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Cabrillo Port Application for Deepwater Port License

Pursuant to the Deepwater Port Act, as amended

33 U.S.C. 1501-1524 & 33 CFR Parts 148, 149, and 150

Submitted to
Commandant, United States Coast Guard
Washington, D.C.

Submitted by
BHP Billiton LNG International Inc.
Houston, Texas

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ABBREVIATIONS AND ACRONYMS

ACHP	Advisory Council on Historic Preservation
BACT	best available control technology
Barg	line pressure unit
Bbl	barrels
Bbl/day	barrel per day
Bcf	billion standard cubic feet
Bcf/d	billion standard cubic feet per day
BHPB	BHP Billiton Limited
BMPs	best management practices
BOD	Biological Oxygen Demand
BOG	boil-off gas
Btu	British thermal unit
Btu/ft^3	British thermal units per cubic foot
Btu/ft^2-hr	British thermal units per feet squared hour
ºC	degrees Celsius
CAA	Clean Air Act
CALM	Catenary Anchor Leg Mooring
CBM	Conventional Buoy Mooring
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CHL	California Historical Landmarks
CO	carbon monoxide
CO_2	carbon dioxide
COE	U.S. Army Corps of Engineers
CSLC	California State Lands Commission
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
dB	decibel
dBA	decibels on the A-weighted scale (human hearing frequency range)
DEIS	Draft Environmental Impact Statement
DNV	Det Norske Veritas
DPV	Dynamic Position Vessel
DWPA	Deepwater Port Act
dwt	dead weight tons
EA	Environmental Analysis

EFH	Essential Fish Habitat
EIA	Energy Information Administration
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
ESA	Endangered Species Act
ESD	emergency shutdown
°F	degrees Fahrenheit
FBE	fusion-bonded epoxy
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
Fps	feet per second
FPSO	Floating production storage and offloading unit
FSRU	floating storage and regasification unit
ft	feet
FWPCA	Federal Water Pollution Control Act
FWS	U.S. Fish and Wildlife Service
gal/yr	gallons per year
GHG	Greenhouse Gas
Gpd	gallons per day
Gpm	gallons per minute
GPS	Global Positioning System
GWP	Global Warming Potential
HAPs	Hazardous Air Pollutants
HDD	horizontal directional drilling
Hp	horsepower
HRI	Historical Research Inventory
H_s	Significant wave height
Hz	hertz-a measurement of cycles per second
IFV	intermediate fluid vaporizer
IGC	International Gas Carrier
IMO	International Maritime Organization
ISO	International Standards Organization
kg/h	kilograms per hour
kg/s	kilograms per second
kW	Kilowatt
kV	Kilovolt
Lb	Pound

lb/h	pounds per hour
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m/s	meters per second
m^3	cubic meters
m^3/d	cubic meters per day
m^3/h	cubic meters per hour
MAOP	maximum allowable operating pressure
MCE	maximum credible earthquake
µg/m^3	micrograms per cubic meter
mg/l	milligrams per liter
Mgd	million gallons per day
MJ/m^3	million Joules per cubic meter
MMbbl	million barrels
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
Mmgal	million gallons
MMPA	Marine Mammals Protection Act
MMS	Minerals Management Service
MMscfd	million standard cubic feet per day
MMTPA	million metric tons per annum
MP	Milepost
MPRSA	Marine Protection, Research, and Sanctuaries Act
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NDE	non-destructive examination
NEC	National Electric Code
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NGV	natural gas vehicle
NHPA	National Historic Preservation Act
NM	nautical miles
NMFS	National Marine Fisheries Service
NMHC	Non-methane hydrocarbons
NO_x	Nitrogen Oxides

NO_2	Nitrogen Dioxide
NOS	National Ocean Service
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NRHP	National Register of Historic Places
NSPS	New Source Performance Standards
NSR	New Source Review
O_3	Ozone
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OPR	Office of Pipeline Research
OPS	Office of Pipeline Safety
ORD	Office of Research and Development
P&Ids	process and instrumentation diagrams
PHI	Points of Historical Interest
PLEM	pipeline ending manifold
PM_{10}	particulate matter (10 microns in diameter)
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psig	per square inch, gauge pressure
ROVs	remote-operated vehicles
SCF	standard cubic foot
SCFD	standard cubic feet per day
SCFH	standard cubic feet per hour
SCR	selective catalytic reduction
SCV	submerged combustion vaporizer
SDV	safety shutdown valve
short t	short ton
short t/h	short ton per hour
SHPO	State Historic Preservation Officer
SIGTTO	Society of International Gas Tanker and Terminal Operators
SO_2	sulfur dioxide
SoCalGas	Southern California Gas Company
SOLAS	International Convention for the Safety of Life at Sea
SPCC Plan	Spill Prevention, Control and Countermeasure Plan

SWPP	Storm Water Pollution Prevention Plan
T	metric ton
T&E	Threatened and endangered
TCF	trillion cubic feet
TCM	trillion cubic meters
Tph	tons per hour
Tpy	tons per year
TWA	time weighted average
U.S.C.	U.S. Code
USCG	U.S. Coast Guard
USDOE	U.S. Department of Energy
USDOI	U.S. Department of Interior
USDOT	U.S. Department of Transportation
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UV	ultraviolet light
VOC	volatile organic compounds

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Section 1

1 Applicant Information

BHP Billiton LNG International Inc.

1.1 Identity of Applicant and Affiliates

1.1.1 Name, Address and Principal Business Activity

Applicant Name:

BHP Billiton LNG International Inc., a Delaware Corporation, is a wholly owned subsidiary of BHP Holdings (Resources) Inc.,

Mailing Address:

BHP Billiton LNG International Inc.
1360 Post Oak Boulevard, Suite 150
Houston, TX 77056-3020

Physical Address:

BHP Billiton LNG International Inc.
1360 Post Oak Boulevard, Suite 150
Houston, TX 77056-3020
(713) 961-8500

BHP Billiton LNG International Inc. was formed to engage in the business of operating liquefied natural gas (LNG) facilities to receive, store, and vaporize LNG and deliver natural gas to the existing natural gas infrastructure in the United States.

1.1.2 Corporate Officers and Directors

Corporate officers of BHP Billiton LNG International Inc. are:

Michael A. Weill	Chief Executive Officer and President
Stephen F. Billiot	Vice President
Alan F. Howell	Vice President

J. Christopher Massey	Vice President and Treasurer
M. Ruth Rhodes	Secretary
Jon M. Bowden	Assistant Secretary

1.1.3 Relationship of Affiliates

BHP Billiton Limited (BHPB), an Australian corporation, is the ultimate parent company of BHP Billiton LNG International Inc. The corporate headquarters of BHPB are located in Melbourne, Australia. BHPB is a leading global natural resources company, with a diversified commodity suite that includes minerals, oil, and gas. One of Australia's oldest and largest companies, it is renowned for continuously developing new operations both domestically and internationally.

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

BHP Billiton LNG International Inc. was incorporated in Delaware March 12, 2003 and is a wholly owned subsidiary of BHP Holdings (Resources) Inc. BHP Holdings (Resources) Inc. is a subsidiary of BHPB. BHPB is part of the Dual Listed Companies merger between BHP Limited, an Australian listed company (now BHP Billiton Limited) and Billiton Plc (now BHP Billiton Plc), which was concluded on June 29, 2001. This was affected by contractual arrangements between the companies and amendments to their constitutional documents. Attachment 1 contains copies of the Incorporation Documents of BHP Billiton LNG International Inc.

1.1.5 1.1.5 Lobbying Activities

Neither BHPB nor the Applicant conducts lobbying activities in the United States.

1.1.6 Terminal Operational Experience

The Cabrillo Port Project (Project) will be operated by staff experienced in the handling of LNG at onshore and offshore ports, and floating production storage and offloading (FPSO) units, 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 Project. The LNG will be regasified and delivered to the intrastate natural gas distribution system of Southern California Gas Company (SoCalGas) using a conventional natural gas pipeline operation. No other commodities will be handled at this port.

The applicant will be the operator of the Project. BHPB manages its investments in, and provides administrative, financial and management support to U.S. and foreign affiliates that engage in petroleum and natural gas operations.

