | 1999 |
| **Revenues and other income** | | | |
| Chevron | **$37,213** | $ 52,129 | $36,586 |
| Texaco[1] | **39,469** | 53,520 | 37,779 |
| Adjustments/eliminations[2] | **8,103** | 13,481 | 11,348 |
| ChevronTexaco | **$84,785** | $119,130 | $85,713 |
| **Net Income** | | | |
| Chevron | **$ 4,092** | $ 5,185 | $ 2,070 |
| Texaco[1] | **2,214** | 2,542 | 1,177 |
| Net income, before extraordinary item | **$ 6,306** | $ 7,727 | $ 3,247 |
| Extraordinary loss net of income tax[3] | **(496)** | — | — |
| ChevronTexaco | **$ 5,810** | $ 7,727 | $ 3,247 |

1 Includes certain reclassification adjustments to conform to historic Chevron presentation.

2 Consolidation of former equity operations and intercompany eliminations.

3 Represents loss associated with the sale of the company's interest in Equilon and Motiva.

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## Notes to Consolidated Financial Statements

Millions of dollars, except per-share amounts

**NOTE 2. TEXACO MERGER TRANSACTION** – Continued

At the time of the merger, each share of Texaco common stock was converted, on a tax-free basis, into the right to receive 0.77 shares of ChevronTexaco common stock. Approximately 425 million additional shares of common stock were issued, representing about 40 percent of the outstanding ChevronTexaco common stock after the merger.

As a condition of approving the merger, the U.S. Federal Trade Commission (FTC) required the divestment of certain Texaco assets: Texaco's investments in its U.S. refining, marketing and transportation affiliates, Equilon Enterprises LLC (Equilon) and Motiva Enterprises LLC (Motiva), as well as other interests in U.S. natural gas processing and transportation facilities and general aviation fuel marketing.

Also at the time of the merger, Texaco placed its interests in Equilon and Motiva in trust, as required by the FTC. Because the company no longer exercised significant influence over these investments, the associated accounting method was changed from equity to the cost basis.

**NOTE 3. EXTRAORDINARY ITEM**

Net income for 2001 included a loss of $643, net of a tax benefit of $144, ($0.61 per common share – diluted), related to the disposition of assets that were required as a condition of the FTC approval of the merger and other assets that were made duplicative by the merger. The after-tax loss on these dispositions was reported as an extraordinary item in accordance with pooling-of-interests accounting requirements.

Included in the total after-tax loss was a loss of $564 connected with the sale of interests in Equilon and Motiva. Proceeds from the sale, which closed in February 2002, were approximately $2,200.

For both assets that were being sold by order of the FTC and other assets that were being disposed of because they were made duplicative by the merger, the total net book value at year-end 2001 was $2,181. This amount was included in "Current assets" on the Consolidated Balance Sheet as "Assets held for sale - merger related." Net income for 2001 associated with all such assets being sold as a result of the merger was approximately $375.

**NOTE 4. EMPLOYEE TERMINATION BENEFITS AND OTHER RESTRUCTURING COSTS**

The company recorded before-tax charges of $1,563 in 2001 for merger-related expenses, which included: employee severance benefits; incremental pension and medical plan costs associated with work force reductions; legal, accounting, SEC filing and investment banker fees; employee and office relocations; and costs for the elimination of redundant facilities and operations.

Included in the 2001 charges were accruals of $891 for employee termination benefits for approximately 4,500 employees and other merger-related expenses that would not benefit future periods. Payments against these accruals during the year were $105. Approximately 1,400 employees had terminated by year-end. The year-end accrual balance of $786 is expected to be mostly extinguished by early 2003, as certain terminating employees are eligible to delay their separation payments one year or more. At year-end 2001, approximately $275 of the accrual balance was classified as long term.

Accrual balances for pre-merger restructuring costs had all been extinguished before the end of 2001.

**NOTE 5. SPECIAL ITEMS, MERGER EFFECTS AND OTHER FINANCIAL INFORMATION**

Net income is affected by transactions that are unrelated to or are not necessarily representative of the company's ongoing operations for the periods presented. These transactions, defined by management and designated "special items, merger effects and extraordinary items," can obscure the underlying results of operations for a year as well as affect comparability

of results between years.

Listed in the following table are categories of these items and their net increase (decrease) to net income, after related tax effects.

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| **Special Items** | | | |
| Asset write-offs and revaluations | | | |
| Exploration and production | | | |
| Impairments – U.S. | **$(1,168)** | $(176) | $(204) |
| – International | **(247)** | — | — |
| Refining, marketing and transportation | | | |
| Impairments – U.S. | **—** | — | (76) |
| – International | **(46)** | (112) | — |
| Chemicals | | | |
| Manufacturing facility impairment – U.S. | **(32)** | (90) | — |
| Other asset write-offs | **(64)** | — | (43) |
| All other | | | |
| Mining asset write-off | **(152)** | — | — |
| Information technology and other assets | **—** | — | (54) |
| | **(1,709)** | (378) | (377) |
| Asset dispositions, net | | | |
| Oil and gas assets – U.S. | **49** | (107) | — |
| Oil and gas assets – International | **—** | 80 | — |
| Real estate and other | **—** | 99 | 87 |
| Pipeline interests | **—** | — | 75 |
| Coal assets | **—** | — | 60 |
| Equity affiliate interest – Japan | **—** | — | (111) |
| | **49** | 72 | 111 |
| Prior-year tax adjustments | **(5)** | 107 | 228 |
| Environmental remediation provisions, net | **(78)** | (264) | (40) |
| Pre-merger restructurings and reorganizations | **—** | — | (257) |
| Other, net | | | |
| Dynegy equity adjustment | **—** | 77 | — |
| Litigation and regulatory issues | **—** | (62) | 104 |
| Tax benefits on asset sales | **—** | 70 | 40 |
| | **—** | 85 | 144 |
| **Total special items** | **$(1,743)** | $(378) | $(191) |
| **Merger Effects** | | | |
| Merger-related expenses | **(1,136)** | — | — |
| Extraordinary loss on merger-related asset sales | **(643)** | — | — |

| | | | |
|---|---|---|---|
| **Total special items and merger effects** | **$(3,522)** | $(378) | $(191) |

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**NOTE 5. SPECIAL ITEMS, MERGER EFFECTS AND OTHER FINANCIAL INFORMATION** – Continued

In accordance with its policy, the company recorded impairments of assets to be held and used when changes in circumstances – primarily related to lower oil and gas prices, downward revisions of reserves and changes in the use of the assets – indicated that the carrying values of the assets could not be recovered through estimated future before-tax undiscounted cash flows. 2001 included a $1,022 impairment of the Midway Sunset Field in California – the result of a write-down in proved oil reserve quantities – upon determination of a lower-than-projected oil recovery from the field's steam injection process. There was also a $247 impairment of the LL-652 Field in Venezuela in 2001 – as slower-than-expected reservoir repressurization resulted in a reduction in the projected volumes of oil recoverable during the company's remaining contract period of operation. Asset impairments included in "Asset write-offs and revaluations" were for assets held for use, except for U.S. coal assets in 1999. In late 1999, these assets were reclassified to "held for use" upon cessation of negotiations with potential buyers.

The aggregate income statement effects from special items are reflected in the following table, including ChevronTexaco's proportionate share of special items related to equity affiliates.

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| **Revenues and other income** | | | |
| Income from equity affiliates | **$ (123)** | $ (141) | $(212) |
| Other income | **84** | 356 | 318 |
| **Total revenues and other income** | **(39)** | 215 | 106 |
| **Costs and other deductions** | | | |
| Operating expenses | **25** | 394 | 280 |
| Selling, general and administrative expenses | **139** | 94 | (81) |
| Exploration expenses | **—** | — | 1 |
| Depreciation, depletion and amortization | **2,294** | 561 | 397 |
| Merger-related expenses | **1,563** | — | — |
| Taxes other than on income | **12** | — | — |
| Interest and debt expense | **—** | 4 | — |
| Minority interest | **—** | (9) | — |
| **Total costs and other deductions** | **4,033** | 1,044 | 597 |
| **Income before income tax expense** | **(4,072)** | (829) | (491) |
| Income tax expense | **(1,193)** | (451) | (300) |
| **Net income before extraordinary item** | **$(2,879)** | $ (378) | $(191) |
| Extraordinary loss, net of income tax | **(643)** | — | — |
| **Net income** | **$(3,522)** | $ (378) | $(191) |

Other financial information is as follows:

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| Total financing interest and debt costs | **$955** | $1,218 | $1,170 |
| Less: capitalized interest | **122** | 108 | 38 |

| | | | |
|---|---|---|---|
| Interest and debt expense | **$833** | $1,110 | $1,132 |
| Research and development expenses | **$209** | $ 211 | $ 226 |
| Foreign currency gains (losses)* | **$191** | $ 182 | $ (15) |

* Includes $12, $66 and $(32) in 2001, 2000 and 1999, respectively, for the company's share of equity affiliates' foreign currency gains (losses).

The excess of market value over the carrying value of inventories for which the LIFO method is used was $1,580, $2,339 and $1,169 at December 31, 2001, 2000 and 1999, respectively. Market value is generally based on average acquisition costs for the year. In 2000, certain inventories were recorded at market, which was lower than LIFO carrying value. Adjustments to market reduced net income $4 in 2000. In 2001 and 1999, the market valuation adjustment reserves established in prior years were eliminated as market prices improved and the associated physical units of inventory were sold. Elimination of these reserves increased net income by $4 and $170 in 2001 and 1999, respectively.

**NOTE 6. INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS**

"Net decrease in operating working capital" is composed of the following:

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| Decrease (increase) in accounts and notes receivable | **$ 2,472** | $(2,162) | $(2,057) |
| (Increase) decrease in inventories | **(294)** | 120 | 32 |
| (Increase) decrease in prepaid expenses and other current assets | **(211)** | 73 | (61) |
| (Decrease) increase in accounts payable and accrued liabilities | **(742)** | 1,327 | 1,718 |
| (Decrease) increase in income and other taxes payable | **(582)** | 733 | 634 |
| Net decrease in operating working capital | **$ 643** | $ 91 | $ 266 |
| Net cash provided by operating activities includes the following cash payments for interest and income taxes: | | | |
| Interest paid on debt (net of capitalized interest) | **$ 873** | $ 1,095 | $ 1,060 |
| Income taxes paid | **$ 5,465** | $ 4,883 | $ 1,868 |
| Net (purchases) sales of marketable securities consists of the following gross amounts: | | | |
| Marketable securities purchased | **$(2,848)** | $(6,671) | $(3,255) |
| Marketable securities sold | **2,665** | 6,751 | 3,852 |
| Net (purchases) sales of marketable securities | **$ (183)** | $ 80 | $ 597 |

The major components of "Capital expenditures" and the reconciliation of this amount to the capital and exploratory expenditures, excluding equity in affiliates, presented in the MD&A are detailed in the following table.

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## Notes to Consolidated Financial Statements

Millions of dollars, except per-share amounts

**NOTE 6. INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS** – Continued

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| Additions to properties, plant and equipment[1] | **$ 6,445** | $6,173 | $ 8,125 |
| Additions to investments | **2,902** [2] | 1,118 | 393 |
| Current year dry-hole expenditures | **418** | 402 | 475 |
| Payments for other liabilities and assets, net | **(52)** | (64) | (1,098)[3] |
| Capital expenditures | **9,713** | 7,629 | 7,895 |
| Expensed exploration expenditures | **393** | 487 | 489 |
| Payments of long-term debt and other financing obligations, net | **210** [4] | 175 | 648 [5] |
| Capital and exploratory expenditures, excluding equity affiliates | **$10,316** | $8,291 | $ 9,032 |

1 2001 net of a noncash reclassification of $63.

2 Includes $1,500 for investment in Dynegy preferred stock.

3 Includes liabilities assumed in acquisitions of Rutherford-Moran Oil Corporation and Petrolera Argentina San Jorge S.A.

4 Represents a deferred payment related to 1993 acquisition of an interest in the Tengizchevroil joint venture.

5 Includes obligations assumed in acquisition of Rutherford-Moran Oil Corporation and other capital lease additions.

The Consolidated Statement of Cash Flows excludes the following significant noncash transaction:

In 2000, Chevron contributed $2,800 of net noncash assets to Chevron Phillips Chemical Company LLC (CPChem). The investment is accounted for under the equity method.

**NOTE 7. SUMMARIZED FINANCIAL DATA – CHEVRON U.S.A. INC.**

Chevron U.S.A. Inc. (CUSA), is a major subsidiary of ChevronTexaco Corporation. CUSA owns, manages and operates on its own behalf or on behalf of other ChevronTexaco subsidiaries, the U.S. integrated petroleum operations, excluding ChevronTexaco's investments in Equilon and Motiva, which were sold in February 2002, and most of the pipeline operations of ChevronTexaco. CUSA and its subsidiaries and affiliates manage and operate most of ChevronTexaco's U.S. businesses and assets related to the exploration and production of crude oil, natural gas and natural gas liquids and also those associated with refining, marketing, supply and distribution of products derived from petroleum, other than natural gas liquids. CUSA also holds ChevronTexaco's investment in CPChem. Summarized financial information for CUSA and its consolidated subsidiaries is presented below.

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000* | 1999* |
| Sales and other operating revenues | **$37,033** | $40,729 | $28,957 |

| | | | |
|---|---|---|---|
| Total costs and other deductions | **34,771** | 38,047 | 28,644 |
| Net income | **1,802** | 2,336 | 885 |

* Certain reclassifications were made to conform to the 2001 presentation.

| | At December 31 | |
|---|---|---|
| | **2001** | 2000 |
| Current assets | **$ 2,888** | $ 4,396 |
| Other assets | **20,795** | 20,738 |
| Current liabilities | **4,344** | 4,094 |
| Other liabilities | **9,797** | 10,251 |
| Net equity | **9,542** | 10,789 |
| Memo: Total Debt | **$ 6,272** | $ 6,728 |

**NOTE 8. SUMMARIZED FINANCIAL DATA – CHEVRON TRANSPORT CORPORATION LTD.**

Chevron Transport Corporation Ltd. (CTC), incorporated in the Bermuda Islands, is an indirect, wholly owned subsidiary of ChevronTexaco Corporation. CTC is the principal operator of ChevronTexaco's international tanker fleet and is engaged in the marine transportation of oil and refined petroleum products. Most of CTC's shipping revenue is derived by providing transportation services to other ChevronTexaco companies. ChevronTexaco Corporation has guaranteed this subsidiary's obligations in connection with certain debt securities issued by a third party. Summarized financial information for CTC and its consolidated subsidiaries is presented as follows:

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| Sales and other operating revenues | **$859** | $728 | $504 |
| Total costs and other deductions | **793** | 777 | 572 |
| Net income (loss) | **67** | (47) | (50) |

| | At December 31 | |
|---|---|---|
| | **2001** | 2000 |
| Current assets | **$196** | $205 |
| Other assets | **527** | 530 |
| Current liabilities | **280** | 309 |
| Other liabilities | **311** | 361 |
| Net equity | **132** | 65 |

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2001.

**NOTE 9. STOCKHOLDERS' EQUITY**

Retained earnings at December 31, 2001 and 2000, included approximately $2,001 and $2,300, respectively, for the company's share of undistributed earnings of equity affiliates. The interests in Equilon and Motiva were placed in trust at the time of the merger, and ChevronTexaco no longer had significant influence over the joint ventures. Accordingly, the method of accounting for these investments was changed in the fourth quarter 2001 from equity to cost basis.

Upon the merger of Chevron and Texaco, the authorized common stock of ChevronTexaco was increased from 2 billion shares of $0.75 par value to 4 billion shares of $0.75 par value. Under the terms of the merger agreement, approximately 425 million shares of ChevronTexaco common stock were issued in exchange for all of the outstanding shares of Texaco common stock based upon an exchange ratio of 0.77 of a ChevronTexaco share for each Texaco

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**NOTE 9. STOCKHOLDERS' EQUITY** – Continued

share. Texaco's common stock held in treasury was canceled at the effective time of the merger.

In 1998, in connection with the renewal of Chevron's Stockholder Rights Plan, Chevron declared a dividend distribution on each outstanding share of its common stock of one Right to purchase participating preferred stock. Since this distribution in 1998, all newly issued shares of the corporation's common stock have been accompanied by a preferred stock purchase Right, including the shares issued in connection with the merger between Chevron and Texaco. Following the merger, the Chevron Stockholder Rights Plan has continued as the Stockholder Rights plan of ChevronTexaco. The Rights issued under the plan become exercisable, unless redeemed earlier by ChevronTexaco, if a person or group acquires or obtains the right to acquire 10 percent or more of the outstanding shares of common stock or commences a tender or exchange offer that would result in that person or group acquiring 10 percent or more of the outstanding shares of common stock, either event occurring without the prior consent of ChevronTexaco. The ChevronTexaco Series A Participating Preferred Stock that the holder of a Right is entitled to receive and the purchase price payable upon exercise of the ChevronTexaco Right are both subject to adjustment. The person or group who acquired 10 percent or more of the outstanding shares of common stock without the prior consent of ChevronTexaco would not be entitled to this purchase.

The Rights will expire in November 2008, or they may be redeemed by the company at 1 cent per Right prior to that date. The Rights do not have voting or dividend rights and until they become exercisable, have no dilutive effect on the earnings per share of the company. Five million shares of the company's preferred stock have been designated Series A Participating Preferred Stock and reserved for issuance upon exercise of the Rights. No event during 2001 made the Rights exercisable.

In 1989, Texaco established a similar stockholder rights plan and reserved and designated 3 million shares as Series D for issuance upon exercise of the Rights. Prior to the merger, the Rights were not exercisable nor did they become exercisable upon the merger. Immediately after the merger, the Texaco Rights and Series D Junior Participating Preferred Stock were delisted and the Texaco stockholder rights plan was terminated.

During 2000 and until June 2001, there were 1,200 shares of Texaco cumulative variable rate preferred stock, called Market Auction Preferred Shares (MAPS), outstanding with an aggregate value of $300. The MAPS were redeemed in June 2001, at a liquidation preference of $250,000 per share, plus premium and accrued and unpaid dividends.

At December 31, 2001, 30 million shares of ChevronTexaco's authorized but unissued common stock were reserved for issuance under the ChevronTexaco Corporation Long-Term Incentive Plan (LTIP), which was approved by the stockholders in 1990. To date, all of the plan's common stock requirements have been met from the company's treasury stock, and there have been no issuances of reserved shares.

**NOTE 10. FINANCIAL AND DERIVATIVE INSTRUMENTS**

**Commodity Derivative Instruments** ChevronTexaco is exposed to market risks related to price volatility of crude oil, refined products, natural gas and refinery feedstock.

The company uses derivative commodity instruments to manage this exposure on a small portion of its activity including: firm commitments and anticipated transactions for the purchase or sale of crude oil, feedstock purchases for company refineries, crude oil and refined products inventories, and fixed price contracts to sell natural gas and natural gas liquids.

The company also uses derivative commodity instruments for limited trading purposes.

The company maintains a policy of requiring that an International Swaps and Derivatives Association Master Agreement govern derivative contracts with certain counterparties to mitigate credit risk. Depending on the nature of the derivative transaction, bilateral collateral arrangements may also be required. When the company is engaged in more than one outstanding derivative transaction with the same counterparty and also has a legally enforceable master netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of the company's credit risk. It is the company's policy to use other master netting agreements with all counterparties with which it conducts significant transactions.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as “Accounts and notes receivable,” “Accounts payable,” “Long-term receivables – net,” and “Deferred credits and other noncurrent obligations.” Gains and losses on the company’s risk management activities are reported as either “Sales and other operating revenues” or “Purchased crude oil and products,” whereas trading gains and losses are reported as “Other income.” These activities are reported under “Operating activities” in the Consolidated Statement of Cash Flows.

**Foreign Currency** The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as “Accounts and notes receivable” or “Accounts payable,” with gains and losses reported as “Other income.” These activities are reported under “Operating activities” in the Consolidated Statement of Cash Flows.

**Interest Rates** The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company’s fixed-rate debt are accounted for as fair value hedges, whereas interest rate swaps related to a portion of the company’s floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

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**Notes to Consolidated Financial Statements**

**Millions of dollars, except per-share amounts**

**NOTE 10. FINANCIAL AND DERIVATIVE INSTRUMENTS** - Continued

During 2001, no new swaps were initiated in connection with debt issues in the year. At year-end 2001, the weighted average maturity of interest rate swaps was approximately five years.

Fair values of the interest rate swaps are reported on the Consolidated Balance Sheet as “Accounts and notes receivables” or “Accounts payable,” with gains and losses reported directly in income as part of “Interest and debt expense.” These activities are reported under “Operating activities” in the Consolidated Statement of Cash Flows.

**Concentrations of Credit Risk** The company’s financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, marketable securities, derivative financial instruments and trade receivables. The company’s short-term investments are placed with a wide array of financial institutions with high credit ratings. This diversified investment policy limits the company’s exposure both to credit risk and to concentrations of credit risk. Similar standards of diversity and creditworthiness are applied to the company’s counterparties in derivative instruments.

The trade receivable balances, reflecting the company’s diversified sources of revenue, are dispersed among the company’s broad customer base worldwide. As a consequence, concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. Letters of credit or negotiated contracts, when the financial strength of a customer is not considered sufficient, are the principal securities obtained to support lines of credit.

**Fair Value** Fair values are derived either from quoted market prices or, if not available, the present value of the expected cash flows. The fair values reflect the cash that would have been received or paid if the instruments were settled at year-end.

Long-term debt of $6,599 and $8,870 had estimated fair values of $7,097 and $8,991 at December 31, 2001 and 2000, respectively.

The company holds cash equivalents and U.S. dollar marketable securities in domestic and offshore portfolios. Eurodollar bonds, floating-rate notes, time deposits and commercial paper are the primary instruments held. Cash equivalents and marketable securities had fair values of $2,449 and $2,543 at December 31, 2001 and 2000, respectively. Of these balances, $1,446 and $1,630 at the respective year-ends were classified as cash equivalents that had average maturities under 90 days. The remainder, classified as marketable securities, had average maturities of approximately 3.6 years.

The company’s $1,500 investment in redeemable, convertible preferred stock of its Dynegy affiliate is carried at fair value.

**NOTE 11. OPERATING SEGMENTS AND GEOGRAPHIC DATA**

ChevronTexaco separately manages its exploration and production; refining, marketing and transportation; and chemicals businesses. The company’s primary country of operation is the United States, its country of domicile. The remainder of the company’s operations is reported as International (outside the United States).

**Segment Earnings** The company evaluates the performance of its operating segments on an after-tax basis, without considering the effects of debt financing interest expense or investment interest income, both of which are managed by the company on a worldwide basis. Corporate administrative costs and assets are not allocated to the operating segments; instead, operating segments are billed only for direct corporate services. Nonbillable costs and merger effects remain as corporate expenses. After-tax segment income (loss) is presented in the following table.

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| **Exploration and Production** | | | |

| | | | |
|---|---|---|---|
| United States | **$ 1,779** | $3,453 | $1,133 |
| International | **2,533** | 3,702 | 1,450 |
| **Total Exploration and Production** | **4,312** | 7,155 | 2,583 |
| **Refining, Marketing and Transportation** | | | |
| United States | **1,254** | 721 | 551 |
| International | **560** | 414 | 546 |
| **Total Refining, Marketing and Transportation** | **1,814** | 1,135 | 1,097 |
| **Chemicals** | | | |
| United States | **(186)** | (31) | 44 |
| International | **58** | 71 | 65 |
| **Total Chemicals** | **(128)** | 40 | 109 |
| **Total Segment Income** | **5,998** | 8,330 | 3,789 |
| Merger effects | **$(1,779)** | — | — |
| Interest expense | **(552)** | (766) | (779) |
| Interest income | **147** | 139 | 81 |
| Other | **(526)** | 24 | 156 |
| **Net Income** | **$ 3,288** | $7,727 | $3,247 |

**Segment Assets** Segment assets do not include intercompany investments or intercompany receivables. “All Other” assets consist primarily of worldwide cash and marketable securities, real estate, information systems, the investment in Dynegy Inc., coal mining operations, power and gasification operations, and technology investments and merger-related assets held for sale at year-end 2001. Segment assets at year-end 2001 and 2000 follow.

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**NOTE 11. OPERATING SEGMENTS AND GEOGRAPHIC DATA —** Continued

| | At December 31 | |
|---|---|---|
| | **2001** | 2000 |
| **Exploration and Production** | | |
| United States | **$12,718** | $15,216 |
| International | **24,177** | 22,463 |
| **Total Exploration and Production** | **36,895** | 37,679 |
| **Refining, Marketing and Transportation** | | |
| United States | **8,902** | 12,118 |
| International | **16,426** | 17,034 |
| **Total Refining, Marketing and Transportation** | **25,328** | 29,152 |
| **Chemicals** | | |
| United States | **2,059** | 2,350 |
| International | **701** | 727 |
| **Total Chemicals** | **2,760** | 3,077 |
| **Total Segment Assets** | **64,983** | 69,908 |
| **All Other** | | |
| United States | **8,950** | 5,361 |
| International | **3,639** | 2,352 |
| **Total All Other** | **12,589** | 7,713 |
| **Total Assets — United States** | **32,629** | 35,045 |
| **Total Assets — International** | **44,943** | 42,576 |
| **Total Assets** | **$77,572** | $77,621 |

**Segment Sales and Other Operating Revenues** Revenues for the exploration and production segment are derived primarily from the production of crude oil and natural gas. Revenues for the refining, marketing and transportation segment are derived from the refining and marketing of petroleum products, such as gasoline, jet fuel, gas oils, kerosene, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the transportation and trading of crude oil and refined products. Prior to the July 2000 formation of CPChem, chemicals segment revenues were derived from the manufacture and sale of petrochemicals, plastic resins, and lube oil and fuel additives. Subsequent to the formation of the joint venture, only revenues from the manufacture and sale of lube oil and fuel additives were included.

"All Other" activities include corporate administrative costs, worldwide cash management and debt financing activities, coal mining operations, power and gasification operations, technology investments, insurance operations and real estate activities. Other than the United States, the only country where ChevronTexaco generates significant revenues is the United Kingdom, which amounted to $10,350, $12,101 and $9,650 in 2001, 2000 and 1999, respectively. Sales revenues are based on the origin of the sale.

Reportable operating segment "Sales and other operating revenues," including internal transfers, for the years 2001, 2000 and 1999 are presented in the following table. Sales from the transfer of products between segments are at prices that approximate market prices.

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| **Exploration and Production** | | | |
| United States | **$ 12,724** | $ 13,927 | $ 7,819 |
| Intersegment | **3,167** | 3,542 | 2,205 |
| Total United States | **15,891** | 17,469 | 10,024 |
| International | **9,126** | 9,052 | 6,202 |
| Intersegment | **7,376** | 6,189 | 3,800 |
| Total International | **16,502** | 15,241 | 10,002 |
| **Total Exploration and Production** | **32,393** | 32,710 | 20,026 |
| **Refining, Marketing and Transportation** | | | |
| United States | **29,294** | 31,926 | 20,468 |
| Excise taxes | **3,954** | 3,837 | 3,702 |
| Intersegment | **392** | 414 | 476 |
| Total United States | **33,640** | 36,177 | 24,646 |
| International | **45,248** | 52,501 | 38,993 |
| Excise taxes | **2,580** | 2,737 | 2,842 |
| Intersegment | **452** | 930 | 160 |
| Total International | **48,280** | 56,168 | 41,995 |
| **Total Refining, Marketing and Transportation** | **81,920** | 92,345 | 66,641 |
| **Chemicals** | | | |
| United States | **335** | 1,985 | 2,791 |
| Excise taxes | **—** | 1 | 2 |
| Intersegment | **89** | 137 | 162 |
| Total United States | **424** | 2,123 | 2,955 |
| International | **670** | 701 | 686 |
| Excise taxes | **12** | 26 | 28 |
| Intersegment | **65** | — | 171 |
| Total International | **747** | 727 | 885 |
| **Total Chemicals** | **1,171** | 2,850 | 3,840 |
| **All Other** | | | |
| United States | **429** | 403 | 456 |
| Intersegment | **60** | 90 | 55 |
| Total United States | **489** | 493 | 511 |
| International | **37** | (1) | 15 |
| Intersegment | **9** | 19 | 12 |

| | | | |
|---|---|---|---|
| Total International | **46** | 18 | 27 |
| **Total All Other** | **535** | 511 | 538 |
| Segment Sales and Other Operating Revenues | | | |
| United States | **50,444** | 56,262 | 38,136 |
| International | **65,575** | 72,154 | 52,909 |
| Total Segment Sales and Other Operating Revenues | **116,019** | 128,416 | 91,045 |
| Elimination of Intersegment Sales | **(11,610)** | (11,321) | (7,041) |
| **Total Sales and Other Operating Revenues** | **$104,409** | $117,095 | $84,004 |

**Segment Income Taxes** Segment income tax expenses for the years 2001, 2000 and 1999 are as follows:

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**Notes to Consolidated Financial Statements**

**Millions of dollars, except per-share amounts**

**NOTE 11. OPERATING SEGMENTS AND GEOGRAPHIC DATA —** Continued

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| **Exploration and Production** | | | |
| United States | **$ 965** | $1,901 | $ 559 |
| International | **3,569** | 4,363 | 2,164 |
| **Total Exploration and Production** | **4,534** | 6,264 | 2,723 |
| **Refining, Marketing and Transportation** | | | |
| United States | **744** | 383 | 279 |
| International | **260** | 152 | 175 |
| **Total Refining, Marketing and Transportation** | **1,004** | 535 | 454 |
| **Chemicals** | | | |
| United States | **(78)** | 31 | (13) |
| International | **23** | 30 | 45 |
| **Total Chemicals** | **(55)** | 61 | 32 |
| All Other* | **(1,123)** | (538) | (644) |
| **Total Income Tax Expense*** | **$ 4,360** | $6,322 | $2,565 |

* Excludes tax of $144 for extraordinary item.

**Other Segment Information** Additional information for the segmentation of major equity affiliates is contained in Note 14. Information related to properties, plant and equipment by segment is contained in Note 15.

**NOTE 12. LITIGATION**

Chevron, Texaco and four other oil companies (refiners) filed suit in 1995 contesting the validity of a patent granted to Unocal Corporation (Unocal) for reformulated gasoline, which ChevronTexaco sells in California in certain months of the year. In March 2000, the U.S. Court of Appeals for the Federal Circuit upheld a September 1998 District Court decision that Unocal's patent was valid and enforceable and assessed damages of 5.75 cents per gallon for gasoline produced in infringement of the patent. In May 2000, the Federal Circuit Court denied a petition for rehearing with the U.S. Court of Appeals for the Federal Circuit filed by the refiners in this case. The refiners petitioned the U.S. Supreme Court and, in February 2001, the Supreme Court denied the petition to review the lower court's ruling and the case was remanded to the District Court for an accounting of all infringing gasoline produced from August 1, 1996, to September 30, 2000. The District Court granted Unocal's motion for summary judgment requesting an accounting and denied the refiners' motion to stay the proceedings and vacate the accounting order. However, the judge presiding over this case recused himself before entering a final judgment and a new judge was assigned. Additionally, in May 2001, the U.S. Patent Office (USPO) granted the refiners' petition to re-examine the validity of Unocal's patent and, in February 2002, the USPO ruled the patent invalid. Unocal has two months to respond to the USPO ruling. The Federal Trade Commission has also announced that it is

investigating whether Unocal's failure to disclose to the California Air Resources Board that it had filed a patent application was unfair competition, which may make Unocal's patent unenforceable.

If Unocal's patent ultimately is upheld and is enforceable, the company's financial exposure includes royalties, plus interest, for production of gasoline that is proved to have infringed the patent. Chevron and Texaco, as well as Texaco's former affiliates Equilon and Motiva, have been accruing in the normal course of business any future estimated liability for potential infringement of the patent covered by the trial court's ruling. In 2000, Chevron and Texaco made payments to Unocal totaling approximately $28 for the original court ruling, including interest and fees.

Unocal has obtained additional patents for alternate formulations that could affect a larger share of U.S. gasoline production. ChevronTexaco believes these additional patents are invalid and unenforceable. However, if such patents are ultimately upheld, the competitive and financial effects on the company's refining and marketing operations, while presently indeterminable, could be material.

Another issue involving the company is the petroleum industry's use of methyl tertiary-butyl ether (MTBE) as a gasoline additive and its potential environmental impact through seepage into groundwater. Along with other oil companies, the company is a party to lawsuits and claims related to the use of the chemical MTBE in certain oxygenated gasolines. These actions may require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. Costs to the company related to these lawsuits and claims are not currently determinable. ChevronTexaco continues the use of MTBE in gasoline it sells in certain areas. The state of California has directed that MTBE be phased out of the manufacturing process by the end of 2002.

**NOTE 13. LEASE COMMITMENTS**

Certain noncancelable leases are classified as capital leases, and the leased assets are included as part of "Properties, plant and equipment, at cost." Such leasing arrangements involve tanker charters, crude oil production and processing equipment, service stations and other facilities. Other leases are classified as operating leases and are not capitalized. The payments on such leases are recorded as expense. Details of the capitalized leased assets are as follows:

| | At December 31 | |
|---|---|---|
| | **2001** | 2000 |
| Exploration and production | **$ 172** | $ 223 |
| Refining, marketing and transportation | **848** | 851 |
| Total | **1,020** | 1,074 |
| Less: accumulated amortization | **567** | 587 |
| Net capitalized leased assets | **$ 453** | $ 487 |

Rental expenses incurred for operating leases during 2001, 2000 and 1999 were as follows:

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**NOTE 13. LEASE COMMITMENTS —** Continued

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| Minimum rentals | **$1,132** | $1,062 | $804 |
| Contingent rentals | **14** | 35 | 16 |
| Total | **1,146** | 1,097 | 820 |
| Less: sublease rental income | **76** | 77 | 73 |
| Net rental expense | **$1,070** | $1,020 | $747 |

Contingent rentals are based on factors other than the passage of time, principally sales volumes at leased service stations. Certain leases include escalation clauses for adjusting rentals to reflect changes in price indices, renewal options ranging from one to 25 years, and/or options to purchase the leased property during or at the end of the initial or renewal lease period for the fair market value or other specified amount at that time.

At December 31, 2001, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

| | At December 31 | |
|---|---|---|
| | Operating Leases | Capital Leases |
| Year: 2002 | $ 692 | $ 80 |
| 2003 | 314 | 111 |
| 2004 | 301 | 54 |
| 2005 | 266 | 49 |
| 2006 | 237 | 47 |
| Thereafter | 731 | 613 |
| Total | $2,541 | $954 |
| Less: amounts representing interest and executory costs | | 323 |
| Net present values | | 631 |
| Less: capital lease obligations included in short-term debt | | 346 |
| Long-term capital lease obligations | | $285 |

**NOTE 14. INVESTMENTS AND ADVANCES**

Descriptions of major affiliates during 2001 are as follows:

**Tengizchevroil** Tengizchevroil (TCO) is a joint venture formed in 1993 to develop the Tengiz and Korolev oil fields in Kazakhstan over a 40-year period. Chevron's ownership was 45 percent during 1999 and 2000. In January 2001, the company purchased an additional 5 percent interest. Upon formation of the joint venture, the company incurred an obligation of $420, payable to the Republic of Kazakhstan upon attainment of a dedicated export system with the capability of the greater of 260,000 barrels of oil per day or TCO's production capacity. As a part of the January transaction, the

company paid $210 of the $420 obligation. The $420 was also included in the carrying value of the original investment, as the company believed, beyond a reasonable doubt, that its full payment would be made.

**Equilon Enterprises LLC** Effective January 1, 1998, Texaco and Shell Oil Company (Shell) formed Equilon, a Delaware limited liability company. Equilon is a joint venture that combined major elements of those companies' western and midwestern U.S. refining and marketing businesses and their nationwide trading, transportation and lubricants businesses. The company's 44 percent ownership interest in Equilon was placed in trust on October 9, 2001, as required by the FTC. The trust completed the disposition of the company's investment in Equilon in February 2002.

Because Equilon is a limited liability company, ChevronTexaco recorded the provision for income taxes and related income tax liability applicable to its share of the venture's income separately in its consolidated financial statements.

See Note 2 for additional information on Equilon.

**Motiva Enterprises LLC** Effective July 1, 1998, Texaco, Shell and Saudi Refining Inc., a corporate affiliate of Saudi Aramco, formed Motiva, a Delaware limited liability company. Motiva is a joint venture that combined the East and Gulf Coast U.S. refining and marketing businesses of Shell and Star Enterprise (Star). Star, in turn, was a joint venture owned 50 percent each by Texaco and Saudi Refining Inc.

Under the terms of the Limited Liability Company Agreement for Motiva, the ownership in Motiva is subject to annual adjustment through year-end 2005, based on the performance of the assets contributed to Motiva. Accordingly, the company's initial 32.5 percent ownership in Motiva was adjusted effective as of January 1, 2000, to just under 31 percent. At January 1, 2001, the company's ownership percentage was adjusted to 35 percent. The company's ownership interest in Motiva was placed in trust on October 9, 2001, as required by the FTC. The trust completed the disposition of the company's investment in Motiva in February 2002.

Because Motiva is a limited liability company, ChevronTexaco recorded the provision for income taxes and related income tax liability applicable to its share of the venture's income separately in its consolidated financial statements.

See Note 2 for additional information on Motiva.

**LG-Caltex Corporation** ChevronTexaco owns 50 percent of LG-Caltex, a joint venture formed in 1967 between the LG Group and Caltex, originally incorporated as Honam Oil Refinery Company Limited, to engage in importing, refining and marketing of petroleum products in Korea.

**Star Petroleum Refining Company, Ltd.** ChevronTexaco has a 64 percent equity ownership interest in Star Petroleum Refining Company Limited (SPRC), which owns the Star refinery at Ma Ta Phut, Thailand. The Thai national petroleum company owns the remaining 36 percent of SPRC.

**Caltex Australia Ltd.** ChevronTexaco has a 50 percent equity ownership interest in Caltex Australia Limited, which is the largest oil company in Australia. The remaining 50 percent of Caltex Australia is publicly owned.

**Chevron Phillips Chemical Company LLC** ChevronTexaco owns 50 percent of CPChem, formed in July 2000 when Chevron merged most of its petrochemicals businesses with those of Phillips Petroleum Company. Because CPChem is a limited liability company, ChevronTexaco records the provision for income taxes and related tax liability applicable to its share of the venture's income separately in its consolidated financial statements.

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**Notes to Consolidated Financial Statements**

Millions of dollars, except per-share amounts

**NOTE 14. INVESTMENTS AND ADVANCES —** Continued

**Dynegy Inc.** Dynegy is a gatherer, processor, transporter and marketer of energy products in North America and the United Kingdom. These products include natural gas, natural gas liquids, crude oil and electricity. In 2001, ChevronTexaco exercised its preemptive rights and acquired a further 1.2 million shares of Dynegy's common stock for $40.8. This additional investment maintained the company's equity ownership in Dynegy at approximately 26.5 percent. Also, in 2001, ChevronTexaco invested $1,500 in Dynegy redeemable, convertible preferred stock. The market value of ChevronTexaco's share of Dynegy common stock at December 31, 2001, was $2,206, based on equivalent closing market prices. The fair value of the redeemable convertible preferred stock was $1,500.

"Sales and other operating revenues" on the Consolidated Statement of Income include $13,868, $15,741 and $10,068 with major affiliated companies for 2001, 2000 and 1999. "Purchased crude oil and products" include $3,859, $4,824 and $2,837 with major affiliated companies for 2001, 2000 and 1999.

"Accounts and notes receivable" on the Consolidated Balance Sheet include $481 and $1,392 due from affiliated companies at December 31, 2001 and 2000, respectively. "Accounts payable" include $168 and $313 due to major affiliated companies at December 31, 2001 and 2000, respectively. These 2001 amounts exclude balances with Equilon and Motiva.