BHPB, through its petroleum subsidiaries, produces crude oil and condensates, natural gas, LNG, liquefied petroleum gas (LPG), and ethane in the U. S. and worldwide. BHPB sells its hydrocarbon production under term contracts and spot sales, mainly to refining and petrochemical companies.

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 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
Pegasus International, Inc.	9821 Katy Freeway, Suite 750 Houston, TX 77024 (713) 465-5777	United States	Pipeline, engineering and design
FMC SOFEC	6677 N. Gessner Houston, TX, 77040 (713) 510-6600	United States	Marine Terminals, and turret mooring systems for Floating Production Storage and Offloading (FPSOs) facilities
Det Norske Veritas, USA	Offshore North America 16340 Park Ten Place, Suite 100 Houston, TX 77084 (281) 721-6600	United States	Design & Safety Risk Assessment Vessel & Facility Classification
Costain Oil, Gas and Process Limited	Costain House Styal Road Manchester M22 5WN England	United Kingdom	LNG regasification process engineering.
ENTRIX, Inc.	590 Ygnacio Valley Road, Suite 200 Walnut Creek, CA 94596 (925)935-9920	United States	Deepwater port license application preparation, environmental analyses

1.3 Qualifications and Experience

1.3.1 Qualifications and Experience of the Applicant

BHPB, the parent company to BHP Billiton LNG International Inc., can trace its origins to natural resources exploration and production in Australia and Asia back to the mid-19th century. However, it is only since the 1960s that BHPB has been involved in the oil and gas industry. This relatively "new" focus of BHPB has allowed it to develop and hone an expertise in offshore and natural gas development technologies that has established it as a leader in the safe, efficient, and innovative operation of floating production systems, natural gas transportation processes, and other offshore technologies.

Globally, BHPB has extensive experience in offshore operations, offshore transfer and storage of liquid cargo, and vessel loading and unloading operations.

BHPB is beginning its fourth year of a hydrocarbon exploration campaign in the Gulf of Mexico featuring a specially built drillship that operates in water depths of up to 9,000 feet. The drillship, CR Luigs, was commissioned with an international drilling contractor and includes several enhancements at the specific request of BHPB. Since its inaugural operation in March 2000, BHPB's drilling team has achieved an exemplary operating and safety record, including the most recent milestone of operating over two years and more than two million man-hours without a lost-time incident. The CR Luigs has not had a single recordable spill while working for BHPB.

BHPB's producing assets in the Gulf of Mexico include:

- Typhoon oil and gas field located in 2000 feet of water approximately 62 miles south of the central Louisiana coastline. The project achieved world-class standards for deepwater operations, with production occurring a rapid-paced three years after discovery. Typhoon has a nameplate capacity of 40,000 barrels of oil and 60-million cubic feet of gas per day. Earlier this year, a nearby discovery at the Boris field was tied back to the Typhoon facility.

- A past record-setter for the largest volume unmanned production system in the Gulf of Mexico, the BHPB-operated platform at West Cameron 76 recently marked 10 years of operation without a lost-time incident. The facility produces approximately 5,500 barrels of oil equivalent per day, which includes approximately 80-million cubic feet of gas.

BHPB also participates in the Genesis field in the deepwater Gulf of Mexico and the Green Canyon 18 and 60 fields on the continental shelf, which together produce approximately 8,500 barrels of oil equivalent as part of BHPB's share of production.

Floating Technology Related Projects

Floating technology for all offshore facility types is a strategic core technical competency for BHP Billiton Petroleum, another BHPB subsidiary. The technical groups within BHPB have strong capabilities and experience in this area, combining detail design with full operation.

BHPB pioneered the use of FPSO units for offshore oil and gas development in the 1980s, evolving and stretching the boundaries of its initial concept with many offshore floating "firsts". The oil and gas FPSO concept is now a standard and proven solution for the industry, with very little limit to its capabilities.

BHPB is at the forefront of the latest floating technology developments, including deepwater facilities and LNG export and receiving terminals, with future projects planned in these areas. BHPB has owned and operated eight floating facilities of various types over the last 18 years. BHPB's experience is diverse, having addressed a variety of operating conditions, stakeholder concerns, and engineering challenges that range from cyclone-prone seas of Southeast Asia and off the coast of Western Australia to the environmentally sensitive coastline of North Wales and the frequently vacationed shores on Liverpool Bay. The table below summarizes these.

Field	Type	Location	Start Date	Water Depth	Oil or Gas	Innovation
Jabiru	FPSO	Timor Sea	1986	120m	Oil	First disconnectable FPSO
Challis	FPSO	Timor Sea	1989	100m	Oil	Cyclone capable, water injection
Skua	FPSO	Timor Sea	1991	80m	Oil	First NGL plant on FPSO
Griffin	FPSO	Indian Ocean	1994	120m	Oil & Gas	Double hull, gas treatment on board & export to shore
Dai Hung	FPU + FSO	South China Sea	1994	110m	Oil	First Western offshore Vietnam
Elang	FPSO	Timor Sea	1998	80m	Oil	Re-use of existing FPSO
Buffalo	FPSO	Timor Sea	1999	25m & 400m	Oil	Complex mooring at edge of bank
Liverpool Bay	FSO	Irish Sea	1996	50m	Oil & Gas	Strict regulatory issues close to shore

Gas Processing Related Projects

BHPB has a long history of involvement in many gas-related activities: onshore and offshore gas production, methane drainage from coal seams, gas processing, LNG production and methanol production. Gas production and processing also is a strategic core technical competency within BHPB. BHPB's Global Engineering team has strong capabilities and expertise in this area, combining detail design and operations.

BHPB is among the leaders in using subsea wells and unmanned satellite platforms for gas production. BHPB has pioneered the search for a natural gas liquefaction process that is both safe for offshore, and can accommodate the special needs for offshore, such as compactness and tolerance to motions when located on a floating hull. BHPB has developed a proprietary liquefaction process design using an optimized dual expansion Nitrogen process, called cLNG (compact LNG). This is based on the evolution of a very old and well-proven nitrogen liquefaction process, and has become accepted as a viable and safe process especially for floating based offshore LNG projects.

BHPB has owned and operated 15 gas facilities of various types over the last 20 years and is a joint venture partner (non-operating) in 5 major gas projects and several minor ones. The table below provides a summary of these facilities and other significant gas related studies that have been performed.

Significant Operated Gas Activities

Field	Type	Location	First Gas	Gas Flow	Features/Innovations
Minerva	Subsea gas production with Onshore Processing	Victoria - Australia	2004	150 Mscfd	▪ Low temperature (J-T) plant with condensate co-product. ▪ Environmentally sensitive area
Angostura	Offshore Oil & Gas Production	Trinidad	2004	280 Mscfd	▪ Gas re-cycling operation with gas sales in the future
Ohanet	Onshore Gas Production & Processing	Sahara Desert - Algeria	2003	700 Mscfd	▪ Cryogenic turbo-expander gas plant with propane, butane and condensate products
Zamzama	Onshore Gas Production & Processing	Dadu - Pakistan	2001	300 Mscfd	▪ Low temperature (J-T) plant with condensate co-product ▪ Remote area
Liverpool Bay	Offshore Gas Production	Irish Sea - UK	1996	300 Mscfd	▪ Environmentally sensitive area ▪ Three unmanned satellite gas platforms
Liverpool Bay	Onshore Gas Production	North Wales - UK	1996	300 Mscfd	▪ Acid Gas removal ▪ Water and NGL removal ▪ Sulphur Production
Griffin	Gas Treatment on FPSO	Indian Ocean - Australia	1994	50 Mscfd	▪ Gas treatment on FPSO with high-pressure (186 bar) gas export to shore
Griffin Gas Plant	Onshore Gas Processing	Onslow - Australia	1994	42 Mscfd	▪ First and only nitrogen removal plant in Australia ▪ Uses HP cryogenic pumps
Victorian Methanol	Methanol Plant	Melbourne - Australia	1994	164 mtpd	▪ Novel LCM technology ▪ Pilot trial for offshore methanol production
West Cameron	Offshore Gas Production	US - Gulf of Mexico	1992	50 Mscfd	▪ Unmanned offshore gas production facility
Skua	Gas Treatment on FPSO	Timor Sea	1991	60 Mscfd	▪ First NGL extraction plant on FPSO
North Ravenspurn	Offshore Gas Production	North Sea - UK	1990	440 Mscfd	▪ First concrete gravity based gas platform in world ▪ Subsea gas production

Esmond/Forbes	Offshore Gas Production	Southern North Sea - UK	1985	220 Mscfd	▪ First offshore deck lift >5000 ft. ▪ Sanction - 1st gas <2 yrs. ▪ Unmanned satellite platforms
Namarah	Onshore Gas Production	Surat Basin - Australia	1983	24 Mscfd	▪ Remote small-scale gas production
Appin	Coal Bed Methane Drainage	NSW - Australia	1982	10 Mscfd	▪ First Coal Bed Methane Drainage in Australia

Significant Non-Operated Gas Activities

Grosvenor	Coal Bed Methane Drainage	Queensland - Australia	2003	50 Mscfd	▪ Coal Bed Methane Drainage
Bruce	Offshore Gas Production	North Sea - UK	1993	700 Mscfd	▪ Major UK gas supplier
North West Shelf LNG	LNG Plant	NW - Australia	1989	8 MMtpa	▪ Currently 3 LNG trains with 4th under construction ▪ High reliability supplier
North West Shelf Gas	Offshore Gas Production	NW - Australia	1984	2000 Mscfd	▪ One of the largest offshore gas suppliers in the world ▪ Multi-platform and subsea
Bass Strait	Offshore Gas Production with Onshore Processing	Victoria - Australia	1969	1100 Mscfd	▪ First major gas development in Australia ▪ Both cryogenic and lean-oil absorption gas plants

Significant Studies and Other Gas Activities

CLNG	BHPB patented LNG production process	On & Offshore LNG plants	1996	1 - 3 MMtpa	▪ Process developed and patented by BHP Billiton ▪ Paper presented at LNG 12 - Year 1998
Bayu-Undan	Offshore Gas Production	Timor Sea - Australia	1998	900 Mscfd	▪ Completed FEED for offshore gas re-cycling project. Sold in 1999.
Bayu-Undan Offshore LNG	Offshore LNG Production	Timor Sea - Australia	1998	3 MMtpa	▪ Completed FEED for offshore LNG production on a gravity base structure.
LNG Receiving Terminals	Onshore LNG Receiving Terminals	Various Locations	1998	0.2 - 4 MMtpa	▪ Large terminals in SE Asia ▪ Small scale terminals in Mediterranean
Palmyra	Onshore Gas Production & Processing	Palmyra - Syria	2002	350 Mscfd	▪ Two complex onshore gas projects, both with LPG and condensate products
South Pars	Offshore Gas Production	Persian Gulf - Iran	1996	1 Bscfd	▪ Major Gas Development
Iran – India Pipeline	Gas Trunkline	Iran - India	1996	2 Bscfd	▪ International Pipeline Project

1.3.2 Qualifications and Experience of Design Firms

Det Norske Veritas, USA

Det Norske Veritas (DNV) has provided classification and consulting services for LNG carriers for over 30 years and has been central in the design development for both spherical and membrane type tank systems. DNV develops and maintains technical standards for the classification of all types of seagoing ships, offshore drilling units and storage and production units for the exploitation of offshore oil and gas reserves. DNV is a leading classification society and a founding member of the International Association of Classification Societies. DNV is authorized by 110 national authorities to undertake approvals and surveys on their behalf. DNV has operated in the U.S. for more than 100 years and has been an active player in the energy sector in the past 20 years. DNV is experienced in the offshore energy sector and has classified several offshore deepwater drilling units and production units. DNV provides risk management consulting services to the oil and gas industry in many areas, including the Environmental Impact Statement for the first FPSO in the Gulf of Mexico.

<u>Project Experience</u>

- Osaka Gas Co Ltd. Assessment of the risk of loss of LNG supply on a generic LNG (liquefaction) plant. The assessment takes into account potential fire/explosion scenarios and equipment breakdown that may lead to more than 14 days of plant shutdown.
- Client–Moss Maritime/ Merlin Production. Risk assessment of an LNG FPSO.
- ARCO Indonesia. Qualitative assessment of the risks to the safe operation of the Tangguh LNG Marine Terminal and Nearshore Pipelines in Indonesia.
- M W Kellogg Limited. LNG installation failure rate data: Compiled failure rate data for specified LNG installation equipment from other DNV sources.
- BG Storage. Qualitative analysis for Isle of Grain Ignition study for the Isle of Grain. Determination of the effect of MAH on personnel on and offsite Isle of Grain site Human factors study for the Isle of Grain site.
- VICO Services Inc. Review of proposed emergency shutdown ESD/EDP system for LNG Plant: Reviewed 2 alternative Emergency Shutdown design cases for risk reduction and cost effectiveness for the P.T. Badak LNG plant at Bontang, Indonesia.
- M W Kellogg Ltd. Concept safety report, Snohvit LNG plant: a proposed new gas liquefaction plant in Northern Norway. The concept safety study included the slugcatcher, the LNG train, the LNG storage tanks, the LPG storage tanks and the inter process area pipework. The focus was on passive and active protection measures in order to prevent escalation from one process area to another.
- Mobil. Risk assessment of an LNG FPSO.
- Mitsubishi Heavy Industries Ltd. Ship and Ocean Engineering Department. Risk assessment and SWIFT study of proposed multi-cargo berth at Mumbai (Peer Pau) port.
- Phillips Petroleum Company UK Ltd. Safety and Environmental review for LNG development: High level review of the onshore and offshore safety and environmental issues affecting the Bayu-Undan LNG development (CONFIDENTIAL).
- Castle Point Borough Council. Risk assessment of former methane terminal at Canvey Island.

- BHP. Risk assessment of LNG production facility located on a Gravity Based Structure for the Bayou Undan field.

- Kvaerner. Risk assessment an LNG (FPSO).

- Statoil. Risk assessment of landbased LNG production facility for Snohvit.

- JGC Cooperation. Risk assessment of proposed floating production, storage and offloading facilities for LNG.

- The joint venture of Technip, Snamprogetti, Kellogg and JGC (TSKJ). Nigeria LNG pre-activities work~~.~~: QRA design study on Unit 1400 propane system.

- Woodside. Risk assessment of LNG production plant in Karratha, Western Australia.

- Total exploration Production / P.T. Badak. Risk assessment of LNG production facilities in BONTANG, Indonesia.

- Kellogg Joint Venture (M.W. Kellogg Company) (JGC Corporation). Preliminary quantitative risk assessment study of the LNG-3 facility.

- Woodside Offshore Petroleum Pty Ltd. Quantitative Risk Assessment for the Burrup Peninsula. Site Questions on Tanker Movements, North West Shelf Development Project.

- JGC/Kellog Joint Venture. Preliminary risk study of a third LNG plant in Bintulu was carried out for JGC Corporation and the MW Kellogg Company, on behalf of Petroliam Nasional Berhad. Two plant scenarios were identified for analysis to be quantified in terms of calculated risk measures. The risk assessment work assisted in ensuring the proposed plant presented the lowest practical risk to the surrounding environment. Both individual and societal risks were examined. The risk measures were obtained in the form of individual risk contours, potential loss of life and societal risk curves.

- Kvaerner Moss Technology. Calculation of temperature response in equator and skirt structure in an LNG carrier during various pre-cooling and filling, heating, and ballast voyage cooling sequences.

- ADGAS. Risk assessment of onshore LNG liquefaction plant in Abu Dhabi.

- Petroliam Nasional Berhad. Risk assessment of Bintulu on-shore LNG facilities.

- Brunei LNG Sendirian Berhad. Quantitative risk assessment of the operation of the new LNG loading facilities.

- Phillips/Marathon. Design analysis of LNG carriers including: Analysis of wave loads, stresses, and crack propagation fatigue and thermal loads.

- Phillips Petroleum Co. Calculation of boil-off for stable conditions.