Equity in earnings, together with investments in and advances to companies accounted for using the equity method, and other investments accounted for at or below cost, are as follows:

| | Investments and Advances At December 31 | | Equity in Earnings Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2001** | 2000 | **2001** | 2000 | 1999 |
| **Exploration and Production** | | | | | |
| Tengizchevroil | **$ 2,459** | $ 1,857 | **$ 332** | $ 376 | $177 |
| Other | **808** | 550 | **205** | 163 | 98 |
| Total Exploration and Production | **3,267** | 2,407 | **537** | 539 | 275 |
| **Refining, Marketing and Transportation** | | | | | |
| Equilon* | **—** | 1,724 | **274** | 151 | 219 |
| Motiva* | **—** | 743 | **276** | 154 | (5) |
| LG-Caltex Oil Corporation | **1,491** | 1,468 | **60** | 80 | 310 |
| Caspian Pipeline Consortium | **928** | 587 | **38** | 22 | 4 |
| Star Petroleum Refining Company Ltd. | **394** | 337 | **(56)** | (4) | (27) |
| Caltex Australia Limited | **267** | 253 | **16** | 13 | (48) |
| Other | **755** | 680 | **92** | 117 | 93 |
| Total Refining, Marketing and Transportation | **3,835** | 5,792 | **700** | 533 | 546 |
| **Chemicals** | | | | | |
| Chevron Phillips Chemical Company LLC | **1,587** | 1,830 | **(229)** | (114) | — |
| Other | **17** | 15 | **2** | (9) | 1 |

| | | | | | |
|---|---|---|---|---|---|
| Total Chemicals | **1,604** | 1,845 | **(227)** | (123) | 1 |
| Dynegy Inc. | **2,628** | 929 | **188** | 127 | 51 |
| All Other | **507** | 365 | **(54)** | 1 | 23 |
| Total Equity Method | **$11,841** | $11,338 | **$1,144** | $1,077 | $896 |
| Other at or Below Cost | **411** | 426 | | | |
| Total Investments and Advances | **$12,252** | $11,764 | | | |
| Total U.S | **$ 5,370** | $ 6,323 | **$ 693** | $ 562 | $419 |
| Total International | **$ 6,882** | $ 5,441 | **$ 451** | $ 515 | $477 |

* Placed in trust at the time of the merger and accounting changed from the equity method to the cost basis. Interests were classified as “Assets held for sale — merger related” at December 31, 2001.

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**NOTE 14. INVESTMENTS AND ADVANCES —** Continued

The following table provides summarized financial information on a 100 percent basis for Equilon, Motiva and all other equity affiliates, as well as ChevronTexaco's total share.

| | Equilon* | | | Motiva* | | |
|---|---|---|---|---|---|---|
| **YEAR ENDED DECEMBER 31** | **2001** | 2000 | 1999 | **2001** | 2000 | 1999 |
| Total revenues | **$36,501** | $50,010 | $29,398 | **$14,459** | $19,446 | $12,196 |
| Income (loss) before income tax expense | **604** | 228 | 347 | **771** | 461 | (69) |
| Net income (loss) | **397** | 148 | 226 | **486** | 300 | (45) |
| **AT DECEMBER 31** | | | | | | |
| Current assets | **$ —** | $ 3,134 | $ 3,426 | **$ —** | $ 1,381 | $ 1,271 |
| Noncurrent assets | **—** | 6,830 | 7,208 | **—** | 5,110 | 5,307 |
| Current liabilities | **—** | 4,587 | 4,853 | **—** | 1,150 | 1,278 |
| Noncurrent liabilities | **—** | 897 | 735 | **—** | 2,017 | 2,095 |
| **NET EQUITY** | **$ —** | $ 4,480 | $ 5,046 | **$ —** | $ 3,324 | $ 3,205 |

[Additional columns below]

[Continued from above table, first column(s) repeated]

| | Other Affiliates | | | ChevronTexaco Share | | |
|---|---|---|---|---|---|---|
| **YEAR ENDED DECEMBER 31** | **2001** | 2000 | 1999 | **2001** | 2000 | 1999 |
| Total revenues | **$69,549** | $56,602 | $33,772 | **$46,649** | $48,925 | $30,135 |
| Income (loss) before income tax expense | **646** | 2,420 | 1,566 | **1,430** | 1,230 | 925 |
| Net income (loss) | **(74)** | 1,689 | 1,326 | **1,144** | 1,077 | 896 |
| **AT DECEMBER 31** | | | | | | |
| Current assets | **$17,015** | $18,442 | $ 7,954 | **$ 5,922** | $ 8,456 | $ 4,992 |
| Noncurrent assets | **40,191** | 34,620 | 18,463 | **16,276** | 16,965 | 12,007 |
| Current liabilities | **14,688** | 16,109 | 7,665 | **4,757** | 7,820 | 5,615 |
| Noncurrent liabilities | **23,255** | 20,905 | 10,924 | **5,600** | 6,263 | 3,243 |
| **NET EQUITY** | **$19,263** | $16,048 | $ 7,828 | **$11,841** | $11,338 | $ 8,141 |

* Accounted for under the equity method pre-merger, and the cost basis post-merger.

**NOTE 15. PROPERTIES, PLANT AND EQUIPMENT[1]**

| | At December 31 |
|---|---|

| | Gross Investment at Cost | | | Net Investment | | |
|---|---|---|---|---|---|---|
| | **2001** | 2000 | 1999 | **2001** | 2000 | 1999 |
| Exploration and Production | | | | | | |
| United States | **$38,157** | $37,342 | $ 39,772 | **$10,560** | $12,093 | $12,773 |
| International | **33,273** | 30,396 | 29,602 | **17,743** | 16,938 | 15,725 |
| Total Exploration and Production | **71,430** | 67,738 | 69,374 | **28,303** | 29,031 | 28,498 |
| Refining, Marketing and Transportation | | | | | | |
| United States | **12,944** | 12,557 | 12,669 | **6,237** | 6,176 | 6,438 |
| International | **11,386** | 10,986 | 11,736 | **6,700** | 6,718 | 7,251 |
| Total Refining, Marketing and Transportation | **24,330** | 23,543 | 24,405 | **12,937** | 12,894 | 13,689 |
| Chemicals | | | | | | |
| United States | **602** | 610 | 3,689 | **321** | 342 | 2,354 |
| International | **698** | 672 | 714 | **405** | 395 | 453 |
| Total Chemicals | **1,300** | 1,282 | 4,403 | **726** | 737 | 2,807 |
| All Other[3] | **2,883** | 3,005 | 2,809 | **1,267** | 1,657 | 1,493 |
| Total United States | **54,529** | 53,485 | 58,922 | **18,367** | 20,275 | 23,048 |
| Total International | **45,414** | 42,083 | 42,069 | **24,866** | 24,044 | 23,439 |
| Total | **$99,943** | $95,568 | $100,991 | **$43,233** | $44,319 | $46,487 |

[Additional columns below]

[Continued from above table, first column(s) repeated]

| | Year ended December 31 | | | | | |
|---|---|---|---|---|---|---|
| | Additions at Cost[2] | | | Depreciation Expense | | |
| | **2001** | 2000 | 1999 | **2001** | 2000 | 1999 |
| Exploration and Production | | | | | | |
| United States | **$1,973** | $1,931 | $1,383 | **$3,508** | $2,138 | $1,932 |
| International | **2,900** | 3,019 | 4,934 | **2,085** | 1,787 | 1,546 |
| Total Exploration and Production | **4,873** | 4,950 | 6,317 | **5,593** | 3,925 | 3,478 |
| Refining, Marketing and Transportation | | | | | | |
| United States | **626** | 484 | 560 | **476** | 516 | 542 |
| International | **566** | 457 | 605 | **555** | 651 | 539 |
| Total Refining, Marketing and Transportation | **1,192** | 941 | 1,165 | **1,031** | 1,167 | 1,081 |
| Chemicals | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| United States | **10** | 78 | 326 | **22** | 77 | 174 |
| International | **31** | 42 | 59 | **19** | 18 | 20 |
| Total Chemicals | **41** | 120 | 385 | **41** | 95 | 194 |
| All Other[3] | **174** | 202 | 181 | **394** | 134 | 181 |
| Total United States | **2,780** | 2,695 | 2,447 | **4,391** | 2,825 | 2,824 |
| Total International | **3,500** | 3,518 | 5,601 | **2,668** | 2,496 | 2,110 |
| Total | **$6,280** | $6,213 | $8,048 | **$7,059** | $5,321 | $4,934 |

1 Net of accumulated abandonment and restoration costs of $2,155, $2,259 and $2,397 at December 31, 2001, 2000 and 1999, respectively.

2 Net of dry hole expense related to prior years' expenditures of $228, $60 and $108 in 2001, 2000 and 1999, respectively.

3 Primarily coal, real estate assets and management information systems.

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**Notes to Consolidated Financial Statements**

**Millions of dollars, except per-share amounts**

**NOTE 16. TAXES**

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| Taxes on income | | | |
| U.S. federal | | | |
| Current | **$ 946** | $1,238 | $ 307 |
| Deferred | **(643)** | 363 | 25 |
| State and local | **276** | 185 | (50) |
| Total United States | **579** | 1,786 | 282 |
| International | **3,764** | 4,378 | 2,285 |
| Current | **3,764** | 4,378 | 2,285 |
| Deferred | **17** | 158 | (2) |
| Total International | **3,781** | 4,536 | 2,283 |
| Total taxes on income | **$4,360** | $6,322 | $2,565 |

The above table does not include a current U.S. tax benefit of $2 and a U.S. deferred tax benefit of $142 associated with the extraordinary item.

In 2001, before-tax income, including related corporate and other charges, for U.S. operations was $1,778, compared with $5,823 in 2000 and $1,738 in 1999. For international operations, before-tax income was $6,513, $8,226 and $4,074 in 2001, 2000 and 1999, respectively. U.S. federal income tax expense was reduced by $202, $165 and $156 in 2001, 2000 and 1999, respectively, for business tax credits.

The company's effective income tax rate varied from the U.S. statutory federal income tax rate because of the following:

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| U.S. statutory federal income tax rate | **35.0%** | 35.0% | 35.0% |
| Effect of income taxes from international operations in excess of taxes at the U.S. statutory rate | **19.0** | 11.0 | 16.7 |
| State and local taxes on income, net of U.S. federal income tax benefit | **2.2** | 0.9 | (0.1) |
| Prior-year tax adjustments | **1.1** | (0.6) | (1.5) |
| Tax credits | **(2.4)** | (1.2) | (2.7) |
| Other | **(1.7)** | 0.2 | (2.3) |
| Consolidated companies | **53.2** | 45.3 | 45.1 |
| Effect of recording equity in income of certain affiliated companies on an after-tax basis | **(0.6)** | (0.3) | (1.0) |

| | | | |
|---|---|---|---|
| Effective tax rate | **52.6%** | **45.0%** | **44.1%** |

The increase in the 2001 effective tax rate was primarily due to U.S. before-tax income (generally subject to a lower tax rate) being a significantly smaller percentage of overall before-tax income in 2001 compared with 2000. The decline in the U.S. before-tax income arose primarily because substantially all of the 2001 merger-related expenses were associated with operations in the United States.

The company records its deferred taxes on a tax-jurisdiction basis and classifies those net amounts as current or noncurrent based on the balance sheet classification of the related assets or liabilities.

The reported deferred tax balances are composed of the following:

| | At December 31 | |
|---|---|---|
| | **2001** | 2000 |
| Deferred tax liabilities | | |
| Properties, plant and equipment | **$ 7,478** | $ 7,224 |
| Inventory | **50** | — |
| Investments and other | **1,334** | 2,085 |
| Total deferred tax liabilities | **8,862** | 9,309 |
| Deferred tax assets | | |
| Abandonment/environmental reserves | **(913)** | (862) |
| Employee benefits | **(863)** | (979) |
| Tax loss carryforwards | **(611)** | (527) |
| AMT/other tax credits | **(511)** | (943) |
| Inventory | **—** | (27) |
| Other accrued liabilities | **(158)** | (43) |
| Miscellaneous | **(2,164)** | (1,454) |
| Total deferred tax assets | **(5,220)** | (4,835) |
| Deferred tax assets valuation allowance | **1,431** | 1,574 |
| Total deferred taxes, net | **$ 5,073** | $ 6,048 |

The valuation allowance relates to foreign tax credit carryforwards, tax loss carryforwards and temporary differences that are not expected to be realized.

At December 31, 2001 and 2000, deferred taxes were classified in the Consolidated Balance Sheet as follows:

| | At December 31 | |
|---|---|---|
| | **2001** | 2000 |
| Prepaid expenses and other current assets | **$ (671)** | $ (327) |
| Deferred charges and other assets | **(399)** | (312) |
| Federal and other taxes on income | **11** | — |
| Noncurrent deferred income taxes | **6,132** | 6,687 |
| Total deferred income taxes, net | **$5,073** | $6,048 |

It is the company's policy for subsidiaries included in the U.S. consolidated tax return to record income tax expense as though they filed separately, with the parent recording the adjustment to income tax expense for the effects of consolidation. Income taxes are accrued for retained earnings of international subsidiaries and corporate joint ventures intended to be remitted. Income taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely.

Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled approximately $9,003 at December 31, 2001. Substantially all of this amount represents earnings reinvested as part of the company's ongoing business. It is not practical to estimate the amount of taxes that might be payable on the eventual remittance of such earnings. On remittance, certain countries impose withholding taxes that, subject to certain limitations, are then available for use as tax credits against a U.S. tax liability, if any.

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**NOTE 16. TAXES —** Continued

Taxes other than on income were as follows:

| | Year ended December 31 | | |
|---|---|---|---|
| | **2001** | 2000 | 1999 |
| Taxes other than on income | | | |
| United States | | | |
| Excise taxes on products and merchandise | **$ 3,954** | $ 3,909 | $ 3,767 |
| Import duties and other levies | **8** | 25 | 34 |
| Property and other miscellaneous taxes | **410** | 345 | 365 |
| Payroll taxes | **148** | 139 | 165 |
| Taxes on production | **225** | 238 | 158 |
| Total United States | **4,745** | 4,656 | 4,489 |
| International | | | |
| Excise taxes on products and merchandise | **2,592** | 2,692 | 2,262 |
| Import duties and other levies | **7,461** | 8,073 | 8,352 |
| Property and other miscellaneous taxes | **268** | 271 | 247 |
| Payroll taxes | **79** | 69 | 77 |
| Taxes on production | **11** | 66 | 14 |
| Total International | **10,411** | 11,171 | 10,952 |
| Total taxes other than on income | **$15,156** | $15,827 | $15,441 |

**NOTE 17. SHORT-TERM DEBT**

| | At December 31 | |
|---|---|---|
| | **2001** | 2000 |
| Commercial paper* | **$ 8,664** | $ 4,258 |
| Notes payable to banks and others with originating terms of one year or less | **1,036** | 1,612 |
| Current maturities of long-term debt | **1,095** | 1,519 |
| Current maturities of long-term capital leases | **45** | 42 |
| Redeemable long-term obligations | | |
| Long-term debt | **488** | 504 |
| Capital leases | **301** | 302 |
| Subtotal | **11,629** | 8,237 |
| Reclassified to long-term debt | **(3,200)** | (5,143) |
| Total short-term debt | **$ 8,429** | $ 3,094 |

* Weighted-average interest rates at December 31, 2001 and 2000, were 1.99 percent and 6.57 percent, respectively, including the effect of interest rate swaps.

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders during the year following the balance sheet date.

The company periodically enters into interest rate swaps on a portion of its short-term debt. See Note 10 for information concerning the company's debt-related derivative activities.

Utilized lines of credit available for short-term financing totaled $210 at December 31, 2001.

At December 31, 2001, the company had $3,200 of committed credit facilities with banks worldwide, which permit the company to refinance short-term obligations on a long-term basis. The facilities support the company's commercial paper borrowings. Interest on borrowings under the terms of specific agreements may be based on the London Interbank Offered Rate, the Reserve Adjusted Domestic Certificate of Deposit Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2001 or at year-end.

At December 31, 2001 and 2000, the company classified $3,200 and $5,143, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2002, as the company has both the intent and ability to refinance this debt on a long-term basis.

**NOTE 18. LONG-TERM DEBT**

ChevronTexaco has three "shelf" registrations on file with the Securities and Exchange Commission that together would permit the issuance of $2,800 of debt securities pursuant to Rule 415 of the Securities Act of 1933.

| | At December 31 | |
|---|---|---|
| | **2001** | 2000 |
| 6.625 notes due 2004 | **$ 499** | $ 499 |
| 8.11 amortizing notes due 2004 | **450** | 540 |
| 7.327 amortizing notes due 2014[1] | **430** | 430 |
| 5.5 note due 2009 | **393** | 392 |
| 7.45 notes due 2004 | **—** | 349 |
| 6 notes due 2005 | **299** | 299 |
| 9.75 debentures due 2020 | **250** | 250 |
| 3.5 convertible notes due 2004 | **—** | 203 |
| 5.7 notes due 2008 | **201** | 201 |
| 8.5 notes due 2003 | **200** | 200 |
| 7.75 debentures due 2033 | **199** | 199 |
| 8.625 debentures due 2031 | **199** | 199 |
| 8.625 debentures due 2032 | **199** | 199 |
| 8.375 debentures due 2022 | **199** | 198 |
| 7.5 debentures due 2043 | **198** | 198 |
| 6.875 debentures due 2023 | **196** | 196 |
| 7.09 notes due 2007 | **150** | 150 |
| 8.25 debentures due 2006 | **150** | 150 |
| 8.625 debentures due 2010 | **150** | 150 |

| | | |
|---|---|---|
| 8.875 debentures due 2021 | **150** | 150 |
| Medium-term notes, maturing from 2001 to 2043 (7.4%)[2] | **360** | 1,081 |
| Other foreign currency obligations (5.6)[2] | **193** | 1,095 |
| Other long-term debt (4.2)[2] | **1,534** | 1,542 |
| Total including debt due within one year | **6,599** | 8,870 |
| Debt due within one year | **(1,095)** | (1,519) |
| Reclassified from short-term debt | **3,200** | 5,143 |
| Total long-term debt | **$ 8,704** | $12,494 |

1 Guarantee of ESOP debt.

2 Less than $150 individually; weighted-average interest rates at December 31, 2001.

Consolidated long-term debt maturing after December 31, 2001, is as follows: 2002 — $1,095; 2003 — $536; 2004 — $857; 2005 — $570; and 2006 — $195; after 2006 — $3,346.

See Note 10 for information concerning the company's debt-related derivative activities.

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**NOTE 19. NEW ACCOUNTING STANDARDS**

The company adopted the Financial Accounting Standards Board (FASB) Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities — an amendment of FASB Statement No. 133," effective January 1, 2001. The adoption of FAS 133 and FAS 138 did not have a significant impact on the company's results of operations, financial position or liquidity.

Recent interpretations of FAS 133 and FAS 138 by the FASB Derivatives Implementation Group prescribe mark-to-market accounting for certain natural gas sales contracts. Some of these interpretations became effective January 1, 2002. Adoption at that time did not result in a material effect to earnings. The effect of subsequent changes in the contracts' fair values is uncertain.

In September 2000, the FASB issued Statement No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities - A Replacement of FASB Statement No. 125" (FAS 140). FAS 140 is effective for transfers occurring after March 31, 2001, and for disclosures relating to securitization transactions and collateral for fiscal years ending after December 15, 2000. Adoption of FAS 140 had no significant effect on ChevronTexaco's accounting or disclosures for the types of transactions in the scope of the new standard.

In June 2001, the FASB issued Statement No. 141, "Business Combinations" (FAS 141), Statement No. 142, "Goodwill and Other Intangible Assets" (FAS 142) and Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 141 is effective for all business combinations initiated after June 30, 2001, and for all business combinations accounted for using the purchase method for which the date of acquisition is July 1, 2001, or later. FAS 142 is effective for fiscal years beginning after December 15, 2001, except for goodwill and intangible assets acquired after June 30, 2001, which were immediately subject to the amortization and nonamortization provisions of the Statement. FAS 143 is effective for fiscal years beginning after June 15, 2002. Adoption of FAS 141 will have no effect on the company's pooling-of-interests method of accounting for the Texaco merger transaction, but will affect future transactions. Similarly, adoption of FAS 142 may affect future transactions, but is not expected to have an effect on the company's prior business combinations. FAS 143 differs in several significant respects from current accounting for asset retirements obligations under FAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." Adoption of FAS 143 will affect future accounting and reporting of the assets, liabilities and expenses related to these obligations. The magnitude of the effect has not yet been determined.

In August 2001, the FASB issued Statement No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144). FAS 144 is effective for fiscal years beginning after December 15, 2001, with initial application effective as of the beginning of the fiscal year adopted. Adoption of FAS 144 will not affect assets classified as held for disposal as a result of disposal activities that were initiated prior to its initial application, but may affect future disposals.

**NOTE 20. EMPLOYEE BENEFIT PLANS**

**Pension Plans and Other Postretirement Benefits** The company has defined benefit pension plans for most employees and provides for certain health care and life insurance plans for active and qualifying retired employees. For the pension plans, the company is required to satisfy the Employee Retirement Income Security Act minimum funding standard. The company's annual contributions for medical and dental benefits are limited to the lesser of actual medical and dental claims or a defined fixed per-capita amount. Life insurance benefits are paid by the company, and annual contributions are based on actual plan experience. Unfunded pension and postretirement benefits are paid directly when incurred; accordingly, these payments are not reflected as changes in plan assets in the following table.

The status of the company's pension plans and other postretirement benefit plans for 2001 and 2000 is as follows:

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**NOTE 20. EMPLOYEE BENEFIT PLANS —** Continued

| | Pension Benefits | | | | | |
|---|---|---|---|---|---|---|
| | **2001** | | 2000 | | Other Benefits | |
| | U.S. | Int'l. | U.S. | Int'l. | **2001** | 2000 |
| **CHANGE IN BENEFIT OBLIGATION** | | | | | | |
| Benefit obligation at January 1 | **$4,977** | **$1,736** | $5,070 | $1,737 | **$ 2,247** | $ 2,103 |
| Service cost | **111** | **47** | 118 | 47 | **21** | 20 |
| Interest cost | **355** | **136** | 363 | 133 | **165** | 161 |
| Plan participants' contributions | **2** | **2** | 2 | 1 | **—** | 18 |
| Plan amendments | **12** | **13** | 7 | 3 | **(10)** | — |
| Actuarial loss | **341** | **108** | 77 | 84 | **244** | 134 |
| Foreign currency exchange rate changes | **—** | **(94)** | — | (151) | **(9)** | (7) |
| Benefits paid | **(532)** | **(110)** | (659) | (121) | **(158)** | (182) |
| Curtailment | **(47)** | **—** | — | (3) | **(3)** | — |
| Special termination benefits[1] | **47** | **14** | — | 6 | **29** | — |
| Plan divestiture | **—** | **(4)** | (1) | — | **—** | — |
| Acquisitions/joint ventures | **(86)** | — | — | — | **—** | — |
| Benefit obligation at December 31 | **5,180** | **1,848** | 4,977 | 1,736 | **2,526** | 2,247 |
| **CHANGE IN PLAN ASSETS** | | | | | | |
| Fair value of plan assets at January 1 | **5,098** | **1,757** | 5,685 | 1,914 | **—** | — |
| Actual return on plan assets | **(221)** | **(90)** | 27 | 71 | **—** | — |
| Foreign currency exchange rate changes | **—** | **(56)** | — | (155) | **—** | — |
| Employer contribution | **2** | **26** | 21 | 47 | **—** | — |
| Plan participants' contributions | **2** | **2** | 2 | 1 | **—** | — |
| Expenses | **(6)** | **—** | (8) | — | **—** | — |
| Benefits paid | **(475)** | **(88)** | (623) | (125) | **—** | — |
| Plan divestiture | **—** | **(4)** | (2) | — | **—** | — |
| Curtailment | **—** | **—** | (4) | 4 | **—** | — |
| Fair value of plan assets at December 31 | **4,400** | **1,547** | 5,098 | 1,757 | **—** | — |
| **FUNDED STATUS** | **(780)** | **(301)** | 121 | 21 | **(2,526)** | (2,247) |
| Unrecognized net actuarial loss (gain) | **837** | **493** | (29) | 161 | **93** | (145) |
| Unrecognized prior-service cost | **129** | **70** | 185 | 75 | **(24)** | (7) |
| Unrecognized net transitional assets | **—** | **(7)** | (2) | (12) | **—** | — |
| Total recognized at December 31 | **$ 186** | **$ 255** | $ 275 | $ 245 | **$(2,457)** | $(2,399) |
| **AMOUNTS RECOGNIZED IN THE CONSOLIDATED BALANCE SHEET AT DECEMBER 31** | | | | | | |
| Prepaid benefit cost | **$ 568** | **$ 574** | $ 560 | $ 557 | **$ —** | $ — |
| Accrued benefit liability | **(529)** | **(334)** | (438) | (330) | **(2,457)** | (2,399) |
| Intangible asset | **10** | **12** | 10 | 12 | **—** | — |
| Accumulated other comprehensive income[2] | **137** | **3** | 143 | 6 | **—** | — |

| | | | | | | |
|---|---|---|---|---|---|---|
| Net amount recognized | **$ 186** | **$ 255** | $ 275 | $ 245 | **$(2,457)** | $(2,399) |
| Weighted-average assumptions as of December 31 Discount rate | **7.3%** | **7.7%** | 7.5% | 7.8% | **7.3%** | 7.6% |
| Expected return on plan assets | **8.8%** | **8.9%** | 10.0% | 9.1% | **—** | — |
| Rate of compensation increase | **4.0%** | **5.4%** | 4.1% | 5.0% | **4.1%** | 4.4% |

1 Primarily relates to a special involuntary termination enhancement to pension and postretirement benefits under the Texaco change-in-control program in 2001.

2 Accumulated other comprehensive income includes deferred income taxes of $48 and $1 in 2001 for U.S. and International, respectively, and $47 and $2 in 2000 for U.S. and International, respectively.

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**Notes to Consolidated Financial Statements**

**Millions of dollars, except per-share amounts**

**NOTE 20. EMPLOYEE BENEFIT PLANS —** Continued

The components of net periodic benefit cost for 2001, 2000 and 1999 were:

| | Pension Benefits | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2001** | | 2000 | | 1999 | | Other Benefits | | |
| | U.S. | Int'l. | U.S. | Int'l. | U.S. | Int'l. | **2001** | 2000 | 1999 |
| Service cost | **$ 111** | **$ 47** | $ 118 | $ 47 | $ 134 | $ 46 | **$ 21** | $ 20 | $ 28 |
| Interest cost | **355** | **136** | 363 | 133 | 350 | 137 | **165** | 161 | 153 |
| Expected return on plan assets | **(443)** | **(170)** | (503) | (167) | (491) | (146) | **—** | — | — |
| Amortization of transitional assets | **(2)** | **(4)** | (31) | (6) | (36) | (17) | **—** | — | — |
| Amortization of prior-service costs | **25** | **12** | 30 | 12 | 27 | 16 | **(1)** | (1) | — |
| Recognized actuarial losses (gains) | **13** | **7** | 10 | (2) | 3 | (2) | **(6)** | (10) | 1 |
| Settlement losses (gains) | **12** | **—** | (61) | 1 | (103) | 1 | **—** | — | — |
| Curtailment losses (gains) | **26** | **—** | (20) | 2 | 6 | 1 | **20** | (15) | (12) |
| Special termination benefit recognition* | **47** | **14** | — | 6 | 205 | 2 | **29** | — | — |
| Net periodic benefit cost | **$ 144** | **$ 42** | $ (94) | $ 26 | $ 95 | $ 38 | **$228** | $155 | $170 |

* Primarily relates to a special involuntary termination enhancement to pension and postretirement benefits under the Texaco change-in-control program in 2001 and a special involuntary termination enhancement to pension benefits in 1999 under a Chevron companywide restructuring program.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were $2,496, $2,187 and $1,269, respectively, at December 31, 2001, and $850, $737 and $33, respectively, at December 31, 2000.

For postretirement benefit measurement purposes, one set of health care cost-trend rates was used for pre-age 65 and post-age 65 retirees. Starting in 2002, with approximately an 11 percent cost increase over the previous year, the trend rates gradually drop to the ultimate rate of 4.5 percent over 5 years. A one-percentage-point change in the assumed health care cost-trend rates would have had the following effects:

| | One Percent Increase | One Percent Decrease |
|---|---|---|
| Effect on total service and interest cost components | $ 20 | $ (20) |
| Effect on postretirement benefit obligation | $231 | $(193) |

**Profit Sharing/Savings** Plan Eligible employees of ChevronTexaco and certain of its subsidiaries participate in either the Chevron Profit Sharing/Savings Plan or the Employees Thrift Plan of Texaco. Charges to expense for these plans were $157, $63 and $64 in 2001, 2000 and 1999, respectively.

**Employee Stock Ownership Plans (ESOP)** In December 1989, Chevron established a leveraged ESOP as part of the Profit Sharing/Savings Plan. The ESOP provides a partial prefunding of the company's future commitments to the Profit Sharing/ Savings Plan, which will result in annual income tax savings for the company.

In 1988, Texaco established a leveraged ESOP as part of the Employees Thrift Plan of Texaco Inc. The Thrift Plan ESOP loan was satisfied in December 2000. The ESOP was designed to provide participants with a benefit of approximately 6 percent of base pay.

As permitted by American Institute of Certified Public Accountants (AICPA) Statement of Position 93-6, “Employers’ Accounting for Employee Stock Ownership Plans,” the company has elected to continue its practices, which are based on Statement of Position 76-3, “Accounting Practices for Certain Employee Stock Ownership Plans,” and subsequent consensus of the Emerging Issues Task Force of the Financial Accounting Standards Board. The debt of the ESOPs is recorded as debt, and shares pledged as collateral are reported as “Deferred compensation and benefit plan trust” in the Consolidated Balance Sheet and the Consolidated Statement of Stockholders’ Equity. The company reports compensation expense equal to ESOP debt principal repayments less dividends received by the ESOPs. Interest incurred on the ESOP debt is recorded as interest expense. Dividends paid on ESOP shares are reflected as a reduction of retained earnings. All ESOP shares are considered outstanding for earnings-per-share computations.

Expense recorded for the ESOPs was $75, $26 and $62 in 2001, 2000 and 1999, respectively, including $62, $48 and $51 of interest expense related to ESOP debt. All dividends paid on the ESOP shares held are used to service the ESOP debt. The dividends used were $86, $77 and $63 in 2001, 2000 and 1999, respectively.

The company made ESOP contributions of $75, $1 and $67 in 2001, 2000 and 1999, respectively, to satisfy ESOP debt service in excess of dividends received by the ESOP. The ESOP shares were pledged as collateral for the debt. Shares are released from a suspense account and allocated to the accounts of plan participants, based on the debt service deemed to be paid in the year in proportion to the total of current-year and remaining debt service. The charge (credit) to compensation expense was $13, $(22) and $11 in 2001, 2000 and 1999, respectively. ESOP shares

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**NOTE 20. EMPLOYEE BENEFIT PLANS —** Continued

as of December 31, 2001 and 2000, were as follows:

| Thousands | **2001** | 2000 |
|---|---|---|
| Allocated shares | **21,790** | 23,706 |
| Unallocated shares | **8,836** | 10,877 |
| Total ESOP shares | **30,626** | 34,583 |

**Benefit Plan Trust** Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2001, the trust contained 7.1 million shares of ChevronTexaco treasury stock. The company intends to continue to pay its obligations under the benefit plans. The trust will use the shares, proceeds from the sale of such shares and dividends on such shares to pay benefits only to the extent that the company does not pay such benefits. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held by the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

**Management Incentive Plans** Chevron had two incentive plans, the Management Incentive Plan (MIP) and the Long-Term Incentive Plan (LTIP) for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. The plans will be expanded to include former employees of Texaco and Caltex. The MIP is an annual cash incentive plan that links awards to performance results of the prior year. The cash awards may be deferred by conversion to stock units or other investment fund alternatives. Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, stock units and nonstock grants. Texaco also had a cash incentive program and a Stock Incentive Plan (SIP) that included stock options, restricted stock and other incentive awards for executives, directors and key employees. Awards under the Caltex LTIP were in the form of performance units and stock appreciation rights. Charges to expense for the combined management incentive plans, excluding expense related to LTIP and SIP stock options and restricted stock awards, which are discussed in Note 21, were $93, $83 and $54 in 2001, 2000 and 1999, respectively.

**Other Incentive Plans** Chevron had a program that provided eligible employees with an annual cash bonus if the company achieved certain financial and safety goals. The program was expanded to include former employees of Texaco and Caltex post-merger. Texaco and Caltex also had similar programs. Charges for the combined programs were $154, $230 and $60 in 2001, 2000 and 1999, respectively.

**NOTE 21. STOCK OPTIONS**

The company applies APB Opinion No. 25 and related interpretations in accounting for its stock-based compensation programs, which are described below. Stock-based compensation expense recognized in connection with these programs was $111, $23 and $21 in 2001, 2000 and 1999, respectively.

Had compensation cost for the company's combined stock options been determined based on the fair market value at the grant dates of the awards consistent with the methodology prescribed by FAS No. 123, net income and earnings per share for 2001, 2000 and 1999 would have been the pro forma amounts shown on the following table:

| | **2001** | 2000 | 1999 |
|---|---|---|---|
| Net income | | | |
| As reported | **$3,288** | $7,727 | $3,247 |
| Pro forma | **$3,202** | $7,687 | $3,134 |
| Earnings per share | | | |
| As reported — basic | **$ 3.10** | $ 7.23 | $ 3.01 |
| — diluted | **$ 3.09** | $ 7.21 | $ 3.00 |
| Pro forma — basic | **$ 3.02** | $ 7.19 | $ 2.91 |

| | | | |
|---|---|---|---|
| — diluted | **$ 3.01** | $ 7.18 | $ 2.90 |

The effects of applying FAS No. 123 in this pro forma disclosure are not indicative of future amounts. FAS No. 123 does not apply to awards granted prior to 1995. In addition, certain options vest over several years, and awards in future years, whose terms and conditions may vary, are anticipated.

**Broad-Based Employee Stock Options** In 1996, Chevron granted to all its eligible employees an option for 150 shares of stock or equivalents at an exercise price of $51.875 per share. In addition, a portion of the awards granted under the LTIP had terms similar to the broad-based employee stock options. The options vested in June 1997.

Options for 7,204,800 shares, including similar-termed LTIP awards, were granted for this program in 1996, and the program expired in 1999.

In 1998, Chevron announced another broad-based Employee Stock Option Program that granted to all eligible employees an option that varied from 100 to 300 shares of stock or equivalents, dependent on the employee's salary or job grade. These options vested after two years in February 2000. Options for 4,820,800 shares were awarded at an exercise price of $76.3125 per share. Outstanding option shares were 3,064,367 at year-end 2000. In 2001, exercises of 653,096 and forfeitures of 44,960 reduced the outstanding option shares to 2,366,311 at the end of the year. The options expire February 11, 2008. The company recorded expenses of $1, $(2) and $4 for these options in 2001, 2000 and 1999, respectively.

The fair value of each option share for the 1998 program on the date of grant under FAS No. 123 was estimated at $19.08 using the average results of Black-Scholes models for the preceding 10 years. The 10-year averages of each assumption used by the Black-Scholes models were: a risk-free interest rate of 7.0 percent, a dividend yield of 4.2 percent, an expected life of seven years and a volatility of 24.7 percent.

**Long-Term Incentive Plan** Stock options granted under the LTIP are generally awarded at market price on the date of grant and are exercisable not earlier than one year and not later than 10 years from the date of grant. However, a portion of the LTIP options granted in 1996 had terms similar to the broad-based employee stock options. The maximum number of shares that may be granted each year is 1 percent of the total outstanding shares of common stock as of January 1 of such year.

Under the Texaco Stock Incentive Plan (SIP), the maximum number of shares that were granted as stock options or restricted stock was 1 percent of the common stock outstanding on December 31 of the previous year. Restricted shares granted under SIP

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**NOTE 21. STOCK OPTIONS —** Continued

contained a performance element, which had to be satisfied in order for all or a specified portion of the shares to vest. Upon the merger, all restricted shares became vested and converted to ChevronTexaco shares at the merger exchange ratio of 0.77. Restricted performance shares awarded in each year under the SIP on a converted basis were as follows:

| | **2001** | 2000 | 1999 |
|---|---|---|---|
| Shares (thousands) | **392** | 409 | 214 |
| Weighted-average fair value | **$91.05** | $73.40 | $81.53 |

Stock options granted under the SIP extend for 10 years from the date of grant and vest over a two-year period at a rate of 50 percent in the first year and 50 percent in the second year. The exercise price cannot be less than the fair market value of the underlying shares of common stock on the date of the grant. The plan provides for restored options. This feature enables a participant who exercises a stock option by exchanging previously acquired common stock or who has shares withheld to satisfy tax withholding obligations to receive new options equal to the number of shares exchanged or withheld. The restored options are fully exercisable six months after the date of grant and the exercise price is the fair market value of the common stock on the day the restored option is granted. Amounts charged to compensation expense in 2001, 2000 and 1999 were $110, $25 and $19.

The fair market value of each stock option granted is estimated on the date of grant under FAS No. 123 using the Black-Scholes option-pricing model with the following weighted-average assumptions:

| | **2001** | 2000 | 1999 |
|---|---|---|---|
| Chevron Plans: | | | |
| Expected life in years | **7** | 7 | 7 |
| Risk-free interest rate | **4.1%** | 5.8% | 5.5% |
| Volatility | **24.4%** | 25.6% | 20.1% |
| Dividend yield | **3.0%** | 3.0% | 3.0% |
| Texaco Plans: | | | |
| Expected life in years | **2** | 2 | 2 |
| Risk-free interest rate | **3.9%** | 6.4% | 5.4% |
| Volatility | **25.9%** | 33.8% | 29.1% |
| Dividend yield | **3.1%** | 3.0% | 3.0% |

The Black-Scholes weighted-average fair value of the Chevron options granted during 2001, 2000 and 1999 was $20.45, $22.34 and $20.40 per share, respectively, and the weighted-average fair value of the Texaco options granted during 2001, 2000 and 1999 was $12.90, $11.56 and $11.21 per share.

Upon the merger, outstanding Texaco stock options were converted to ChevronTexaco options at the merger exchange rate of 0.77. The following table presents the combined stock options outstanding as of December 31, 2001, 2000 and 1999, with information on Texaco's stock options on a converted basis. This table excludes Chevron LTIP awards granted with terms similar to the broad-based employee stock options:

| | Options (thousands) | Weighted-Average Exercise Price |
|---|---|---|

| | | |
|---|---|---|
| Outstanding at December 31, 1998 | 18,167 | $67.94 |
| Granted | 3,388 | 86.05 |
| Exercised | (7,584) | 71.35 |
| Restored | 5,735 | 83.83 |
| Forfeited | (783) | 83.62 |
| Outstanding at December 31, 1999 | 18,923 | $73.99 |
| Granted | 3,763 | 77.18 |
| Exercised | (1,460) | 53.99 |
| Restored | 456 | 78.42 |
| Forfeited | (812) | 84.18 |
| Outstanding at December 31, 2000 | 20,870 | $75.67 |
| Granted | 3,777 | 89.84 |
| Exercised | (8,209) | 78.16 |
| Restored | 6,766 | 89.77 |
| Forfeited | (584) | $85.76 |
| Outstanding at December 31, 2001 | 22,620 | $81.13 |
| Exercisable at December 31 | | |
| 1999 | 12,735 | $68.87 |
| 2000 | 16,021 | $74.95 |
| 2001 | 19,028 | $79.64 |

The following table summarizes information on stock options outstanding at December 31, 2001:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number Outstanding (Thousands) | Weighted-Average Remaining Contractual Life (Years) | Weighted-Average Exercise Price | Number Exercisable (Thousands) | Weighted-Average Exercise Price |
| $31 to $41 | 153 | 0.5 | $34.43 | 153 | $34.43 |
| 41 to 51 | 2,057 | 2.8 | 45.48 | 2,057 | 45.48 |
| 51 to 61 | 51 | 5.2 | 56.34 | 51 | 56.34 |
| 61 to 71 | 739 | 4.8 | 66.28 | 734 | 66.27 |
| 71 to 81 | 4,871 | 6.4 | 78.96 | 4,871 | 78.96 |
| 81 to 91 | 10,973 | 7.0 | 86.80 | 7,981 | 86.34 |
| 91 to 101 | 3,776 | 7.4 | 91.81 | 3,181 | 91.62 |
| $31 to $101 | 22,620 | 6.4 | $81.13 | 19,028 | $79.64 |

**NOTE 22. OTHER CONTINGENCIES AND COMMITMENTS**

The U.S. federal income tax liabilities have been settled through 1993 for Chevron and Caltex and through 1991 for Texaco. The company's California franchise tax liabilities have been settled through 1991 for Chevron and 1987 for Texaco.

Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all open years.

At December 31, 2001, the company and its subsidiaries, as direct or indirect guarantors, had contingent liabilities of $1,118 for notes of affiliated companies and $742 for notes of others. Following the February 2002 disposition of the interests in

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**NOTE 22. OTHER CONTINGENCIES AND COMMITMENTS** – Continued

Equilon and Motiva, contingent liabilities for notes of affiliated companies were reduced by $432.