- Statoil Zeebrugge gas terminal conceptual safety evaluation.

- MRV Technology. Evaluation of concrete secondary containment system of an LNG storage tank.

- Shipowners (Gotaas-Larsen and L Hoegh). Assessment of technical standard of existing LNG ships. The assessment comprised inspection, detailed structural analysis of hull and tanks, evaluation of aging effects in materials, maintenance and operation and review of historical data.

FMC SOFEC

FMC SOFEC, established in 1972, is a subsidiary of FMC Corporation, a major multinational company based in Chicago. For offshore development projects, FMC SOFEC can provide its customers with TLPs FSOs, FPSOs, subsea equipment, tanker-based mooring systems, fluid transfer and control systems and metering and offloading systems. FMC is a global leader in the design, construction, installation and commissioning of proven systems for a broad range of marine and subsea related requirements including: Floating Production Systems, Permanent and Disconnectable Internal Turret Moorings, External Cantilevered Turret Moorings, Innovative Spread Moorings, Marine Import/Export Terminals, Single Point Moorings (SPM) and Conventional Multiple Buoy Moorings (CMBM), Riser Systems, and Swivel Systems.

<u>Project Experience</u>

- CLJOC, Vietnam. External turret mooring system: FMC designed and constructed the external turret mooring system to moor a 151,000 dwt purpose built FPSO. The FPSO will receive product oil and re-inject both produced gas and water. The SOFEC © turret is designed to support a single production platform in Phase I, with space to accept additional production from a second future production platform in Phase II of the project.

- OCP/Techint, Ecuador. External turret mooring system: FMC was awarded the design and supply of two Catenary Anchor Leg Mooring (CALM) Buoy systems for the OCP pipeline project in Ecuador.

- Exxon/Mobil, Kizomba A Offshore Angola. Mooring System Design: SOFEC is responsible for the mooring system and design of the spread moor system.

- Esso Chad, Offshore Cameroon. Mooring System Design: FMC SOFEC is responsible for the design and fabrication of the Tower Yoke Mooring System including the Jacket and Tower, the mechanical Yoke linkage and ship-mounted Mooring Support Structure.

- PTTEP Bongkot, Gulf of Thailand. External turret mooring system: Design, construct and supply an external turret mooring system for a purpose built 60,000 dwt FSO in 256 ft (78m) water depth in the Bongkot Gas Field, Gulf of Thailand.

- Enterprise Oil, Campos Basin, Brazil. External turret mooring system: Design, construct and supply an external cantilevered bow turret mooring system for a 350,000 dwt FSO vessel to produce the Bijupira & Salema fields in Campos Basin, Brazil.

- Matrix Oil, Langsa Field offshore North Sumatra, Malaccan Straits. External turret mooring system: Design and supply the spread mooring anchor lines and on-vessel chain support and installation equipment for a 32,000 dwt FPSO for Matric Oil in the Langsa Fields, offshore North Sumatra in the Malaccan Straits. The spread mooring is an 8 – leg system in 328 ft (100 m) of water.

- FMC Hong Kong/China National Offshore Oil Company. QHD32-6 Bohai Bay. External turret mooring system: Design and provide project management for a Soft Yoke Tower mooring for 162,000 dwt newly built vessel. FMC SOFEC provided project management for the design, fabrication, supply, and installation of the complete mooring system.

- Vietsovpertro, South China Sea Vietnam. External turret mooring system: Design, construct and supply an external mooring system for a purpose-built 150,000 dwt FSO in 154 ft (74m) water depth in the White Tiger Field. Designed for a twenty year operating life.

- Shell, South China Sea Palawan Island, Philippines. External turret mooring system: Design, construct, and install a CALM buoy system for the Shell Malampaya Deep Water Gas to Power Project. The Malampaya project is located in the South China Sea offshore the Palawan on the Philippines. The purpose for this buoy is for the transfer of condensate from the Production Platform to tankers through a 2.5 kilometers long 24 inch pipeline.

- Petro Canada, Canada. Design a disconnectable turret mooring system for a 960,000 barrel ("bbl") purpose-built FPSO. FMC SOFEC designed a disconnectable turret to be installed in a purpose-built ice strengthened FPSO. The turret design permits the vessel to disconnect and reconnect to the mooring to avoid icebergs and severe ice conditions.

- BHPP Petroleum, Western Australia Timor Sea. External turret mooring system: Design, construct and supply an external mooring system for an 103,000 dwt vessel in BHP Petroleum's newly discovered Buffalo Oil field. Located in the Western Australia sector of the Timor Sea. The field is located below shallow water bank in approximately 89 ft (27 m) water depth and surrounded by deeper water ranging from 280 to 350 meters in depth. The selected option to develop the Buffalo field consists of a wellhead platform producing to a nearby leased Floating Production, Storage and Offloading (FPSO) vessel.

- ADCO, Abu-Dhabi - UAE. CALM system: Design, construct and install a CALM system to accommodate up to 450,000 dwt tanker. This project involved design, construction and installation of an export CALM system in 75 ft (23 m) water depth. This includes extension of the existing 36-in sealines and removal of two existing Conventional Buoy Moorings (CBM).

- Petronas, Petronas (Terengganu), Malaysia. CALM system: Design, construct and install a replacement CALM system to accommodate 35,000 to 85,000 dwt tankers in 65 ft (19.8) water depth. Remove an existing system and install a replacement CALM plus 180 feet of chain per leg.

- Petronas, Petronas (MASA), Malaysia. External fixed turret Design: Construct an external fixed turret for a 94,236 dwt FPSO. FMC SOFEC designed and constructed an external fixed turret mooring system for a permanently moored FPSO (in 100-year storm conditions) located in 246 ft (75m).

- Cairn Energy India Pty Ltd, Rava Field East Coast of India. CALM system: Designed and constructed a 12.5 meter diameter CALM buoy as part of its stock buoy program. FMC SOFEC replaced a buoy that experienced catastrophic failure and successfully fitted its CALM system to the existing 6 leg anchor chains.

- PEMEX, Mexico. External cantilevered bow turret fort a 350,000 dwt FSO: FMC SOFEC designed and constructed an external turret mooring system for an FSO installed in 266 ft. (81m) water depth in the Cantarell Field, Bay of Campeche in the Gulf of Mexico. The turret uses a ten leg asymmetric catenary wire/chain mooring system.

- Petrozuata, Venezuela. CALM system: Design and construct a CALM system to accommodate a 96,920 dwt tanker. FMC SOFEC designed and constructed a CALM system located in 82 ft (25m) water depth to transfer diluted or refined crude oil and gas oil products from the PLEM to the tanker and to transfer naptha dilutent from tankers to shore. The buoy design includes a two path swivel with triple floating hoselines. Two marine pipelines (36 and 24 inches) connect the buoy to the onshore pump station.

- Marathon, Gabon. External turret mooring system. Design and supply a permanent spread mooring system for installation on a 135,000 dwt FSO vessel in 150 ft (46m) water depth for Martathon's Tchatamba Field offshore Gabbon. FMC SOFEC supplied a twelve leg anchoring system and the design/supply of deck mounted equipment including chain supports and jacking system.

- Butinge, Lithuania. CALM system. External turret mooring system: Design, construct and supervise installation of a CALM system to accommodate any crude tanker from 35,000 dwt to 80,000 dwt in near-artic icing conditions. The CALM is provided with a PLEM to transition from the submarine pipeline to each of the two loading hoses. Crude transfer is through a 36-inch pipeline.

- Petrobras, Albacora Field- Brazil. Internal turret mooring system: Design and construct an internal turret mooring system for 282,000 dwt FPSO. The turret system is designed to accommodate 25 flexible risers arranged in a radial pattern around the turret chain table. The ten-path swivel stack includes fluid paths for production, oil import/export, gas lift, and water injection. Multi-line swivels provide hydraulic and pneumatic controls. The turret uses an eight-leg symmetric catenery wire/chain mooring system.

- Baracuda Field, Brazil. Internal turret mooring system: Design and construct a permanent internal turret mooring system for a 50,000 dwt FPSO. One of the world's deepest FPSO systems at 2,739 ft (835 m). The turret system is designed to accommodate 34 flexible risers and the largest number of risers ever handled by a tanker-based FPSO and the largest number of flowpaths ever to be manifold in an internal turret system. Turret design is based upon a turret shaft support by a large diameter roller bearing at the FPSOs top deck allowing ready access to inspection and maintenance. Catenary risers are routed to the periphery of turret shaft to reduce congestion. The six path fluid swivel includes production, test, gas lift, gas export, and hydraulic control. The turret uses a six leg symmetric catenary wire/chain mooring system.

- Chevron, Escravos Field- Nigeria. External cantilevered bow turret for a purpose-built 37,000 dwt FSO: Design and construct an external turret mooring system for a purpose-built FSO installed in 95 ft (29m) water depth. The FSO handles the refrigeration and depressurization of liquefied petroleum gas (LPG) for Chevron Nigeria Ltd. The turret uses a six leg symmetric all chain mooring system.

- Kuwait Oil Company, Kuwait. CALM system: Design and construct two CALM systems to accommodate up to 456,000 dwt tankers. FMC SOFEC designed and constructed two CALM systems for National Petroleum Construction Company (NPCC) to be installed in 100 ft (30.5 m) water depth. Both units were equipped with sophisticated SCADA systems for remote tracking.

- Shell, Todd Oil Services. Maui B Field – New Zealand. External cantilevered bow turret for a 135,000 dwt in 375ft (114 m) water depth. FMC SOFEC designed and constructed an elevated external turret mooring system for the harsh environments offshore Taranaki, New Zealand. The elevated turret design minimizes hydrodynamic loads and provides a more direct and efficient load path. The turret uses a ten-leg asymmetric catenary wire/chain mooring system for increased fatigue resistance and elasticity.

- J.Ray McDermott. Chevron Nemba Field Angola. Spread mooring system: Design and supply a permanent spread mooring system for installation on an Early Production System (EPS) in 390 ft (119m) water depth for Chevron's Nemba Field Development off Cabinda, Angola. FMC SOFEC supplied an eight leg anchoring system and the design/supply of deck-mounted equipment including horizontal sheaves and chain support assemblies.

- ADCO Abu-Dhabi UAE. CALM system: Design, construct and install a CALM system to accommodate 450,000 dwt tankers. FMC SOFEC designed, constructed and installed an export CALM system in 68 ft (21 m) water depth. This included an extension of the existing 42-in sealine and removal of the existing CBM. This was the third project in which FMC SOFEC was involved in the replacement of a CBM system with a more efficient Single Pont Mooring (SPM) system.

- Amoco Orient Petroleum Co, People's Republic of China Liuhua 11-1. Internal turret mooring system: Design and construct permanent internal turret mooring for FPSO vessel to be moored in 960 ft (293 m) water depth in "Typhoon Alley" southeast of Hong Kong. The Liuhua 11-1 field is a subsea development having 20 clustered wells and floating facilities, which include both semi-submersible and FPSO. The permanent turret mooring system installed in the FPSO enables the tanker to remain on station during 100-year typhoon conditions characterized by wave height up to 15 meters, currents more than 3 knots and 87knot winds.

- CBI Statia Terminals, St. Eustatius. CALM system: Design, construct and install a dual product CALM system in of 210 ft (64) water depth for crude oil import and product export as part of transshipment terminal facility. This system was designed to survive extreme environmental conditions.

- CFE #2, Tuxpan, Mexico. Mooring system. Design and fabricate a second CALM system for import of refined products for power generators in Mexico. The fluid transfer system was designed to allow circulation of hot diesel after every unloading. The first FMC SOFEC system was installed in 1989 off Tuxpan.

Pegasus International, Inc.

Pegasus International, Inc. was formed in 1999 from the merger of ECI Consulting Engineers, MPC International, GER Services Inc., Gibbs Ellison Inc., and Mentor Project Engineering Ltd. Mentor Project Engineering, a subsea and pipeline engineering consultant, has completed over 200 projects for over 60 clients in 20 different countries. Pegasus International provides a variety of offshore pipeline services including: Conceptual Design, Cost Estimating, Permitting, Detailed Design of Pipelines, Detailed Design of Riser Systems, Consulting, Specification Development, Pipeline Related Facilities, and Construction Management.

<u>Project Experience</u>

- Amerada Hess Corporation, Baldpate Development GB 260 Gulf of Mexico. Detailed design, procurement assistance and construction management of a 12-inch gas and 16-inch oil export pipeline system. Design included a steel catenary riser for each pipeline. Water depths ranged from 440 to 1650 feet.

- Dauphin Island Gathering Partners, Dauphin Island Gathering System Offshore Alabama Gulf of Mexico.

- Detailed design, procurement assistance and construction management associated with an extensive gathering system from offshore Alabama, Gulf of Mexico, to onshore Alabama. Pipeline sizes ranged from 4 to 24 inches and water depths ranged from shore to 1100 feet. A 16-inch pipeline (Virgo Pipeline) in the system contained a pipeline end sled (PLES) and a diverless jumper system. Metering facilities, both onshore and offshore were included.

- British Gas, Miskar Gas Pipeline Tunisia. Performed procurement assistance and construction management for an 80-mile, 24-inch export gas pipeline in Tunisia. The pipeline included 2 miles of onshore pipeline and a 2-mile long dredged shore approach.

- Leviathan Gas Pipeline Partners L.L.C. Detailed design, procurement and construction management for the complete installation of an oil export pipeline from GC-254 to SS-332 in the

Gulf of Mexico. The pipeline is approximately 45 miles long with water depths ranging from 440 to 3300 feet. Design included a piggable "Y" assembly for diverless future connections.

- British Borneo Exploration, Inc., Morpeth and Allegheny Developments Gulf of Mexico. Provided engineering and project management assistance during the design, procurement and installation phases of each project. Allegheny consisted of five 4-inch flowlines and 12-inch oil and gas export lines. Morpeth consisted of three 4-inch flowlines; an 8-inch gas export pipeline and a 12-inch oil export pipeline. Water depths were 1650 feet at Morpeth and 3300 feet at Allegheny.

- British Gas, Dolphin Gas Pipeline, Trinidad. Provided detailed design, procurement support and overall construction management for a 40-mile, 24-inch gas pipeline from the Dolphin Platform, offshore Trinidad to an existing platform. Water depths ranged from 200 to 450 feet.

- BP Exploration. Mississippi Canyon 109A Gulf of Mexico. Provided specialist assistance to monitor the design of two 8-inch pipelines in water depths to 1080 feet. Construction procedures were developed to supplement the design philosophy. Pegasus also provided procurement assistance and construction management support.

- Exxon Pipeline Co. Diana Offshore Texas, Gulf of Mexico. Provided detailed design, procurement assistance and construction support in support of the shelf section of the Diana Hoover Offshore Pipeline System (HOOPS). The 20-inch pipeline was installed from a directionally drilled shore crossing to approximately 400 feet of water. Pegasus also prepared a deepwater repair study.

- Shell. Various Gulf of Mexico projects. Pegasus provided key engineering and drafting personnel in support of the following Shell projects among others; Auger Pipeline, Mars Pipeline, Ram Powell Pipeline, Mensa Flowline, Popeye Flowline, Bullwinkle Pipeline, Europa Pipeline, Ursa Pipeline, Destin Pipeline, Brutus Export Pipelines, Enchilada Pipeline.

- BP. Destin to Pompano Pipeline Vioska Knoll. Gulf of Mexico: Performed detailed design of a 16-inch export gas pipeline from VK-989 to VK-900 in the Gulf of Mexico. The design included a J-tube and subsea tie-in. Procurement assistance and construction management was also provided.

Costain Oil, Gas & Process Limited

Costain Oil, Gas & Process Limited is a subsidiary of Costain Engineering & Construction Ltd who in turn are an operating company of the CostainGroup plc. Costain Oil, Gas & Process Limited is a major international engineering and construction company which offers a complete process contracting expertise across a wide range of industry sectors, including: Oil & Gas Production, Gas Processing, Oil Refining, Chemical and Polymers, Pharmaceuticals and Biotechnology, Water and Environmental, Power and Industrial. Services provided to these industries range from feasibility studies and project definition through to complete turnkey project execution. In-house engineering and management resources applied to such activities are: Project Management, Engineering, Procurement, Construction, Operation and Maintenance. Experience includes refurbishment and debottlenecking, plant expansion and the provision of new facilities. The company has special expertise in cryogenic gas separation technology.