The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, throughput agreements and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The aggregate amounts of required payments under these various commitments are 2002 – $1,370; 2003 – $1,402; 2004 – $1,302; 2005 – $1,179; 2006 – $1,094; 2007 and after – $1,311. Total payments under the agreements were $1,509 in 2001, $1,506 in 2000 and $1,165 in 1999.

The company has commitments related to preferred shares of subsidiary companies, which are accounted for as minority interest. MVP Production Inc., a subsidiary, has variable rate cumulative preferred shares of $75 owned by one minority holder. The shares are voting and are redeemable in 2003. Dividends on these shares were $4 in 2001, 2000 and 1999. Texaco Capital LLC, a wholly owned finance subsidiary, has issued $65 of Deferred Preferred Shares, Series C. Dividends amounting to $59 on Series C, at a rate of 7.17 percent compounded annually, will be paid at the redemption date of February 28, 2005, unless earlier redemption occurs. Early redemption may result upon the occurrence of certain specific events.

ChevronTexaco provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell Oil and Saudi Refining Inc. as part of the agreement for the sale of the company's interests in those investments. Generally, the indemnities provided are limited to contingent liabilities that may become actual liabilities within 18 months of the sale of the company's interests, and are reduced by any reserves that were established prior to the sale. Excluding environmental liabilities, the company's financial exposure related to those indemnities is limited to $300. Additionally, the company has provided indemnities for certain environmental liabilities arising out of conditions that existed prior to the formation of Equilon and Motiva and during the periods of ChevronTexaco's ownership interest in those entities as well as for customary representations and warranties within the agreements.

The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemical or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including but not limited to: Superfund sites and refineries, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold. The amount of such future cost is indeterminable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. While the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemicals concerns.

ChevronTexaco receives claims from, and submits claims to, customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers, and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its commodities and other derivatives activities, including forward exchange contracts and interest rate swaps. However, the results of operations and the financial position of certain equity affiliates may be affected by their business activities involving the use of derivative instruments.

The company's operations, particularly exploration and production, can be affected by other changing economic, regulatory and political environments in the various countries in which it operates, including the United States. In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results, and are carefully considered by management when evaluating the level of current and future activity in such countries.

For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated oil and gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for ChevronTexaco's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills in California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. ChevronTexaco currently estimates its maximum possible net before-tax liability at less than $400. At the same time, a possible maximum net amount that could be owed to ChevronTexaco is estimated at more than $200. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Areas in which the company and its affiliates have significant operations include the United States of America, Canada, Australia, the United Kingdom, Norway, Denmark, Kuwait, Republic of Congo, Angola, Nigeria, Chad, Equatorial Guinea, Democratic Republic of Congo, South Africa, Indonesia, Papua New Guinea, the Philippines, Singapore, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad and Korea. The company's Tengizchevroil affiliate operates in Kazakhstan. The company's Chevron Phillips Chemical Company LLC affiliate manufactures and markets a wide range of petrochemicals and plastics on a worldwide basis, with manufacturing facilities in existence or under construction in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium. The company's Dynegy affiliate has operations in the United States, Canada, the United Kingdom and other European countries.

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**Notes to Consolidated Financial Statements**

**Millions of dollars, except per-share amounts**

**NOTE 23. EARNINGS PER SHARE (EPS)**

Basic EPS includes the effects of deferrals of salary and other compensation awards that are invested in ChevronTexaco stock units by certain officers and employees of the company and is based upon net income less preferred stock dividend requirements. Diluted EPS includes the effects of these deferrals as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (see Note 21, "Stock Options"). The following table sets forth the computation of basic and diluted EPS:

| | **2001** | | | 2000 | | | 1999 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Net Income | Shares (millions) | Per-Share Amount | Net Income | Shares (millions) | Per-Share Amount | Net Income | Shares (millions) | Per-Share Amount |
| Net income | **$3,288** | | | $7,727 | | | $3,247 | | |
| Weighted-average common shares outstanding | | **1,059.3** | | | 1,066.6 | | | 1,067.7 | |
| Dividend equivalents paid on Chevron stock units | **2** | | | 2 | | | 3 | | |
| Deferred awards held as Chevron stock units | | **0.8** | | | 0.9 | | | 1.1 | |
| Preferred stock dividends | **(6)** | | | (15) | | | (29) | | |
| **BASIC EPS COMPUTATION** | **$3,284** | **1,060.1** | **$3.10** | $7,714 | 1,067.5 | $7.23 | $3,221 | 1,068.8 | $3.01 |
| Dilutive effects of stock options, restricted stock and convertible debentures | **4** | **2.8** | | 3 | 2.4 | | 3 | 4.8 | |
| **DILUTED EPS COMPUTATION** | **$3,288** | **1,062.9** | **$3.09** | $7,717 | 1,069.9 | $7.21 | $3,224 | 1,073.6 | $3.00 |

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## Quarterly Results and Stock Market Data

| Unaudited | 2001 | | | | 2000 | | | |
|---|---|---|---|---|---|---|---|---|
| Millions of dollars, except per-share amounts | **4TH Q** | **3RD Q** | **2ND Q** | **1ST Q** | 4TH Q | 3RD Q | 2ND Q | 1ST Q |
| **REVENUES AND OTHER INCOME** | | | | | | | | |
| Sales and other operating revenues[1] | **$21,239** | **$25,954** | **$28,597** | **$28,619** | $31,981 | $30,379 | $28,695 | $26,040 |
| (Loss) income from equity affiliates | **(38)** | **320** | **574** | **288** | 139 | 427 | 245 | 266 |
| Other income | **259** | **217** | **89** | **127** | 238 | 384 | 149 | 187 |
| **TOTAL REVENUES AND OTHER INCOME** | **21,460** | **26,491** | **29,260** | **29,034** | 32,358 | 31,190 | 29,089 | 26,493 |
| **COSTS AND OTHER DEDUCTIONS** | | | | | | | | |
| Purchased crude oil and products, operating and other expenses | **15,632** | **18,348** | **19,834** | **19,408** | 22,610 | 21,837 | 20,197 | 18,068 |
| Depreciation, depletion and amortization | **3,562** | **1,172** | **1,168** | **1,157** | 1,529 | 1,292 | 1,227 | 1,273 |
| Taxes other than on income[1] | **3,557** | **3,702** | **3,940** | **3,957** | 4,311 | 3,530 | 4,058 | 3,928 |
| Merger-related expenses | **1,407** | **83** | **48** | **25** | – | – | – | – |
| Minority interests | **32** | **17** | **34** | **38** | 28 | 29 | 27 | 27 |
| Interest and debt expense | **171** | **186** | **217** | **259** | 267 | 263 | 284 | 296 |
| **TOTAL COSTS AND OTHER DEDUCTIONS** | **24,361** | **23,508** | **25,241** | **24,844** | 28,745 | 26,951 | 25,793 | 23,592 |
| **(LOSS) INCOME BEFORE INCOME TAX** | **(2,901)** | **2,983** | **4,019** | **4,190** | 3,613 | 4,239 | 3,296 | 2,901 |
| **INCOME TAX (CREDIT) EXPENSE** | **(526)** | **1,219** | **1,910** | **1,757** | 1,574 | 1,910 | 1,555 | 1,283 |
| **NET (LOSS) INCOME BEFORE EXTRAORDINARY ITEM** | **$ (2,375)** | **$ 1,764** | **$ 2,109** | **$ 2,433** | $ 2,039 | $ 2,329 | $ 1,741 | $ 1,618 |
| **EXTRAORDINARY LOSS, NET OF INCOME TAX** | **(147)** | **(496)** | **–** | **–** | – | – | – | – |
| **NET (LOSS) INCOME[2]** | **$ (2,522)** | **$ 1,268** | **$ 2,109** | **$ 2,433** | $ 2,039 | $ 2,329 | $ 1,741 | $ 1,618 |
| **NET (LOSS) INCOME PER SHARE BEFORE EXTRAORDINARY ITEM – BASIC** | **$ (2.24)** | **$ 1.66** | **$ 1.99** | **$ 2.30** | $ 1.93 | $ 2.18 | $ 1.62 | $ 1.50 |
| **– DILUTED** | **$ (2.24)** | **$ 1.66** | **$ 1.99** | **$ 2.29** | $ 1.92 | $ 2.17 | $ 1.62 | $ 1.50 |
| **NET (LOSS) INCOME PER SHARE – BASIC** | **$ (2.38)** | **$ 1.19** | **$ 1.99** | **$ 2.30** | $ 1.93 | $ 2.18 | $ 1.62 | $ 1.50 |
| **– DILUTED** | **$ (2.38)** | **$ 1.19** | **$ 1.99** | **$ 2.29** | $ 1.92 | $ 2.17 | $ 1.62 | $ 1.50 |
| **DIVIDENDS PAID PER SHARE[3]** | **$ 0.70** | **$ 0.65** | **$ 0.65** | **$ 0.65** | $ 0.65 | $ 0.65 | $ 0.65 | $ 0.65 |
| **COMMON STOCK PRICE RANGE – HIGH** | **$ 93.77** | **$ 93.61** | **$ 98.49** | **$ 93.45** | $ 88.94 | $ 92.31 | $ 94.88 | $ 94.25 |
| **– LOW** | **$ 82.00** | **$ 78.60** | **$ 84.59** | **$ 78.44** | $ 78.19 | $ 76.88 | $ 82.31 | $ 69.94 |
| [1] Includes consumer excise taxes: | **$ 1,634** | **$ 1,359** | **$ 1,771** | **$ 1,782** | $ 1,769 | $ 1,585 | $ 1,679 | $ 1,568 |
| [2] Net (charges) credits for special items and merger effects included in net (loss) income: | **$ (3,021)** | **$ (416)** | **$ (64)** | **$ (21)** | $ (254) | $ (81) | $ 40 | $ (83) |
| [3] Chevron dividend pre-merger | | | | | | | | |

In accordance with pooling-of-interests accounting, the quarterly results in the preceding table give retroactive effect to the merger, with all periods presented as if Chevron and Texaco had always been combined.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX) and on the Pacific Exchange. As of March 8, 2002, stockholders of record numbered approximately 250,000. Through October 9, 2001, the common stock traded under the name of Chevron Corporation (trading symbol: CHV).

There are no restrictions on the company's ability to pay dividends.

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## Five-Year Financial Summary

| Millions of dollars, except per-share amounts | **2001** | 2000 | 1999 | 1998 | 1997 |
|---|---|---|---|---|---|
| **COMBINED STATEMENT OF INCOME DATA** | | | | | |
| **REVENUES AND OTHER INCOME** | | | | | |
| Total sales and other operating revenues | **$104,409** | $117,095 | $84,004 | $71,937 | $ 99,964 |
| Income from equity affiliates and other income | **1,836** | 2,035 | 1,709 | 1,321 | 2,347 |
| **TOTAL REVENUES AND OTHER INCOME** | **106,245** | 119,130 | 85,713 | 73,258 | 102,311 |
| **TOTAL COSTS AND OTHER DEDUCTIONS** | **97,954** | 105,081 | 79,901 | 70,422 | 93,118 |
| **INCOME BEFORE INCOME TAXES** | **8,291** | 14,049 | 5,812 | 2,836 | 9,193 |
| **INCOME TAX EXPENSE** | **4,360** | 6,322 | 2,565 | 919 | 3,273 |
| **INCOME BEFORE EXTRAORDINARY ITEM** | **$ 3,931** | $ 7,727 | $ 3,247 | $ 1,917 | $ 5,920 |
| **EXTRAORDINARY LOSS, NET OF INCOME TAX** | **(643)** | – | – | – | – |
| **NET INCOME** | **$ 3,288** | $ 7,727 | $ 3,247 | $ 1,917 | $ 5,920 |
| **NET INCOME PER SHARE BEFORE EXTRAORDINARY ITEM – BASIC** | **$ 3.71** | $ 7.23 | $ 3.01 | $ 1.76 | $ 5.54 |
| **– DILUTED** | **$ 3.70** | $ 7.21 | $ 3.00 | $ 1.75 | $ 5.48 |
| **NET INCOME PER SHARE – BASIC** | **$ 3.10** | $ 7.23 | $ 3.01 | $ 1.76 | $ 5.54 |
| **– DILUTED** | **$ 3.09** | $ 7.21 | $ 3.00 | $ 1.75 | $ 5.48 |
| **CASH DIVIDENDS PER SHARE*** | **$ 2.65** | $ 2.60 | $ 2.48 | $ 2.44 | $ 2.28 |
| **COMBINED BALANCE SHEET DATA (AT DECEMBER 31)** | | | | | |
| Current assets | **$ 18,327** | $ 17,913 | $17,043 | $14,157 | $ 16,161 |
| Noncurrent assets | **59,245** | 59,708 | 58,337 | 55,967 | 53,699 |
| **Total assets** | **77,572** | 77,621 | 75,380 | 70,124 | 69,860 |
| Short-term debt | **8,429** | 3,094 | 6,063 | 5,579 | 4,076 |
| Other current liabilities | **12,225** | 13,567 | 11,620 | 9,480 | 11,520 |
| Long-term debt and capital lease obligations | **8,989** | 12,821 | 13,145 | 11,675 | 10,708 |
| Other noncurrent liabilities | **13,971** | 14,770 | 14,761 | 14,523 | 13,318 |
| **Total liabilities** | **43,614** | 44,252 | 45,589 | 41,257 | 39,622 |
| **Stockholders' equity** | **$ 33,958** | $ 33,369 | $29,791 | $28,867 | $ 30,238 |

* Chevron dividend pre-merger.

## Supplemental Information on Oil and Gas Producing Activities

Unaudited

In accordance with Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities" (FAS 69), this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables V through VII present information on the company's estimated net proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves, and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Nigeria, Angola, Chad, Congo and Democratic Republic of Congo. The Asia-Pacific geographic area includes activities principally in Australia, China, Indonesia, Kazakhstan, Kuwait, Papua

New Guinea, Philippines and Thailand. The “Other” geographic category includes activities in the United Kingdom, Canada, Denmark, Netherlands, Norway, Trinidad, Colombia, Venezuela, Brazil, Argentina and other countries. Amounts shown for affiliated companies are ChevronTexaco’s 50 percent equity share of Tengizchevroil (TCO), an exploration and production partnership operating in the Republic of Kazakhstan, and a 30 percent equity share of Hamaca, an exploration and production partnership operating in Venezuela, beginning in 2000. The company increased its ownership in TCO from 45 percent to 50 percent in January 2001.

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## TABLE I – COSTS INCURRED IN EXPLORATION, PROPERTY ACQUISITIONS AND DEVELOPMENT[1]

| | Consolidated Companies | | | | | Affiliated Companies | | |
|---|---|---|---|---|---|---|---|---|
| Millions of dollars | U.S. | Africa | Asia-Pacific | Other | Total | TCO[2] | Hamaca | Worldwide |
| **YEAR ENDED DECEMBER 31, 2001** | | | | | | | | |
| Exploration | | | | | | | | |
| Wells | **$ 620** | **$172** | **$ 186** | **$ 197** | **$1,175** | **$ –** | **$ –** | **$1,175** |
| Geological and geophysical | **46** | **35** | **42** | **65** | **188** | **–** | **–** | **188** |
| Rentals and other | **65** | **48** | **15** | **98** | **226** | **–** | **–** | **226** |
| Total exploration | **731** | **255** | **243** | **360** | **1,589** | **–** | **–** | **1,589** |
| Property acquisitions[3] | | | | | | | | |
| Proved[4] | **25** | **4** | **–** | **–** | **29** | **362** | **–** | **391** |
| Unproved | **50** | **38** | **12** | **–** | **100** | **108** | **–** | **208** |
| Total property acquisitions | **75** | **42** | **12** | **–** | **129** | **470** | **–** | **599** |
| Development | **1,754** | **551** | **1,168** | **494** | **3,967** | **266** | **275** | **4,508** |
| **TOTAL COSTS INCURRED** | **$2,560** | **$848** | **$1,423** | **$ 854** | **$5,685** | **$736** | **$275** | **$6,696** |
| **YEAR ENDED DECEMBER 31, 2000** | | | | | | | | |
| Exploration | | | | | | | | |
| Wells | $ 526 | $139 | $ 179 | $ 63 | $ 907 | $ – | $ – | $ 907 |
| Geological and geophysical | 60 | 35 | 67 | 105 | 267 | – | – | 267 |
| Rentals and other | 73 | 43 | 55 | 83 | 254 | – | – | 254 |
| Total exploration | 659 | 217 | 301 | 251 | 1,428 | – | – | 1,428 |
| Property acquisitions[3] | | | | | | | | |
| Proved[4] | 162 | 1 | 278 | 1 | 442 | – | – | 442 |
| Unproved | 66 | 9 | – | 184 | 259 | – | – | 259 |
| Total property acquisitions | 228 | 10 | 278 | 185 | 701 | – | – | 701 |
| Development | 1,453 | 435 | 1,067 | 718 | 3,673 | 240 | – | 3,913 |
| **TOTAL COSTS INCURRED** | $2,340 | $662 | $1,646 | $1,154 | $5,802 | $240 | $ – | $6,042 |
| **YEAR ENDED DECEMBER 31, 1999** | | | | | | | | |
| Exploration | | | | | | | | |
| Wells | $ 361 | $115 | $ 132 | $ 94 | $ 702 | $ – | $ – | $ 702 |
| Geological and geophysical | 87 | 48 | 65 | 94 | 294 | – | – | 294 |
| Rentals and other | 81 | 40 | 70 | 57 | 248 | – | – | 248 |
| Total exploration | 529 | 203 | 267 | 245 | 1,244 | – | – | 1,244 |
| Property acquisitions[3,5] | | | | | | | | |
| Proved[4] | 13 | – | 687 | 864 | 1,564 | – | – | 1,564 |
| Unproved | 66 | 38 | 750 | 477 | 1,331 | – | – | 1,331 |
| Total property acquisitions | 79 | 38 | 1,437 | 1,341 | 2,895 | – | – | 2,895 |
| Development | 1,230 | 540 | 829 | 606 | 3,205 | 148 | – | 3,353 |
| **TOTAL COSTS INCURRED** | $1,838 | $781 | $2,533 | $2,192 | $7,344 | $148 | $ – | $7,492 |

1 Includes costs incurred whether capitalized or expensed. Excludes support equipment expenditures.

2 Includes acquisition costs for an additional 5 percent interest in 2001.

3 Proved amounts include wells, equipment and facilities associated with proved reserves.

4 Does not include properties acquired through property exchanges.

5 Includes acquisition costs and related deferred income taxes for purchases of Rutherford-Moran Oil Corporation and Petrolera Argentina San Jorge S.A.

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**Supplemental Information on Oil and Gas Producing Activities – Continued**

Unaudited

**TABLE II – CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES**

| | Consolidated Companies | | | | | Affiliated Companies | | |
|---|---|---|---|---|---|---|---|---|
| Millions of dollars | U.S. | Africa | Asia-Pacific | Other | Total | TCO | Hamaca* | Worldwide |
| **AT DECEMBER 31, 2001** | | | | | | | | |
| Unproved properties | **$ 753** | **$ 304** | **$ 565** | **$ 1,168** | **$ 2,790** | **$ 108** | **$ –** | **$ 2,898** |
| Proved properties and related producing assets | **35,665** | **5,487** | **10,332** | **9,435** | **60,919** | **1,878** | **88** | **62,885** |
| Support equipment | **766** | **390** | **2,177** | **313** | **3,646** | **293** | **–** | **3,939** |
| Deferred exploratory wells | **91** | **450** | **128** | **114** | **783** | **–** | **–** | **783** |
| Other uncompleted projects | **1,080** | **690** | **654** | **437** | **2,861** | **245** | **376** | **3,482** |
| **GROSS CAPITALIZED COSTS** | **38,355** | **7,321** | **13,856** | **11,467** | **70,999** | **2,524** | **464** | **73,987** |
| Unproved properties valuation | **382** | **86** | **73** | **222** | **763** | **–** | **–** | **763** |
| Proved producing properties – Depreciation and depletion | **25,844** | **2,998** | **4,733** | **4,827** | **38,402** | **219** | **3** | **38,624** |
| Future abandonment and restoration | **1,016** | **449** | **281** | **342** | **2,088** | **19** | **–** | **2,107** |
| Support equipment depreciation | **452** | **160** | **1,122** | **162** | **1,896** | **123** | **–** | **2,019** |
| Accumulated provisions | **27,694** | **3,693** | **6,209** | **5,553** | **43,149** | **361** | **3** | **43,513** |
| **NET CAPITALIZED COSTS** | **$10,661** | **$3,628** | **$ 7,647** | **$ 5,914** | **$27,850** | **$2,163** | **$461** | **$30,474** |
| **AT DECEMBER 31, 2000** | | | | | | | | |
| Unproved properties | $ 1,233 | $ 176 | $ 540 | $ 1,219 | $ 3,168 | $ 378 | $ 63 | $ 3,609 |
| Proved properties and related producing assets | 34,587 | 5,050 | 8,905 | 8,702 | 57,244 | 1,158 | 71 | 58,473 |
| Support equipment | 721 | 366 | 2,126 | 272 | 3,485 | 254 | 42 | 3,781 |
| Deferred exploratory wells | 182 | 407 | 120 | 161 | 870 | – | – | 870 |
| Other uncompleted projects | 741 | 640 | 674 | 570 | 2,625 | 136 | – | 2,761 |
| **GROSS CAPITALIZED COSTS** | 37,464 | 6,639 | 12,365 | 10,924 | 67,392 | 1,926 | 176 | 69,494 |
| Unproved properties valuation | 317 | 69 | 66 | 170 | 622 | – | – | 622 |
| Proved producing properties – Depreciation and depletion | 23,528 | 2,700 | 3,986 | 3,940 | 34,154 | 131 | – | 34,285 |
| Future abandonment and restoration | 1,071 | 413 | 274 | 317 | 2,075 | 13 | – | 2,088 |
| Support equipment depreciation | 380 | 141 | 1,224 | 172 | 1,917 | 97 | 1 | 2,015 |
| Accumulated provisions | 25,296 | 3,323 | 5,550 | 4,599 | 38,768 | 241 | 1 | 39,010 |
| **NET CAPITALIZED COSTS** | $12,168 | $3,316 | $ 6,815 | $ 6,325 | $28,624 | $1,685 | $175 | $30,484 |
| **AT DECEMBER 31, 1999** | | | | | | | | |
| Unproved properties | $ 1,190 | $ 185 | $ 617 | $ 1,204 | $ 3,196 | $ 378 | $ – | $ 3,574 |
| Proved properties and related producing assets | 36,614 | 4,442 | 6,745 | 10,657 | 58,458 | 689 | – | 59,147 |
| Support equipment | 913 | 322 | 2,151 | 244 | 3,630 | 243 | – | 3,873 |
| Deferred exploratory wells | 196 | 304 | 169 | 141 | 810 | – | – | 810 |
| Other uncompleted projects | 822 | 758 | 969 | 633 | 3,182 | 405 | – | 3,587 |
| **GROSS CAPITALIZED COSTS** | 39,735 | 6,011 | 10,651 | 12,879 | 69,276 | 1,715 | – | 70,991 |
| Unproved properties valuation | 282 | 54 | 82 | 109 | 527 | – | – | 527 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Proved producing properties – Depreciation and depletion | 25,301 | 2,317 | 3,376 | 5,770 | 36,764 | 99 | – | 36,863 |
| Future abandonment and restoration | 1,189 | 383 | 252 | 535 | 2,359 | 10 | – | 2,369 |
| Support equipment depreciation | 321 | 114 | 1,083 | 76 | 1,594 | 80 | – | 1,674 |
| Accumulated provisions | 27,093 | 2,868 | 4,793 | 6,490 | 41,244 | 189 | – | 41,433 |
| **NET CAPITALIZED COSTS** | $12,642 | $3,143 | $ 5,858 | $ 6,389 | $28,032 | $1,526 | $ – | $29,558 |

* Existing costs were transferred from a consolidated subsidiary to an affiliate at year-end 2000. Previously reported in Consolidated Companies – Other.

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## TABLE III – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES[1]

The company's results of operations from oil and gas producing activities for the years 2001, 2000 and 1999 are shown in the following table. Net income from exploration and production activities as reported on page FS-5 reflects income taxes computed on an effective rate basis. In accordance with FAS No. 69, income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page FS-5.

| | Consolidated Companies | | | | | Affiliated Companies | | |
|---|---|---|---|---|---|---|---|---|
| Millions of dollars | U.S. | Africa | Asia-Pacific | Other | Total | TCO | Hamaca | Worldwide |
| **YEAR ENDED DECEMBER 31, 2001** | | | | | | | | |
| Revenues from net production | | | | | | | | |
| Sales | **$ 5,024** | **$ 1,147** | **$ 1,264** | **$2,181** | **$ 9,616** | **$ 673** | **$ 6** | **$10,295** |
| Transfers | **3,991** | **1,913** | **2,796** | **1,107** | **9,807** | **–** | **–** | **9,807** |
| Total | **9,015** | **3,060** | **4,060** | **3,288** | **19,423** | **673** | **6** | **20,102** |
| Production expenses | **(2,272)** | **(447)** | **(856)** | **(687)** | **(4,262)** | **(142)** | **(6)** | **(4,410)** |
| Proved producing properties: depreciation, depletion and abandonment provision | **(1,614)** | **(344)** | **(498)** | **(658)** | **(3,114)** | **(80)** | **$ (1)** | **(3,195)** |
| Exploration expenses | **(424)** | **(132)** | **(234)** | **(298)** | **(1,088)** | **–** | **–** | **(1,088)** |
| Unproved properties valuation | **(38)** | **(33)** | **(9)** | **(77)** | **(157)** | **–** | **–** | **(157)** |
| Other (expense) income[2] | **(1,823)** | **(110)** | **(209)** | **(5)** | **(2,147)** | **9** | **2** | **(2,136)** |
| Results before income taxes | **2,844** | **1,994** | **2,254** | **1,563** | **8,655** | **460** | **1** | **9,116** |
| Income tax expense | **(1,074)** | **(1,455)** | **(1,432)** | **(620)** | **(4,581)** | **(138)** | **–** | **(4,719)** |
| **RESULTS OF PRODUCING OPERATIONS** | **$ 1,770** | **$ 539** | **$ 822** | **$ 943** | **$ 4,074** | **$ 322** | **$ 1** | **$ 4,397** |
| **YEAR ENDED DECEMBER 31, 2000** | | | | | | | | |
| Revenues from net production | | | | | | | | |
| Sales | $ 5,878 | $ 2,804 | $ 1,404 | $2,310 | $12,396 | $ 710 | $ – | $13,106 |
| Transfers | 4,387 | 650 | 3,203 | 1,409 | 9,649 | – | – | 9,649 |
| Total | 10,265 | 3,454 | 4,607 | 3,719 | 22,045 | 710 | – | 22,755 |
| Production expenses | (2,182) | (405) | (865) | (727) | (4,179) | (114) | – | (4,293) |
| Proved producing properties: depreciation, depletion and abandonment provision | (1,558) | (337) | (585) | (676) | (3,156) | (53) | – | (3,209) |
| Exploration expenses | (395) | (166) | (176) | (217) | (954) | – | – | (954) |
| Unproved properties valuation | (49) | (16) | (7) | (75) | (147) | – | – | (147) |
| Other (expense) income[2] | (631) | 45 | (13) | 237 | (362) | (56) | – | (418) |
| Results before income taxes | 5,450 | 2,575 | 2,961 | 2,261 | 13,247 | 487 | – | 13,734 |
| Income tax expense | (1,927) | (1,974) | (1,724) | (984) | (6,609) | (146) | – | (6,755) |
| **RESULTS OF PRODUCING OPERATIONS** | $ 3,523 | $ 601 | $ 1,237 | $1,277 | $ 6,638 | $ 341 | $ – | $ 6,979 |
| **YEAR ENDED DECEMBER 31, 1999** | | | | | | | | |
| Revenues from net production | | | | | | | | |
| Sales | $ 3,411 | $ 1,756 | $ 861 | $1,548 | $ 7,576 | $ 356 | $ – | $ 7,932 |
| Transfers | 2,830 | 446 | 2,108 | 948 | 6,332 | – | – | 6,332 |
| Total | 6,241 | 2,202 | 2,969 | 2,496 | 13,908 | 356 | – | 14,264 |
| Production expenses | (1,948) | (394) | (747) | (747) | (3,836) | (88) | – | (3,924) |
| Proved producing properties: depreciation, depletion and abandonment provision | (1,527) | (338) | (469) | (624) | (2,958) | (47) | – | (3,005) |
| Exploration expenses | (410) | (164) | (286) | (227) | (1,087) | – | – | (1,087) |
| Unproved properties valuation | (53) | (8) | (26) | (30) | (117) | – | – | (117) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Other (expense) income[2] | (585) | (61) | (69) | 5 | (710) | (9) | – | (719) |
| Results before income taxes | 1,718 | 1,237 | 1,372 | 873 | 5,200 | 212 | – | 5,412 |
| Income tax expense | (539) | (848) | (852) | (452) | (2,691) | (63) | – | (2,754) |
| **RESULTS OF PRODUCING OPERATIONS** | $ 1,179 | $ 389 | $ 520 | $ 421 | $ 2,509 | $ 149 | $ – | $ 2,658 |

1 The value of owned production consumed as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

2 Includes gas processing fees, net sulfur income, foreign currency transaction gains and losses, certain significant impairment write-downs, miscellaneous expenses, etc. Also includes net income from related oil and gas activities that do not have oil and gas reserves attributed to them (for example, net income from technical and operating service agreements) and items identified in the Management's Discussion and Analysis on pages FS-5 and FS-6.

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**Supplemental Information on Oil and Gas Producing Activities – Continued**

Unaudited

**TABLE IV – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES – UNIT PRICES AND COSTS[1,2]**

| | Consolidated Companies | | | | | Affiliated Companies | | |
|---|---|---|---|---|---|---|---|---|
| | U.S. | Africa | Asia-Pacific | Other | Total | TCO | Hamaca | Worldwide |
| **YEAR ENDED DECEMBER 31, 2001** | | | | | | | | |
| Average sales prices | | | | | | | | |
| Liquids, per barrel | **$21.34** | **$23.70** | **$20.11** | **$22.59** | **$21.68** | **$13.31** | **$12.45** | **$21.08** |
| Natural gas, per thousand cubic feet | **4.38** | **0.04** | **3.04** | **2.51** | **3.78** | **0.47** | **–** | **3.69** |
| Average production costs, per barrel | **5.90** | **3.39** | **4.20** | **4.17** | **4.81** | **2.54** | **13.09** | **4.68** |
| **YEAR ENDED DECEMBER 31, 2000** | | | | | | | | |
| Average sales prices | | | | | | | | |
| Liquids per barrel | $25.61 | $26.58 | $22.97 | $27.34 | $25.35 | $20.14 | $ – | $25.09 |
| Natural gas, per thousand cubic feet | 3.87 | 0.03 | 2.57 | 2.29 | 3.39 | 0.13 | – | 3.33 |
| Average production costs, per barrel | 5.23 | 3.04 | 4.17 | 4.49 | 4.55 | 2.91 | – | 4.48 |
| **YEAR ENDED DECEMBER 31, 1999** | | | | | | | | |
| Average sales prices | | | | | | | | |
| Liquids, per barrel | $14.92 | $17.39 | $14.67 | $16.94 | $15.63 | $10.53 | $ – | $15.40 |
| Natural gas, per thousand cubic feet | 2.12 | 0.05 | 1.86 | 1.83 | 2.02 | 0.38 | – | 2.00 |
| Average production costs, per barrel | 4.37 | 3.06 | 3.61 | 4.48 | 4.04 | 2.39 | – | 3.98 |

1 The value of owned production consumed as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

2 Natural gas converted to crude oil-equivalent gas (OEG) barrels at a rate of 6 MCF=1 OEG barrel.

**TABLE V – RESERVE QUANTITY INFORMATION**

The company's estimated net proved underground oil and gas reserves and changes thereto for the years 2001, 2000 and 1999 are shown in the following table. Proved reserves are estimated by company asset teams composed of earth scientists and reservoir engineers. These proved reserve estimates are reviewed annually by the company's Reserves Advisory Committee to ensure that rigorous professional standards and the reserves definitions prescribed by the U.S. Securities and Exchange Commission are consistently applied throughout the company.

Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Due to the inherent uncertainties and the limited nature of reservoir data, estimates of underground reserves are subject to change as additional information becomes available.

Proved reserves do not include additional quantities recoverable beyond the term of the lease or concession agreement or that may result from extensions of currently proved areas or from applying secondary or tertiary recovery processes not yet tested and determined to be economic.

Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods.

"Net" reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty

obligations in effect at the time of the estimate.

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**TABLE V – RESERVE QUANTITY INFORMATION** – Continued

ChevronTexaco operates, under a risked service agreement, Venezuela's Block LL-652, located in the northeast section of Lake Maracaibo. ChevronTexaco is accounting for LL-652 as an oil and gas activity and, at December 31, 2001, had recorded 18 million barrels of proved crude oil reserves.

No reserve quantities have been recorded for the company's other service agreements – the Boscan Field in Venezuela and a long-term purchase agreement associated with a service agreement for the Chuchupa Field in Colombia for the period 2005 – 2016.

**NET PROVED RESERVES OF CRUDE OIL, CONDENSATE AND NATURAL GAS LIQUIDS**
Million of barrels

| | Consolidated Companies | | | | | Affiliates | | |
|---|---|---|---|---|---|---|---|---|
| | U.S. | Africa | Asia-Pacific | Other | Total | TCO | Hamaca | World-wide |
| **RESERVES AT JANUARY 1, 1999** | 2,972 | 1,359 | 2,082 | 782 | 7,195 | 1,075 | – | 8,270 |
| Changes attributable to: | | | | | | | | |
| Revisions | (12) | 4 | (178) | 31 | (155) | 115 | – | (40) |
| Improved recovery | 78 | 62 | 112 | 21 | 273 | – | – | 273 |
| Extensions and discoveries | 116 | 47 | 27 | 49 | 239 | 76 | – | 315 |
| Purchases[1] | 35 | – | 59 | 177 | 271 | – | – | 271 |
| Sales[2] | (76) | – | – | (2) | (78) | – | – | (78) |
| Production | (259) | (128) | (215) | (112) | (714) | (33) | – | (747) |
| **RESERVES AT DECEMBER 31, 1999** | 2,854 | 1,344 | 1,887 | 946 | 7,031 | 1,233 | – | 8,264 |
| Changes attributable to: | | | | | | | | |
| Revisions | (26) | 48 | 109 | 14 | 145 | 105 | – | 250 |
| Improved recovery | 83 | 20 | 69 | 9 | 181 | – | – | 181 |
| Extensions and discoveries | 85 | 92 | 40 | 57 | 274 | 7 | 374 | 655 |
| Purchases[1] | 8 | 131 | – | 3 | 142 | – | – | 142 |
| Sales[2] | (146) | – | – | (96) | (242) | – | – | (242) |
| Production | (244) | (130) | (211) | (111) | (696) | (35) | – | (731) |
| **RESERVES AT DECEMBER 31, 2000** | 2,614 | 1,505 | 1,894 | 822 | 6,835 | 1,310 | 374 | 8,519 |
| Changes attributable to: | | | | | | | | |
| Revisions | **(225)** | **45** | **135** | **(60)** | **(105)** | **46** | **(2)** | **(61)** |
| Improved recovery | **79** | **35** | **47** | **51** | **212** | **–** | **–** | **212** |
| Extensions and discoveries | **67** | **88** | **34** | **40** | **229** | **88** | **115** | **432** |
| Purchases[1] | **1** | **–** | **–** | **–** | **1** | **146** | **–** | **147** |
| Sales[2] | **(11)** | **–** | **–** | **–** | **(11)** | **–** | **–** | **(11)** |
| Production | **(224)** | **(129)** | **(204)** | **(108)** | **(665)** | **(49)** | **–** | **(714)** |
| **RESERVES AT DECEMBER 31, 2001** | **2,301** | **1,544** | **1,906** | **745** | **6,496** | **1,541** | **487** | **8,524** |
| Developed reserves | | | | | | | | |
| At January 1, 1999 | 2,397 | 941 | 1,477 | 482 | 5,297 | 646 | – | 5,943 |
| At December 31, 1999 | 2,266 | 980 | 1,314 | 636 | 5,196 | 790 | – | 5,986 |
| At December 31, 2000 | 2,083 | 976 | 1,276 | 538 | 4,873 | 795 | – | 5,668 |
| **At December 31, 2001** | **1,887** | **923** | **1,491** | **517** | **4,818** | **1,007** | **38** | **5,863** |

[Additional columns below]

[Continued from above table, first column(s) repeated]

**NET PROVED RESERVES OF NATURAL GAS**

Billions of cubic feet

| | Consolidated Companies | | | | | Affiliates | | |
|---|---|---|---|---|---|---|---|---|
| | U.S. | Africa | Asia-Pacific | Other | Total | TCO | Hamaca | World-wide |
| **RESERVES AT JANUARY 1, 1999** | 8,602 | 292 | 2,660 | 2,882 | 14,436 | 1,384 | – | 15,820 |
| Changes attributable to: | | | | | | | | |
| Revisions | (141) | 49 | 411 | 251 | 570 | 126 | – | 696 |
| Improved recovery | 11 | – | 237 | 10 | 258 | – | – | 258 |
| Extensions and discoveries | 789 | – | 51 | 186 | 1,026 | 98 | – | 1,124 |
| Purchases[1] | 35 | – | 901 | 183 | 1,119 | – | – | 1,119 |
| Sales[2] | (155) | – | – | – | (155) | – | – | (155) |
| Production | (1,148) | (15) | (172) | (337) | (1,672) | (27) | – | (1,699) |
| **RESERVES AT DECEMBER 31, 1999** | 7,993 | 326 | 4,088 | 3,175 | 15,582 | 1,581 | – | 17,163 |
| Changes attributable to: | | | | | | | | |
| Revisions | 92 | 450 | 308 | 67 | 917 | 126 | – | 1,043 |
| Improved recovery | 17 | – | – | 5 | 22 | – | – | 22 |
| Extensions and discoveries | 990 | 1 | 236 | 143 | 1,370 | 9 | 33 | 1,412 |
| Purchases[1] | 262 | 12 | – | – | 274 | – | – | 274 |
| Sales[2] | (367) | – | – | (70) | (437) | – | – | (437) |
| Production | (1,064) | (17) | (190) | (329) | (1,600) | (33) | – | (1,633) |
| **RESERVES AT DECEMBER 31, 2000** | 7,923 | 772 | 4,442 | 2,991 | 16,128 | 1,683 | 33 | 17,844 |
| Changes attributable to: | | | | | | | | |
| Revisions | **(20)** | **780** | **330** | **(10)** | **1,080** | **317** | **–** | **1,397** |
| Improved recovery | **24** | **7** | **11** | **16** | **58** | **–** | **–** | **58** |
| Extensions and discoveries | **587** | **329** | **164** | **445** | **1,525** | **130** | **9** | **1,664** |
| Purchases[1] | **41** | **–** | **6** | **6** | **53** | **187** | **–** | **240** |
| Sales[2] | **(180)** | **–** | **–** | **–** | **(180)** | **–** | **–** | **(180)** |
| Production | **(988)** | **(16)** | **(194)** | **(360)** | **(1,558)** | **(55)** | **–** | **(1,613)** |
| **RESERVES AT DECEMBER 31, 2001** | **7,387** | **1,872** | **4,759** | **3,088** | **17,106** | **2,262** | **42** | **19,410** |
| Developed reserves | | | | | | | | |
| At January 1, 1999 | 7,262 | 266 | 1,894 | 2,125 | 11,547 | 832 | – | 12,379 |
| At December 31, 1999 | 6,733 | 276 | 2,342 | 2,368 | 11,719 | 1,011 | – | 12,730 |
| At December 31, 2000 | 6,408 | 294 | 3,108 | 2,347 | 12,157 | 1,019 | – | 13,176 |
| **At December 31, 2001** | **6,246** | **444** | **3,170** | **2,231** | **12,091** | **1,477** | **6** | **13,574** |

1 Includes reserves acquired through property exchanges.

2 Includes reserves disposed of through property exchanges.

**INFORMATION ON CANADIAN OIL SANDS NET PROVED RESERVES NOT INCLUDED ABOVE:**

In addition to conventional liquids and natural gas proved reserves, ChevronTexaco has significant interests in proved oil sands reserves in Canada associated with the Athabasca project. For internal management purposes, ChevronTexaco views these reserves and their development as an integral part of total upstream operations. However, U.S. Securities and Exchange Commission regulations define these reserves as mining-related and not a part of conventional oil and gas reserves. Net proved oil sands reserves were 186 million barrels as of December 31, 2001. Production is expected to begin

in late 2002.