Project Experience

- Burlington Resources, Cumbria, UK. Gas Compression and Treatment Plant. Project management, engineering, procurement, construction and commissioning of a 130 MMscfd onshore gas compression and sour gas treatment plant.

- ADGAS, Das Island, UAE. Major Overhaul Term Contract. Planning, management, procurement and execution of triennial turnarounds for three LNG trains. Work consisted of collating the requirements, planning the shutdown and defining the restart date.

- ADGAS, Das Island, UAE. LNG Third Train. Construction and commissioning of a 320-ton per hour LNG train constructed alongside existing offshore facilities. Construction was 35% of total value and construction elements including civil, mechanical, electrical, and instrumentation.

- Milford Haven Refinery, UK. Clean Fuels Project. Front-end design and engineering services for the debottlenecking of the Milford Haven Refinery to allow for production of cleaner fuels to comply with government tariffs.

- Transco, Partington, UK. Process design, engineering, procurement and construction management for the upgrade of facilities for removing nitrogen from LNG.

- Transco, Cambridge, UK. Detail design, procurement, construction, installation and commissioning of an API 617 centrifugal compressor for and turbine for upgrade of existing gas compression facilities for periods of high demand.

- Texaco Limited, Pembroke, UK. Fuel Gas LPG Recovery Plant. Detail design, procurement, project management and construction management of a fuel gas LPG recovery plant.

- Worley PTY Limited, Australia. Offshore LNG Conceptual Study for an LNG offshore plant.

- Naturgass Vest AS, Kollsnes, Norway. Conceptual design and basic engineering for a 120 tpd LNG plant, including pre-treatment, liquefaction, storage and utilities.

- British Gas Tunisia Limited, Sfax, Tunisia. Miskar ‘A’ Offshore Platform. Investigation of process equipment and pipeline for solutions to enable increased production.

- BP, Damietta, Egypt. Technical and project management services on conceptual design studies for base load LNG facility.

- Enron, Teeside, UK. Gas Treatment Plant Development. Engineering, procurement and construction services for modifications to an existing gas processing plant.

- Shell Expro, Bacton, UK. SEAL Onshore Gas Reception Facilities Upgrade. Project management, detail design, engineering, procurement, construction and commissioning of a gas reception facility, as part of a major North Sea development for the export of conditioned gas to Transco, the Interconnector (UK) and Continental Europe.

- British Gas Storage, Isle of Grain, UK. Conceptual process study to address optimal methods for removing ethane and nitrogen from natural gas feed at existing LNG plants.

- British Gas, Isle of Grain, UK. LNG Peak Shaving Plants. Process design, engineering, procurement and supply, erection and commissioning of two 200 tpd natural gas liquefaction plants.

- PowerGen, Connah’s Quav, UK. Gas Process Plant. Front-end design, engineering, procurement, construction and commissioning for a 200 MMscfd gas processing plant to condition natural gas from Liverpool Bay to meet NTS specification.

- ScottishPower, North Yorkshire, UK. Gas Gathering and Power Generation. Front-end design, engineering, procurement, construction and commissioning for a gas processing plant and 40 MW power plant.

- Shell Expro, Mossmorran, UK. LPG Road Tanker loading. Conceptual design for the provision of propane, butane, firewater, potable water, instrument air, electrical supply and instrument cables from the Mossmorran NGL Plant to the Britannia Gas Road Tanker Loading Terminal.

- Felixstowe Docks, UK. Trinity Terminal III Extension. Design and construction of a 270m long extension to the existing deep water berth and associated container yard and services, berth access dredging, reclamation and future onshore developments.

- Oman LLC, Yibal, Oman. Government Butane Plant for Petroleum Devleopment. Detail design, procurement, construction, commissioning and initial operation of a new 55 ton/day butane plant.

- Carless Refinery, Harwich, UK. Oil Transfer Jetty. Construction included dolphins, loading platforms, pipebridge, operators cabin, fire control room and all mechanical and electrical works.

- Mobil, Coryton Refinery, UK. Pile and Berthing Dolphin Installation.

- Sheerness Docks, UK. Regular contract for over 20 years for construction of berthing dolphins, extension of facilities, repairs, etc.

ENTRIX, Inc.

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.

Project Experience

- Calypso Pipeline Project — Federal Energy Regulatory Commission (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 Floating Storage and Regasfication Unit (FSRU) — 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 Energy Information Administration (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 International Boundary and Water Commission application) — Texas

- Patriot Project — FERC Third-Party 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 Re-permitting 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 —National Pollutant Discharge Elimination System (NPDES) Permit Applications — Gulf Coast and Eastern United States

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Section

2

2 Deepwater FSRU Data

2.1 FSRU Location and Use

2.1.1 Location and Use

The Project, which, will receive, store and re-gasify LNG, will be located approximately 13.9 miles off the coast of Ventura County in Southern California, in 2,900 feet of water**.** The Project will include a 21.1-mile long, 30-inch diameter send out pipeline that will transport natural gas from the offshore facilities to an interconnection onshore at Ormond Beach (near Oxnard, California) with the existing intrastate pipeline system of SoCalGas for ultimate distribution throughout the Southern California region.

More specifically, the Project will consist of an offshore Floating, Storage and Re-gasification Unit (FSRU) and an interconnected send out pipeline that will tie into the existing on-shore natural gas distribution system of SoCalGas. The project will have a capability of re-gasifying up to 1.5 billion cubic feet per day (Bcf/d), with an anticipated average rate of 0.6 to 0.9 Bcf/d. The connection from the FSRU to the send out pipeline will consist of: a fixed turret style mooring point, three flexible riser pipes, and a Pipeline Ending Manifold (PLEM) on the seabed. The send out pipeline will run from the PLEM, through a shore crossing, and on shore to the tie-in with the SoCalGas system. LNG carriers will transport foreign source LNG to the Project from gas reserves throughout the Pacific Basin.

The Project will provide much needed natural gas supply to West Coast markets and will help meet the forecasted growth in demand for natural gas in Southern California where new gas-fired electric generation facilities are resulting in significant increases in gas usage in that region**.**

2.1.2 Lease Blocks Identification, Ownership Interests, and Use

The Project will be located in the Outer Continental Shelf (OCS) waters 13.9 miles offshore of Ventura County, California, between the Cities of Oxnard and Port Hueneme. The proposed natural gas pipeline corridor is shown in Figure 2.1-1 at the end of this chapter. No lease blocks will be involved in the Project. The nearest lease block is Lease OCS-P 0202, Platform Gina, which is located in OCS waters 3.7 miles offshore of Port Hueneme. The existing leases and rights of way are shown in the Desktop Study, Chart 001, provided in the *Confidential-Sensitive Information* document.

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. No other economic mineral exploration or production has taken place on the blocks that will be part of this Project as discussed in detail in Environmental Analysis (EA), Section 5.16 Energy and Mineral Resources. Limited ship traffic and fishing (commercial and/or sport fishing) may occur on some of the Project blocks (see EA, Sections 5.8 Traffic and Transportation and 5.13 Socioeconomics).

2.1.3 Pipelines and Rights-of-Way Crossings

A desk top survey of the pipeline route was completed during preliminary engineering. Subsea hazards, pipeline and cable crossings, and other potential 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 existing pipelines and rights of way crossings are shown in the Desktop Study, Chart 001, provided in the *Confidential-Sensitive Information* document. In addition, the pipeline route by segment is presented in the EA, Section 3.3 Project Description (Figure 3.3-15).

A 200-foot-wide right-of-way will be set aside, for both the construction and permanent rights-of-way, in all offshore areas in which the pipeline is to be laid. The resulting offshore right-of-way area would be 511 acres (21.1 miles by 200 feet). Approximately 412 acres of this right-of-way would be in Federal waters and approximately 99 acres would be in California state waters.

2.2 Overall Site Plan

See Figures 2.1-1, 2.2-1, and 2.2-2 for maps of the Southern California Coastal Region and the Project Vicinity. Figure 2.1-1 is a Project Vicinity Map which presents the location of the FSRU, pipeline and onshore landfall. Figure 2.2-1, Profile of Facilities, is a single-line drawing showing the location and type of each component of the proposed deepwater port, including the FSRU, mooring turret, flexible riser, PLEM, send out pipeline and onshore pipeline tie-in. Figure 2.2-2 is a Southern California Coastal Region Map.

2.3 Site Plan for Marine Components

2.3.1 Proposed Size and Location of Marine Components

Refer to Figure 2.2-1 for a profile of the marine components, and Figure 2.3-1 for the FSRU plan and elevation diagram. The design report provided in the *Confidential-Sensitive Information* document (reference Document No. 1209-DR-0012) depicts the mooring point plan and elevation and indicates the proposed anchorage areas in the drawing “Turret General Arrangement 3 x 3 Mooring System Ventura Location.” The same document also contains the following drawings showing the proposed dimensions of the PLEM and turret: 1) PLEM Assembly, Plan & Elevation; 2) Turret General Arrangement Pull-in Deck, Plan View; and 3) Turret Head Arrangement Elevation, Ventura Location, Base Case.

The Desktop Study, Chart 001, provided in the *Confidential-Sensitive Information* document, also shows the existing pipeline and cables within the project setting. Figure 2.1-1 shows the shipping lanes for vessel traffic use in the Project area. Support vessels would be moored on the aft of the FSRU, near the provision crane and lay down area, indicated on Figure 2.5-1.

A more detailed discussion with additional figures of the marine components is included in the Project Description of the EA, which is included with this application.

2.3.2 Charted Water Depths

Existing bathymetry at the FSRU site is limited to available nautical charts with 100 and 50 fathom contours given for the general area. NOAA Chart 18725 was the main chart used, as indicated by Figure 2.1-1. The desktop study referenced in the *Confidential-Sensitive Information* document also provides bathymetric data for the project.

2.3.3 Reconnaissance Hydrographic Survey

A reconnaissance hydrographic survey of the FSRU area utilizing digital and analog echosounder records will be conducted to assess bathymetry to a depth of plus or minus two feet. A desk top study has revealed that maximum water depth at the location of the planned mooring is about 2,900 feet.

The Project will lie within an area marked by intense deformation and tectonic activity. At the beach landing the seabed is relatively smooth and featureless. At the upper continental slope (197 feet – 1,640 feet water depths) the seabed is characterized by a series of canyons and channels. At water depths below 1,640 feet, the pipeline route runs across large sandy submarine fan (Hueneme fan) fed by the canyons. There are two major fault systems that are buried under the Hueneme fan and run across the pipeline route in water depths of 1,575 feet to 2,165 feet.

2.4 Soil Data

A detailed site investigation (to be conducted July/August 2003) involving soil borings and in situ testing is planned for the FSRU site to delineate geotechnical conditions in more detail. This detailed analysis of the general character and condition of the ocean bottom, sub-bottom, and upland soils at the mooring location and throughout the pipeline route will include an opinion from a registered engineer. These data will be used to refine the design the FSRU moorings. See also Section 5.4 in the Environmental Analysis on Geological Resources and Hazards.

In general, the entire Project route is underlain by sediment deposited by water or wind. The sandy material that underlies the onshore portion (landward of the beach) of the Project (the staging area for Project construction) likely represents alluvial material deposited along a former shoreline or eolian (wind-deposited) material deposited in former sand dunes.

Soil in the immediate vicinity of the Project has been mapped as Pacheco silty clay loam, which consists of poorly drained silty clay loams 5 feet or more deep that form in basins or on alluvial plains (0 to 2 percent slope). At depths below 4 feet, silt and sand may be stratified. This soil has a moderately low permeability, high organic matter content, high natural fertility, and moderate shrink-swell potential. The groundwater table for this soil type is generally within 2 to 3 feet of ground surface during the wet season. These soils are used primarily for vegetable and lemon crops, field crops, and urban development.

Because the shoreline beach material in which the pipeline will be placed is sandy and has a low shrink-swell potential, expansive soils are not considered a potentially significant hazard along the onshore portion of the Project.

The movement of equipment and materials during pipeline construction could destabilize the soil surface and increase erosion potential from water and wind in the staging area. The most sensitive time for erosion to occur is after initial disturbance of the unpaved ground surface and before reestablishment of vegetative cover or placement of pavement, as appropriate. Changes in drainage patterns as a result of the Project’s construction could result in erosion of the soil subsequent to the Project construction. Wind erosion can occur in dry, sandy soils where vegetative cover is difficult to establish and maintain. Severe erosion, however, is not anticipated due to the flat to gently sloping topography and sandy composition of the soil of most adjacent areas where a staging area would be located. With the application of standard measures to alleviate soil erosion during and after construction, there should be no significant impact.

2.5 Operational Information

2.5.1 LNG Carrier Data

The LNG tankers to be accommodated at the FSRU will be on average about 276 meters in length, by 65 meters in width and 27 meters in depth, with approximately 68,000 to 120,000 dwt. Their cargo tanks would typically have about 100,000 m^3 to 220,000 m^3 storage capacity. Documentation to show that the charted water depth at the FSRU is sufficient to provide a net under-keel clearance of 5 feet is shown in Figure 2.1-1 at the end of this chapter. The FSRU will be moored in 2,900 feet of water.

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.

These vessel characteristics 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 Applicant's duty to evaluate all vessels calling at the FSRU prior to entering into a commercial contract for LNG delivery. All LNG vessels using the FSRU will be required to meet the FSRU's standards to ensure the highest level of operational safety.

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

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

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. These data are considered sufficient for conceptual design; however, site-specific data will be obtained for the final design. The California Current (CC) flows in a southeasterly direction between 125-560 miles offshore of the California coast. There is no distinct western boundary of this current, but greater than 90% of the southeastward transport is within 450 miles of the California coast. The CC flows at a mean depth of approximately 984 feet and is strongest in the spring and summer in association with the predominately northwesterly winds related to the seasonal migration of the North Pacific high pressure cell. The seasonal maximum velocity of the current occurs in July and August at a rate of approximately 20 feet min-1 or 0.33 ft s-1 as measured at a depth of approximately 984 feet.

Low tide is typically under 1 foot. High tide is greater than 6.5 feet. The most common range of tides in this area is 4 – 4.5 feet.

2.5.3 Design Meteorological and Oceanographic Parameters

The FSRU is designed to withstand the meteorological and oceanographic parameters listed below. If actual meteorological or oceanographic conditions exceed these parameters (such as in extreme weather conditions of storm, hurricane or tsunami), it could invoke a shutdown of the LNG transfer operations, departure of the tanker from the mooring, a prohibition on mooring, and a shutdown of all operations and evacuation of the port. The Marine Operations Manual in the *Confidential-Sensitive Information* document provides more detail on the methods used for determining these events.

Air Temperature:

Maximum	(100 year return period)	36ºC
Minimum	(100 year return period)	-1ºC

Saline air	Yes
Rainfall:	
Rainfall, inches/year	
Average	13.9
Rainy season	winter
Seawater:	
Design Temperature	
Maximum	32ºC
Minimum	12ºC

Wind:

Maximum Design Wind Speed (meters per second)	
2-second gust speed	33.8
1-minute mean speed	27.1
10-minute mean speed	24.6
60-minute mean speed	22.7

Prevailing wind speed and direction	WSW
(from Los Angeles Airport)	3.35 (7.5 miles per hour) annual average

Survival 100 year return period storm:

Wave height maximum (Hmax)	44.9 ft.
Wave period maximum (Tmax)	13.3 secs.
Wind speed (1 hour mean)	29 m/sec (58 knots)
Current	1 m/sec (2 knots)

2.5.4 Operating Limits

The LNG transfer operations from LNG Carriers to the FSRU receiving terminal will be based upon verified information that the LNG carriers are compatible in design and equipment with the FSRU, and that all operations and communications can be conducted safely and efficiently. BHPB will conduct a checklist procedure with the LNG carrier owner/operator prior to arranging the transfer.