The oil sands reserves are not considered in the standardized measure of discounted cash flows for conventional oil and gas reserves, which is found on page FS-50.

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**Supplemental Information on Oil and Gas Producing Activities** – Continued

Unaudited

**TABLE VI – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES**

The standardized measure of discounted future net cash flows, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of FAS No. 69. Estimated future cash inflows from production are computed by applying year-end prices for oil and gas to year-end quantities of estimated net proved reserves. Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10 percent midperiod discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided does not represent management's estimate of the company's expected future cash flows or value of proved oil and gas reserves. Estimates of proved reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The arbitrary valuation prescribed under FAS No. 69 requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and should not be relied upon as an indication of the company's future cash flows or value of its oil and gas reserves.

| | Consolidated Companies | | | | | Affiliated Companies | | |
|---|---|---|---|---|---|---|---|---|
| Millions of dollars | U.S. | Africa | Asia-Pacific | Other | Total | TCO | Hamaca | Worldwide |
| **AT DECEMBER 31, 2001** | | | | | | | | |
| Future cash inflows from production | **$ 54,238** | **$ 28,019** | **$ 43,389** | **$20,432** | **$146,078** | **$ 29,433** | **$ 5,922** | **$181,433** |
| Future production and development costs | **(30,871)** | **(10,106)** | **(20,845)** | **(8,873)** | **(70,695)** | **(8,865)** | **(1,093)** | **(80,653)** |
| Future income taxes | **(7,981)** | **(10,476)** | **(9,858)** | **(4,370)** | **(32,685)** | **(5,805)** | **(1,642)** | **(40,132)** |
| Undiscounted future net cash flows | **15,386** | **7,437** | **12,686** | **7,189** | **42,698** | **14,763** | **3,187** | **60,648** |
| 10 percent midyear annual discount for timing of estimated cash flows | **(6,882)** | **(3,609)** | **(5,857)** | **(2,602)** | **(18,950)** | **(9,121)** | **(2,433)** | **(30,504)** |
| **STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS** | **$ 8,504** | **$ 3,828** | **$ 6,829** | **$ 4,587** | **$ 23,748** | **$ 5,642** | **$ 754** | **$ 30,144** |
| **AT DECEMBER 31, 2000** | | | | | | | | |
| Future cash inflows from production | $127,945 | $ 34,856 | $ 47,351 | $27,426 | $237,578 | $ 30,350 | $ 3,917 | $271,845 |
| Future production and development costs | (30,305) | (8,023) | (18,416) | (7,466) | (64,210) | (7,250) | (679) | (72,139) |
| Future income taxes | (33,614) | (16,124) | (13,245) | (7,481) | (70,464) | (6,440) | (1,101) | (78,005) |
| Undiscounted future net cash flows | 64,026 | 10,709 | 15,690 | 12,479 | 102,904 | 16,660 | 2,137 | 121,701 |
| 10 percent midyear annual discount for timing of estimated cash flows | (27,747) | (4,186) | (6,764) | (4,405) | (43,102) | (11,180) | (1,431) | (55,713) |
| **STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS** | $ 36,279 | $ 6,523 | $ 8,926 | $ 8,074 | $ 59,802 | $ 5,480 | $ 706 | $ 65,988 |
| **AT DECEMBER 31, 1999** | | | | | | | | |
| Future cash inflows from production | $ 76,931 | $ 33,218 | $ 45,358 | $27,973 | $183,480 | $ 24,380 | $ – | $207,860 |
| Future production and development costs | (26,159) | (6,430) | (17,136) | (8,802) | (58,527) | (4,900) | – | (63,427) |
| Future income taxes | (15,354) | (17,178) | (13,553) | (6,970) | (53,055) | (4,980) | – | (58,035) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Undiscounted future net cash flows | 35,418 | 9,610 | 14,669 | 12,201 | 71,898 | 14,500 | – | 86,398 |
| 10 percent midyear annual discount for timing of estimated cash flows | (16,296) | (2,996) | (6,249) | (4,607) | (30,148) | (10,400) | – | (40,548) |
| **STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS** | $ 19,122 | $ 6,614 | $ 8,420 | $ 7,594 | $ 41,750 | $ 4,100 | $ – | $ 45,850 |

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**TABLE VII – CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED RESERVES**

| | Consolidated Companies | | | Affiliated Companies | | | Worldwide | | |
|---|---|---|---|---|---|---|---|---|---|
| Millions of dollars | **2001** | 2000 | 1999 | **2001** | 2000 | 1999 | **2001** | 2000 | 1999 |
| **PRESENT VALUE AT JANUARY 1** | **$ 59,802** | $ 41,750 | $ 14,447 | **$ 6,186** | $4,100 | $ 310 | **$ 65,988** | $ 45,850 | $ 14,757 |
| Sales and transfers of oil and gas produced, net of production costs | **(15,161)** | (17,866) | (10,072) | **(531)** | (596) | (268) | **(15,692)** | (18,462) | (10,340) |
| Development costs incurred | **3,967** | 3,673 | 3,205 | **541** | 240 | 148 | **4,508** | 3,913 | 3,353 |
| Purchases of reserves | **40** | 2,055 | 3,706 | **778** | – | – | **818** | 2,055 | 3,706 |
| Sales of reserves | **(366)** | (5,010) | (696) | **–** | – | – | **(366)** | (5,010) | (696) |
| Extensions, discoveries and improved recovery, less related costs | **2,747** | 8,710 | 4,866 | **484** | 1,112 | 226 | **3,231** | 9,822 | 5,092 |
| Revisions of previous quantity estimates | **524** | (428) | (856) | **400** | 1,284 | 738 | **924** | 856 | (118) |
| Net changes in prices, development and production costs | **(59,995)** | 29,358 | 49,264 | **(2,457)** | 457 | 4,650 | **(62,452)** | 29,815 | 53,914 |
| Accretion of discount | **10,144** | 7,027 | 2,131 | **876** | 582 | 50 | **11,020** | 7,609 | 2,181 |
| Net change in income tax | **22,046** | (9,467) | (24,246) | **119** | (993) | (1,753) | **22,165** | (10,460) | (25,999) |
| Net change for the year | **(36,054)** | 18,052 | 27,302 | **210** | 2,086 | 3,791 | **(35,844)** | 20,138 | 31,093 |
| **VALUE AT DECEMBER 31** | **$ 23,748** | $ 59,802 | $ 41,749 | **$ 6,396** | $6,186 | $ 4,101 | **$ 30,144** | $ 65,988 | $ 45,850 |

The changes in present values between years, which can be significant, reflect changes in estimated proved reserve quantities and prices and assumptions used in forecasting production volumes and costs. Changes in the timing of production are included with “Revisions of previous quantity estimates.”

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## EXHIBIT INDEX

| Exhibit No. | Description |
|---|---|
| 3.1* | Restated Certificate of Incorporation of ChevronTexaco Corporation, dated October 9, 2001. |
| 3.2 | By-Laws of ChevronTexaco Corporation, as amended April 25, 2001, filed as Exhibit 3 to ChevronTexaco Corporation's Report on Form 10-Q for the quarterly period ended March 31, 2001, and incorporated herein by reference. |
| 4.1 | Rights Agreement dated as of November 23, 1998, between ChevronTexaco Corporation and ChaseMellon Shareholder Services L.L.C., as Rights Agent, filed as Exhibit 4.1 to ChevronTexaco Corporation's Current Report on Form 8-K dated November 23, 1998, and incorporated herein by reference. |
| 4.2 | Amendment No. 1 to Rights Agreement dated as of October 15, 2000, between ChevronTexaco Corporation and ChaseMellon Shareholder Services L.L.C., as Rights Agent, filed as Exhibit 4.2 to ChevronTexaco Corporation's Registration Statement on Form 8-A dated December 7, 2000, and incorporated herein by reference.<br>Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the corporation and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the corporation and its subsidiaries on a consolidated basis. A copy of such instrument will be furnished to the Commission upon request. |
| 10.1 | ChevronTexaco Corporation Deferred Compensation Plan for Directors, as amended and restated effective January 1, 2001, filed as Exhibit 10.1 to ChevronTexaco Corporation's Annual Report on Form 10-K for the year ended December 31, 2000, and incorporated herein by reference. |
| 10.2 | Management Incentive Plan of ChevronTexaco Corporation, as amended and restated effective October 30, 1996, filed as Appendix B to ChevronTexaco Corporation's Notice of Annual Meeting of Stockholders and Proxy Statement dated March 21, 1997, and incorporated herein by reference. |
| 10.3 | ChevronTexaco Corporation Excess Benefit Plan, amended and restated as of July 1, 1996, filed as Exhibit 10 to ChevronTexaco Corporation's Report on Form 10-Q for the quarterly period ended March 31, 1997, and incorporated herein by reference. |
| 10.4 | ChevronTexaco Restricted Stock Plan for Non-Employee Directors, as amended and restated effective April 30, 1997, filed as Appendix A to ChevronTexaco Corporation's Notice of Annual Meeting of Stockholders and Proxy Statement dated March 21, 1997, and incorporated herein by reference. |
| 10.5 | ChevronTexaco Corporation Long-Term Incentive Plan, as amended and restated effective October 30, 1996, filed as Appendix C to ChevronTexaco Corporation's Notice of Annual Meeting of Stockholders and Proxy Statement dated March 21, 1997, and incorporated herein by reference. |
| 10.6 | ChevronTexaco Corporation Salary Deferral Plan for Management Employees, effective January 1, 1997, filed as Exhibit 10 to ChevronTexaco Corporation's Report on Form 10-Q for the quarterly period ended June 30, 1997, and incorporated herein by reference. |
| 10.7 | Agreement and Plan of Merger dated as of October 15, 2000, among Texaco Inc., ChevronTexaco Corporation and Keepep Inc., filed as Exhibit 2.1 to a Current Report on Form 8-K filed by the company on October 16, 2000 and an amended Current Report on Form 8-K filed by the company on October 16, 2000, and incorporated herein by reference. |

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**EXHIBIT INDEX**
**(continued)**

| Exhibit No. | Description |
|---|---|
| 10.8 | Amendment No. 1 to Agreement and Plan of Merger, dated as of March 30, 2001, among Texaco Inc., ChevronTexaco Corporation and Keepep Inc., filed as Annex A-1 to Amendment No. 4 to the Registration Statement on Form S-4 filed by ChevronTexaco Corporation on August 27, 2001, and incorporated herein by reference. |
| 10.10 | Stock Option Agreement dated as of October 15, 2000 between ChevronTexaco Corporation and Texaco Inc., filed as Exhibit 2.2 to a Current Report on Form 8-K filed by the company on October 16, 2000, and an amended Current Report on Form 8-K filed by the company on October 16, 2000, and incorporated herein by reference. |
| 10.11 | Stock Option Agreement dated as of October 15, 2000 between ChevronTexaco Corporation and Texaco Inc., filed as Exhibit 2.3 to a Current Report on Form 8-K filed by the company on October 16, 2000, and an amended Current Report on Form 8-K filed by the company on October 16, 2000, and incorporated herein by reference. |
| 10.12* | Employment Agreement dated as of December 4, 2001 between ChevronTexaco Corporation and Glenn Tilton. |
| 10.13* | Texaco Inc. Stock Incentive Plan, adopted May 9, 1989, as amended May 13, 1993, and May 13, 1997. |
| 10.14* | Supplemental Pension Plan of Texaco Inc., dated June 26, 1975. |
| 10.15* | Supplemental Bonus Retirement Plan of Texaco Inc., dated May 1, 1981. |
| 10.16* | Texaco Inc. Director and Employee Deferral Plan approved March 28, 1997. |
| 12.1* | Computation of Ratio of Earnings to Fixed Charges (page E-3). |
| 21.1* | Subsidiaries of ChevronTexaco Corporation (page E-4). |
| 23.1* | Consent of PricewaterhouseCoopers LLP (page E-5). |
| 23.2* | Consent of Arthur Andersen LLP (page E-6). |
| 24.1 to 24.17 | Powers of Attorney for directors and certain officers of ChevronTexaco Corporation, authorizing the signing of the Annual Report on Form 10-K on their behalf. |
| 99.1* | Definitions of Selected Financial Terms (page E-7). |
| 99.2 | Decision and Order of the Federal Trade Commission filed as Exhibit 99.2 to ChevronTexaco Corporation's Current Report on Form 8-K filed September 10, 2001, and incorporated herein by reference. |
| 99.3* | Letter to U.S. Securities and Exchange Commission pursuant to Temporary Note 3T to Article 3 of Regulation S-X. (page E-8) |

* Filed herewith.

On October 9, 2001, the company changed its name from Chevron Corporation to ChevronTexaco Corporation. Filings with the Securities and Exchange Commission prior to that date may be found under the company's former name.

Copies of above exhibits not contained herein are available, at a fee of $2 per document, to any security holder upon written request to the Secretary's Department, ChevronTexaco Corporation, 575 Market Street, San Francisco, California 94105.

**Exhibit 12.1**

**ChevronTexaco Corporation – Total Enterprise Basis**
**Computation of Ratio of Earnings to Fixed Charges**

(Dollars in Millions)

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2001 | 2000 | 1999 | 1998 | 1997 |
| Net Income Before Extraordinary Item | | | $3,247 | $1,917 | $5,920 |
| Income Tax Expense | | | 2,565 | 919 | 3,273 |
| Distributions (Less Than) Greater Than Equity in Earnings of Affiliates | (489) | (26) | (288) | 49 | (908) |
| Minority Interest | 121 | 111 | 71 | 62 | 82 |
| Previously Capitalized Interest Charged to Earnings During Period | 67 | 71 | 74 | 57 | 53 |
| Interest and Debt Expense | 833 | ,110 | 1,132 | 1,057 | 870 |
| Interest Portion of Rentals* | 357 | 340 | 249 | 255 | 251 |
| **Earnings Before Provision for Taxes And Fixed Charges** | **$9,180** | **$15,655** | **$7,050** | **$4,316** | **$9,541** |
| Interest and Debt Expense | $ 833 | $ 1,110 | $1,132 | $1,057 | $ 870 |
| Interest Portion of Rentals* | 357 | 340 | 249 | 255 | 251 |
| Preferred Stock Dividends of Subsidiaries | 48 | 50 | 55 | 33 | 33 |
| Capitalized Interest | 122 | 108 | 38 | 63 | 109 |
| **Total Fixed Charges** | $1,360 | $ 1,608 | $1,474 | $1,408 | $1,263 |
| **Ratio Of Earnings To Fixed Charges** | **6.75** | **9.74** | **4.78** | **3.07** | **7.55** |

Calculated as one-third of rentals. Considered a reasonable approximation of interest factor.

Exhibit 21.1

## SUBSIDIARIES OF CHEVRONTEXACO CORPORATION*
**At December 31, 2001**

| Name of Subsidiary | State or Country in Which Organized |
|---|---|
| Chevron Capital Corporation | Delaware |
| Chevron Finance Company | Delaware |
| Chevron U.S.A. Inc. | Pennsylvania |
| Principal Divisions: | |
| Chevron U.S.A. Production Company | |
| Chevron Products Company | |
| Limited Liability Company: | |
| Chevron Chemical Company LLC | Delaware |
| Other subsidiaries: | |
| Chevron Capital U.S.A. Inc. | Delaware |
| Chevron Oil Finance Company | Delaware |
| ChevronTexaco Overseas Petroleum Inc. | Delaware |
| Chevron U.K. Limited | United Kingdom |
| Chevron International Limited | Liberia |
| Chevron LNG Shipping Company Limited | Bermuda |
| Chevron Finance Holdings Limited | Bermuda |
| Chevron Asiatic Limited | Delaware |
| Chevron Australia Pty Limited | Australia |
| Texaco Inc. | Delaware |
| TRMI Holdings Inc. | Delaware |
| Texaco Overseas Holdings Inc. | Delaware |
| ChevronTexaco Global Energy Inc. | Delaware |
| Chevron Canada Finance Limited | Canada |
| Chevron Canada Limited | Canada |
| Chevron Nigeria Limited | Nigeria |
| Chevron Pipeline Company | Delaware |
| Cabinda Gulf Oil Company Limited | Bermuda |
| The Pittsburg & Midway Coal Mining Co. | Missouri |
| P.T. Caltex Pacific Indonesia | Indonesia |
| Texaco International Trader Inc. | Delaware |
| Saudi Arabian Texaco Inc. | Delaware |
| TEPI Holdings Inc. | Delaware |
| Texaco Exploration and Production Inc. | Delaware |
| Texaco Capital LLC | Turks and Caicos Islands |
| Texaco Capital Inc. | Delaware |

* All of the subsidiaries in the above list are wholly owned, either directly or indirectly, by ChevronTexaco Corporation. Certain subsidiaries are not listed since, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary at December 31, 2001.

**Exhibit 23.1**

## CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 33-58463 and 333-90977) of ChevronTexaco Corporation, and to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 333-72672, 333-02011, 333-21805, 333-21807, 333-21809, 333-26731, 333-46261, 33-3899, 33-34039, 33-35283) of ChevronTexaco Corporation, and to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-90977-01) of Chevron Capital Corporation and ChevronTexaco Corporation, and to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-90977-02) of Chevron Canada Capital Company and ChevronTexaco Corporation, and to the incorporation by reference in the Registration Statement on Form S-3 (No. 33-14307) of Chevron Capital U.S.A. Inc. and ChevronTexaco Corporation, and to the incorporation by reference in the Registration Statement on Form S-8 (No. 2-90907) of ChevronTexaco Global Energy Inc. of our report dated March 8, 2002, relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

**PRICEWATERHOUSECOOPERS LLP**

San Francisco, California
March 27, 2002

**Exhibit 23.2**

## CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report dated February 22, 2001 included in this Form 10-K, into the following previously filed Registration Statements.

| | Form | File Number |
|---|---|---|
| ChevronTexaco Corporation | S-3 | 33-58463 |
| | S-3 | 333-90977 |
| | S-8 | 333-72672 |
| | S-8 | 333-02011 |
| | S-8 | 333-21805 |
| | S-8 | 333-21807 |
| | S-8 | 333-21809 |
| | S-8 | 333-26731 |
| | S-8 | 333-46261 |
| | S-8 | 33-3899 |
| | S-8 | 33-34039 |
| | S-8 | 33-35283 |
| Chevron Capital Corporation and ChevronTexaco Corporation | S-3 | 333-90977-01 |
| Chevron Canada Capital Company and ChevronTexaco Corporation | S-3 | 333-90977-02 |
| Chevron Capital USA Inc. and ChevronTexaco Corporation | S-3 | 33-14307 |
| Chevron Texaco Global Energy Inc. | S-8 | 2-90907 |

**Arthur Andersen LLP**

New York, New York
March 27, 2002

# DEFINITIONS OF SELECTED FINANCIAL ERMS

**Return On Average Stockholders' Equity**

Net income divided by average stockholders' equity. Average stockholders' equity is computed by averaging the sum of the beginning of year and end of year balances.

**Return On Average Capital Employed**

Net income (adjusted for after-tax interest expense, minority interest) divided by average capital employed. Capital employed is stockholders' equity plus short-term debt plus long-term debt plus capital lease obligations plus minority interests. Average capital employed is computed by averaging the sum of capital employed at the beginning of the year and at the end of the year.

**Total Debt to Total-Debt-Plus-Equity Ratio**

Total debt, including capital lease obligations, divided by total debt plus stockholders' equity.

**Current Ratio**

Current assets divided by current liabilities.

**Interest Coverage Ratio**

Income before income tax expense and cumulative effect of change in accounting principle, plus interest and debt expense and amortization of capitalized interest, divided by before-tax interest costs.

Exhibit 99.3

**CHEVRONTEXACO CORPORATION**

575 Market Street
San Francisco, California 94105

**LETTER TO COMMISSION PURSUANT TO TEMPORARY NOTE 3T**

**March 27, 2002**

Securities and Exchange Commission
450 Fifth Street, N.W.
Washington, D.C. 20549-0408

Ladies and Gentlemen:

Pursuant to Temporary Note 3T to Article 3 of Regulation S-X, ChevronTexaco Corporation has obtained a letter of representation from Arthur Andersen LLP ("Andersen") stating that the December 31, 2000 and 1999 audits of Texaco Inc.'s financial statements were subject to their quality control system for the U.S. accounting and auditing practice to provide reasonable assurance that the engagements were conducted in compliance with professional standards, that there was appropriate continuity of Andersen personnel working on the audits, availability of national office consultation, and availability of personnel at foreign affiliates of Andersen to conduct the relevant portions of the audits.

Very truly yours,

CHEVRONTEXACO CORPORATION

/s/ JOHN S. WATSON

John S. Watson
Vice President, Finance
and Chief Financial Officer

**CHEVRONTEXACO CORP filed this 10-Q on 05/15/2002.**

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# Form 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **March 31, 2002**

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number 1-368-2

# ChevronTexaco Corporation

(Exact name of registrant as specified in its charter)

| Delaware | 94-0890210 | 575 Market Street, San Francisco, California 94105 |
|---|---|---|
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification Number) | (Address of principal executive offices) (Zip Code) |

Registrant's telephone number, including area code (415) 894-7700

NONE

(Former name or former address, if changed since last report.)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate the number of shares of each of the issuer's classes of common stock, as of the latest practicable date:

| Class | Outstanding as of March 31, 2002 |
|---|---|
| Common stock, $0.75 par value | 1,067,468,322 |

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## CAUTIONARY STATEMENTS RELEVANT TO FORWARD-LOOKING INFORMATION FOR THE PURPOSE OF "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This quarterly report on Form 10-Q of ChevronTexaco Corporation contains forward-looking statements relating to ChevronTexaco's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as "anticipates," "expects," "intends," "plans," "targets," "projects," "believes," "seeks," "estimates" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, ChevronTexaco undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the factors that could cause actual results to differ materially are crude oil and natural gas prices; refining margins and marketing margins; chemicals prices and competitive conditions affecting supply and demand for aromatics, olefins and additives products; actions of competitors; the competitiveness of alternate energy sources or product substitutes; technological developments; inability of the company's joint-venture partners to fund their share of operations and development activities; potential failure to achieve expected production from existing and future oil and gas development projects; potential delays in the development, construction or start-up of planned projects; the successful integration of the former Chevron, Texaco and Caltex businesses; potential disruption or interruption of the company's production or manufacturing facilities due to accidents or political events; potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental regulations (including, particularly, regulations and litigation dealing with gasoline composition and characteristics); and potential liability resulting from pending or future litigation. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed herein also could have material adverse effects on forward-looking statements.

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## PART I. FINANCIAL INFORMATION

## CHEVRONTEXACO CORPORATION AND SUBSIDIARIES

## CONSOLIDATED STATEMENT OF INCOME
**(Unaudited)**

| Millions of Dollars, Except Per-Share Amounts | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| **Revenues and Other Income** | | |
| Sales and other operating revenues[1] | **$ 20,844** | $ 29,030 |
| Income from equity affiliates | **112** | 288 |
| Other income | **199** | 127 |
| **Total Revenues and Other Income** | **21,155** | 29,445 |
| **Costs and Other Deductions** | | |
| Purchased crude oil and products | **11,813** | 16,880 |
| Operating expenses | **1,752** | 1,879 |
| Selling, general and administrative expenses | **863** | 898 |
| Exploration expenses | **85** | 162 |
| Depreciation, depletion and amortization | **1,205** | 1,157 |
| Merger-related expenses | **183** | 25 |
| Taxes other than on income[1] | **3,780** | 3,957 |
| Interest and debt expense | **147** | 259 |
| Minority interests | **12** | 38 |
| **Total Costs and Other Deductions** | **19,840** | 25,255 |
| **Income Before Income Tax Expense** | **1,315** | 4,190 |
| **Income Tax Expense** | **590** | 1,757 |
| **Net Income** | **$ 725** | $ 2,433 |
| **Per Share of Common Stock:** | | |
| **Net Income – Basic** | **$ 0.68** | $ 2.30 |
| **– Diluted** | **$ 0.68** | $ 2.29 |
| **Dividends** | **$ .70** | $ .65[2] |
| **Weighted Average Number of Shares Outstanding (000s) – Basic** | **1,060,080** | 1,058,635 |
| **– Diluted** | **1,062,010** | 1,059,754 |
| [1] Includes consumer excise taxes | **$ 1,688** | $ 1,782 |

[2] Chevron dividend pre-merger

See accompanying notes to consolidated financial statements.

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**CHEVRONTEXACO CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME**
**(Unaudited)**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| **Net Income** | **$725** | $2,433 |
| Unrealized holding gain on securities | **63** | 12 |
| Minimum pension liability adjustment | **—** | 9 |
| Net derivatives gain (loss) on hedge transactions | **5** | (13) |
| Currency translation adjustment | **(17)** | 2 |
| **Other Comprehensive Income, net of tax** | **51** | 10 |
| **Comprehensive Income** | **$776** | $2,443 |

See accompanying notes to consolidated financial statements.

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**CHEVRONTEXACO CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED BALANCE SHEET**

| Millions of Dollars | At March 31 2002 | At December 31 2001 |
|---|---|---|
| | (Unaudited) | |
| **ASSETS** | | |
| Cash and cash equivalents | **$ 3,525** | $ 2,117 |
| Marketable securities | **811** | 1,033 |
| Accounts and notes receivable | **9,021** | 8,279 |
| Inventories: | | |
| Crude oil and petroleum products | **2,268** | 2,207 |
| Chemicals | **208** | 209 |
| Materials, supplies and other | **553** | 532 |
| | **3,029** | 2,948 |
| Prepaid expenses and other current assets | **2,119** | 1,769 |
| Assets held for sale – merger related | **7** | 2,181 |
| **Total Current Assets** | **18,512** | 18,327 |
| Long-term receivables, net | **1,253** | 1,225 |
| Investments and advances | **12,664** | 12,252 |
| Properties, plant and equipment, at cost | **101,130** | 99,943 |
| Less: accumulated depreciation, depletion and amortization | **57,684** | 56,710 |
| | **43,446** | 43,233 |
| Deferred charges and other assets | **2,795** | 2,535 |
| **Total Assets** | **$ 78,670** | $77,572 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Short-term debt | **$ 9,163** | $ 8,429 |
| Accounts payable | **7,375** | 6,427 |
| Accrued liabilities | **2,979** | 3,399 |
| Federal and other taxes on income | **1,532** | 1,398 |
| Other taxes payable | **1,033** | 1,001 |
| **Total Current Liabilities** | **22,082** | 20,654 |
| Long-term debt | **8,389** | 8,704 |
| Capital lease obligations | **283** | 285 |
| Deferred credits and other noncurrent obligations | **4,277** | 4,394 |
| Noncurrent deferred income taxes | **6,028** | 6,132 |
| Reserves for employee benefit plans | **3,196** | 3,162 |
| Minority interests | **292** | 283 |
| **Total Liabilities** | **44,547** | 43,614 |
| Preferred stock (authorized 100,000,000 shares, $1.00 par value, none issued) | **—** | — |
| Common stock (authorized 4,000,000,000 shares, $0.75 par value, 1,137,021,057 shares issued) | **853** | 853 |
| Capital in excess of par value | **4,822** | 4,811 |
| Retained earnings | **32,750** | 32,767 |
| Accumulated other comprehensive loss | **(255)** | (306) |
| Deferred compensation and benefit plan trust | **(652)** | (752) |
| Treasury stock, at cost (69,552,735 and 69,800,315 | | |

| | | |
|---|---|---|
| shares at March 31, 2002 and December 31, 2001, respectively) | **(3,395)** | (3,415) |
| **Total Stockholders' Equity** | **34,123** | 33,958 |
| **Total Liabilities and Stockholders' Equity** | **$ 78,670** | $77,572 |

See accompanying notes to consolidated financial statements.

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**CHEVRONTEXACO CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENT OF CASH FLOWS**
**(Unaudited)**

| Millions of Dollars | Three Months Ended March 31, 2002 | 2001 |
|---|---|---|
| **Operating Activities** | | |
| Net income | **$ 725** | $ 2,433 |
| Adjustments | | |
| Depreciation, depletion and amortization | **1,205** | 1,157 |
| Dry hole expenses | **39** | 72 |
| Distributions less than income from equity affiliates | **(51)** | (17) |
| Net before-tax gains on asset retirements and sales | **(27)** | (16) |
| Net foreign currency gains | **(121)** | (7) |
| Deferred income tax provision | **(204)** | 159 |
| Net (increase) decrease in operating working capital | **(229)** | 169 |
| Minority interest in net income | **12** | 38 |
| Other, net | **(276)** | (28) |
| **Net Cash Provided by Operating Activities** | **1,073** | 3,960 |
| **Investing Activities** | | |
| Capital expenditures | **(1,845)** | (1,993) |
| Proceeds from asset sales | **2,177** | 64 |
| Net sales (purchases) of marketable securities | **222** | (98) |
| Net purchases of other short-term investments | **—** | (656) |
| **Net Cash Provided By (Used for) Investing Activities** | **554** | (2,683) |
| **Financing Activities** | | |
| Net borrowings of short-term obligations | **861** | 1,099 |
| Proceeds from issuance of long-term debt | **25** | 690 |
| Repayments of long-term debt and other financing obligations | **(371)** | (1,871) |
| Cash dividends | **(747)** | (662) |
| Dividends paid to minority interests | **(2)** | (54) |
| Net sales of treasury shares | **21** | 57 |
| **Net Cash Used for Financing Activities** | **(213)** | (741) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | **(6)** | (13) |
| **Net Change in Cash and Cash Equivalents** | **1,408** | 523 |
| **Cash and Cash Equivalents at January 1** | **2,117** | 2,328 |
| **Cash and Cash Equivalents at March 31** | **$ 3,525** | $ 2,851 |

See accompanying notes to consolidated financial statements.

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## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### Note 1. Interim Financial Statements

The accompanying consolidated financial statements of ChevronTexaco Corporation and its subsidiaries (the company) have not been audited by independent accountants, except for the balance sheet at December 31, 2001. In the opinion of the company's management, the interim data include all adjustments necessary for a fair statement of the results for the interim periods. These adjustments were of a normal recurring nature, except for the special charge and merger-related expenses described in Note 2.

On October 9, 2001, Texaco Inc. (Texaco) became a wholly owned subsidiary of Chevron Corporation (Chevron) pursuant to a merger transaction, and Chevron changed its name to ChevronTexaco Corporation. The combination was accounted for as a pooling of interests. The accompanying consolidated financial statements give retroactive effect to the merger, with all periods presented as if Chevron and Texaco had always been combined.

Certain notes and other information have been condensed or omitted from the interim financial statements presented in this Quarterly Report on Form 10-Q. Therefore, these financial statements should be read in conjunction with the company's 2001 Annual Report on Form 10-K.

The results for the three-month period ended March 31, 2002, are not necessarily indicative of future financial performance.

### Note 2. Net Income

Net income for the first quarter of 2002 included a special charge of $74 million for the company's share of a write-down by its Dynegy affiliate of investments in telecommunications businesses and $132 million for merger-related expenses. Net income for the first quarter of 2001 included $21 million for merger-related expenses.

Net income in the first quarters 2002 and 2001 included foreign currency gains of $131 million and $87 million, respectively.

### Note 3. Information Relating to the Statement of Cash Flows

The "Net (increase) decrease in operating working capital" is composed of the following:

| | Three Months Ended March 31 | |
|---|---|---|
| Millions of Dollars | **2002** | **2001** |
| (Increase) decrease in accounts and notes receivable | **$(811)** | $ 865 |
| Increase in inventories | **(81)** | (477) |
| Increase in prepaid expenses and other current assets | **(7)** | (371) |
| Increase (decrease) in accounts payable and accrued liabilities | **567** | (268) |
| Increase in income and other taxes payable | **103** | 420 |
| Net (increase) decrease in operating working capital | **$(229)** | $ 169 |

"Net Cash Provided by Operating Activities" includes the following cash payments for interest on debt and for income taxes:

| | Three Months Ended March 31 | |
|---|---|---|
| Millions of Dollars | **2002** | **2001** |

| | | |
|---|---|---|
| Interest paid on debt (net of capitalized interest) | **$146** | $ 250 |
| Income taxes paid | **$705** | $1,227 |

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

The "Net sales (purchases) of marketable securities" consists of the following gross amounts:

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| Marketable securities purchased | **$(1,537)** | $(766) |
| Marketable securities sold | **1,759** | 668 |
| Net sales (purchases) of marketable securities | **$ 222** | $ (98) |

"Net purchases of other short-term investments," of $656 million in 2001 were in a variety of short-term money market instruments with maturities similar to the company's commercial paper portfolio. There were no investments under this program in 2002.

The major components of "Capital expenditures" and the reconciliation of this amount to the capital and exploratory expenditures presented in "Management's Discussion and Analysis of Financial Condition and Results of Operations," are presented in the following table.

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| Additions to properties, plant and equipment | **$1,489** | $1,290 |
| Additions to investments | **330** | 618 |
| Current year dry hole expenditures | **29** | 64 |
| Payments for other liabilities and assets, net | **(3)** | 21 |
| Capital expenditures | **1,845** | 1,993 |
| Other exploration expenditures | **46** | 90 |
| Repayments of long-term debt and other financing obligations | **2** | 210* |
| Capital and exploratory expenditures, excluding equity affiliates | **1,893** | 2,293 |
| Equity in affiliates | **257** | 213 |
| Capital and exploratory expenditures, including equity affiliates | **$2,150** | $2,506 |

* Deferred payment related to 1993 acquisition of an interest in the Tengizchevroil joint venture.

The Consolidated Statement of Cash Flows excludes the following non-cash transactions:

The company's Employee Stock Ownership Plan (ESOP) repaid $100 million of matured debt guaranteed by ChevronTexaco Corporation in January of 2002 and 2001, respectively. These payments were recorded by the company as reductions to "Short-term debt" and "Deferred Compensation."

**Note 4. Operating Segments and Geographic Data**

ChevronTexaco separately manages its exploration and production; refining, marketing and transportation; and chemicals

businesses. “All Other” activities include corporate administrative costs, worldwide cash management and debt financing activities, coal mining operations, power and gasification operations, technology investments, insurance operations and real estate activities. The company’s primary country of operation is the United States of America, its country of domicile. The remainder of the company’s operations is reported as International (outside the United States).

The company evaluates the performance of its operating segments on an after-tax basis, without considering the effects of debt financing interest expense or investment interest income, both of which are

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

managed by the company on a worldwide basis. Corporate administrative costs and assets are not allocated to the operating segments. However, operating segments are billed for the direct use of corporate services. Nonbillable costs and merger effects remain at the corporate level. After-tax segment income (loss) for the three-month month periods ended March 31, 2002 and 2001, is presented in the following table.

**Segment Income**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| Exploration and Production | | |
| United States | **$ 304** | $1,313 |
| International | **837** | 939 |
| Total Exploration and Production | **1,141** | 2,252 |
| Refining, Marketing and Transportation | | |
| United States | **(154)** | 189 |
| International | **93** | 267 |
| Total Refining, Marketing and Transportation | **(61)** | 456 |
| Chemicals | | |
| United States | **3** | (44) |
| International | **12** | 7 |
| Total Chemicals | **15** | (37) |
| Total Segment Income | **1,095** | 2,671 |
| Merger effects | **(132)** | (21) |
| Interest Expense | **(105)** | (169) |
| Interest Income | **18** | 33 |
| Other | **(151)** | (81) |
| Net Income | **$ 725** | $2,433 |

Segment assets do not include intercompany investments or intercompany receivables. “All Other” assets consist primarily of worldwide cash and marketable securities, real estate, information systems, the investment in Dynegy Inc., coal mining operations, power and gasification operations, technology investments and merger-related assets held for sale. Segment assets at March 31, 2002, and year-end 2001 follow.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**Segment Assets**

| Millions of Dollars | At March 31 2002 | At December 31 2001 |
|---|---|---|
| Exploration and Production | | |
| United States | **$12,223** | $12,718 |
| International | **24,493** | 24,177 |
| Total Exploration and Production | **36,716** | 36,895 |
| Refining, Marketing and Transportation | | |
| United States | **9,573** | 8,902 |
| International | **17,239** | 16,426 |
| Total Refining, Marketing and Transportation | **26,812** | 25,328 |
| Chemicals | | |
| United States | **2,058** | 2,059 |
| International | **685** | 701 |
| Total Chemicals | **2,743** | 2,760 |
| Total Segment Assets | **66,271** | 64,983 |
| All Other | | |
| United States | **8,053** | 8,950 |
| International | **4,346** | 3,639 |
| Total All Other | **12,399** | 12,589 |
| Total Assets – United States | **31,907** | 32,629 |
| Total Assets – International | **46,763** | 44,943 |
| Total Assets | **$78,670** | $77,572 |

Operating segment sales and other operating revenues, including internal transfers, for the three-month periods ended March 31, 2002 and 2001, are presented in the following table. Sales from the transfer of products between segments are at prices that approximate market prices.

Revenues for the exploration and production segment are derived primarily from the production of crude oil and natural gas. Revenues for the refining, marketing and transportation segment are derived from the refining and marketing of petroleum products, such as gasoline, jet fuel, gas oils, kerosene, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the transportation and trading of crude oil and refined products. Revenues for the chemicals segment are derived from the manufacture and sale of lube oil and fuel additives. “All Other” activities include corporate administrative costs, worldwide cash management and debt financing activities, coal mining operations, power and gasification operations, technology investments, insurance operations and real estate activities.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**Sales and Other Operating Revenues**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| Exploration and Production | | |
| United States | **$ 2,086** | $ 6,419 |
| International | **3,217** | 3,953 |
| Sub-total | **5,303** | 10,372 |
| Intersegment Elimination – United States | **(812)** | (849) |
| Intersegment Elimination – International | **(1,849)** | (1,585) |
| Total Exploration and Production | **2,642** | 7,938 |
| Refining, Marketing and Transportation | | |
| United States | **7,153** | 8,838 |
| International | **10,834** | 12,105 |
| Sub-total | **17,987** | 20,943 |
| Intersegment Elimination – United States | **(40)** | (75) |
| Intersegment Elimination – International | **(180)** | (119) |
| Total Refining, Marketing and Transportation | **17,767** | 20,749 |
| Chemicals | | |
| United States | **106** | 92 |
| International | **173** | 194 |
| Sub-total | **279** | 286 |
| Intersegment Elimination – United States | **(23)** | (22) |
| Intersegment Elimination – United States | **(18)** | (24) |
| Total Chemicals | **238** | 240 |
| All Other | | |
| United States | **234** | 103 |
| International | **5** | 14 |
| Sub-total | **239** | 117 |
| Intersegment Elimination – United States | **(42)** | (12) |
| Intersegment Elimination – International | **–** | (2) |
| Total All Other | **197** | 103 |
| **Sales and Other Operating Revenues** | | |
| United States | **9,579** | 15,452 |
| International | **14,229** | 16,266 |
| Sub-total | **23,808** | 31,718 |
| Intersegment Elimination – United States | **(917)** | (958) |
| Intersegment Elimination – International | **(2,047)** | (1,730) |
| Total Sales and Other Operating Revenues | **$20,844** | $29,030 |

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**Note 5. Employee Termination Benefits and Other Restructuring Costs**

The company expects to incur approximately $2 billion of one-time before-tax expenses in connection with the merger of Chevron and Texaco. Major expenses include employee severance payments; incremental pension and medical plan benefit costs associated with workforce reductions; legal, accounting, SEC filing and investment banker fees; employee and office relocations; and costs for the elimination of redundant facilities and operations.

In 2001, before-tax merger-related expenses were $1,563 million ($1,136 million after tax). In the first quarter 2002, such expenses were $183 million ($132 million after tax). The combined total of $1,746 million ($1,268 million after tax) included accruals of $891 million and $11 million in 2001 and the first quarter 2002, respectively, for severance-related benefits for approximately 4,500 employees and other merger-related expenses that will not benefit future operations.

Activity for this merger-related accrual balance is summarized in the table below:

| Millions of dollars | **Amount** |
|---|---|
| Accrued – 2001 | $ 891 |
| Paid – 2001 | (105) |
| **Balance at December 31, 2001** | **786** |
| Accrued – first quarter 2002 | 11 |
| Paid – first quarter 2002 | (259) |
| **Balance at March 31, 2002** | **$ 538** |

The ending accrual balance is expected to be extinguished within one year, except for $56 million classified as long-term, which is associated with elections by certain employees to defer severance payments until 2004. Approximately 2,700 employees had terminated as of March 31, 2002. Substantially all of the remaining terminations are expected to occur by the end of this year.

**Note 6. Summarized Financial Data – Chevron U.S.A. Inc.**

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of ChevronTexaco Corporation. CUSA and its subsidiaries and affiliates manage and operate most of ChevronTexaco's U.S. businesses and assets related to the exploration and production of crude oil, natural gas and natural gas liquids and also those associated with refining, marketing, supply and distribution of products derived from petroleum, other than natural gas liquids, excluding most of the pipeline operations of ChevronTexaco. CUSA also holds ChevronTexaco's investment in the Chevron Phillips Chemical Company joint venture, which is accounted for using the equity method. Summarized financial information for CUSA and its consolidated subsidiaries is presented in the following table.

| | **Three Months Ended March 31** | |
|---|---|---|
| Millions of Dollars | **2002** | **2001** |
| Sales and other operating revenues | **$11,224** | $9,576 |
| Costs and other deductions | **11,650** | 8,623 |
| Net income | **(253)** | 704 |

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

| Millions of Dollars | At March 31 2002 | At December 31 2001 |
|---|---|---|
| Current assets | **$ 4,577** | $ 2,888 |
| Other assets | **20,542** | 20,795 |
| Current liabilities | **5,145** | 4,344 |
| Other liabilities | **10,630** | 9,797 |
| Net worth | **9,344** | 9,542 |
| Memo: Total Debt | **$ 6,271** | $ 6,272 |

**Note 7. Summarized Financial Data – Chevron Transport Corporation Limited**

Chevron Transport Corporation Limited (CTC), incorporated in the Bermuda Islands, is an indirect, wholly owned subsidiary of ChevronTexaco Corporation. CTC is the principal operator of ChevronTexaco's international tanker fleet and is engaged in the marine transportation of crude oil and refined petroleum products. Most of CTC's shipping revenue is derived by providing transportation services to other ChevronTexaco companies. ChevronTexaco Corporation has guaranteed this subsidiary's obligations in connection with certain debt securities issued by a third party. Summarized financial information for CTC and its consolidated subsidiaries is presented as follows:

| | Three Months Ended March 31 | |
|---|---|---|
| Millions of Dollars | 2002 | 2001 |
| Sales and other operating revenues | **$205** | $259 |
| Costs and other deductions | **216** | 209 |
| Net (loss) income | **(12)** | 51 |

| Millions of Dollars | At March 31 2002 | At December 31 2001 |
|---|---|---|
| Current assets | **$230** | $196 |
| Other assets | **504** | 527 |
| Current liabilities | **302** | 280 |
| Other liabilities | **312** | 311 |
| Net worth | **120** | 132 |

There were no restrictions on CTC's ability to pay dividends or make loans or advances at March 31, 2002.

**Note 8. Income Taxes**

Taxes on income for the first quarter of 2002 were $590 million, compared with $1,757 million in last year's first quarter. The effective tax rate for the first quarter of 2002 was 45 percent compared with 42 percent in last year's first quarter. The increase in the effective tax rate in 2002 was primarily due to a higher proportion of international before-tax income, generally taxed at higher rates. Partially offsetting this increase were higher capital loss benefits and other tax credits as a percentage of before-tax income.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**Note 9. Litigation**

Chevron, Texaco and four other oil companies (refiners) filed suit in 1995 contesting the validity of a patent granted to Unocal Corporation (Unocal) for reformulated gasoline, which ChevronTexaco sells in California in certain months of the year. In March 2000, the U.S. Court of Appeals for the Federal Circuit upheld a September 1998 District Court decision that Unocal's patent was valid and enforceable and assessed damages of 5.75 cents per gallon for gasoline produced in infringement of the patent. In May 2000, the Federal Circuit Court denied a petition for rehearing with the U.S. Court of Appeals for the Federal Circuit filed by the refiners in this case. The refiners petitioned the U.S. Supreme Court and, in February 2001, the Supreme Court denied the petition to review the lower court's ruling and the case was remanded to the District Court for an accounting of all infringing gasoline produced from August 1, 1996, to September 30, 2000. The District Court is considering Unocal's motion for summary judgment requesting an accounting and the refiners' motion to stay the proceedings and vacate the accounting order. Oral arguments on these motions were held in early May 2002.

Separately, in May 2001, the U.S. Patent Office (USPO) granted the refiners' petition to re-examine the validity of Unocal's patent and, in February 2002, the USPO rejected all of the claims presented by Unocal. Unocal has responded to the USPO ruling and the USPO has not replied. The Federal Trade Commission has also announced that it is investigating whether Unocal's failure to disclose to the California Air Resources Board that it had filed a patent application was unfair competition, which may make Unocal's patent unenforceable.

If Unocal's patent ultimately is upheld and is enforceable, the company's financial exposure includes royalties, plus interest, for production of gasoline that is proved to have infringed the patent. Chevron and Texaco have been accruing in the normal course of business any future estimated liability for potential infringement of the patent covered by the trial court's ruling. In 2000, Chevron and Texaco made payments to Unocal totaling approximately $28 million for the original court ruling, including interest and fees.

Unocal has obtained additional patents for alternate formulations that could affect a larger share of U.S. gasoline production. ChevronTexaco believes these additional patents are invalid and unenforceable. However, if such patents are ultimately upheld, the competitive and financial effects on the company's refining and marketing operations, while presently indeterminable, could be material.

Another issue involving the company is the petroleum industry's use of methyl tertiary-butyl ether (MTBE) as a gasoline additive and its potential environmental impact through seepage into groundwater. Along with other oil companies, the company is a party to lawsuits and claims related to the use of the chemical MTBE in certain oxygenated gasolines. These actions may require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. Costs to the company related to these lawsuits and claims are not currently determinable. ChevronTexaco continues the use of MTBE in gasoline it sells in certain areas. The state of California has directed that MTBE be phased out of the manufacturing process by the end of 2003.

**Note 10. Other Contingencies and Commitments**

The U.S. federal income tax liabilities have been settled through 1993 for Chevron and Caltex and through 1991 for Texaco. The company's California franchise tax liabilities have been settled through 1991 for Chevron and 1987 for Texaco.

Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

The company and its subsidiaries have certain other contingent liabilities with respect to guarantees, direct or indirect, of debt of affiliated companies or others and long-term unconditional purchase obligations and commitments, throughput agreements and take-or-pay agreements, some of which relate to suppliers' financing arrangements.

The company has commitments related to preferred shares of subsidiary companies, which are accounted for as minority interest. MVP Production Inc., a subsidiary, has variable rate cumulative preferred shares of $75 million owned by one minority holder. The shares are voting and are redeemable in 2003. Texaco Capital LLC, a wholly owned finance subsidiary, has issued $65 million of Deferred Preferred Shares, Series C. Dividends of $59 million on Series C, equivalent to a rate of 7.17 percent compounded annually, will be paid at the redemption date of February 28, 2005, unless earlier redemption occurs. Early redemption may result upon the occurrence of certain specific events.

ChevronTexaco provided certain indemnities of contingent liabilities of Equilon Enterprises LLC (Equilon) and Motiva Enterprises LLC (Motiva) to Shell Oil and Saudi Refining Inc. as part of the agreement for the sale of the company's interests in those investments. Generally, the indemnities provided are limited to contingent liabilities that may become actual liabilities within 18 months of the sale of the company's interests, and are reduced by any reserves that were established prior to the sale. Excluding environmental liabilities, the company's financial exposure related to those indemnities is limited to $300 million. Additionally, the company has provided indemnities for certain environmental liabilities arising out of conditions that existed prior to the formation of Equilon and Motiva and during the periods of ChevronTexaco's ownership interest in those entities as well as for customary representations and warranties within the agreements.

The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemical or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including but not limited to: Superfund sites and refineries, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold. The amount of such future cost is indeterminable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. While the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemicals concerns.

ChevronTexaco receives claims from, and submits claims to, customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers, and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its commodities and other derivatives activities, including forward exchange contracts and interest rate swaps. However, the results of operations and the financial position of certain equity affiliates may be affected by their business activities involving the use of derivative instruments.

The company's operations, particularly exploration and production, can be affected by other changing economic, regulatory and political environments in the various countries in which it operates, including the United States. The Organization of Petroleum Exporting Countries (OPEC) has at times made efforts to support crude oil prices by limiting production. In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest or strained relations

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results, and are carefully considered by management when evaluating the level of current and future activity in such countries.

Areas in which the company and its affiliates have significant operations include the United States of America, Canada, Australia, the United Kingdom, Norway, Denmark, Kuwait, Republic of Congo, Angola, Nigeria, Chad, Equatorial Guinea, Democratic Republic of Congo, South Africa, Indonesia, Papua New Guinea, the Philippines, Singapore, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad and Korea. The company's Tengizchevroil affiliate operates in Kazakhstan. The company's Chevron Phillips Chemical Company LLC affiliate manufactures and markets a wide range of petrochemicals and plastics on a worldwide basis, with manufacturing facilities in existence or under construction in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium. The company's Dynegy affiliate has operations in the United States, Canada, the United Kingdom and other European countries.

For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated oil and gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for ChevronTexaco's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills in California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. ChevronTexaco currently estimates its maximum possible net before-tax liability at less than $400 million. At the same time, a possible maximum net amount that could be owed to ChevronTexaco is estimated at more than $200 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

**Note 11. New Accounting Standards**

Recent interpretations of Financial Accounting Standards Board (FASB) Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 138, "Accounting for Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133", by the FASB Derivatives Implementation Group prescribe mark-to-market accounting for certain natural gas sales contracts and power sales agreements. Some of these interpretations became effective January 1, 2002. Adoption at that time did not result in a material effect to earnings. Implementation of these interpretations during the first quarter 2002 resulted in after-tax gains of $37 million. The effect of subsequent changes in the contracts' fair values is uncertain. Other interpretations became effective April 1, 2002, and apply to certain power sales agreements of the company's affiliates. The financial statement effects of these interpretations are currently being evaluated.

In June 2001, the FASB issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 is effective for fiscal years beginning after June 15, 2002. FAS 143 differs in several significant respects from current accounting for asset retirements obligations under FAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." Adoption of FAS 143 will affect future accounting and reporting of the assets, liabilities and expenses related to these obligations. The magnitude of the effect has not yet been determined.

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## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### First Quarter 2002 Compared With First Quarter 2001

**Financial Results**

**EARNINGS BY MAJOR OPERATING AREA, EXCLUDING SPECIAL ITEMS AND MERGER-RELATED EXPENSES**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| Exploration and Production | | |
| United States | **$ 304** | $1,313 |
| International | **837** | 939 |
| Total Exploration and Production | **1,141** | 2,252 |
| Refining, Marketing and Transportation | | |
| United States | **(154)** | 189 |
| International | **93** | 267 |
| Total Refining, Marketing and Transportation | **(61)** | 456 |
| Chemicals | **15** | (37) |
| All Other | **(164)** | (217) |
| Earnings Excluding Special Items and Merger-related Expenses* | **931** | 2,454 |
| Special Item | **(74)** | — |
| Merger-related Expenses | **(132)** | (21) |
| **Net Income*** | **$ 725** | $2,433 |
| * Includes Foreign Currency Gains | **$ 131** | $ 87 |

Net income for the first quarter of 2002 was $725 million ($0.68 per share-diluted), a decline of 70 percent from 2001 first quarter net income of $2.433 billion ($2.29 per share diluted). Net income for the first quarter of 2002 included a special charge of $74 million for the company's share of a write-down by its Dynegy affiliate of investments in telecommunications businesses and $132 million for merger-related expenses. Last year's first quarter net income included merger-related expenses of $21 million. Earnings of $931 million, excluding special items and merger-related expenses, were down more than 60 percent from last year's very strong first quarter results.

First quarter 2002 earnings were adversely affected by significantly lower prices for crude oil, natural gas and refined products than in last year's first quarter. The lower prices affected the company's U.S. businesses the most. U.S exploration and production (upstream) segment earnings of $304 million decreased 77 percent between periods, as the average U.S. crude oil realization fell about 30 percent to $17.38 per barrel and the average natural gas realization declined by two-thirds to $2.27 per thousand cubic feet. The U.S. refining, marketing and transportation (downstream) sector recorded a $154 million loss for the quarter, reflecting industry margins that were at the lowest levels since the mid-1990s.

**Texaco Merger Transaction**

Agreements have been reached on all of the asset dispositions mandated by the Federal Trade Commission (FTC) as a condition of approving the merger. The sale of the company's interests in Equilon and Motiva – joint ventures engaged in

U.S. downstream businesses – closed in February, resulting in cash proceeds of $2.2 billion, including dividends due. Sales of other assets, with a combined net book value of

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$7 million, are scheduled to close in the coming months. Completion of these dispositions remains subject to certain closing conditions, including final approval by the FTC. Net income effects from the remaining asset sales will not be material to the company's results of operations.

Teams of company employees worldwide are implementing initiatives designed to capture savings from merger synergies. By the end of the first quarter, the company had processes in place to achieve its interim target rate of $1.2 billion in annual synergy savings before tax, and expects to realize the total objective of $1.8 billion in savings by early 2003. Some examples of initiatives to-date on merger integration activities are as follows:

- **Exploration** – High grading investment opportunities in the combined-company portfolio; sharing knowledge of drilling prospects by staffs of the combining companies.

- **Production** – Leveraging operating efficiencies in common areas operated separately by Chevron and Texaco prior to the merger; high-grading development spending to increase production volumes. Progress has also been made in reducing operating expenses in areas of overlap for upstream producing operations.

- **Refining** – Collaborating across the worldwide refinery network to adopt best practices in process technology.

- **Marketing** – Leveraging the company's size and purchasing power to reduce costs of advertising, convenience store operations and the product distribution network.

- **Shipping** – Improving the use of company and chartered tankers as more opportunities are provided to optimize ship utilization.

- **Corporate and Other** – Consolidating offices, computer systems and telecommunications networks.

The company expects to incur approximately $2 billion of one-time before-tax expenses through 2003 in connection with the merger of Chevron and Texaco. Major expenses include employee severance payments; incremental pension and medical plan benefit costs associated with workforce reductions; legal, accounting, SEC filing and investment banker fees; employee and office relocations; and costs for the elimination of redundant facilities and operations.

In 2001, before-tax merger-related expenses were $1,563 million ($1,136 million after tax). In the first quarter 2002, such expenses were $183 million ($132 million after tax). The combined total of $1,746 million ($1,268 million after tax) included accruals of $891 million and $11 million in 2001 and the first quarter 2002, respectively, for severance-related benefits for approximately 4,500 employees and other merger-related expenses that will not benefit future operations.

Activity for this merger-related accrual balance is summarized in the table below:

| Millions of dollars | **Amount** |
|---|---|
| Accrued – 2001 | $ 891 |
| Paid – 2001 | (105) |
| **Balance at December 31, 2001** | **786** |
| Accrued – first quarter 2002 | 11 |
| Paid – first quarter 2002 | (259) |
| **Balance at March 31, 2002** | **$ 538** |

The ending accrual balance is expected to be extinguished within one year, except for $56 million classified as long-term, which is associated with elections by certain employees to defer severance payments until 2004. Approximately 2,700 employees had terminated as of March 31, 2002. Substantially all of the remaining terminations are expected to occur by the end of this year.

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**Recent Events**

Operational highlights in early 2002 include:

- **U.S. Gulf of Mexico** – In April, the company announced a significant discovery at its Tahiti prospect, located in deepwater Gulf of Mexico's Green Canyon Block 640. Appraisal drilling is under way. ChevronTexaco is the operator and has a 58 percent interest.

- **U.K. North Sea** – Production began in February at the Jade Field, in which the company has a 20 percent interest. Daily production rates for the field of 200 million cubic feet of natural gas and 16,000 barrels of oil are expected by the third quarter of 2002, when the drilling of additional development wells is completed.

- **Africa** – ChevronTexaco was named as operator for future exploration and development activities along the shared maritime border between of the Republic of Congo and Angola. The company has interests located nearby in Haute Mer (Republic of Congo) and Block 14 (Angola). Terms of participation among all the parties are being discussed. In Nigeria, technology-licensing agreements were signed by Chevron Nigeria Limited, Nigerian National Petroleum Corporation and Sasol/ Chevron Holdings Limited to initiate work on the $1.3 billion Escravos gas-to-liquids plant. The project represents the most extensive technology cooperation to date between Nigerian and South African entities. Project completion is scheduled for 2006. Also in Nigeria, in May, ChevronTexaco announced the second oil discovery in deepwater Nigeria Block OPL 222, which is operated by Elf Petroleum Nigeria Ltd. ChevronTexaco has a 30 percent interest in OPL 222.

- **Southeast Asia** – The company was awarded a license to explore for oil and gas in Block A, located in the eastern section of the Gulf of Thailand in offshore Cambodia. The company is the operator and has a 70 percent interest in the license.

- **Chemicals** – Chevron Phillips Chemical Company LLC (CPChem), the company's 50 percent-owned petrochemical affiliate, and its partner announced plans for a $1 billion expansion to the existing joint venture aromatics complex in Saudi Arabia. The expansion will produce benzene, ethylbenzene, styrene and propylene from the facility, which currently produces benzene, cyclohexane and motor gasoline. Start-up is expected in 2006. In addition, CPChem and its partner are increasing the cyclohexane capacity at the complex in Saudi Arabia to 620 million pounds. The additional 130 million pounds of capacity is expected to be operational by the first quarter of 2003. CPChem will continue to market the products that are exported from the region.

**Operating Environment and Outlook**

ChevronTexaco's exploration and production (upstream) earnings are affected significantly by fluctuations in industry price levels for crude oil and natural gas. Average U.S. natural gas and crude oil prices in the first quarter of 2002 were significantly lower than in last year's first quarter. Henry Hub spot natural gas prices declined more than 60 percent from $6.69 to $2.44 per thousand cubic feet. The average spot price for West Texas Intermediate (WTI), a benchmark crude oil, was $21.44 per barrel, compared with $28.76 in last year's first quarter. During April, the spot WTI price rebounded to an average of $26.27 per barrel, and the Henry Hub spot natural gas price climbed to an average of $3.44 per thousand cubic feet.

The Organization of Petroleum Exporting Countries (OPEC) continues its effort to support crude oil prices by limiting production. OPEC curtailments restrained ChevronTexaco's net production by approximately 35,000 barrels per day in the 2002 quarter, versus having no effect in the corresponding 2001 period. In addition, production under certain operating service agreements, which is not included in the company's net working interest production, was also curtailed 20,000 barrels per day in this year's first quarter, compared with approximately 5,000 barrels per day in the year-ago period. The long-term effect on industry prices due to OPEC production quotas remains uncertain.

In addition to OPEC production quotas, civil unrest, political uncertainty and economic conditions may affect the company's producing operations. Community protests have disrupted the company's production

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in the past, most recently in Nigeria and Indonesia. The company continues to monitor developments closely in the countries in which it operates.

The United Kingdom (U.K.) recently announced proposed changes to the U.K. North Sea tax regulations, under which a supplementary charge would effectively increase the U.K. corporation tax rate from 30 percent to 40 percent. If enacted, these changes will be effective from April 17, 2002. At the time of enactment, the company would record a one-time charge of approximately $100 million against net income to adjust historical deferred tax balances. On an annual basis, the company estimates incremental income tax expense of approximately $50 million as a result of the higher tax rates – based upon current forecasts of crude oil and natural gas prices, capital expenditures and production levels. The impact of the tax change on cash flow for the remainder of 2002 and for the 2003-2004 period is anticipated to be largely neutral, as accelerated capital allowances will essentially offset effects of the higher tax rate.

Downstream operating earnings are closely tied to refining and marketing margins, which can vary among the geographic areas in which the company operates. Results from the company's downstream business segment, particularly in the United States, suffered during the first quarter 2002 from industry margins that were at their lowest levels since the mid-1990s. Weaker product margins resulted from refined product prices that declined more between periods than the cost of crude oil feedstock for the refineries. Product margins in the United States have trended upward in the second quarter of 2002.

Chemical earnings continue to suffer from raw material and energy costs that cannot be fully recovered in prices of commodity chemicals because of industry over-capacity. Chemical margins are not expected to improve significantly in the near-term.

**Review of Operations**

Total revenues for the quarter were $21.2 billion, down from $29.4 billion in last year's first quarter. Revenues declined on sharply lower prices for crude oil, natural gas and refined products.

Operating, selling, general and administrative expenses declined $162 million due to lower fuel costs and other savings from combining the former operations of Chevron, Texaco and Caltex.

Interest and debt expense declined $112 million from the 2001 first quarter. The decrease was driven by lower interest rates on the company's commercial paper in 2002.

Taxes on income for the first quarter of 2002 were $590 million, compared with $1,757 million in last year's first quarter. The effective tax rate for the first quarter of 2002 was 45 percent compared with 42 percent in last year's first quarter. The increase in the effective tax rate in 2002 was primarily due to a higher proportion of international before-tax income, generally taxed at higher rates. Partially offsetting this increase were higher capital loss benefits and other tax credits as a percentage of before tax income.

Foreign currency gains included in first quarter 2002 net income were $131 million, compared with $87 million in 2001. Gains of $159 million in the 2002 quarter were attributable to the devaluation of the Argentine peso. These gains were partially offset by losses associated with the weakening of the U.S. dollar against the Australian dollar.

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The following table presents a comparison of selected operating data.

**SELECTED OPERATING DATA[1, 2]**

| | Three Months Ended March 31 | |
|---|---|---|
| | **2002** | **2001** |
| **U.S. Exploration and Production** | | |
| Net Crude Oil and Natural Gas Liquids Production (MBPD) | **619** | 610 |
| Net Natural Gas Production (MMCFPD) | **2,509** | 2,888 |
| Sales of Natural Gas (MMCFPD) | **6,844** | 8,073 |
| Sales of Natural Gas Liquids (MBPD) | **322** | 364 |
| Revenue from Net Production | | |
| Crude Oil ($/Bbl.) | **$17.38** | $24.42 |
| Natural Gas ($/MCF) | **$ 2.27** | $ 7.52 |
| **International Exploration and Production** | | |
| Net Crude Oil and Natural Gas Liquids Production (MBPD) | **1,356** | 1,341 |
| Net Natural Gas Production (MMCFPD) | **1,948** | 1,774 |
| Sales of Natural Gas (MMCFPD) | **3,589** | 2,493 |
| Sales of Natural Gas Liquids (MBPD) | **131** | 96 |
| Revenue from Liftings | | |
| Liquids ($/Bbl.) | **$19.02** | $23.44 |
| Natural Gas ($/MCF) | **$ 2.20** | $ 2.77 |
| Other Produced Volumes (MBPD)[3] | **96** | 111 |
| **U.S. Refining, Marketing and Transportation[4]** | | |
| Sales of Gasoline (MBPD)[5] | **697** | 666 |
| Sales of Other Refined Products (MBPD) | **885** | 927 |
| Refinery Input (MBPD) | **868** | 894 |
| Average Refined Product Sales Price ($/Bbl.) | **$26.24** | $40.35 |
| **International Refining, Marketing and Transportation** | | |
| Sales of Refined Products (MBPD) | **2,147** | 2,345 |
| Refinery Input (MBPD) | **1,167** | 1,144 |

[1] Includes equity in affiliates, unless noted otherwise.

[2] MBPD = thousand barrels per day; MMCFPD = million cubic feet per day; Bbl. = barrel; MCF = thousand cubic feet

[3] Represents total field production under the Boscan operating service agreement in Venezuela.

[4] Excludes Equilon and Motiva.

[5] Includes branded and unbranded gasoline.

**U.S. Exploration and Production**

| | Three Months Ended March 31 | |
|---|---|---|
| Millions of Dollars | **2002** | **2001** |
| **Segment Income** | **$304** | $1,313 |

U.S. Exploration and Production earnings of $304 million for the first quarter 2002 declined by slightly more than $1 billion compared with last year's quarter, driven by significantly lower crude oil and natural gas realizations and a 5 percent decline in oil-equivalent production. Partially offsetting these unfavorable effects were lower operating and exploration expenses. Operating expenses for fuel, steam and utilities

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decreased as a result of lower natural gas prices. Exploration expense reductions reflected lower amounts for well write-offs and acquisitions of seismic and survey data.

The average natural gas realization for the quarter was $2.27 per thousand cubic feet, compared with $7.52 in the year-ago period. The average crude oil realization was $17.38 per barrel, versus $24.42 in the corresponding 2001 quarter.

Net liquids production increased 2 percent to 619,000 barrels per day, as a result of higher production in deepwater Gulf of Mexico. Net natural gas production averaged 2.509 billion cubic feet per day, down 13 percent from the 2001 period. Drilling and production had been accelerated in the year-ago period to take advantage of the favorable natural gas price environment.

**International Exploration and Production**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| **Segment Income*** | **$837** | $939 |
| * Includes Foreign Currency Gains | **$153** | $ 46 |

International Exploration and Production earnings of $837 million decreased 11 percent, primarily the result of 20 percent-lower average liquids and natural gas realizations. Partially offsetting these effects were a 3 percent increase in net oil-equivalent production and gains of $37 million from mark-to-market accounting applied to certain natural gas sales contracts under an accounting rule that became effective at the beginning of the year.

Net international liquids production increased 1 percent to 1,356,000 barrels per day – primarily from operations in the United Kingdom. OPEC curtailments restrained net production approximately 35,000 barrels per day in the 2002 quarter, versus having no effect in the corresponding 2001 period. Production under certain operating service agreements, which are not included in net working interest production statistics, was also curtailed 20,000 barrels per day in this year's first quarter, compared with approximately 5,000 barrels per day in the year-ago period.

Net natural gas production increased 10 percent to 1.948 billion cubic feet per day. New production from the Philippines and higher production in Australia, Colombia, Nigeria, and Thailand offset declines in Canada and Denmark.

Earnings for the quarter included net foreign currency gains of $153 million, compared with $46 million in 2001. The 2002 quarter included gains of approximately $159 million attributable to the devaluation of the Argentine peso, partially offset by losses associated with the weakening of the U.S. dollar against the Australian dollar.

**U.S. Refining, Marketing and Transportation**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| **Segment (Loss) Income** | **$(154)** | $189 |

U.S. Refining, Marketing and Transportation incurred a loss of $154 million, down $343 million from the year-ago quarter. Weaker product margins resulted from refined product prices that declined more between periods than the cost of crude oil feedstock for the refineries. More extensive planned refinery maintenance in the 2002 quarter, requiring product purchases, contributed to the decline in margins. Included in earnings for the first quarter 2002 was $36 million from investments in Equilon and Motiva, compared with $69 million in the 2001 quarter.

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The average U.S. refined product sales realization declined 35 percent to $26.24 per barrel. U.S. refined product sales volumes, excluding the company's share of Equilon and Motiva, decreased less than 1 percent in the first quarter 2002 to 1,582,000 barrels per day. A 5 percent increase to 570,000 barrels per day in branded gasoline sales was more than offset by decreases in sales volumes for jet and fuel oils.

**International Refining, Marketing and Transportation**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| **Segment Income*** | **$ 93** | $267 |
| * Includes Foreign Currency (Losses) Gains | **$(18)** | $ 55 |

International Refining, Marketing and Transportation earnings of $93 million in the first quarter 2002 declined by $174 million, primarily due to lower overall refined product margins in most areas and lower earnings for the shipping operations. Earnings in the 2002 quarter included foreign currency losses of $18 million, primarily from New Zealand, South Africa and the company's Australian affiliate, compared with gains of $55 million in 2001.

Total refined products sales volumes decreased 8 percent to 2,147,000 barrels per day, mainly on lower trading, marine fuels, and Canadian refined product sales.

**Chemicals**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| **Segment Income (Losses)*** | **$15** | $(37) |
| * Includes Foreign Currency Losses | **$ (1)** | $ (4) |

Chemical operations earned $15 million in 2002, compared with losses of $37 million in last year's first quarter. Profits were higher for the company's Oronite business, while losses were lower for the 50 percent-owned Chevron Phillips Chemical Company LLC affiliate. Product sales margins for the affiliate, while improved as a result of lower feedstock costs in 2002, remained weak.

**All Other**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| Net Charges, Excluding Special Items and Merger-related Expenses* | **$(164)** | $(217) |
| Special Item | **(74)** | — |
| Merger-related Expenses | **(132)** | (21) |
| **Segment Charges*** | **$(370)** | $(238) |
| * Includes Foreign Currency Losses | **$ (3)** | $ (10) |

All Other consists of the company's investment in Dynegy Inc., coal mining operations, power and gasification operations, worldwide cash management and debt financing activities, corporate administrative costs, insurance operations, real estate

activities, technology investments and certain e-businesses. Net charges before the special item and merger-related expenses were $164 million in 2002, $53 million lower than the 2001 quarter.

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Coal mining operations earned $5 million, down marginally from $6 million in the 2001 quarter. Operating results for the company's power and gasification ventures improved $16 million to a loss of $2 million in the 2002 first quarter. The company's share of Dynegy's operating earnings increased $6 million to $40 million, primarily related to earnings improvements in the transmission and distribution business, with the addition of Northern Natural Gas Company and, in the wholesale energy network.

Net charges – excluding merger-related expenses and special items – from other activities were $207 million, compared with $239 million in 2001. The favorable effects of lower interest expense and higher interest income more than offset increases to other corporate charges.

The special item represented a charge of $74 million for the company's share of a write-down by its Dynegy affiliate of investments in telecommunications businesses.

Merger-related expenses of $132 million in 2002 included employee severance benefits, actuarial losses on pension benefits for terminated employees and expenses associated with contract terminations.

**Liquidity and Capital Resources**

Cash and cash equivalents and marketable securities totaled over $4.3 billion at March 31, 2002 – a $1.2 billion increase from year-end 2001. Contributing to this increase was the receipt of $2.2 billion in proceeds, including dividends due, from the sale of the company's investments in Equilon and Motiva. Cash provided by operating activities was about $1.1 billion in the first quarter of 2002 compared with $4.0 billion in the year-ago quarter and was adversely affected by significantly lower crude oil, natural gas and refined products prices. Cash provided by operating activities and asset sales in the first quarter of 2002 was sufficient to fund the company's capital program and dividends to stockholders.

In March 2002, the company paid dividends of $747 million to common stockholders. On April 24, 2002, ChevronTexaco declared a quarterly dividend of 70 cents per share, unchanged from the preceding quarter, payable on June 10, 2002.

At the end of the first quarter, ChevronTexaco had $3.2 billion in committed credit facilities with various major banks, which permit the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and also can be used for general credit requirements. No borrowings were outstanding under these facilities at March 31, 2002. In addition, ChevronTexaco has three existing "shelf" registrations on file with the Securities and Exchange Commission that together would permit registered offerings of up to $2.8 billion of debt securities. At March 31, 2002, the company also had lines of credit available for short-term financing totaling $500 million, of which $190 million had not been used.

ChevronTexaco's total debt and capital lease obligations were $17.8 billion at March 31, 2002, up from $17.4 billion at year-end 2001. In the first quarter of 2002, net repayments of $346 million in long-term debt were more than offset by proceeds of $861 million from net additional short-term debt. Changes in long-term debt during the first quarter included a $250 million repayment of Texaco North Sea UK notes and a $100 million repayment of ChevronTexaco Corporation 8.11 percent notes. Also included in the reduction in the company's long-term debt levels was a non-cash reduction of $100 million of ESOP debt.

The company's debt due within 12 months, consisting primarily of commercial paper and the current portion of long-term debt, totaled $12.4 billion at March 31, 2002, up from $11.6 billion at December 31, 2001. Of this total short-term debt, $3.2 billion was reclassified to long-term at the end of both periods. Settlement of these obligations was not expected to require the use of working capital in 2002, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis. The company's practice has been to continually refinance its commercial paper, maintaining levels it believes to be appropriate.

In April 2002, the company agreed to fund up to $125 million for its 50 percent-owned Chevron Phillips Chemical Company LLC affiliate. It is anticipated that the funding will take place through the acquisition of preferred securities, which are expected to be issued in the second quarter.

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In November 2001, the company acquired $1.5 billion in Dynegy redeemable, convertible preferred stock. The instrument is convertible at ChevronTexaco's option into Dynegy common shares during a period ending in November 2003 at a conversion price of $31.64 per share. If the company does not exercise its option, Dynegy is obligated to redeem the preferred stock for $1.5 billion cash at the end of the period. During the period in which the company holds the preferred stock, changes in its fair value are reflected as "Unrealized gains (losses) on securities" as part of "Other comprehensive income". At March 31, 2002, other comprehensive income included a cumulative unrealized after-tax gain of $68 million for the Dynegy preferred shares. In addition to the investment in Dynegy preferred stock, the carrying value of the company's investment in Dynegy common stock, accounted for under the equity method, was $1.3 billion at March 31, 2002.

The company's debt ratio (total debt to total-debt-plus-equity) was 34 percent at March 31, 2002, about the same as at year-end 2001. The company continually monitors its spending levels, market conditions and related interest rates to maintain what it perceives to be reasonable debt levels.

The company benefits from lower interest rates available on short-term debt; however, ChevronTexaco's proportionately large amount of short-term debt keeps its ratio of current assets to current liabilities at relatively low levels. The current ratio was 0.84 at March 31, 2002, down from 0.89 at year-end 2001.

The company's future debt level is dependent primarily on its results of operations, its capital-spending program and cash that may be generated from asset dispositions. The company believes it has substantial borrowing capacity to meet unanticipated cash requirements. In periods of sustained low crude oil and natural gas prices (below levels of approximately $20 per barrel for West Texas Intermediate benchmark crude oil and $2.50 per thousand cubic feet for Henry Hub benchmark natural gas) and narrow refined products margins, cash provided by operating activities and asset sales may not be sufficient to fund the company's investing activities and cash dividends and may result in increased borrowings or a reduction in overall cash levels. ChevronTexaco's senior debt is rated AA by Standard and Poor's Corporation and Aa2 by Moody's Investor Service, except for senior debt of Texaco Inc. which is rated Aa3. ChevronTexaco's U.S. commercial paper is rated A-1+ by Standard and Poor's and Prime 1 by Moody's, and the company's Canadian commercial paper is rated R-1 (middle) by Dominion Bond Rating Service. All of these ratings denote high-quality, investment-grade securities.

**Worldwide capital and exploratory expenditures**, including the company's share of affiliates' expenditures, were $2.150 billion in the first quarter of 2002, compared with $2.506 billion in last year's first quarter. Expenditures for international exploration and production projects were $1.155 billion – 54 percent of the total expenditures – reflecting the company's continued emphasis on increasing international oil and gas production. Capital expenditures in this year's first quarter included more than $400 million for the acquisition of assets previously leased associated with the Captain Field in the North Sea and an approximate $200 million additional investment in the company's Dynegy affiliate. In the first quarter of 2001, expenditures included the acquisition of an additional 5 percent interest in the Tengizchevroil affiliate and higher development spending in the Gulf of Mexico, related to natural gas production.

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**CAPITAL AND EXPLORATORY EXPENDITURES BY MAJOR OPERATING AREA**

| Millions of Dollars | Three Months Ended March 31 2002 | 2001 |
|---|---|---|
| **United States** | | |
| Exploration and Production | **$ 375** | $ 577 |
| Refining, Marketing and Transportation | **110** | 163 |
| Chemicals | **27** | 13 |
| All Other | **326** | 93 |
| **Total United States** | **838** | 846 |
| **International** | | |
| Exploration and Production | **1,155** | 1,480 |
| Refining, Marketing and Transportation | **152** | 175 |
| Chemicals | **3** | 4 |
| All Other | **2** | 1 |
| **Total International** | **1,312** | 1,660 |
| **Worldwide** | **$2,150** | $2,506 |

**Contingencies and Significant Litigation**

Chevron, Texaco and four other oil companies (refiners) filed suit in 1995 contesting the validity of a patent granted to Unocal Corporation (Unocal) for reformulated gasoline, which ChevronTexaco sells in California in certain months of the year. In March 2000, the U.S. Court of Appeals for the Federal Circuit upheld a September 1998 District Court decision that Unocal's patent was valid and enforceable and assessed damages of 5.75 cents per gallon for gasoline produced in infringement of the patent. In May 2000, the Federal Circuit Court denied a petition for rehearing with the U.S. Court of Appeals for the Federal Circuit filed by the refiners in this case. The refiners petitioned the U.S. Supreme Court and, in February 2001, the Supreme Court denied the petition to review the lower court's ruling and the case was remanded to the District Court for an accounting of all infringing gasoline produced from August 1, 1996, to September 30, 2000. The District Court is considering Unocal's motion for summary judgment requesting an accounting and the refiners' motion to stay the proceedings and vacate the accounting order. Oral arguments on these motions were held in early May 2002.

Separately, in May 2001, the U.S. Patent Office (USPO) granted the refiners' petition to re-examine the validity of Unocal's patent and, in February 2002, the USPO rejected all of the claims presented by Unocal. Unocal has responded to the USPO ruling and the USPO has not replied to their response. The Federal Trade Commission has also announced that it is investigating whether Unocal's failure to disclose to the California Air Resources Board that it had filed a patent application was unfair competition, which may make Unocal's patent unenforceable.

If Unocal's patent ultimately is upheld and is enforceable, the company's financial exposure includes royalties, plus interest, for production of gasoline that is proved to have infringed the patent. Chevron and Texaco have been accruing in the normal course of business any future estimated liability for potential infringement of the patent covered by the trial court's ruling. In 2000, Chevron and Texaco made payments to Unocal totaling approximately $28 million for the original court ruling, including interest and fees.

Unocal has obtained additional patents for alternate formulations that could affect a larger share of U.S. gasoline production. ChevronTexaco believes these additional patents are invalid and unenforceable.

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However, if such patents are ultimately upheld, the competitive and financial effects on the company's refining and marketing operations, while presently indeterminable, could be material.

Another issue involving the company is the petroleum industry's use of methyl tertiary-butyl ether (MTBE) as a gasoline additive and its potential environmental impact through seepage into groundwater. Along with other oil companies, the company is a party to lawsuits and claims related to the use of the chemical MTBE in certain oxygenated gasolines. These actions may require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. Costs to the company related to these lawsuits and claims are not currently determinable. ChevronTexaco continues the use of MTBE in gasoline it sells in certain areas. The state of California has directed that MTBE be phased out of the manufacturing process by the end of 2003.

The U.S. federal income tax liabilities have been settled through 1993 for Chevron and Caltex and through 1991 for Texaco. The company's California franchise tax liabilities have been settled through 1991 for Chevron and 1987 for Texaco.

Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

The company and its subsidiaries have certain other contingent liabilities with respect to guarantees, direct or indirect, of debt of affiliated companies or others and long-term unconditional purchase obligations and commitments, throughput agreements and take-or-pay agreements, some of which relate to suppliers' financing arrangements.

The company has commitments related to preferred shares of subsidiary companies, which are accounted for as minority interest. MVP Production Inc., a subsidiary, has variable rate cumulative preferred shares of $75 million owned by one minority holder. The shares are voting and are redeemable in 2003. Texaco Capital LLC, a wholly owned finance subsidiary, has issued $65 million of Deferred Preferred Shares, Series C. Dividends of $59 million on Series C, equivalent to a rate of 7.17 percent compounded annually, will be paid at the redemption date of February 28, 2005, unless earlier redemption occurs. Early redemption may result upon the occurrence of certain specific events.

ChevronTexaco provided certain indemnities of contingent liabilities of Equilon Enterprises LLC (Equilon) and Motiva Enterprises LLC (Motiva) to Shell Oil and Saudi Refining Inc. as part of the agreement for the sale of the company's interests in those investments. Generally, the indemnities provided are limited to contingent liabilities that may become actual liabilities within 18 months of the sale of the company's interests, and are reduced by any reserves that were established prior to the sale. Excluding environmental liabilities, the company's financial exposure related to those indemnities is limited to $300 million. Additionally, the company has provided indemnities for certain environmental liabilities arising out of conditions that existed prior to the formation of Equilon and Motiva and during the periods of ChevronTexaco's ownership interest in those entities as well as for customary representations and warranties within the agreements.

The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemical or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including but not limited to: Superfund sites and refineries, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold. The amount of such future cost is indeterminable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. While the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of future costs may be material to

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results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemicals concerns.

ChevronTexaco receives claims from, and submits claims to, customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers, and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its commodities and other derivatives activities, including forward exchange contracts and interest rate swaps. However, the results of operations and the financial position of certain equity affiliates may be affected by their business activities involving the use of derivative instruments.

The company's operations, particularly exploration and production, can be affected by other changing economic, regulatory and political environments in the various countries in which it operates, including the United States. OPEC has at times made efforts to support crude oil prices by limiting production. In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results, and are carefully considered by management when evaluating the level of current and future activity in such countries.

Areas in which the company and its affiliates have significant operations include the United States of America, Canada, Australia, the United Kingdom, Norway, Denmark, Kuwait, Republic of Congo, Angola, Nigeria, Chad, Equatorial Guinea, Democratic Republic of Congo, South Africa, Indonesia, Papua New Guinea, the Philippines, Singapore, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad and Korea. The company's Tengizchevroil affiliate operates in Kazakhstan. The company's Chevron Phillips Chemical Company LLC affiliate manufactures and markets a wide range of petrochemicals and plastics on a worldwide basis, with manufacturing facilities in existence or under construction in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium. The company's Dynegy affiliate has operations in the United States, Canada, the United Kingdom and other European countries.

For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated oil and gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for ChevronTexaco's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills in California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. ChevronTexaco currently estimates its maximum possible net before-tax liability at less than $400 million. At the same time, a possible maximum net amount that could be owed to ChevronTexaco is estimated at more than $200 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

**New Accounting Standards**

Recent interpretations of Financial Accounting Standards Board (FASB) Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 138, "Accounting for Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133", by the

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FASB Derivatives Implementation Group prescribe mark-to-market accounting for certain natural gas sales contracts and power sales agreements. Some of these interpretations became effective January 1, 2002. Adoption at that time did not result in a material effect to earnings. Implementation of these interpretations during the first quarter 2002 resulted in after-tax gains of $37 million. The effect of subsequent changes in the contracts' fair values is uncertain. Other interpretations became effective April 1, 2002, and apply to certain power sales agreements of the company's affiliates. The financial statement effects of these interpretations are currently being evaluated.

In June 2001, the FASB issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 is effective for fiscal years beginning after June 15, 2002. FAS 143 differs in several significant respects from current accounting for asset retirements obligations under FAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies". Adoption of FAS 143 will affect future accounting and reporting of the assets, liabilities and expenses related to these obligations. The magnitude of the effect has not yet been determined.

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## PART II. OTHER INFORMATION

**Item 1. Legal Proceedings.**

None

**Item 6. Exhibits and Reports on Form 8-K**

(a) Exhibits

(4) Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the company and its subsidiaries on a consolidated basis. A copy of any such instrument will be furnished to the Commission upon request.

(10.1) ChevronTexaco Deferred Compensation Plan for Management Employees, as amended and restated effective April 1, 2002.

(10.2) ChevronTexaco Long-Term Incentive Plan, including March 27, 2002 amendments, filed as Appendix B to ChevronTexaco Corporation's Notice of Annual Meeting and Proxy Statement dated April 15, 2002, and incorporated herein by reference.

(12) Computation of Ratio of Earnings to Fixed Charges

Copies of above exhibits not contained herein are available, at a fee of $2 per document, to any security holder upon written request to the Secretary's Department, ChevronTexaco Corporation, 575 Market Street, San Francisco, California 94105.

(b) Reports on Form 8-K

None.

## SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CHEVRONTEXACO CORPORATION

(Registrant)

Date May 15, 2002

/s/ S. J. CROWE

S. J. Crowe, Vice President and Comptroller
(Principal Accounting Officer and
Duly Authorized Officer)



Powered by:

**CHEVRONTEXACO CORP filed this 10-Q on 08/09/2002.**

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

# Form 10-Q

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **June 30, 2002**

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number 1-368-2

# ChevronTexaco Corporation

(Exact name of registrant as specified in its charter)

| Delaware | 94-0890210 | 575 Market Street, San Francisco, California 94105 |
|---|---|---|
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification Number) | (Address of principal executive offices) (Zip Code) |

Registrant's telephone number, including area code (415) 894-7700

NONE

(Former name or former address, if changed since last report.)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate the number of shares of each of the issuer's classes of common stock, as of the latest practicable date:

| Class | Outstanding as of June 30, 2002 |
|---|---|
| Common stock, $.75 par value | 1,068,073,461 |

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SIGNATURE

Quarterly Report for Period Ended June 30, 2002

Exhibit 12.1

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## CAUTIONARY STATEMENTS RELEVANT TO FORWARD-LOOKING INFORMATION FOR THE PURPOSE OF "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This quarterly report on Form 10-Q of ChevronTexaco Corporation contains forward-looking statements relating to ChevronTexaco's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as "anticipates," "expects," "intends," "plans," "targets," "projects," "believes," "seeks," "estimates" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, ChevronTexaco undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the factors that could cause actual results to differ materially are crude oil and natural gas prices; refining margins and marketing margins; chemicals prices and competitive conditions affecting supply and demand for aromatics, olefins and additives products; actions of competitors; the competitiveness of alternate energy sources or product substitutes; technological developments; future developments in the energy-trading business sector and their effects on the operations of the company and its Dynegy affiliate; inability of the company's joint-venture partners to fund their share of operations and development activities; potential failure to achieve expected production from existing and future oil and gas development projects; potential delays in the development, construction or start-up of planned projects; the successful integration of the former Chevron, Texaco and Caltex businesses; potential disruption or interruption of the company's production or manufacturing facilities due to accidents or political events; potential liability for remedial actions under existing or future environmental regulations and litigation; significant investment or product changes under existing or future environmental regulations (including, particularly, regulations and litigation dealing with gasoline composition and characteristics); and potential liability resulting from pending or future litigation. In addition, such statements could be affected by general domestic and international economic and political conditions. Unpredictable or unknown factors not discussed herein also could have material adverse effects on forward-looking statements.

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## PART I. FINANCIAL INFORMATION

### Item 1. Financial Statements

### CHEVRONTEXACO CORPORATION AND SUBSIDIARIES

### CONSOLIDATED STATEMENT OF INCOME
**(Unaudited)**

| Millions of Dollars, Except Per-Share Amounts | Three Months Ended June 30 2002 | Three Months Ended June 30 2001 | Six Months Ended June 30 2002 | Six Months Ended June 30 2001 |
|---|---|---|---|---|
| **Revenues and Other Income** | | | | |
| Sales and other operating revenues[1] | **$ 25,223** | $ 29,031 | **$ 46,067** | $ 58,061 |
| Income from equity affiliates | **81** | 574 | **193** | 862 |
| Other income | **29** | 89 | **228** | 216 |
| **Total Revenues and Other Income** | **25,333** | 29,694 | **46,488** | 59,139 |
| **Costs and Other Deductions** | | | | |
| Purchased crude oil and products | **14,694** | 17,288 | **26,507** | 34,168 |
| Operating expenses | **1,699** | 1,843 | **3,451** | 3,722 |
| Selling, general and administrative expenses | **1,153** | 887 | **2,016** | 1,785 |
| Exploration expenses | **135** | 249 | **220** | 411 |
| Depreciation, depletion and amortization | **1,241** | 1,168 | **2,446** | 2,325 |
| Write-down of Dynegy investment | **702** | — | **702** | — |
| Merger-related expenses | **119** | 48 | **302** | 73 |
| Taxes other than on income[1] | **4,137** | 3,941 | **7,917** | 7,898 |
| Interest and debt expense | **160** | 217 | **307** | 476 |
| Minority interest | **10** | 34 | **22** | 72 |
| **Total Costs and Other Deductions** | **24,050** | 25,675 | **43,890** | 50,930 |
| **Income Before Income Tax Expense** | **1,283** | 4,019 | **2,598** | 8,209 |
| **Income Tax Expense** | **876** | 1,911 | **1,466** | 3,668 |
| **Net Income** | **$ 407** | $ 2,108 | **$ 1,132** | $ 4,541 |
| **Per Share of Common Stock:** | | | | |
| **Net Income – Basic** | **$ .39** | $ 1.99 | **$ 1.07** | $ 4.29 |
| **– Diluted** | **$ .39** | $ 1.99 | **$ 1.07** | $ 4.28 |
| **Dividends** | **$ .70** | $ .65[2] | **$ 1.40** | $ 1.30[2] |
| **Weighted Average Number of Shares Outstanding (000s) – Basic** | **1,060,434** | 1,060,023 | **1,060,258** | 1,059,332 |
| **– Diluted** | **1,062,289** | 1,063,679 | **1,062,150** | 1,062,454 |
| [1] Includes consumer excise taxes: | **$ 1,751** | $ 1,772 | **$ 3,439** | $ 3,554 |

[2] Chevron dividend pre-merger

See accompanying notes to consolidated financial statements.

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**CHEVRONTEXACO CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME**
**(Unaudited)**

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| Millions of Dollars | 2002 | 2001 | 2002 | 2001 |
| **Net Income** | **$ 407** | $2,108 | **$1,132** | $4,541 |
| **Other Comprehensive (Loss) Gain** | | | | |
| Currency translation adjustment | **27** | (15) | **10** | (13) |
| Unrealized holding gains on securities: | | | | |
| Net (loss) gain arising during period | | | | |
| Before income taxes | **(297)** | (3) | **(200)** | 9 |
| Income taxes | **104** | — | **70** | — |
| Reclassification to net income of net recognized loss | | | | |
| Before income taxes | **217** | — | **217** | — |
| Income taxes | **(76)** | — | **(76)** | — |
| Total | **(52)** | (3) | **11** | 9 |
| Net derivatives gain on equity investees' hedge transactions: | | | | |
| Before income taxes | **56** | 27 | **63** | 8 |
| Income taxes | **(20)** | (9) | **(22)** | (3) |
| Total | **36** | 18 | **41** | 5 |
| Minimum pension liability adjustment: | | | | |
| Before income taxes | **(85)** | — | **(85)** | 14 |
| Income taxes | **31** | — | **31** | (5) |
| Total | **(54)** | — | **(54)** | 9 |
| **Other Comprehensive (Loss) Gain** | **(43)** | — | **8** | 10 |
| **Comprehensive Income** | **$ 364** | $2,108 | **$1,140** | $4,551 |

See accompanying notes to consolidated financial statements.

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**CHEVRONTEXACO CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED BALANCE SHEET**

| Millions of Dollars | At June 30 2002 | At December 31 2001 |
|---|---|---|
| | (Unaudited) | |
| **ASSETS** | | |
| Cash and cash equivalents | **$ 2,652** | $ 2,117 |
| Marketable securities | **763** | 1,033 |
| Accounts and notes receivable | **8,937** | 8,279 |
| Inventories: | | |
| Crude oil and petroleum products | **2,216** | 2,207 |
| Chemicals | **191** | 209 |
| Materials, supplies and other | **537** | 532 |
| Total inventories | **2,944** | 2,948 |
| Prepaid expenses and other current assets | **2,408** | 1,769 |
| Assets held for sale – merger related | **—** | 2,181 |
| **Total Current Assets** | **17,704** | 18,327 |
| Long-term receivables | **1,386** | 1,225 |
| Investments and advances | **12,139** | 12,252 |
| Properties, plant and equipment, at cost | **102,406** | 99,943 |
| Less: accumulated depreciation, depletion and amortization | **58,627** | 56,710 |
| Properties, plant and equipment, net | **43,779** | 43,233 |
| Deferred charges and other assets | **2,634** | 2,535 |
| **Total Assets** | **$ 77,642** | $77,572 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Short-term debt | **$ 7,070** | $ 8,429 |
| Accounts payable | **7,010** | 6,427 |
| Accrued liabilities | **3,064** | 3,399 |
| Federal and other taxes on income | **1,816** | 1,398 |
| Other taxes payable | **1,082** | 1,001 |
| **Total Current Liabilities** | **20,042** | 20,654 |
| Long-term debt | **9,432** | 8,704 |
| Capital lease obligations | **266** | 285 |
| Deferred credits and other noncurrent obligations | **4,454** | 4,394 |
| Noncurrent deferred income taxes | **6,052** | 6,132 |
| Reserves for employee benefit plans | **3,354** | 3,162 |
| Minority interests | **286** | 283 |
| **Total Liabilities** | **43,886** | 43,614 |
| Preferred stock (authorized 100,000,000 shares, $1.00 par value, none issued) | **—** | — |
| Common stock (authorized 4,000,000,000 shares, $.75 par value, 1,137,021,057 shares issued) | **853** | 853 |
| Capital in excess of par value | **4,827** | 4,811 |
| Retained earnings | **32,409** | 32,767 |
| Accumulated other comprehensive loss | **(298)** | (306) |
| Deferred compensation and benefit plan trust | **(652)** | (752) |
| Treasury stock, at cost (68,947,596 and 69,800,315 shares at June 30, 2002 and December 31, 2001, respectively) | **(3,383)** | (3,415) |

| | | |
|---|---|---|
| **Total Stockholders' Equity** | **33,756** | 33,958 |
| **Total Liabilities and Stockholders' Equity** | **$ 77,642** | $77,572 |

See accompanying notes to consolidated financial statements.

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**CHEVRONTEXACO CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENT OF CASH FLOWS**
**(Unaudited)**

| Millions of Dollars | Six Months Ended June 30 2002 | 2001 |
|---|---|---|
| **Operating Activities** | | |
| Net income | **$ 1,132** | $ 4,541 |
| Adjustments | | |
| Depreciation, depletion and amortization | **2,446** | 2,325 |
| Write-down of Dynegy investment, before-tax | **702** | — |
| Dry hole expense | **105** | 226 |
| Distributions more (less) than income from equity affiliates | **56** | (446) |
| Net before-tax gains on asset retirements and sales | **(40)** | (40) |
| Net foreign currency (gains) losses | **(68)** | 8 |
| Deferred income tax provision | **(201)** | 238 |
| Net (increase) decrease in operating working capital | **(32)** | 296 |
| Minority interest in net income | **22** | 72 |
| Other | **(442)** | (140) |
| **Net Cash Provided by Operating Activities** | **3,680** | 7,080 |
| **Investing Activities** | | |
| Capital expenditures | **(3,581)** | (3,977) |
| Proceeds from asset sales | **2,198** | 73 |
| Net sales (purchases) of marketable securities | **266** | (113) |
| Net purchases of other short-term investments | **—** | (666) |
| **Net Cash Used for Investing Activities** | **(1,117)** | (4,683) |
| **Financing Activities** | | |
| Net borrowings of short-term obligations | **107** | 1,827 |
| Proceeds from issuance of long-term debt | **57** | 695 |
| Repayments of long-term debt and other financing obligations | **(719)** | (2,331) |
| Redemption of market auction preferred shares | **—** | (300) |
| Cash dividends | **(1,494)** | (1,325) |
| Dividends paid to minority interests | **(20)** | (80) |
| Net sales of treasury shares | **38** | 123 |
| **Net Cash Used For Financing Activities** | **(2,031)** | (1,391) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | **3** | (14) |
| **Net Change in Cash and Cash Equivalents** | **535** | 992 |
| **Cash and Cash Equivalents at January 1** | **2,117** | 2,328 |
| **Cash and Cash Equivalents at June 30** | **$ 2,652** | $ 3,320 |

See accompanying notes to consolidated financial statements.

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## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### Note 1. Interim Financial Statements

The accompanying consolidated financial statements of ChevronTexaco Corporation and its subsidiaries (the company) have not been audited by independent accountants, except for the balance sheet at December 31, 2001. In the opinion of the company's management, the interim data include all adjustments necessary for a fair statement of the results for the interim periods. These adjustments were of a normal recurring nature, except for the special items and merger-related expenses described in Note 2, including the write-down of the company's investment in Dynegy Inc. (Dynegy) discussed in detail in Note 3.

On October 9, 2001, Texaco Inc. (Texaco) became a wholly owned subsidiary of Chevron Corporation (Chevron) pursuant to a merger transaction, and Chevron changed its name to ChevronTexaco Corporation. The combination was accounted for as a pooling of interests. The accompanying consolidated financial statements give retroactive effect to the merger, with all periods presented as if Chevron and Texaco had always been combined.

Certain notes and other information have been condensed or omitted from the interim financial statements presented in this Quarterly Report on Form 10-Q. Therefore, these financial statements should be read in conjunction with the company's 2001 Annual Report on Form 10-K.

The results for the three- and six-month periods ended June 30, 2002, are not necessarily indicative of future financial results.

### Note 2. Net Income

Net income for the second quarter of 2002 included special charges of $753 million and $73 million for merger-related expenses. The special charges included $531 million for a write-down of ChevronTexaco's investment in its Dynegy affiliate, which is discussed in Note 3; $100 million for the company's share of Dynegy's own write-downs and other adjustments; and $122 million for environmental remediation costs and the settlement of a litigation issue. The 2001 second quarter included $36 million for merger-related expenses.

Net income for the first six months of 2002 included special charges of $827 million and merger-related expenses of $205 million. In addition to the second quarter 2002 special items, the six-month period included a special charge of $74 million for the company's share of a write-down by Dynegy of investments in its telecommunications businesses. Net income for the first six months of 2001 included merger-related expenses of $57 million.

Foreign currency losses were $141 million and $20 million in the second quarters 2002 and 2001, respectively. For the six-month periods, losses were $10 million in 2002, compared with gains of $67 million in 2001.

### Note 3. Information Relating to the Company's Investment in Dynegy

ChevronTexaco's Dynegy Inc. equity affiliate is an energy merchant with physical assets and marketing, logistics and risk-management capabilities for products, including natural gas, natural gas liquids and electricity. ChevronTexaco owns approximately 26 percent of Dynegy's common stock and also holds $1.5 billion aggregate principal amount of Dynegy preferred stock. Dynegy is obligated to redeem all the preferred stock for an aggregate $1.5 billion in cash in November 2003, except to the extent ChevronTexaco chooses to convert preferred shares into Dynegy common stock at a conversion price of $31.64 per share. ChevronTexaco accounts for its investment in Dynegy as part of "All Other" for financial reporting purposes.

Under a long-term contract, Dynegy purchases most natural gas produced by ChevronTexaco in the United States. ChevronTexaco is a secured creditor with respect to amounts owed by Dynegy for these purchases, which are included as revenues in results of operations for ChevronTexaco's U.S. exploration and production (upstream) reporting segment.

Dynegy is experiencing a marked reduction in available liquidity resulting from a combination of lower than previously

anticipated cash flow from operations, significantly impaired access to sources of capital, increased

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

collateralization of its business operations and depressed levels of commercial activity. Dynegy's debt ratings have been downgraded below investment grade level, and it is the subject of regulatory investigations and is the defendant in a number of lawsuits seeking large amounts of damages. Additionally, at the request of Dynegy, its independent accountants are currently conducting a re-audit of Dynegy's 1999-2001 financial statements in anticipation of their restatement and thereafter the independent accountants will perform interim reviews of Dynegy's 2002 quarterly financial statements. Dynegy's ability to meet its obligations in the ordinary course may depend largely on its ability to execute in a timely fashion an announced $2 billion capital program, including the pending sale of Northern Natural Gas Company.

ChevronTexaco's net income for the second quarter of 2002 included a charge of $531 million for a partial write-down of the investment in Dynegy common and preferred stock to its estimated fair value at June 30, 2002. In addition, second quarter net income included a charge of $100 million for ChevronTexaco's share of Dynegy's own write-downs and other adjustments. See also Note. 2 for a discussion of special items included in net income.

The write-down of the company's investment in Dynegy was required under applicable accounting rules because the decline in the fair value of the investment below its carrying value was determined to be other than temporary. Further deterioration in the securities' fair value subsequent to June 30, 2002, was not reflected in the second quarter charge. Following the write-down, the remaining book value of the company's investment in Dynegy at June 30, 2002, was $1.981 billion – composed of $1.283 billion for the preferred stock and $698 million for the common stock. An additional charge to third quarter earnings would be required to the extent the fair value of the Dynegy securities at September 30, 2002, is below the carrying value, and the decline in value is deemed to be other than temporary.

**Note 4. Information Relating to the Statement of Cash Flows**

The "Net (increase) decrease in operating working capital" was composed of operating changes of the following:

| | Six Months Ended June 30 | |
|---|---|---|
| Millions of Dollars | **2002** | **2001** |
| Increase in accounts and notes receivable | **$(712)** | $(334) |
| Decrease (increase) in inventories | **4** | (380) |
| Increase in prepaid expenses and other current assets | **(130)** | (394) |
| Increase in accounts payable and accrued liabilities | **336** | 920 |
| Increase in income and other taxes payable | **470** | 484 |
| Net (increase) decrease in operating working capital | **$ (32)** | $ 296 |

"Net Cash Provided by Operating Activities" included the following cash payments for interest on debt and for income taxes:

| | Six Months Ended June 30 | |
|---|---|---|
| Millions of Dollars | **2002** | **2001** |
| Interest on debt (net of capitalized interest) | **$ 301** | $ 485 |
| Income taxes | **$1,223** | $3,021 |

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

The "Net sales (purchases) of marketable securities" consisted of the following gross amounts:

| Millions of Dollars | Six Months Ended June 30 2002 | 2001 |
|---|---|---|
| Marketable securities purchased | **$(3,744)** | $(1,552) |
| Marketable securities sold | **4,010** | 1,439 |
| Net sales (purchases) of marketable securities | **$ 266** | $ (113) |

"Net purchases of other short-term investments," of $666 million in 2001 were in a variety of short-term money market instruments with maturities similar to the company's commercial paper portfolio. There were no investments under this program in 2002.

The major components of "Capital expenditures" and the reconciliation of this amount to the capital and exploratory expenditures, excluding equity affiliates, presented in "Management's Discussion and Analysis of Financial Condition and Results of Operations" are presented in the following table:

| Millions of Dollars | Six Months Ended June 30 2002 | 2001 |
|---|---|---|
| Additions to properties, plant and equipment | **$2,984** | $2,900 |
| Additions to investments | **548** | 955 |
| Current year dry hole expenditures | **91** | 191 |
| Payments for other liabilities and assets, net | **(42)** | (69) |
| Capital expenditures | **3,581** | 3,977 |
| Other exploration expenditures | **115** | 185 |
| Payments of long-term debt and other financing obligations | **2** | 210* |
| Capital and exploratory expenditures, excluding equity affiliates | **$3,698** | $4,372 |
| Equity in affiliates | **625** | 749 |
| Capital and exploratory expenditures, including equity affiliates | **$4,323** | $5,121 |

* Deferred payment related to 1993 acquisition of an interest in the Tengizchevroil joint venture.

The Consolidated Statement of Cash Flows excludes two separate non-cash transactions affecting the balance sheet that were for the company's Employee Stock Ownership Plan (ESOP) repayments of $100 million each of matured debt guaranteed by ChevronTexaco Corporation in January 2002 and 2001. These payments were recorded by the company as reductions to "Short-term debt" and "Deferred Compensation."

**Note 5. Operating Segments and Geographic Data**

ChevronTexaco separately manages its exploration and production; refining, marketing and transportation; and chemicals businesses. "All Other" activities include corporate administrative costs, worldwide cash management and debt financing activities, the company's investment in Dynegy, coal mining operations, power and gasification operations, technology investments, insurance operations and real estate activities. The company's primary country of operation is the United States of America, its country of domicile. The remainder of the company's operations is reported as International (outside

the United States).

The company evaluates the performance of its operating segments on an after-tax basis, without considering the effects of debt financing interest expense or investment interest income, both of which are managed by the company on a worldwide basis. Corporate administrative costs and assets are not allocated to the operating

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

segments. However, operating segments are billed for the direct use of corporate services. Nonbillable costs and merger effects remain at the corporate level. After-tax segment income (loss) for the three- and six-month periods ended June 30, 2002 and 2001, is presented in the following table:

**Segment Income**

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| Millions of Dollars | **2002** | **2001** | **2002** | **2001** |
| Exploration and Production | | | | |
| United States | **$ 536** | $ 884 | **$ 840** | $2,197 |
| International | **710** | 832 | **1,547** | 1,771 |
| Total Exploration and Production | **1,246** | 1,716 | **2,387** | 3,968 |
| Refining, Marketing and Transportation | | | | |
| United States | **(30)** | 531 | **(184)** | 720 |
| International | **48** | 139 | **141** | 406 |
| Total Refining, Marketing and Transportation | **18** | 670 | **(43)** | 1,126 |
| Chemicals | | | | |
| United States | **15** | 10 | **18** | (34) |
| International | **21** | 17 | **33** | 24 |
| Total Chemicals | **36** | 27 | **51** | (10) |
| Total Segment Income | **1,300** | 2,413 | **2,395** | 5,084 |
| Merger Effects | **(73)** | (36) | **(205)** | (57) |
| Interest Expense | **(116)** | (146) | **(221)** | (315) |
| Interest Income | **15** | 44 | **33** | 77 |
| Other | **(719)** | (167) | **(870)** | (248) |
| Net Income | **$ 407** | $2,108 | **$1,132** | $4,541 |

Segment assets do not include intercompany investments or intercompany receivables. “All Other” assets consist primarily of worldwide cash and marketable securities, real estate, information systems, the investment in Dynegy Inc., coal mining operations, power and gasification operations and technology investments. At

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

December 31, 2001, this category also included $2.2 billion for merger-related assets held for sale. Segment assets at June 30, 2002, and year-end 2001 follow:

**Segment Assets**

| Millions of Dollars | At June 30 2002 | At December 31 2001 |
|---|---|---|
| Exploration and Production | | |
| United States | **$11,987** | $12,718 |
| International | **25,041** | 24,177 |
| Total Exploration and Production | **37,028** | 36,895 |
| Refining, Marketing and Transportation | | |
| United States | **9,533** | 8,902 |
| International | **17,524** | 16,426 |
| Total Refining, Marketing and Transportation | **27,057** | 25,328 |
| Chemicals | | |
| United States | **2,072** | 2,059 |
| International | **678** | 701 |
| Total Chemicals | **2,750** | 2,760 |
| Total Segment Assets | **66,835** | 64,983 |
| All Other | | |
| United States | **7,210** | 8,950 |
| International | **3,597** | 3,639 |
| Total All Other | **10,807** | 12,589 |
| Total Assets – United States | **30,802** | 32,629 |
| Total Assets – International | **46,840** | 44,943 |
| Total Assets | **$77,642** | $77,572 |

Operating segment sales and other operating revenues, including internal transfers, for the three- and six-month periods ended June 30, 2002 and 2001, are presented in the following table. Sales from the transfer of products between segments are at prices that approximate market.

Revenues for the exploration and production segment are derived primarily from the production of crude oil and natural gas. Revenues for the refining, marketing and transportation segment are derived from the refining and marketing of petroleum products, such as gasoline, jet fuel, gas oils, kerosene, lubricants, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the transportation and trading of crude oil and refined products. Revenues for the chemicals segment are derived from the manufacture and sale of additives for lubricants and fuel. Revenues from “All Other” activities include coal mining operations, power and gasification operations, technology investments, insurance operations and real estate activities.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**Sales and Other Operating Revenues**

| Millions of Dollars | Three Months Ended June 30 2002 | Three Months Ended June 30 2001 | Six Months Ended June 30 2002 | Six Months Ended June 30 2001 |
|---|---|---|---|---|
| Exploration and Production | | | | |
| United States* | **$ 2,507** | $ 4,329 | **$ 4,593** | $10,404 |
| International | **3,712** | 4,879 | **6,929** | 8,832 |
| Sub-total | **6,219** | 9,208 | **11,522** | 19,236 |
| Intersegment Elimination – United States | **(1,276)** | (883) | **(2,088)** | (1,732) |
| Intersegment Elimination – International | **(2,357)** | (2,682) | **(4,206)** | (4,267) |
| Total Exploration and Production | **2,586** | 5,643 | **5,228** | 13,237 |
| Refining, Marketing and Transportation | | | | |
| United States | **9,732** | 9,609 | **16,885** | 18,447 |
| International | **12,442** | 13,201 | **23,210** | 25,306 |
| Sub-total | **22,174** | 22,810 | **40,095** | 43,753 |
| Intersegment Elimination – United States | **(39)** | (54) | **(79)** | (129) |
| Intersegment Elimination – International | **(18)** | (52) | **(132)** | (171) |
| Total Refining, Marketing and Transportation | **22,117** | 22,704 | **39,884** | 43,453 |
| Chemicals | | | | |
| United States | **108** | 103 | **214** | 195 |
| International | **181** | 199 | **354** | 393 |
| Sub-total | **289** | 302 | **568** | 588 |
| Intersegment Elimination – United States | **(26)** | (21) | **(49)** | (43) |
| Intersegment Elimination – International | **(16)** | (31) | **(34)** | (55) |
| Total Chemicals | **247** | 250 | **485** | 490 |
| All Other | | | | |
| United States* | **330** | 435 | **564** | 882 |
| International | **5** | 13 | **10** | 27 |
| Sub-total | **335** | 448 | **574** | 909 |
| Intersegment Elimination – United States | **(62)** | (12) | **(104)** | (24) |
| Intersegment Elimination – International | **—** | (2) | **—** | (4) |
| Total All Other | **273** | 434 | **470** | 881 |
| **Sales and Other Operating Revenues** | | | | |
| United States | **12,677** | 14,476 | **22,256** | 29,928 |
| International | **16,340** | 18,292 | **30,503** | 34,558 |
| Sub-total | **29,017** | 32,768 | **52,759** | 64,486 |
| Intersegment Elimination – United States | **(1,403)** | (970) | **(2,320)** | (1,928) |
| Intersegment Elimination – International | **(2,391)** | (2,767) | **(4,372)** | (4,497) |
| Total Sales and Other Operating Revenues | **$25,223** | $29,031 | **$46,067** | $58,061 |

* 2001 includes segment reclassifications to conform to 2002 presentation.

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**Note 6. Employee Termination Benefits and Other Restructuring Costs**

The company expects to incur approximately $2 billion of one-time before-tax expenses in connection with the merger of Chevron and Texaco. Major expenses include employee severance payments; incremental pension and medical plan benefit costs associated with workforce reductions; legal, accounting, SEC filing and investment banker fees; employee and office relocations; and costs for the elimination of redundant facilities and operations.

In 2001, before-tax merger-related expenses were $1.563 billion ($1.136 billion after tax). In the three- and six-month periods ended June 30, 2002, such expenses were $119 million ($73 million after tax) and $302 million ($205 million after tax), respectively. The cumulative total of $1.865 billion ($1.341 billion after tax) included accruals of $891 million and $13 million in 2001 and the first six months 2002, respectively, for severance-related benefits for approximately 4,500 employees and other merger-related expenses that will not benefit future operations.

Activity for this merger-related accrual balance is summarized in the table below:

| Millions of dollars | **Amount** |
|---|---|
| Additions – 2001 | $ 891 |
| Payments – 2001 | (105) |
| **Balance at December 31, 2001** | **786** |
| Additions – 2002 | 13 |
| Payments – 2002 | (372) |
| Balance at June 30, 2002 | $ 427 |

The ending accrual balance is expected to be extinguished within one year, except for $56 million classified as long-term, which is associated with elections by certain employees to defer severance payments until 2004. Approximately 3,500 of the 4,500 employees had terminated by June 30, 2002. Substantially all of the remaining terminations are expected to occur by the end of this year.

**Note 7. Summarized Financial Data – Chevron U.S.A. Inc.**

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of ChevronTexaco Corporation. CUSA and its subsidiaries manage and operate most of ChevronTexaco's U.S. businesses and assets related to the exploration and production of crude oil, natural gas and natural gas liquids and also those associated with refining, marketing, supply and distribution of products derived from petroleum, other than natural gas liquids, excluding most of the pipeline operations of ChevronTexaco. CUSA also holds divisions overseeing or operating global businesses such as aviation fuel, lubricants, shipping and trading, and divisions providing administrative, technical, etc. services to affiliated companies. CUSA also holds ChevronTexaco's investment in the Chevron Phillips Chemical Company joint venture, which is accounted for using the equity method, and Dynegy Inc.

During the second quarter of 2002, ChevronTexaco implemented a legal reorganization in which certain ChevronTexaco subsidiaries transferred assets to or under CUSA and other ChevronTexaco companies were merged with and into CUSA. The summarized financial information for CUSA and its consolidated subsidiaries presented in the table below gives retroactive effect to the reorganization in a manner similar to a pooling of interests, with all periods presented as if the companies had always been combined and the reorganization had occurred on January 1, 2001. However, the financial information included below may not reflect the financial

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

position and operating results in the future or the historical results in the periods presented had the reorganization actually occurred on January 1, 2001.

| Millions of Dollars | Six Months Ended June 30 2002 | Six Months Ended June 30 2001 |
|---|---|---|
| Sales and other operating revenues | **$28,268** | $27,532 |
| Costs and other deductions | **29,193** | 24,596 |
| Net (loss) income | **(646)** | 2,081 |

| Millions of Dollars | At June 30 2002 | At December 31 2001 |
|---|---|---|
| Current assets | **$ 5,371** | $ 4,349 |
| Other assets | **29,178** | 31,430 |
| Current liabilities | **6,370** | 5,992 |
| Other liabilities | **22,213** | 20,571 |
| Net equity | **5,966** | 9,216 |
| Memo: Total Debt | **$ 6,269** | $10,576 |

**Note 8. Summarized Financial Data – Chevron Transport Corporation**

Chevron Transport Corporation Limited (CTC), incorporated in Bermuda, is an indirect, wholly owned subsidiary of ChevronTexaco Corporation. CTC is the principal operator of ChevronTexaco's international tanker fleet and is engaged in the marine transportation of crude oil and refined petroleum products. Most of CTC's shipping revenue is derived by providing transportation services to other ChevronTexaco companies. ChevronTexaco Corporation has guaranteed this subsidiary's obligations in connection with certain debt securities issued by a third party.

Summarized financial information for CTC and its consolidated subsidiaries is presented as follows:

| Millions of Dollars | Three Months Ended June 30 2002 | Three Months Ended June 30 2001 | Six Months Ended June 30 2002 | Six Months Ended June 30 2001 |
|---|---|---|---|---|
| Sales and other operating revenues | **$211** | $232 | **$416** | $491 |
| Costs and other deductions | **244** | 208 | **460** | 417 |
| Net (loss) income | **(30)** | 24 | **(42)** | 75 |

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

| Millions of Dollars | At June 30 2002 | At December 31 2001 |
|---|---|---|
| Current assets | **$224** | $196 |
| Other assets | **485** | 527 |
| Current liabilities | **323** | 280 |
| Other liabilities | **296** | 311 |
| Net equity | **90** | 132 |

There were no restrictions on CTC's ability to pay dividends or make loans or advances at June 30, 2002.

**Note 9. Income Taxes**

Taxes on income for the second quarter and first half 2002 were $876 million and $1.466 billion, respectively, compared with $1.911 billion and $3.668 billion for the comparable periods in 2001. The effective tax rates for the second quarter 2002 and 2001 were 68 percent and 48 percent, respectively. For the year-to-date periods, the effective tax rates were 56 percent and 45 percent, respectively. The increase in the effective tax rate for both 2002 periods was primarily the result of a higher proportion of international before-tax income, generally taxed at higher rates, whereas the U.S. operations generated before-tax losses. In the second quarter 2002, a significant portion of the write-down of the company's investment in Dynegy did not generate U.S. tax benefits.

**Note 10. Litigation**

Chevron, Texaco and four other oil companies (refiners) filed suit in 1995 contesting the validity of a patent ('393' patent) granted to Unocal Corporation (Unocal) for reformulated gasoline, which ChevronTexaco sells in California in certain months of the year. In March 2000, the U.S. Court of Appeals for the Federal Circuit upheld a September 1998 District Court decision that Unocal's patent was valid and enforceable and assessed damages of 5.75 cents per gallon for gasoline produced in infringement of the patent. In February 2001, the U.S. Supreme Court concluded it would not review the lower court's ruling, and the case was sent back to the District Court for an accounting of all infringing gasoline produced from August 1, 1996, to September 30, 2000. Additionally, the U.S. Patent and Trademark Office (USPTO) granted a motion by the refiners to re-examine the validity of Unocal's patent. The District Court judge requested further briefing and advised that she would not enter final judgement orders in this case until the USPTO had completed its reexamination of the '393' patent. During 2002 the USPTO rejected the validity of the '393' patent and another Unocal patent, the '126' patent, which could affect a larger share of U.S. gasoline production. Separately, the U.S. Federal Trade Commission has also announced that it is investigating whether Unocal's conduct in this matter was unfair competition, which may make Unocal's patent unenforceable.

Unocal has obtained additional patents that could affect a larger share of U.S. gasoline production. ChevronTexaco believes these additional patents are invalid, unenforceable and/or not infringed. The company's financial exposure in the event of unfavorable conclusions to the patent litigation and regulatory reviews may include royalties, plus interest, for production of gasoline that is proved to have infringed the patents. The competitive and financial effects on the company's refining and marketing operations, while presently indeterminable, could be material. ChevronTexaco – as well as Chevron and Texaco separately pre-merger – has been accruing in the normal course of business any future estimated liability for potential infringement of the '393' patent covered by the 1998 trial court's ruling. In 2000 prior to the merger, Chevron and Texaco made payments to Unocal totaling approximately $28 million for the original court ruling, including interest and fees.

Another issue involving the company is the petroleum industry's use of methyl tertiary-butyl ether (MTBE) as a gasoline additive and its potential environmental impact through seepage into groundwater. Along with other oil companies, ChevronTexaco is a party to lawsuits and claims related to the use of the chemical MTBE in

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

certain oxygenated gasolines. These actions may require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. In July 2002, ChevronTexaco and Exxon Mobil Corp. (ExxonMobil) reached a settlement of an MTBE-related litigation matter with the City of Santa Monica, California. Under the terms of the settlement, ChevronTexaco and ExxonMobil guaranteed to fund the cost of building and operating a water treatment facility to remove MTBE and other contaminants from certain water wells and to pay a cash settlement to cover costs of alleged contamination. The City of Santa Monica agreed to release ChevronTexaco and ExxonMobil from a lawsuit filed in 2000 against a group of oil refiners, suppliers, and owners and operators of pipelines and other facilities for allegedly contaminating water wells with MTBE. The settlement also states that ChevronTexaco and ExxonMobil may be repaid a portion of the construction and operating costs if the City of Santa Monica fully recovers funds from the other companies named in the suit. ChevronTexaco has worked to reduce the use of MTBE in gasoline it manufactures in the United States. The State of California has directed that MTBE be phased out of the manufacturing process by the end of 2003, and the company intends to comply with this mandate.

**Note 11. Other Contingencies and Commitments**

U.S. federal income tax liabilities have been settled through 1996 for ChevronTexaco (formerly Chevron), 1993 for ChevronTexaco Global Energy Inc. (formerly Caltex), and 1991 for Texaco Inc. California franchise tax liabilities have been settled through 1991 for ChevronTexaco and 1987 for Texaco Inc.

Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

The company and its subsidiaries have certain other contingent liabilities with respect to guarantees, direct or indirect, of debt of affiliated companies or others and long-term unconditional purchase obligations and commitments, throughput agreements and take-or-pay agreements, some of which relate to suppliers' financing arrangements.

Commitments related to preferred shares of subsidiary companies are accounted for as minority interest. MVP Production Inc., a subsidiary, has variable rate cumulative preferred shares of $75 million owned by one minority holder. The shares are voting and are redeemable in 2003. Texaco Capital LLC, a wholly owned finance subsidiary, has issued $65 million of Deferred Preferred Shares, Series C. Dividends of $59 million on the Series C preferred shares, equivalent to a rate of 7.17 percent compounded annually, will be paid at the redemption date of February 28, 2005, unless earlier redemption occurs. Early redemption may result upon the occurrence of certain events.

ChevronTexaco provided certain indemnities of contingent liabilities of Equilon Enterprises LLC (Equilon) and Motiva Enterprises LLC (Motiva) to Shell Oil Company and Saudi Refining, Inc. as part of the February 2002 sale of the company's interests in those investments. Generally, the indemnities provided are limited to contingent liabilities that may become actual liabilities within 18 months of the sale and are reduced by any reserves that were established prior to the sale. Excluding environmental liabilities, the company's financial exposure related to those indemnities is limited to $300 million. Additionally, the company has provided indemnities for certain environmental liabilities arising out of conditions that existed prior to the formation of Equilon and Motiva and during the periods of ChevronTexaco's ownership interest in those entities as well as for customary representations and warranties within the agreements.

The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemical or petroleum substances, including MTBE, by the company or other parties. Such contingencies

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

may exist for various sites, including but not limited to: Superfund sites and refineries, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold. The amount of such future cost is indeterminable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. While the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemicals concerns.

ChevronTexaco receives claims from, and submits claims to, customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve. The company also suspends the costs of exploratory wells pending a final determination of the commercial potential of the related oil and gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity and/or development decisions. If the company decides not to continue development, the costs of these wells are expensed. The company and its affiliates also routinely assess their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its commodities and other derivatives activities, including forward exchange contracts and interest rate swaps. However, the results of operations and the financial position of certain equity affiliates, including Dynegy, may be affected by their business activities involving the use of derivative instruments.

The company's operations, particularly exploration and production, can be affected by other changing economic, regulatory and political environments in the various countries in which it operates, including the United States. The Organization of Petroleum Exporting Countries (OPEC) has at times made efforts to support crude oil prices by limiting production, which can affect production at the company's facilities, and those of its partners, in OPEC member countries. In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results, and are carefully considered by management when evaluating the level of current and future activity in such countries.

Areas in which the company and its affiliates have significant operations include the United States of America, Canada, Australia, the United Kingdom, Norway, Denmark, Kuwait, Republic of Congo, Angola, Nigeria, Chad, Equatorial Guinea, Democratic Republic of Congo, South Africa, Indonesia, Papua New Guinea, the Philippines, Singapore, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad and Korea. The company's Tengizchevroil affiliate operates in Kazakhstan. The company's Chevron Phillips Chemical Company LLC affiliate manufactures and markets a wide range of petrochemicals and plastics on a worldwide basis, with manufacturing facilities in existence or under construction in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium. The company's Dynegy affiliate has operations in the United States, Canada, the United Kingdom and other European countries.

For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated oil and gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for ChevronTexaco's interests in four producing zones at the Naval Petroleum Reserve at Elk

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**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Hills in California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. ChevronTexaco currently estimates its maximum possible net before-tax liability at less than $400 million. At the same time, a possible maximum net amount that could be owed to ChevronTexaco is estimated at more than $200 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

**Note 12. New Accounting Standards**

Recent interpretations of Financial Accounting Standards Board (FASB) Statement No. 133, “Accounting for Derivative Instruments and Hedging Activities” (FAS 133), as amended by FAS 138, “Accounting for Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133”, by the FASB Derivatives Implementation Group prescribe mark-to-market accounting for certain natural gas sales contracts. Some of these interpretations became effective January 1, 2002. Adoption at that time did not result in a material effect to net income. Other interpretations became effective April 1, 2002, and apply to certain power sales agreements of the company’s affiliates. Upon adoption of these interpretations, certain power sales agreements of the company’s affiliates were recorded as cash flow hedges. An after-tax gain of approximately $40 million was included in other comprehensive income in the second quarter reflecting the company’s share of the change in the fair value of the cash flow hedges. The effect of these cash flow hedges upon net income in the second quarter was not significant.

In June 2001, the FASB issued Statement No. 143, “Accounting for Asset Retirement Obligations” (FAS 143). FAS 143 is effective for fiscal years beginning after June 15, 2002. FAS 143 differs in several significant respects from current accounting for asset retirement obligations under FAS 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies.” Adoption of FAS 143 will affect future accounting and reporting of the assets, liabilities and expenses related to these obligations. The magnitude of the effect has not yet been determined.

Effective July 15, 2002, Consensus 02-3 of the FASB Emerging Issues Task Force (EITF) requires companies involved in energy trading and risk management activities to present the gains and losses stemming from those activities on a net basis in the income statement. The company is currently evaluating these reclassification requirements, which will have no impact on net income.

In July, the FASB issued Statement No. 146, “Accounting for Costs Associated with Exit or Disposal Activities.” The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activity. The statement replaces EITF Issue No. 94-3, “Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).” FAS 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002.

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**Item 2**

## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### Second Quarter 2002 Compared With Second Quarter 2001 And First Half 2002 Compared With First Half 2001

**Financial Results**

### EARNINGS BY MAJOR OPERATING AREA, EXCLUDING SPECIAL ITEMS AND MERGER EFFECTS

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| Millions of Dollars | 2002 | 2001 | 2002 | 2001 |
| Exploration and Production | | | | |
| United States | **$ 548** | $ 884 | **$ 852** | $2,197 |
| International | **710** | 832 | **1,547** | 1,771 |
| Total Exploration and Production | **1,258** | 1,716 | **2,399** | 3,968 |
| Refining, Marketing and Transportation | | | | |
| United States | **56** | 531 | **(98)** | 720 |
| International | **48** | 139 | **141** | 406 |
| Total Refining, Marketing and Transportation | **104** | 670 | **43** | 1,126 |
| Chemicals | **36** | 27 | **51** | (10) |
| All Other | **(165)** | (269) | **(329)** | (486) |
| Earnings Excluding Special Items and Merger Effects* | **1,233** | 2,144 | **2,164** | 4,598 |
| Special Items | **(753)** | — | **(827)** | — |
| Merger-related Expenses | **(73)** | (36) | **(205)** | (57) |
| **Net Income*** | **$ 407** | $2,108 | **$1,132** | $4,541 |
| * Includes Foreign Currency (Losses) Gains | **$ (141)** | $ (20) | **$ (10)** | $ 67 |

Net income for the second quarter 2002 was $407 million ($0.39 per share – diluted), compared with net income of $2.108 billion ($1.99 per share – diluted) for the 2001 second quarter. Net income for this year's second quarter included special charges of $753 million and $73 million for merger-related expenses. The special charges included $531 million for the write-down of the company's investment in its Dynegy Inc. (Dynegy) affiliate; $100 million for the company's share of Dynegy's own write-downs and other adjustments; and $122 million for environmental remediation costs and the settlement of a litigation issue. The second quarter 2001 included $36 million for merger-related expenses. Excluding special items and merger effects in both quarters, operating earnings were $1.233 billion ($1.16 per share – diluted), down over 40 percent from last year's second quarter.

Net income for the first six months of 2002 was $1.132 billion ($1.07 per share – diluted), compared with $4.541 billion ($4.28 per share – diluted) recorded in the first half of 2001. Special items reduced earnings $827 million in 2002 and merger-related expenses were $205 million. The 2001 six months included $57 million for merger-related expenses.

Excluding special items and merger effects in both six-month periods, operating earnings of $2.164 billion in 2002 were down more than 50 percent from last year's results.

Earnings in both 2002 periods were adversely affected by lower prices for crude oil and natural gas and lower margins for refined products than in last year's periods. The lower prices affected the company's U.S. businesses the most.
U.S. exploration and production (upstream) segment earnings fell by 38 percent and 61 percent for

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the second quarter and six-month periods, respectively. The average U.S. natural gas realization for the quarter dropped nearly 40 percent from the year-ago period to $3.04 per thousand cubic feet. The average U.S. crude oil and natural gas liquids realization was about one dollar per barrel lower in the 2002 quarter at $21.75 per barrel. For the six-month period, the average U.S. natural gas realization was down 57 percent to $2.66 per thousand cubic feet, while the average U.S. crude oil and natural gas liquids realization was nearly 18 percent lower at $19.35 per barrel.

U.S. refining, marketing and transportation (downstream) earnings reflected significantly lower refining and marketing margins for both the quarter and six-month periods. Although improved from lower levels early this year, refined product margins remained weak. The second quarter and six-month 2001 periods also included $208 million and $256 million, respectively, of earnings from assets that were sold under mandate of the U.S. Federal Trade Commission (FTC) as a condition of the merger. International downstream results declined due to the adverse effects of foreign currency fluctuations and lower freight rates for the international shipping organizations. Margins declined in the Asia-Pacific and European areas of operations but improved slightly in Latin America.

## Texaco Merger Transaction

Under mandate of the FTC, the company sold its interests in Equilon and Motiva – joint ventures engaged in U.S. downstream businesses – in February, resulting in cash proceeds of $2.2 billion, including dividends due. Other mandated asset dispositions were completed in the second quarter. Net income and cash proceeds from these other sales were not material.

Company employees worldwide are implementing initiatives to capture savings from merger synergies. At the beginning of second quarter 2002, the company had achieved a run rate of $1.2 billion before tax in annual synergy savings and expects to achieve its interim target run rate of $1.8 billion before tax in annual synergy savings by October 2002, six months ahead of the original schedule. The company announced a new target of $2.2 billion of annual synergy savings to be achieved by April 2003. Some examples of the merger integration initiatives to-date are as follows:

- **Exploration** – High-grading investment opportunities in the combined-company portfolio; sharing knowledge of drilling prospects by staffs of the combining companies. Combined company exploration expenses for six months 2002 were about 46 percent lower than in the same period last year pre-merger.

- **Production** – Leveraging operating efficiencies in common areas operated separately by Chevron and Texaco prior to the merger; high-grading development spending to increase production volumes. Progress has also been made in reducing operating expenses in areas of overlap for upstream producing operations, including reducing the consumption of steam used in the company's heavy oil operations in California's San Joaquin Valley.

- **Refining** – Collaborating across the worldwide refinery network to adopt best practices in process technology.

- **Shipping** – Improving the use of company and chartered tankers as more opportunities are provided to optimize ship utilization.

- **Procurement** – Leveraging the company's size and purchasing power to reduce both capital costs and operating expenses. For example, in the company's marketing operations, benefits have been achieved to reduce the cost of advertising, convenience store operations and the product distribution network.

- **Corporate and Other** – Consolidating offices, computer systems and telecommunications networks. The company has also redeemed certain higher-cost debt and reduced combined interest costs.

The company expects to incur approximately $2 billion of one-time before-tax expenses through 2002 in connection with the Chevron and Texaco merger transaction. Major expenses include employee severance payments; incremental pension and medical plan benefit costs associated with workforce reductions; legal, accounting, SEC filing and investment banker fees; employee and office relocations; and costs for the elimination of redundant facilities and operations.

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In 2001, before-tax merger-related expenses were $1.563 billion ($1.136 billion after tax). In the three- and six-month periods ended June 30, 2002, such expenses were $119 million ($73 million after tax) and $302 million ($205 million after tax), respectively. The cumulative total of $1.865 billion ($1.341 billion after tax) included accruals of $891 million and $13 million in 2001 and the first six months 2002, respectively, for severance-related benefits for approximately 4,500 employees and other merger-related expenses that will not benefit future operations.

Activity for this merger-related accrual balance is summarized in the table below:

| Millions of dollars | **Amount** |
|---|---|
| Additions – 2001 | $ 891 |
| Payments – 2001 | (105) |
| **Balance at December 31, 2001** | **786** |
| Additions – 2002 | 13 |
| Payments – 2002 | (372) |
| **Balance at June 30, 2002** | **$ 427** |

The ending accrual balance is expected to be extinguished within one year, except for $56 million classified as long-term, which is associated with elections by certain employees to defer severance payments until 2004. Approximately 3,500 of the 4,500 employees had terminated by June 30, 2002. Substantially all of the remaining terminations are expected to occur by the end of this year.

**Recent Events**

Operational highlights since the first quarter of 2002 include:

- **U.S. Exploration and Production** – In July, ChevronTexaco and its partners reached agreement to relinquish interests in the Destin Dome 56 Unit leases, offshore Florida. ChevronTexaco will receive approximately $46 million from the federal government as compensation for the investment made to date in the development. It is expected that payment will be received later in the third quarter and that the effect of the settlement on net income will not be material.

- **Norway** – ChevronTexaco was awarded interests in two licenses on the Norwegian Continental Shelf, adding 115 square miles for oil and gas exploration. The licenses are located offshore about 90 to 150 miles, in water depths of 1,900 to 3,000 feet.

- **Nigeria** – The company announced a second oil discovery on the non-operated deepwater Nigerian Block OPL 222. The discovery – Usan-1 – is approximately 60 miles offshore in a water depth of over 2,000 feet. Ukot-1, the first oil discovery on the block, was drilled and tested in 1998. Following the drilling of Usan-1, a comprehensive evaluation of the discovery and block commercial potential will be undertaken.

- **Angola** – The eighth significant discovery – Gabela – was made in Angola's ChevronTexaco-operated deepwater Block 14. This latest discovery will be followed by geological and engineering studies to assess its reserve potential.

- **China** – ChevronTexaco and its partners confirmed an oil discovery in the Liaodong Bay 02/31 Block in Bohai Bay, China. The well, drilled in approximately 60 feet of water, encountered multiple oil zones that tested at a combined rate of 4,600 barrels per day.

- **Qatar** – Chevron Phillips Chemical Company LLC, a 50 percent-owned affiliate, signed an agreement for a 49 percent interest in a $1.1 billion project to produce high density polyethylene and normal alpha olefins in Qatar.

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**Operating Environment and Outlook**

ChevronTexaco's exploration and production earnings are affected significantly by fluctuations in industry price levels for crude oil and natural gas. Average U.S. natural gas and crude oil prices in the first half of 2002 were significantly lower than in last year's first half. Henry Hub spot natural gas prices declined about 47 percent from $5.54 to $2.94 per thousand cubic feet. The average spot price for West Texas Intermediate (WTI), a benchmark crude oil, was $24.02 per barrel, compared with $28.33 in last year's first half. In early August, the spot WTI price was about $27.00 per barrel, and the Henry Hub spot natural gas price was $3.00 per thousand cubic feet.

The Organization of Petroleum Exporting Countries (OPEC) continues its effort to support crude oil prices by limiting production. OPEC curtailments restrained ChevronTexaco's net production by approximately 40,000 barrels per day in the first half of 2002, versus having no effect in the corresponding 2001 period. In addition, production under certain operating service agreements, which is not included in the company's net working interest production, was also curtailed 20,000 barrels per day in this year's first half, compared with approximately 7,000 barrels per day in the year-ago period. The long-term effect on industry prices due to OPEC production quotas remains uncertain.

In addition to OPEC production quotas, the company's operations are periodically affected by operating incidents, civil unrest, political uncertainty and economic conditions. In July 2002, international production of crude oil and natural gas was adversely affected by operating incidents in Nigeria, Angola and the United Kingdom. The effect of these incidents on the company's average third quarter oil-equivalent production is expected to be about 35,000 barrels per day. Substantially all of the shut-in production had resumed by early August.

In July, the United Kingdom (U.K.) enacted changes to the U.K. North Sea tax regulations, under which a supplementary charge will effectively increase the U.K. corporation tax rate from 30 percent to 40 percent. The changes are effective from April 17, 2002. The company will record a one-time charge of approximately $100 million against net income in the third quarter to adjust historical deferred tax balances. On an annual basis, the company estimates incremental income tax expense of approximately $50 million as a result of the higher tax rates – based upon current forecasts of crude oil and natural gas prices, capital expenditures and production levels. The impact of the tax change on cash flow for the remainder of 2002 and for the 2003-2004 period is anticipated to be largely neutral, as accelerated capital allowances will essentially offset effects of the higher tax rate.

Downstream operating earnings are closely tied to refining and marketing margins, which can vary among the geographic areas in which the company operates. Results from the company's downstream business, particularly in the United States, were negatively affected during the first half of 2002 by industry margins that early in the year had been at their lowest levels since the mid-1990s. Product margins in the United States trended upward in the second quarter of 2002. However, competitive markets and weak demand – reflective of slowed world economies – may hamper near-term improvement in profits for this sector.

Chemicals margins remained weak because of a protracted industry over-supply condition and are not expected to improve significantly in the near-term.

**Information Relating to the Company's Investment in Dynegy**

ChevronTexaco's Dynegy Inc. equity affiliate is an energy merchant with physical assets and marketing, logistics and risk-management capabilities for products, including natural gas, natural gas liquids and electricity. ChevronTexaco owns approximately 26 percent of Dynegy's common stock and also holds $1.5 billion aggregate principal amount of Dynegy preferred stock. Dynegy is obligated to redeem all the preferred stock for an aggregate $1.5 billion in cash in November 2003, except to the extent ChevronTexaco chooses to convert preferred shares into Dynegy common stock at a conversion price of $31.64 per share. ChevronTexaco accounts for its investment in Dynegy as part of "All Other" for financial reporting purposes.

Under a long-term contract, Dynegy purchases most of the natural gas produced by ChevronTexaco in the United States. ChevronTexaco is a secured creditor with respect to amounts owed by Dynegy for these

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purchases, which are included as revenues in results of operations for ChevronTexaco's U.S. exploration and production (upstream) reporting segment.

Dynegy is experiencing a marked reduction in available liquidity resulting from a combination of lower than previously anticipated cash flow from operations, significantly impaired access to sources of capital, increased collateralization of its business operations and depressed levels of commercial activity. Dynegy's debt ratings have been downgraded below investment grade level, and it is the subject of regulatory investigations and is the defendant in a number of lawsuits seeking large amounts of damages. Additionally, at the request of Dynegy, its independent accountants are currently conducting a re-audit of Dynegy's 1999-2001 financial statements in anticipation of their restatement and thereafter the independent accountants will perform interim reviews of Dynegy's 2002 quarterly financial statements. Dynegy's ability to meet its obligations in the ordinary course may depend largely on its ability to execute in a timely fashion an announced $2 billion capital program, including the pending sale of Northern Natural Gas Company.

ChevronTexaco's net income for the second quarter of 2002 included a charge of $531 million for a partial write-down of the investment in Dynegy common and preferred stock to its estimated fair value at June 30, 2002. In addition, second quarter net income included a charge of $100 million for ChevronTexaco's share of Dynegy's own write-downs and other adjustments. These charges to ChevronTexaco net income have been classified as special items apart from operating earnings in this management's discussion.

The write-down of the company's investment in Dynegy was required under applicable accounting rules because the decline in the fair value of the investment below its carrying value was determined to be other than temporary. Further deterioration in the securities' fair value subsequent to June 30, 2002, was not reflected in the second quarter charge. Following the write-down, the remaining book value of the company's investment in Dynegy at June 30, 2002, was $1.981 billion – composed of $1.283 billion for the preferred stock and $698 million for the common stock. An additional charge to third quarter earnings would be required to the extent the fair value of the Dynegy securities at September 30, 2002, is below the carrying value, and the decline in value is deemed to be other than temporary.

**Review of Operations**

Total revenues and other income for the second quarter 2002 were $25.3 billion, down from $29.7 billion in last year's second quarter. For the first six months of 2002, total revenues and other income were $46.5 billion, down from $59.1 billion in the corresponding 2001 period. Revenues and other income from worldwide upstream operations decreased about 42 percent in the 2002 six months, primarily on lower prices for crude oil and natural gas, worldwide. Additionally sales volumes of natural gas in the United States were down in 2002. Downstream revenues and other income were also down about 8 percent – the result of lower refined products prices.

Operating, selling, general and administrative expenses, excluding special items, in the second quarter of 2002 were $2.663 billion, down slightly from $2.730 billion in last year's second quarter. For the six-month period, such expenses, excluding special items, were $5.278 billion, compared with $5.507 billion in last year's first half, mainly due to lower fuel costs earlier in the year and the benefits of merger synergies.

Exploration expenses in the second quarter of 2002 were $135 million, down from $249 million in last year's second quarter. For the six-month period, exploration expenses were $220 million, compared to $411 million in 2001. Both 2002 periods benefited from reduced amounts for well write-offs and declines in other exploration expenses.

Depreciation, depletion and amortization (DD&A) expense was $1.241 billion in the second quarter of 2002, compared with $1.168 billion in the 2001 quarter. For the six-month periods, DD&A expense of $2.446 billion was $121 million higher than in the first half of 2001.

Taxes on income for the second quarter and first half 2002 were $876 million and $1.466 billion, respectively, compared with $1.911 billion and $3.668 billion for the comparable periods in 2001. The effective tax rates for the second quarter 2002 and 2001 were 68 percent and 48 percent, respectively. For the year-to-date periods, the effective tax rates were 56 percent and 45 percent, respectively. The increase in the effective tax rate for both

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2002 periods was primarily the result of a higher proportion of international before-tax income, generally taxed at higher rates, whereas the U.S. operations generated before-tax losses. In the second quarter 2002, a significant portion of the write-down of the company's investment in Dynegy did not generate U.S. tax benefits.

Foreign currency losses included in second quarter 2002 net income were $141 million compared with $20 million in the year-ago period. In 2002, fluctuations of the U.S. dollar against the currencies of most other countries in which the company has significant operations resulted in losses, with the notable exception of the Argentine peso, which was permitted to float against the dollar earlier in the year. For the six-month periods, foreign currency losses were $10 million in 2002, compared with gains of $67 million in 2001.

The following table presents a comparison of selected operating data.

**SELECTED OPERATING DATA**[1, 2]

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | 2002 | 2001 | 2002 | 2001 |
| **U.S. Exploration and Production** | | | | |
| Net Crude Oil and Natural Gas Liquids Production (MBPD) | **627** | 616 | **623** | 613 |
| Net Natural Gas Production (MMCFPD) | **2,504** | 2,783 | **2,506** | 2,835 |
| Sales of Natural Gas (MMCFPD)[3] | **5,125** | 8,499 | **5,980** | 8,708 |
| Sales of Natural Gas Liquids (MBPD) | **223** | 316 | **254** | 340 |
| Revenue from Net Production | | | | |
| Crude Oil ($/Bbl.) | **$23.05** | $23.22 | **$20.22** | $23.81 |
| Natural Gas ($/ MCF) | **$ 3.04** | $ 4.80 | **$ 2.66** | $ 6.18 |
| **International Exploration and Production** | | | | |
| Net Crude Oil and Natural Gas Liquids Production (MBPD) | **1,293** | 1,342 | **1,324** | 1,341 |
| Net Natural Gas Production (MMCFPD) | **1,932** | 1,675 | **1,940** | 1,724 |
| Sales of Natural Gas (MMCFPD) | **3,168** | 2,360 | **3,377** | 2,377 |
| Sales of Natural Gas Liquids (MBPD) | **138** | 105 | **134** | 101 |
| Revenue from Liftings | | | | |
| Liquids ($/Bbl.) | **$22.97** | $24.79 | **$20.99** | $24.12 |
| Natural Gas ($/MCF) | **$ 1.94** | $ 2.39 | **$ 2.07** | $ 2.59 |
| Other Produced Volumes (MBPD)[4] | **94** | 104 | **95** | 108 |
| **U.S. Refining, Marketing and Transportation** [5] | | | | |
| Sales of Gasoline (MBPD)[6] | **772** | 725 | **735** | 696 |
| Sales of Other Refined Products (MBPD) | **909** | 1,008 | **884** | 968 |
| Refinery Input (MBPD) | **1,041** | 1,009 | **955** | 952 |
| Average Refined Product Sales Price ($/ Bbl.) | **$33.91** | $39.80 | **$30.45** | $40.06 |
| **International Refining, Marketing and Transportation** | | | | |
| Sales of Refined Products (MBPD) | **2,210** | 2,463 | **2,162** | 2,410 |
| Refinery Input (MBPD) | **1,115** | 1,132 | **1,141** | 1,138 |

[1] Includes equity in affiliates.

[2] MBPD = thousand barrels per day; MMCFPD = million cubic feet per day; Bbl. = barrel; MCF = thousand cubic feet.

[3] Decrease between periods reflects reductions in company's trading activity.

[4] Represents total field production under the Boscan operating service agreement in Venezuela.

[5] Excludes Equilon and Motiva.

[6] Includes branded and unbranded gasoline.

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**U.S. Exploration and Production**

| Millions of Dollars | Three Months Ended June 30 2002 | Three Months Ended June 30 2001 | Six Months Ended June 30 2002 | Six Months Ended June 30 2001 |
|---|---|---|---|---|
| Operating Earnings | **$548** | $884 | **$852** | $2,197 |
| Special Items | **(12)** | — | **(12)** | — |
| **Segment Income** | **$536** | $884 | **$840** | $2,197 |

U.S. exploration and production operating earnings of $548 million in the 2002 quarter declined mainly due to significantly lower natural gas realizations, lower liquids realizations and a decline in oil-equivalent production. The average natural gas realization for the quarter was $3.04 per thousand cubic feet, compared with $4.80 in the year-ago period. The average natural gas realization for the first half of 2002 was $2.66 per thousand cubic feet, less than half the $6.18 obtained in the year-ago period. The average liquids realization was down about 5 percent to $21.75 per barrel in the second quarter and down nearly 18 percent to $19.35 in the first half of the year. Partially offsetting these unfavorable earnings impacts were lower operating and exploration expenses in the 2002 quarter and six months.

Net oil-equivalent production declined 3 percent from last year's second quarter and 4 percent for the six months. The net liquids production component was up 2 percent to 627,000 barrels per day in the quarter and 623,000 barrels per day year to date. Net natural gas production averaged 2.504 billion cubic feet per day in the second quarter, down 10 percent from the 2001 period. Six-month natural gas production was 2.506 billion cubic feet per day, compared with 2.835 billion cubic feet per day in the year ago period. Drilling and production were accelerated in 2001 to take advantage of the favorable natural gas price environment.

In the United States, substantially all of the company's natural gas and natural gas liquids production is sold to its Dynegy affiliate. Please see pages 6 to 7 and 21 to 22 of this Quarterly Report on Form 10-Q for further information relating to the company's investment in Dynegy.

The 2002 special charge of $12 million was for environmental remediation costs.

**International Exploration and Production**

| Millions of Dollars | Three Months Ended June 30 2002 | Three Months Ended June 30 2001 | Six Months Ended June 30 2002 | Six Months Ended June 30 2001 |
|---|---|---|---|---|
| **Segment Income/ Operating Earnings*** | **$710** | $832 | **$1,547** | $1,771 |
| * Includes Foreign Currency (Losses) Gains | **$ (62)** | $ (33) | **$ 91** | $ 13 |

Quarterly international exploration and production earnings of $710 million declined about 15 percent, mostly the result of lower realizations and higher depreciation expense. These effects were partially offset by lower exploration expense. In the first half of 2002, earnings of $1.547 billion were about 13 percent lower than last year's first half.

Net oil-equivalent production in the second quarter was essentially unchanged from the year-ago period. The net liquids production component declined about 4 percent to 1,293,000 barrels per day. Production was lower in Indonesia, primarily due to changes in certain production-sharing contract terms. In Nigeria, production declined chiefly as a result of OPEC-related curtailments. The effect of OPEC quotas on Nigerian production in the 2002 quarter was 45,000 barrels per day, versus having no effect in the corresponding 2001 period. Production under certain operating service agreements, which are not included in net working interest production statistics, was curtailed approximately 20,000 barrels per day in this year's second quarter, compared to about 10,000 barrels per day in the year-ago period. Net natural gas production increased

15 percent to 1.932 billion cubic feet per day. New production from the Philippines, along with higher production in several other countries, contributed to the increase.

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Net oil-equivalent production for the first half of 2002 increased about 1 percent from the year-ago period to 1,648,000 barrels per day, primarily the result of increases in gas production. Net natural gas production increased nearly 13 percent to 1.940 billion cubic feet per day. Net liquids production was 1,324,000 barrels per day, down slightly from last year. The effect of OPEC-related curtailments on average daily Nigerian production in the first six months of 2002 was 40,000 barrels per day.

The average natural gas realization for the quarter was $1.94 per thousand cubic feet, compared with $2.39 in the year-ago period. The average natural gas realization for the first half of 2002 was $2.07 per thousand cubic feet, compared with $2.59 last year. The average liquids realization was down about 7 percent to $22.97 per barrel in the second quarter and down 13 percent to $20.99 in the first half of the year.

Earnings for the quarter included net foreign currency losses of $62 million, compared with losses of $33 million in 2001. Currency losses in several countries, particularly Venezuela and Canada, were partially offset by gains attributable to the weakening of the Argentine peso against the U.S. dollar. For the six-month periods, foreign currency gains were $91 million in 2002 and $13 million in 2001. The 2002 period reflected significant gains in the first quarter attributable to the devaluation of the Argentine peso.

**U.S. Refining, Marketing and Transportation**

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| Millions of Dollars | **2002** | **2001** | **2002** | **2001** |
| Operating Earnings | **$ 56** | $531 | **$ (98)** | $720 |
| Special Items | **(86)** | — | **(86)** | — |
| **Segment (Loss) Income** | **$(30)** | $531 | **$(184)** | $720 |

U.S. refining, marketing and transportation operating earnings of $56 million declined nearly 90 percent from the year-ago quarter. The decrease was mainly due to significantly lower margins for refined products and the absence in the 2002 quarter of $208 million in earnings from assets that were sold under mandate of the FTC as a condition of the merger. The effect of lower gross margins was partially offset by lower operating expenses.

For the first six months of 2002, operating losses were $98 million, compared with earnings of $720 million in the corresponding 2001 period. In addition to the impact of lower product margins and the absence of about $256 million in earnings from assets sold as a condition of the merger, extensive planned refinery maintenance in this year's first quarter required product purchases, which further reduced profitability.

The quarter's average refined product sales realization decreased 15 percent to $33.91 per barrel. Year to date, average refined product sales realizations were $30.45 per barrel, compared with $40.06 last year. Refined product sales volumes, excluding the company's share of Equilon and Motiva in the 2001 period, decreased 3 percent to 1,681,000 barrels per day, primarily due to a decline in sales of jet and marine fuels. Branded gasoline sales volumes increased about 4 percent to 588,000 barrels per day from the year-ago quarter. For the first half of 2002, refined product sales volumes were 1,619,000 barrels per day, down from 1,664,000 barrels per day in 2001.

Special items in 2002 were for environmental remediation costs and the settlement of a litigation issue with the City of Santa Monica, California. Please see pages 15 and 30 for further information.

**International Refining, Marketing and Transportation**

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| Millions of Dollars | **2002** | **2001** | **2002** | **2001** |

| | | | | |
|---|---|---|---|---|
| **Segment Income/Operating Earnings*** | **$ 48** | $139 | **$ 141** | $406 |
| * Includes Foreign Currency (Losses) Gains | **$(102)** | $ 6 | **$(123)** | $ 61 |

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International refining, marketing and transportation earnings of $48 million in the second quarter and $141 million in the six months of 2002 both declined about 65 percent from the corresponding periods in 2001. The declines were primarily due to the effects of foreign currency fluctuations, and lower freight rates for the international shipping operations. Margins declined in the Asia-Pacific and European areas of operations but improved slightly in Latin America. Total refined products sales volumes decreased 10 percent to 2,210,000 barrels per day in the second quarter, primarily the result of lower demand for jet fuel and marine fuels. On a year-to-date basis, sales volumes were 2,162,000 barrels per day – also down 10 percent.

Earnings in the 2002 quarter included foreign currency losses of $102 million, compared with gains of $6 million in 2001. For six months, foreign currency losses were $123 million, compared with gains of $61 million in 2001. Currency losses in 2002 occurred mainly in Brazil, New Zealand, Australia, Korea and the United Kingdom.

**Chemicals**

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| Millions of Dollars | 2002 | 2001 | 2002 | 2001 |
| **Segment Income (Loss)/ Operating Earnings (Loss)*** | **$ 36** | $27 | **$ 51** | $(10) |
| * Includes Foreign Currency Losses | **$ 2** | $ (1) | **$ 1** | $ (5) |

Chemicals operations earned $36 million in 2002, up $9 million from last year's second quarter. On a year-to-date basis, chemicals operations earned $51 million, compared with the loss of $10 million posted in last year's six months. Earnings improved for both the company's Oronite Division and its 50 percent-owned affiliate, Chevron Phillips Chemical Company LLC. Protracted weak demand for commodity chemicals and industry over-supply conditions continued to suppress earnings for this sector.

**All Other**

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| Millions of Dollars | 2002 | 2001 | 2002 | 2001 |
| Net Operating Charges* | **$(165)** | $(269) | **$ (329)** | $(486) |
| Special Items | **(655)** | — | **(729)** | — |
| Merger-related Expenses | **(73)** | (36) | **(205)** | (57) |
| **Net Charges*** | **$(893)** | $(305) | **$(1,263)** | $(543) |
| * Includes Foreign Currency Gains (Losses) | **$ 21** | $ 8 | **$ 21** | $ (2) |

All Other activities include the company's ownership interest in Dynegy, coal mining operations, power and gasification businesses, worldwide cash management and debt financing activities, corporate administrative costs, insurance operations, real estate activities and technology investments. Net operating charges for the second quarter 2002, were $165 million, $104 million lower than in 2001. For the six-month periods, net operating charges of $329 million in 2002 were $157 lower than in the 2001 period.

The company's share of operating earnings from Dynegy were $3 million in the 2002 quarter, down from $35 million in 2001. For the six months, operating earnings from Dynegy were $43 million, down from $69 million in 2001.

Coal mining operations earned $1 million in the second quarter of 2002, compared with $7 million in last year's second quarter. Six-month operating earnings were $6 million in 2002, down from $13 million last year.

Power and gasification incurred losses of $15 million for the quarter and $17 million for the six months in 2002. Losses of $9 million and $27 million were recorded in the corresponding 2001 periods.

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Net operating charges from other activities were $154 million in the second quarter 2002, compared with $302 million in the 2001 period. The 2002 period benefited from the effect of lower income tax expense and corporate charges. For the six-month periods, net operating charges from other activities were $361 million in 2002 and $541 million in 2001. In addition to the benefits indicated in the 2002 second quarter, the six-month period also benefited from lower net interest expense.

Special items in the 2002 quarter included charges of $531 million for the write-down of the company's investment in Dynegy, $100 million for the company's share of Dynegy's own write-downs and other adjustments, and $24 million for environmental remediation costs. In the first quarter 2002, special items included $74 million for the company's share of Dynegy's write-down of its investments in telecommunications businesses. For further information related to the company's investment in Dynegy, please see "Information Relating to the Company's Investment in Dynegy" on pages 6 to 7 and pages 21 to 22 of this Quarterly Report on
Form 10-Q.

Merger-related expenses reduced net income by $73 million in the second quarter 2002, compared to $36 million in 2001. For the six-month 2002 and 2001 periods, the effect of merger-related expenses on net income was $205 million and $57 million, respectively.

Foreign currency gains were $21 million in the second quarter of 2002, compared with gains of $8 million in 2001. For six months, foreign currency gains were $21 million, compared with losses of $2 million in 2001.

**Liquidity and Capital Resources**

Cash, cash equivalents and marketable securities totaled $3.4 billion at June 30, 2002 – a $0.3 billion increase from year-end 2001. Cash provided by operating activities was $3.7 billion in the first half of 2002, compared with $7.1 billion in the year-ago period. The 2002 amount was adversely affected by lower crude oil and natural gas prices and reduced refined product margins. During the first half of 2002, the company received proceeds of $2.2 billion, including dividends due, from the sale of the company's investments in Equilon and Motiva. These proceeds, in addition to cash provided by operating activities in the first half of 2002, enabled the company to fund its capital program, to pay dividends to stockholders, and to reduce overall debt levels.

During the first six months of 2002, the company paid dividends of $1.494 billion to common stockholders. On July 31, 2002, ChevronTexaco declared a quarterly dividend of 70 cents per share, unchanged from the preceding quarter, payable on September 10, 2002.

At the end of the 2002 second quarter, ChevronTexaco had $3.2 billion in committed credit facilities with various major banks, which permit the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and also can be used for general credit requirements. No borrowings were outstanding under these facilities at June 30, 2002. At the end of July, the total of these committed credit facilities had increased to approximately $4.4 billion. During the second quarter, the company increased the total value of "shelf" registrations on file with the Securities and Exchange Commission (SEC) by $2 billion. The company currently has three existing "shelf" registrations on file with the SEC that together would permit registered debt offerings of up to $4.8 billion of debt securities. At June 30, 2002, the company also had lines of credit available for short-term financing totaling $500 million, of which $330 million had not been used.

ChevronTexaco's total debt and capital lease obligations were $16.8 billion at June 30, 2002, down from $17.4 billion at year-end 2001. In the first six months of 2002, net repayments of $662 million in long-term debt and other financial obligations were slightly offset by proceeds of $107 million from net additional short-term debt. Changes in long-term debt included a $250 million repayment of Texaco North Sea U.K. notes, a $192 million repayment of New Zealand debt, and a $100 million repayment of ChevronTexaco Corporation 8.11 percent notes. Also included in the decline in the company's long-term debt levels was a non-cash reduction of $100 million of ESOP debt. Proceeds from new long-term debt issuances were $57 million. In July, the company redeemed $200 million of Texaco Capital Inc. 8.375 percent bonds due 2022. The redemption premium was 3.67 percent.

The company's debt due within 12 months, consisting primarily of commercial paper and the current portion of long-term debt, totaled $11.3 billion at June 30, 2002, down from $11.6 billion at December 31, 2001. Of this

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total, $4.2 billion and $3.2 billion were reclassified to long-term at the end of each period, respectively. Settlement of these obligations was not expected to require the use of working capital in 2002, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis. The company's practice has been to refinance its commercial paper continually, maintaining levels it believes to be appropriate.

In July 2002, the company acquired $125 million in cumulative preferred shares of Chevron Phillips Chemical Company, its 50 percent-owned affiliate.

For information concerning the company's investment in Dynegy, please see "Information Relating to the Company's Investment in Dynegy" on pages 6 to 7 and pages 21 to 22 of this Quarterly Report on Form 10-Q.

The company benefits from lower interest rates available on short-term debt; however, ChevronTexaco's proportionately large amount of short-term debt keeps its ratio of current assets to current liabilities at relatively low levels. Current assets also include inventories valued on a Last-In-First-Out (LIFO) basis, which are significantly lower than current costs in all periods presented. The current ratio was 0.9 at June 30, 2002, about the same level as at year-end 2001.

ChevronTexaco's debt ratio (total debt to total-debt-plus-equity) was 33 percent at June 30, 2002, about the same as at year-end 2001. The company continually monitors its spending levels, market conditions and related interest rates to maintain what it perceives to be reasonable debt levels.

The company's future debt level is dependent primarily on its results of operations, its capital-spending program and cash that may be generated from asset dispositions. The company believes it has borrowing capacity to meet unanticipated cash requirements. Additionally, the company believes that during periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, it has the flexibility to increase borrowings and/or modify capital spending plans to enable maintaining the common stock dividend and the company's high-quality debt ratings.

ChevronTexaco's senior debt is rated AA by Standard and Poor's Corporation and Aa2 by Moody's Investor Service, except for senior debt of Texaco Inc. which is rated Aa3. ChevronTexaco's U.S. commercial paper is rated A-1+ by Standard and Poor's and Prime 1 by Moody's, and the company's Canadian commercial paper is rated R-1 (middle) by Dominion Bond Rating Service. All of these ratings denote high-quality, investment-grade securities.

**Worldwide capital and exploratory expenditures,** including the company's share of affiliates' expenditures, were $4.3 billion in the first half of 2002, compared with $5.1 billion in last year's first half. Expenditures for international exploration and production projects were $2.3 billion – 52 percent of the total expenditures – reflecting the company's continued emphasis on increasing international oil and gas production. Capital expenditures in this year's first half included more than $400 million for the acquisition of assets associated with the Captain Field in the North Sea that were previously leased and an approximate $200 million additional investment in the company's Dynegy affiliate. In the first half of 2001, expenditures included the acquisition of an additional 5 percent interest in the Tengizchevroil affiliate and higher development spending in the Gulf of Mexico, related to natural gas production.

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**CAPITAL AND EXPLORATORY EXPENDITURES BY MAJOR OPERATING AREA**

| Millions of Dollars | Three Months Ended June 30 2002 | Three Months Ended June 30 2001 | Six Months Ended June 30 2002 | Six Months Ended June 30 2001 |
|---|---|---|---|---|
| **United States** | | | | |
| Exploration and Production | **$ 444** | $ 656 | **$ 819** | $1,233 |
| Refining, Marketing and Transportation | **148** | 203 | **258** | 366 |
| Chemicals | **44** | 53 | **71** | 66 |
| All Other | **172** | 470 | **498** | 563 |
| **Total United States** | **808** | 1,382 | **1,646** | 2,228 |
| **International** | | | | |
| Exploration and Production | **1,113** | 995 | **2,268** | 2,475 |
| Refining, Marketing and Transportation | **231** | 228 | **383** | 403 |
| Chemicals | **7** | 8 | **10** | 12 |
| All Other | **14** | 2 | **16** | 3 |
| **Total International** | **1,365** | 1,233 | **2,677** | 2,893 |
| **Worldwide** | **$2,173** | $2,615 | **$4,323** | $5,121 |

**Contingencies and Significant Litigation**

Chevron, Texaco and four other oil companies (refiners) filed suit in 1995 contesting the validity of a patent ('393' patent) granted to Unocal Corporation (Unocal) for reformulated gasoline, which ChevronTexaco sells in California in certain months of the year. In March 2000, the U.S. Court of Appeals for the Federal Circuit upheld a September 1998 District Court decision that Unocal's patent was valid and enforceable and assessed damages of 5.75 cents per gallon for gasoline produced in infringement of the patent. In February 2001, the U.S. Supreme Court concluded it would not review the lower court's ruling, and the case was sent back to the District Court for an accounting of all infringing gasoline produced from August 1, 1996, to September 30, 2000. Additionally, the U.S. Patent and Trademark Office (USPTO) granted a motion by the refiners to re-examine the validity of Unocal's patent. The District Court judge requested further briefing and advised that she would not enter final judgement in this case until the USPTO had completed its reexamination of the '393' patent. During 2002 the USPTO rejected the validity of the '393' patent and another Unocal patent, the '126' patent, which could affect a larger share of U.S. gasoline production. Separately, the U.S. Federal Trade Commission has also announced that it is investigating whether Unocal's conduct in this matter was unfair competition, which may make Unocal's patent unenforceable.

Unocal has obtained additional patents that could affect a larger share of U.S. gasoline production. ChevronTexaco believes these additional patents are invalid, unenforceable, and/or not infringed. The company's financial exposure in the event of unfavorable conclusions to the patent litigation and regulatory reviews may include royalties, plus interest, for production of gasoline that is proved to have infringed the patents. The competitive and financial effects on the company's refining and marketing operations, while presently indeterminable, could be material. ChevronTexaco – as well as Chevron and Texaco separately pre-merger – has been accruing in the normal course of business any future estimated liability for potential infringement of the '393' patent covered by the 1998 trial court's ruling. In 2000 prior to the merger, Chevron and Texaco made payments to Unocal totaling approximately $28 million for the original court ruling, including interest and fees.

Another issue involving the company is the petroleum industry's use of methyl tertiary-butyl ether (MTBE) as a gasoline additive and its potential environmental impact through seepage into groundwater. Along with other oil companies, ChevronTexaco is a party to lawsuits and claims related to the use of the chemical MTBE in certain oxygenated gasolines. These actions may require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims

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related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. In July 2002, ChevronTexaco and Exxon Mobil Corp. (ExxonMobil) reached a settlement of an MTBE-related litigation matter with the City of Santa Monica, California. Under the terms of the settlement, ChevronTexaco and ExxonMobil guaranteed to fund the cost of building and operating a water treatment facility to remove MTBE and other contaminants from certain water wells and to pay a cash settlement to cover costs of alleged contamination. The City of Santa Monica agreed to release ChevronTexaco and ExxonMobil from a lawsuit filed in 2000 against a group of oil refiners, suppliers, and owners and operators of pipelines and other facilities for allegedly contaminating water wells with MTBE. The settlement also states that ChevronTexaco and ExxonMobil may be repaid a portion of the construction and operating costs if the City of Santa Monica fully recovers funds from the other companies named in the suit. ChevronTexaco has worked to reduce the use of MTBE in gasoline it manufactures in the United States. The State of California has directed that MTBE be phased out of the manufacturing process by the end of 2003, and the company intends to comply with this mandate.

U.S. federal income tax liabilities have been settled through 1996 for ChevronTexaco (formerly Chevron), 1993 for ChevronTexaco Global Energy Inc. (formerly Caltex), and 1991 for Texaco Inc. California franchise tax liabilities have been settled through 1991 for Chevron and 1987 for Texaco.

Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

The company and its subsidiaries have certain other contingent liabilities with respect to guarantees, direct or indirect, of debt of affiliated companies or others and long-term unconditional purchase obligations and commitments, throughput agreements and take-or-pay agreements, some of which relate to suppliers' financing arrangements.

Commitments related to preferred shares of subsidiary companies are accounted for as minority interest. MVP Production Inc., a subsidiary, has variable rate cumulative preferred shares of $75 million owned by one minority holder. The shares are voting and are redeemable in 2003. Texaco Capital LLC, a wholly owned finance subsidiary, has issued $65 million of Deferred Preferred Shares, Series C. Dividends of $59 million on the Series C preferred shares, equivalent to a rate of 7.17 percent compounded annually, will be paid at the redemption date of February 28, 2005, unless earlier redemption occurs. Early redemption may result upon the occurrence of certain specific events.

ChevronTexaco provided certain indemnities of contingent liabilities of Equilon Enterprises LLC (Equilon) and Motiva Enterprises LLC (Motiva) to Shell Oil Company and Saudi Refining, Inc. as part of the February 2002 sale of the company's interests in those investments. Generally, the indemnities provided are limited to contingent liabilities that may become actual liabilities within 18 months of the sale and are reduced by any reserves that were established prior to the sale. Excluding environmental liabilities, the company's financial exposure related to those indemnities is limited to $300 million. Additionally, the company has provided indemnities for certain environmental liabilities arising out of conditions that existed prior to the formation of Equilon and Motiva and during the periods of ChevronTexaco's ownership interest in those entities as well as for customary representations and warranties within the agreements.

The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemical or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including but not limited to: Superfund sites and refineries, oil fields, service stations, terminals, and land development areas, whether operating, closed or sold. The amount of such future cost is indeterminable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties. While the company has provided for known environmental obligations that are probable and reasonably

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estimable, the amount of future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemicals concerns.

ChevronTexaco receives claims from, and submits claims to, customers, trading partners, U.S. federal, state and local regulatory bodies, host governments, contractors, insurers and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve. The company also suspends the costs of exploratory wells pending a final determination of the commercial potential of the related oil and gas fields. The ultimate disposition of these well costs is dependent on the results of future drilling activity and/or development decisions. If the company decides not to continue development, the costs of these wells are expensed. The company and its affiliates also routinely assess their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its commodities and other derivatives activities, including forward exchange contracts and interest rate swaps. However, the results of operations and the financial position of certain equity affiliates, including Dynegy, may be affected by their business activities involving the use of derivative instruments.

The company's operations, particularly exploration and production, can be affected by other changing economic, regulatory and political environments in the various countries in which it operates, including the United States. The Organization of Petroleum Exporting Countries (OPEC) has at times made efforts to support crude oil prices by limiting production, which can affect production at the company's facilities, and those of its partners, in OPEC member countries. In certain locations, host governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest or strained relations between a host government and the company or other governments may affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results, and are carefully considered by management when evaluating the level of current and future activity in such countries.

Areas in which the company and its affiliates have significant operations include the United States of America, Canada, Australia, the United Kingdom, Norway, Denmark, Kuwait, Republic of Congo, Angola, Nigeria, Chad, Equatorial Guinea, Democratic Republic of Congo, South Africa, Indonesia, Papua New Guinea, the Philippines, Singapore, China, Thailand, Venezuela, Argentina, Brazil, Colombia, Trinidad and Korea. The company's Tengizchevroil affiliate operates in Kazakhstan. The company's Chevron Phillips Chemical Company LLC affiliate manufactures and markets a wide range of petrochemicals and plastics on a worldwide basis, with manufacturing facilities in existence or under construction in the United States, Puerto Rico, Singapore, China, South Korea, Saudi Arabia, Qatar, Mexico and Belgium. The company's Dynegy affiliate has operations in the United States, Canada, the United Kingdom and other European countries.

For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated oil and gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for ChevronTexaco's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills in California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. ChevronTexaco currently estimates its maximum possible net before-tax liability at less than $400 million. At the same time, a possible maximum net amount that could be owed to ChevronTexaco is estimated at more than $200 million. The timing of the settlement and the exact amount within this range of estimates are uncertain.

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**New Accounting Standards**

Recent interpretations of Financial Accounting Standards Board (FASB) Statement No. 133, “Accounting for Derivative Instruments and Hedging Activities” (FAS 133), as amended by FAS 138, “Accounting for Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133”, by the FASB Derivatives Implementation Group prescribe mark-to-market accounting for certain natural gas sales contracts. Some of these interpretations became effective January 1, 2002. Adoption at that time did not result in a material effect to net income. Other interpretations became effective April 1, 2002, and apply to certain power sales agreements of the company’s affiliates. Upon adoption of these interpretations, certain power sales agreements of the company’s affiliates were recorded as cash flow hedges. An after-tax gain of approximately $40 million was included in other comprehensive income in the second quarter reflecting the company’s share of the change in the fair value of the cash flow hedges. The effect of these cash flow hedges upon net income in the second quarter was not significant.

In June 2001, the FASB issued Statement No. 143, “Accounting for Asset Retirement Obligations” (FAS 143). FAS 143 is effective for fiscal years beginning after June 15, 2002. FAS 143 differs in several significant respects from current accounting for asset retirement obligations under FAS 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies.” Adoption of FAS 143 will affect future accounting and reporting of the assets, liabilities and expenses related to these obligations. The magnitude of the effect has not yet been determined.

Effective July 15, 2002, a consensus (Consensus 02-3) of the FASB Emerging Issues Task Force (EITF) will require companies involved in energy trading and risk management activities to present the gains and losses stemming from those activities on a net basis in the income statement. The company is currently evaluating these reclassification requirements, which will have no impact on net income.

In July, the FASB has issued Statement No. 146, “Accounting for Costs Associated with Exit or Disposal Activities.” The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activity. The statement replaces EITF Issue No. 94-3, “Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring).” FAS 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002.

**Compliance with Certification Requirements**

On August 7, 2002, ChevronTexaco filed a Current Report on Form 8-K reporting compliance by its Chief Executive Officer and its Chief Financial Officer with Securities and Exchange Commission Emergency Order 4-460, requiring certification of reports filed by ChevronTexaco earlier this year. The certification by such officers of this Quarterly Report on Form 10-Q, as required by Section 906 of the Sarbanes-Oxley Act of 2002, has been submitted to the SEC as additional correspondence accompanying this report.

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## PART II. OTHER INFORMATION

### Item 1. Legal Proceedings

*Richmond Refinery — Notices of Violation, Bay Area Air Quality Management District*

Chevron Products Company's (a division of Chevron U.S.A.) Richmond, California, refinery has been issued approximately 35 Notices of Violation during the calendar years 2001 and 2002, which allege non-compliance with the regulations of the Bay Area Air Quality Management District. The Notices of Violation address a variety of issues related to air emissions including, but not limited to, leaks of volatile organic compounds from the facility's processing equipment. The company has determined that the Notices of Violation will likely result in the payment of a civil penalty in excess of $100,000.

### Item 4. Submission of Matters to a Vote of Security Holders

The following matters were submitted to a vote of stockholders at the Annual Meeting on May 15, 2002.

Voters elected fifteen incumbent directors for one-year terms. The vote tabulation for individual directors was:

| Directors | Shares For | Shares Withheld |
|---|---|---|
| S. H. Armacost | 851,784,428 | 12,155,584 |
| R. J. Eaton | 852,357,831 | 11,582,181 |
| S. L. Ginn | 847,125,344 | 16,814,668 |
| C. A. Hills | 846,394,397 | 17,545,615 |
| F. G. Jenifer | 846,609,348 | 17,330,664 |
| J. B. Johnston | 851,726,618 | 12,213,394 |
| S. Nunn | 838,962,946 | 24,977,066 |
| D. J. O'Reilly | 852,943,974 | 10,996,038 |
| P. J. Robertson | 852,762,326 | 11,177,686 |
| C. R. Shoemate | 852,429,783 | 11,510,229 |
| F. A. Shrontz | 851,794,289 | 12,145,723 |
| G. F. Tilton | 851,904,572 | 12,035,440 |
| T. A. Vanderslice | 845,770,618 | 18,169,394 |
| C. Ware | 846,519,850 | 17,420,162 |
| J. A. Young | 851,885,519 | 12,054,493 |

Voters approved the appointment of PricewaterhouseCoopers LLP as the company's independent accountants by a vote of 828,578,905 (96.55 percent) for and 29,616,962 (3.45 percent) against. There were also 5,747,753 abstentions.

Voters approved the performance-based provisions of the Management Incentive Plan by a vote of 781,694,519 (91.56 percent) for and 72,013,438 (8.44 percent) against. There were 10,206,205 abstentions.

Voters approved the performance-based provisions of the Long-Term Incentive Plan by a vote of 754,785,336 (88.45 percent) for and 98,604,456 (11.55 percent) against. There were 10,524,974 abstentions.

A stockholder proposal to eliminate Bioaccumulative Halogenated Pollutants was rejected. There were 37,083,197 votes (5.40 percent) for the proposal and 650,230,566 votes (94.60 percent) against. There were also 25,701,984 abstentions.

A stockholder proposal to report on potential environmental damage to the Arctic National Wildlife Refuge was rejected. There were 52,396,610 votes (7.64 percent) for the proposal and 633,461,602 votes (92.36 percent) against. There were also 27,143,603 abstentions.

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A stockholder proposal to submit the stockholder rights plan to a stockholder vote was rejected. There were 345,220,127 votes (49.37 percent) for the proposal and 354,068,712 votes (50.63 percent) against. There were also 13,698,372 abstentions.

**Item 6. Exhibits and Reports on Form 8-K**

(a) Exhibits

(4) Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the company and its subsidiaries on a consolidated basis. A copy of any such instrument will be furnished to the Commission upon request.

(12) Computation of Ratio of Earnings to Fixed Charges

(b) Reports on Form 8-K

On August 7, 2002, ChevronTexaco filed a Current Report on Form 8-K reporting compliance by its Chief Executive Officer and its Chief Financial Officer with Securities and Exchange Commission Emergency Order 4-460, requiring certification of reports filed by ChevronTexaco earlier this year.

**SIGNATURE**

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CHEVRONTEXACO CORPORATION

(Registrant)

Date August 9, 2002

/s/ S. J. CROWE

S. J. Crowe, Vice President and Comptroller
(Principal Accounting Officer and
Duly Authorized Officer)

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**EXHIBIT INDEX**

| Exhibit Number | Description |
|---|---|
| (4) | Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the company and its subsidiaries on a consolidated basis. A copy of any such instrument will be furnished to the Commission upon request. |
| (12) | Computation of Ratio of Earnings to Fixed Charges |

# Appendix A
# Tables

**Table 2.1-1. Lease Blocks for the Pelican Project**

**Confidential–Sensitive Information**

Table 2.5-1. LNG Carrier Characteristics

| LNG Tank Type | | Spherical Tanks | | Membrane Tanks | |
|---|---|---|---|---|---|
| LNG Carrier Designation ($m^3$) | | 125,000 | 145,000 | 138,000 | 160,000 |
| LNG capacity ($m^3$) | | 128,000 | 145,000 | 138,000 | 160,000 |
| Length overall (m) | | 272 | 290 | 278.8 | 290 |
| Molded beam (m) | | 47 | 49 | 44 | 46 |
| Parallel Body Fore/Aft of Manifold (m) | Laden | 36.0/47.5 | 60.3/83.5 | 59.5/82.5 | 62.1/85.9 |
| | Ballast | | | 58.8/78.6 | |
| Draft fully loaded (m) | | 11.0 | 11.4 | 11.3 | 11.6 |
| Maximum displacement (metric tons) | | 94,000 | 104,000 | 98,000 | 116,000 |
| Minimum water depth at Berth (m)[2] | | 14.7 | 15.1 | 15.0 | 15.3 |
| Design Discharge Rate ($m^3$/hr) | | 11,000 | 12,000 | 11,000 | 12,000 |

[2] Minimum Water Depth based on UKC equal to 15 percent of design draft plus allowance for sea/swell conditions of 2.0 m significant wave height ($H_s$)

# Table 2.5-2
# Extreme Wave Conditions due to Winter Storms

## Confidential – Sensitive Information

## Table 2.5-3
## Extreme Wave Conditions due to Hurricane Storms

**Confidential – Sensitive Information**

## Table 2.5-4

## Maximum Water Surface Elevation (in feet above MSL) due to 100-Year Hurricane

## Confidential – Sensitive Information

Table 2.5-5. Wind Limitations

| Operation | Limit[3] |
|---|---|
| Berthing limit | 11.58 m/s (22.5 knots) |
| Loading limit | 15.44 m/s (30.0 knots) |

[3] One hour average wind speeds measured at 10 m above sea level

Table 2.5-6. Sea/Swell Limitations

| Operation | Wave direction (relative to vessel headings) | $H_s$ (m) | $T_p$ (sec) |
|---|---|---|---|
| Berthing | All wave directions | 1.50 | all periods |
| Unloading | Head Seas (+/- 30 deg. off bow or stern) | 2.50 | 0 to 10 |
| | | 2.00 | 10 to 14 |
| | | 1.50 | >14 |
| | Beam Seas (+/- 60 deg off beam) | 2.00 | 0 to 8 |
| | | 1.50 | 8 to 12 |
| | | 1.25 | >12 |

**Table 2.5-7. Design parameters for the gravity based structures (GBS units).**

**Confidential–Sensitive Information**

Table 2.5-8. Design characteristics for the gravity based structures (GBS units).

| **Design Characteristic** | | **Design Value** |
|---|---|---|
| LNG Carrier Berths/ Offloading Stations | | Two |
| Mooring | | Ability to berth two, 160,000 $m^3$ LNG carriers at any given time |
| Tanker Fuel Bunkering | | 8-inch diameter line for bunker fuel trans-shipment between berths |
| Tugboat (single point mooring) | | 4 |
| LNG Carrier Design (typical) | Size, normal ($m^3$) | 100,000 to 160,000 carry capacity |
| | Tank design pressure | 3.6 psi (250 millibar) |
| | Normal Tank Operating Pressure | 1.18 psi (80 millibar) |
| LNG Unloading | Design Unloading Rate | 52,800 GPM (12,000 $m^3$/hr) |
| | Unloading pump head | 390 feet maximum |
| | | 325 feet normal |
| | | 270 feet minimum |
| | Temperature | minus 250°F to minus 260°F |
| | Moisture content | Nil |

**Table 4.4-1. List of Engineering Planning and Design Studies for the Pelican Project**

**Confidential–Sensitive Information**

**Table 5.1-1. Comparison of Vaporizer Technologies**

**Confidential–Sensitive Information**

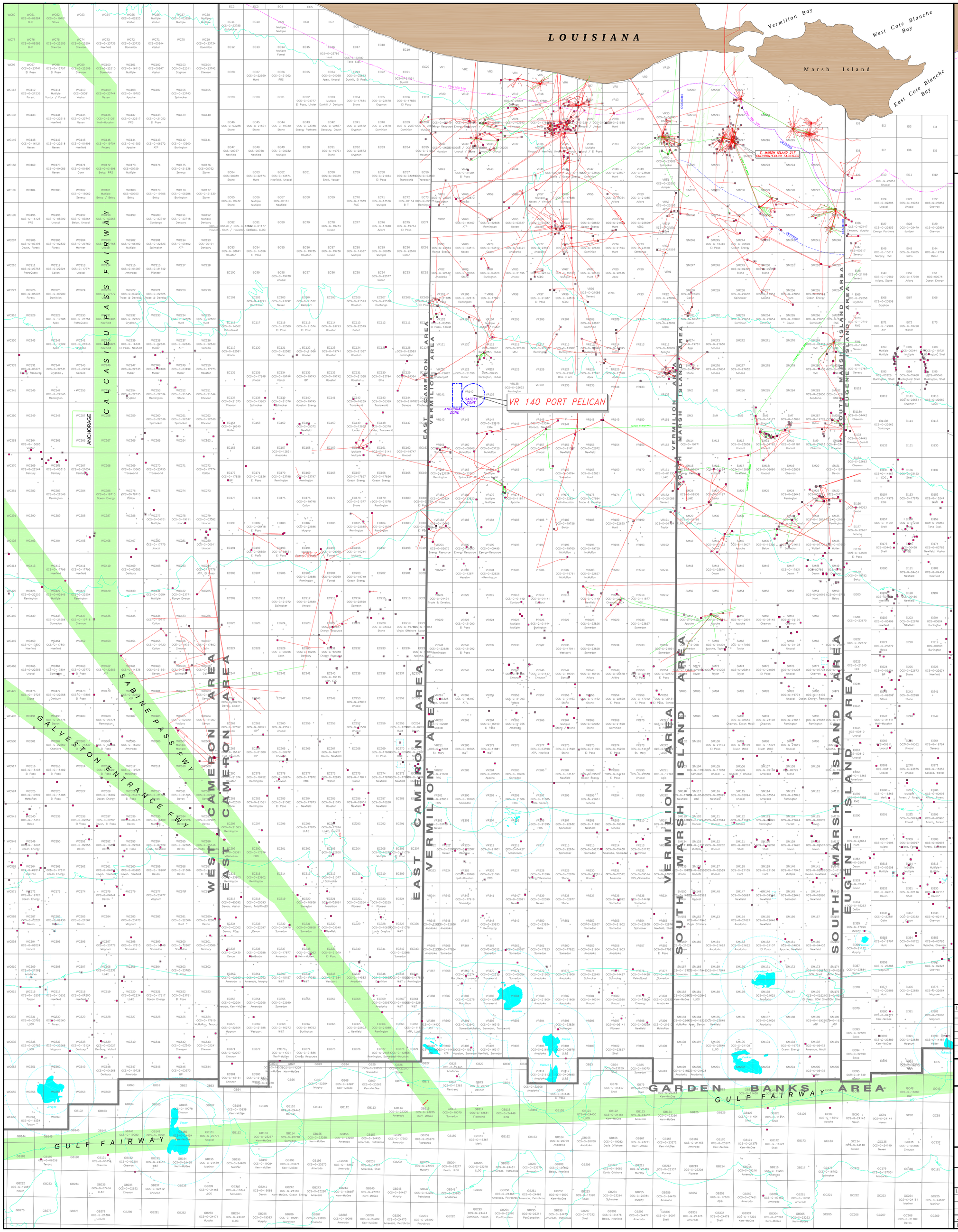
Table 5.2-1. Summary of potential air emission sources.

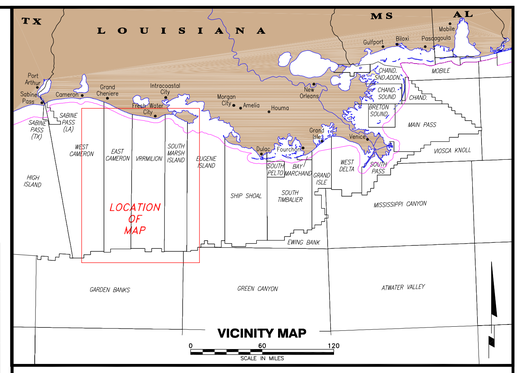
| Potential Emission Source | Utilization | Emissions and Air Permitting Status |
|---|---|---|
| Backup diesel generators (two) | Operated only in event of an emergency, but will be tested at a utilization of five percent to insure successful startup. | Emissions:<br>$PM_{10}$, 5.31 TPY<br>CO, 16.26 TPY<br>$CO_2$, 2,801 TPY<br>NMHC, 6.0 TPY<br>$NO_X$, 75.45 TPY<br>$CO_2$-e[6], 5,978 TPY<br>PSD or equivalent permit. |
| Diesel crane engine, cherry picker engine for material handling and offloading from boats. | 40 percent | |
| Diesel powered vehicles to transport parts and personnel | 60 percent | |
| Firewater diesel powered pump engines | Operated only in event of an emergency, but would be tested at a utilization of five percent to insure successful startup. | |
| Diesel (250 bbl), aviation fuel (two 700 gal) tanks and waste oil (two portable ) storage tanks | Not determined at this time. | Negligible breathing and working losses of VOCs.<br><br>PSD or equivalent permit. |
| Emergency Flare | 100 percent (continuous pilot) | PSD or equivalent permit. Continuously purged with nitrogen to prevent air infiltration through the flare tip. |
| Fuel gas compressor, boil-off gas compressor, various pumps, heaters, scrubbers, mobile and utility equipment | Not applicable | Electric- powered equipment; exempt from air permitting |
| LNG storage tanks (two) | Not applicable | LNG vapors (boil-off gas) used to fuel turbine generators or sent to PIPL. In emergency, vapors sent to flare. |
| LNG unloading arms (eight total, four per berth). Each berth has two arms for LNG carrier unloading, one arm for vapor return, and one spare arm. | Two days per LNG carrier | PSD or equivalent permit. The unloading arms will be equipped with vapor recovery but will emit small amounts of VOCs during offloading operations. |

[6] $CO_2$-e = $CO_2$-Equivalents

| Potential Emission Source | Utilization | Emissions and Air Permitting Status |
|---|---|---|
| Turbine generators (three, LM2000) fueled by LNG boil-off gas from the LNG offloading and storage. | Supply electricity to operate the facility. 95 percent utilization with one as backup (five percent utilization). | Emissions:<br>$PM_{10}$, 12.93 TPY<br>CO, 120.24 TPY<br>$CO_2$, 228,672 TPY<br>NMHC, 41.33 TPY<br>$NO_X$, 197.50 TPY<br>$CO_2$-e, 237,680 TPY<br>PSD or equivalent permit. Largest source of $NO_x$ at Terminal. |
| LNG carriers | Two days per LNG carrier | PSD or equivalent permit. |
| Assist tugs | Four tugs (three mooring, one standby) | PSD or equivalent permit. |
| Support vessel | One per month | PSD or equivalent permit. |
| Crew boat | One per day | PSD or equivalent permit. |
| Helicopters | One per day | PSD or equivalent permit. |

# Appendix B
# Figures




GRID NORTH

LEGEND

- EXISTING GAS & GAS/OIL PIPELINES
- EXISTING OIL PIPELINES
- SAFETY ZONE — SAFETY ZONE
- ANCHORAGE ZONE — ANCHORAGE ZONE
- EXISTING SHIPPING FAIRWAYS
- ~50m — WATER DEPTH CONTOURS IN METERS
- McDred — NATURAL BANKS
- ARTIFICIAL REEFS

STRUCTURE / HAZARD

- EXISTING PLATFORM
- REMOVED PLATFORM
- EXPLORATION WELL
- VALVE

| Issue No. | Date | Description | Inter | Drwn | Chkd | Aprv |
|---|---|---|---|---|---|---|
| 5 | 12/16/02 | REVISIONS PER ENTRIX | | RDT | LJC | |
| 4 | 12/12/02 | REVISIONS PER ENTRIX | | RDT | – | |

# PORT PELICAN

MARINE FAIRWAYS,
LNG CARRIER VESSEL ROUTE
PROPOSED PORT PELICAN INTERCONNECTOR PIPELINE
& EXISTING STRUCTURES IN PORT PELICAN TERMINAL REGION

The LNG Carrier Vessel Route and Proposed Port Pelican Interconnector Pipeline alignment are confidential-sensitive information.

**FUGRO CHANCE INC.**
200 Dulles Dr. Lafayette, Louisiana 70506-3001 (337) 237-1500

GEODETIC DATUM: NAD 1927
PROJECTION: LOUISIANA SOUTH
GRID UNITS: US SURVEY FEET

FEET 0 20,000' 40,000'
SCALE
MILES 0 2.0 4.0 6.0 8.0

| Issue No. | Date | Description | Inter | Drwn | Chkd | Aprv |
|---|---|---|---|---|---|---|
| 3 | 12/3/02 | REVISED ANCHORAGE ZONE PER ENTRIX | | RDT | LJC | |
| 2 | 11/22/02 | REVISIONS PER ENTRIX | | RDT | LJC | |
| 1 | 11/7/02 | COMPILATION OF H:\023264C.DWG & H:\023264E.DWG | | RDT | LJC | |

Job No.: 02-3264
Dwgfile: H:\2002\023264\CAD\MARINE\023264H

**MAP 1**

Plotted: 12/12/02

**Map 2 Map Showing Location of Pelican Interconnector Pipeline (PIPL) and Known Crossings with Existing Pipelines**

**Confidential–Sensitive Information**

11/21/02 10:21 Tdunn S:\Secure\Pelican\176903\CADD\PIT-ENT-GN-DWG-EV-0004.dwg

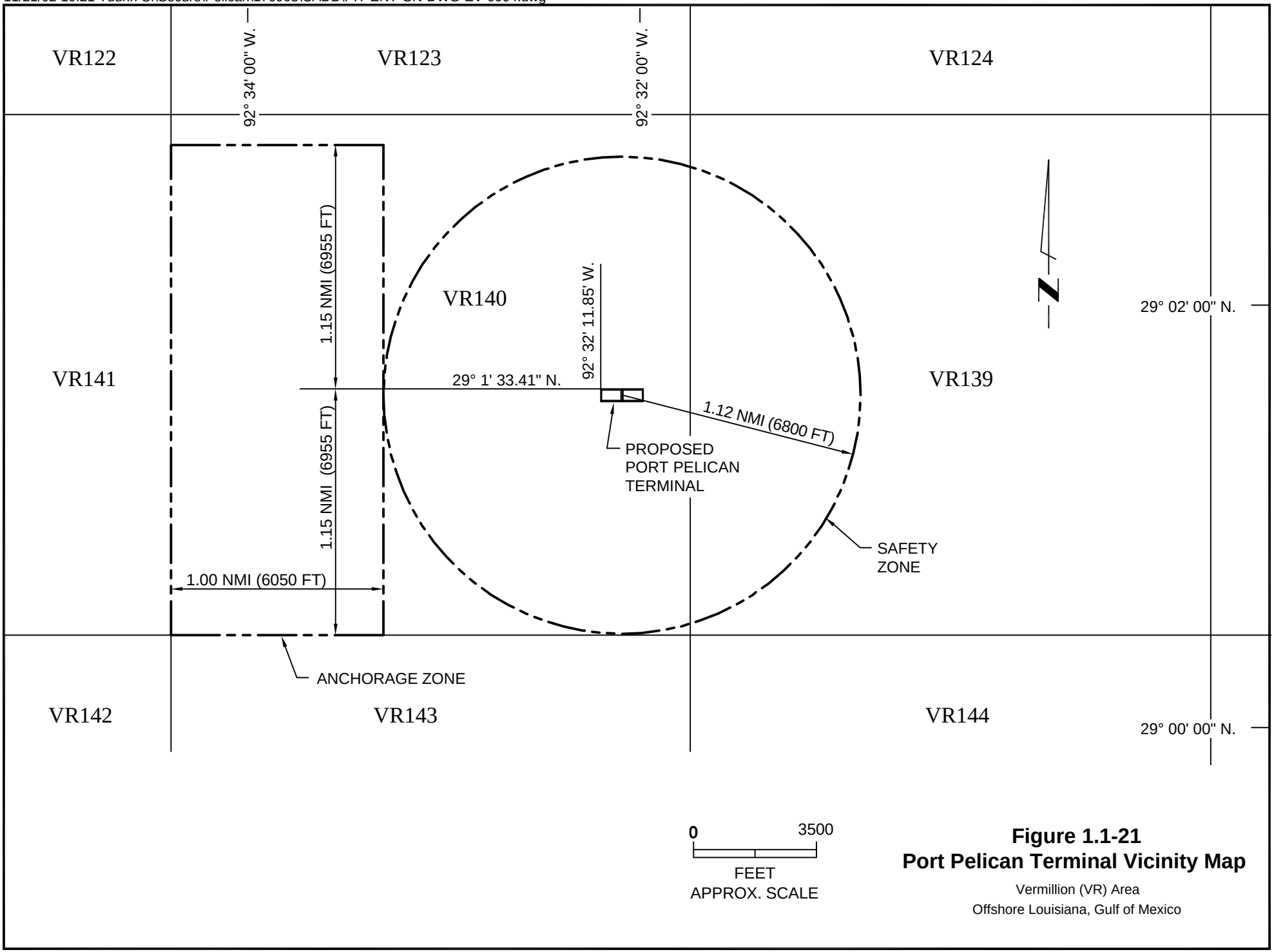
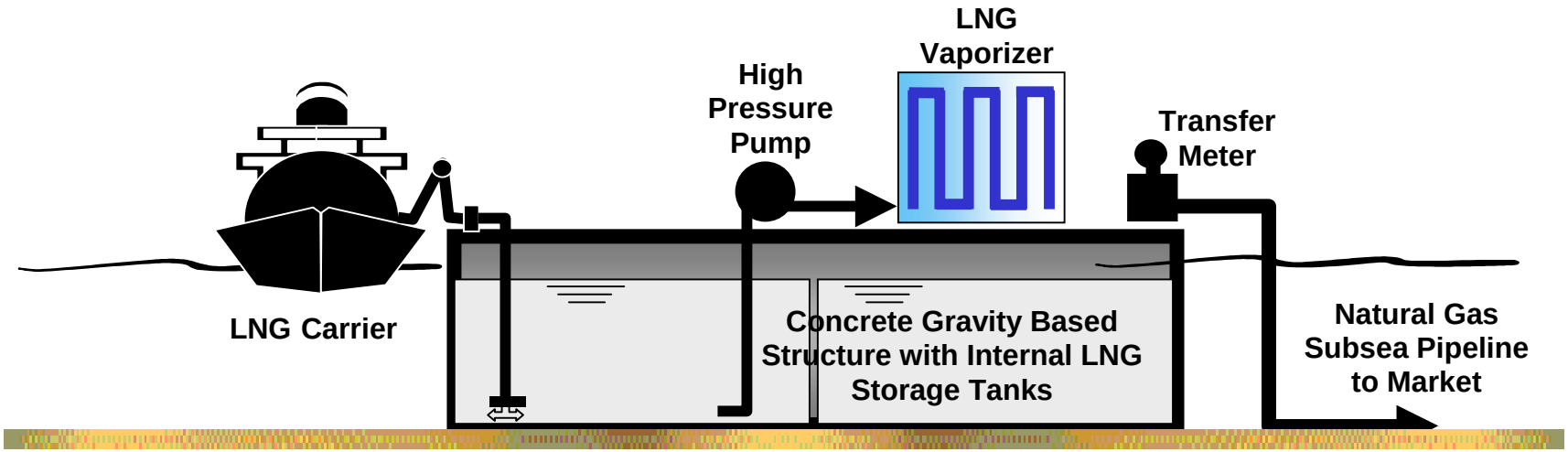



**Figure 1.1-21**
**Port Pelican Terminal Vicinity Map**

Vermillion (VR) Area
Offshore Louisiana, Gulf of Mexico

**Figure 1.1-3 Port Pelican Terminal Overhead View**

**Confidential–Sensitive Information**




- LNG Storage, -255$^{o}$ F, at Atmospheric Pressure.
- High pressure LNG pumps to pipeline pressure.
- Vaporizer units convert LNG into natural gas.
- Custody transfer meters gas transmission to Pipeline/Market.

**Figure 2.3-4**
**Port Pelican Basic Process Design -- Liquefied Natural Gas to Domestic Gas Supply**

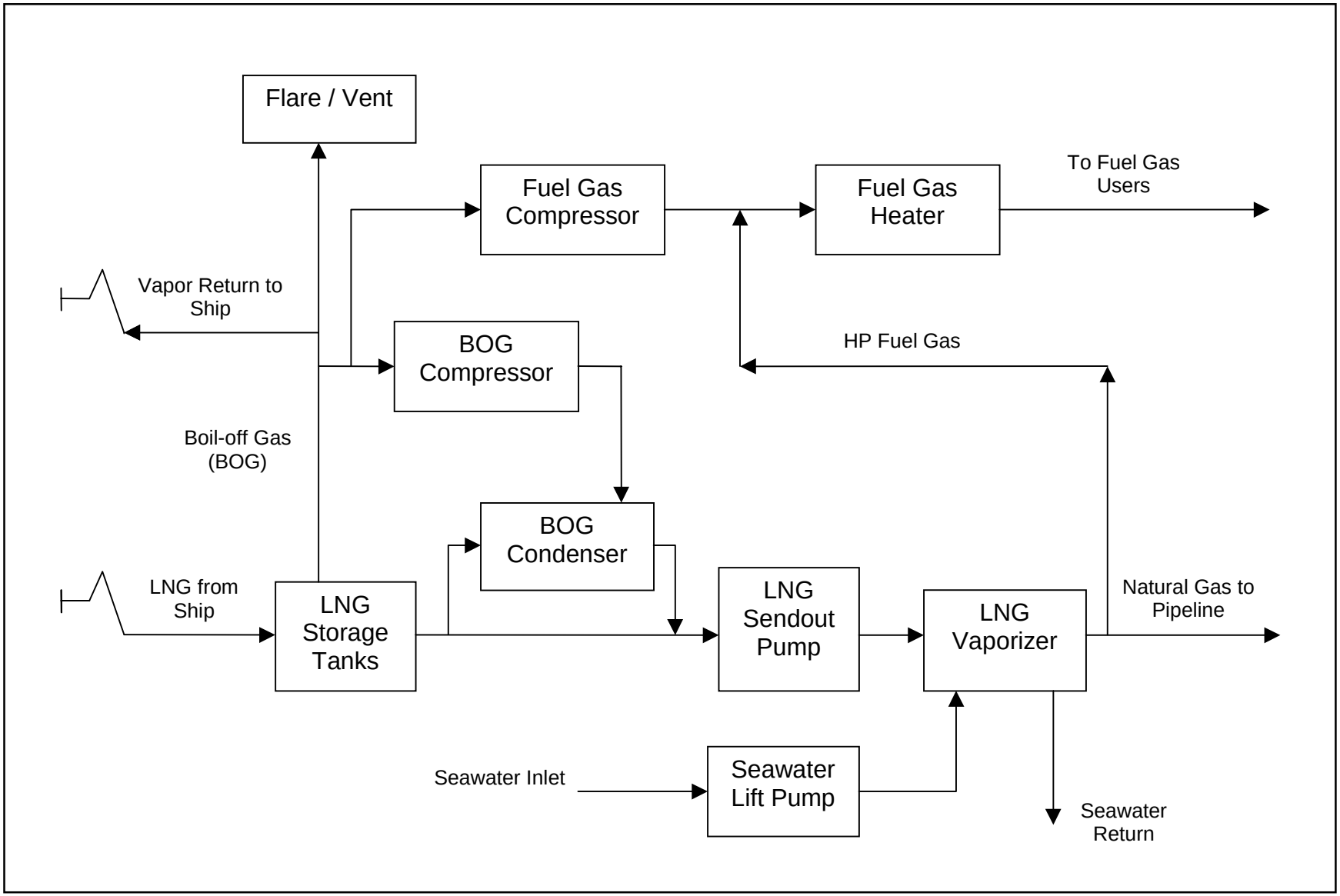



**Figure 1.1-6 Process Block Diagram**

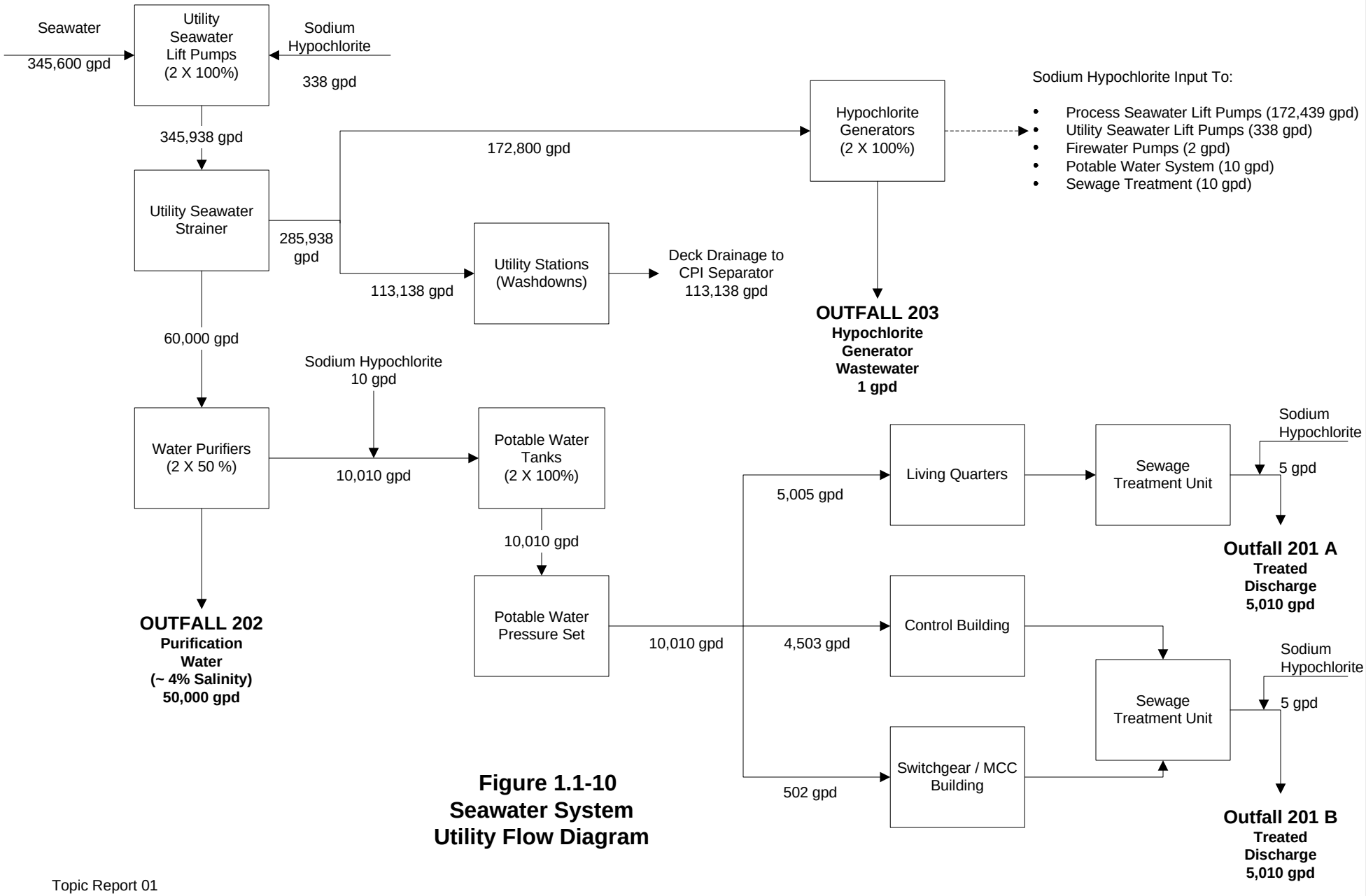



**Figure 1.1-10**
**Seawater System**
**Utility Flow Diagram**