Before entering the exclusion zone around the FSRU, the LNG carriers will establish initial contact by satellite communication or radio as early as practicable. Speed limits will be established within this 1,640-foot (500-meter) radius exclusion zone. As the LNG carrier comes into the closer transfer area, contact will be established on VHF Channel 16 or 72 at the earliest opportunity. Proposed speed limits would be established within 1 nautical mile range of the FSRU not to exceed 5 knots, and within 500 yards not to exceed 2 knots.

Throughout berthing operations, the visibility shall be good enough for safe maneuvering, accounting for safe navigation and collision avoidance requirements. Maneuvers will be conducted when both vessels are satisfied that conditions are suitable for berthing and LNG transfer.

The designated pilot/mooring master, who will be trained on a ship-handling simulator, will manage the LNG carrier approach, berthing and departure procedures.

A Position Monitoring System will monitor and control the LNG transfer operation. It will display the relative positions of the loading arms on the FSRU and the manifold flanges on the LNG Carrier, both during the connection procedure and throughout the LNG transfer process. This proven, jetty-based system, will monitor and warn for unacceptable relative motions and distances, in time to safely allow the shutdown of the transfer pumps, closing of the isolation valves, and final disconnection of the loading arms if necessary.

Computer analyses of the relative motions and loads in the berth mooring lines & fenders, maneuvering simulations, and later model tests will verify the limits for the LNG Carriers operating in side-by-side mode to the FSRU. There are three predominate factors that may impose these operational limits. These are:

1. Sea conditions for safe approach, berthing and departure of the LNG Carrier.

2. Operational envelope of the loading arms.

3. Loads in the mooring lines and fenders between the two vessels.

Real-time computer analyses of the coupled vessel motions suggest that the berth mooring line and fender loads may govern the loading limits. Preliminary simulations suggest that the approach, berthing and departure operations can be safely accomplished with the aid of tugs and/or thrusters. The operational limits can therefore be generally regarded as the following:

	Limit	Constraint
Berthing:	2.5 m (Hs)	Prudent seamanship
Offloading:	3.0 m (Hs)	Line & fender loads / loading arm limits
Disconnection	3.5 m (Hs)	Prudent seamanship

The metocean report for the FSRU location shows that for 98% of the time the sea state is less than or equal to a wave height of 2.4m (Hs). This means that the availability and operability of the berth for LNG transfer operations are expected to be very high, with very little if any consequence to the reliability of gas supply to the mainland.

2.5.5 Fixed and Floating Offshore Components

2.5.5.1 Component Descriptions

The FSRU will receive, store, and regasify LNG. Natural gas then will be sent out to the send out pipeline. Each of these operating functions and the associated equipment are described below. Onboard utilities and systems associated with FSRU operations, including electric power generation and distribution, instrumentation and controls, and fire and safety systems, are also described. Detailed plans, specifications, and other information for various systems and equipment that are provided as appendices are noted in the text. Since the FSRU is part ship, part storage tank, and part re-gasification unit, three separate design standards, guidance, and regulations must be satisfied. The vessel portion of the FSRU is subject to marine codes, the LNG storage tanks are subject to LNG storage and transfer rules, and the LNG re-gasification and send out processes are subject to process standards and codes.

The vessel is a turret moored floating receiving unit designed for loading LNG from a side-by-side moored LNG tanker, storing the specified LNG up to design capacity, regasfying the LNG to the required quantity and sending it onshore through the turret system and the interconnected send out pipeline.

The FSRU will be a ship-shaped double sided, double bottom new LNG storage and re-gasification facility. The FSRU will have a length of 286 m and breadth of 65 m, with a displacement of approximately 190,000 dead weight tonnage (dwt).

2.5.5.2 LNG Carrier Offloading

LNG carriers would deliver LNG to the FSRU. Each LNG carrier would approach the FSRU in accordance with strict berthing guidelines. Figure 2.5-1, located at the end of this chapter, shows a plan view of the FSRU with a moored LNG carrier.

An LNG carrier mooring arrangement based on experience from similar operations will be used. Based on this configuration, hydrodynamic analyses have been performed to calculate relative motion at the location of the loading arm, tension in mooring lines and forces in fenders. Based on these analyses the LNG carrier mooring line spread will include 4 heads lines, 4 breast lines, 4 spring lines and 4 stern lines.

The FSRU's offloading facilities are designed to accommodate LNG carriers ranging in capacity from 100,000 m^3 to 220,000 m^3. Ships will be berthed and unloaded on the starboard side of the FSRU. The /starboard side will have four loading arms packages. Each package includes four 16-inch diameter marine 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 80,000 gallons per minute of LNG through the liquid loading arms and stored in the LNG storage tanks at a temperature of approximately minus 260°F. During offloading, most of the displaced vapor from the LNG storage tanks will be de-superheated by injection of a small amount of LNG and returned to the LNG carrier through the vapor arm or it may be directed to the re-gasification area and sent out with the regasified LNG via pipeline. The FSRU 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 FSRU 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.

2.5.5.3 LNG Storage

The FSRU will store LNG in three Moss spherical tanks. Each tank will have a 91,000 m^3 LNG storage capacity and the total FSRU LNG storage capacity will be 273,000 m^3. LNG is stored at low temperature, approximately -260^o F, and approximately atmospheric pressure. Even though the normal tank operating pressure is approximately atmospheric, the tanks will be designed for up to about 30 per square inch gauge pressure (psig) internal pressure. This design pressure allows the tanks to be operated as a closed system, containing boiled off natural gas vapors, for several days. The design pressure would also allow the tanks to be emptied using pressure to force out the contents, rather than by pumping.

The Moss spherical tank design which is the most widely used design in marine LNG transport will be installed to the FSRU. The tanks are classified as "Independent Tanks Type B" as defined in the relevant rules. The internal tank shell is aluminum, surrounded by insulating layers and clad in an external steel shell. Each Moss spherical tank is supported on a steel skirt ring that is braced inside the double hull of the vessel. Each tank is located in a separate cargo hold with the tank skirt mounted directly on the foundation deck. The spherical design reduces sloshing forces that can build up and cause damage in non-symmetrical tanks. This allows the Moss tanks to be used without any filling restrictions, allowing loading and unloading operations on the open seas. The entire internal and external shells of Moss type tanks can be inspected, and if necessary readily repaired, as contrasted with membrane lined tank systems, where access and repair requires significant downtime. Moss tanks have a normal fatigue based life expectancy of 100-years.

The low storage temperature is maintained by boil-off of natural gas, meaning the boil-off of natural gas from the LNG provides evaporative cooling that keeps the remaining liquid at the low temperature. This process is comparable to water boiling in an open pan, except the temperature is much lower. Regardless of the amount of heat transferred from a stove burner to a pan of boiling water, as long as the pan is open to the atmosphere to allow steam to disperse, the temperature of boiling water will remain at approximately 212º F. If the pan were covered and sealed, the steam pressure would build and then the temperature of the water would increase. Water at atmospheric pressure will remain at 212º F while steam boils off. LNG at atmospheric pressure will remain at approximately -260º F while natural gas boils off.

To control the boil off rate the LNG tanks on the FSRU will be insulated. The insulation will be designed to allow a boil off of 0.12% per day under normal ambient conditions. The boiled off natural gas will be sent out through the natural gas sendout line or recovered and used as fuel for FSRU electric power generation.

2.5.5.3.1 Boil-Off Gas Compression

LNG vaporized in the tank by heat picked up from the surroundings is referred to as boil-off gas (BOG). BOG 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.

BOG will be compressed to approximately 50 psig, and routed to the BOG condenser. Compressed BOG is condensed by mixing it with a portion of the cold LNG being pumped out of the LNG storage tanks. The LNG leaving 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.

To meet the FSRU operating requirements, four compressors with a capacity of 8,000 kg/h will be provided: one high discharge pressure and three low discharge pressure compressors.

2.5.5.3.2 LNG Send Out/Re-Gasification

There will be eight Kaldair TX180 submerged combustion vaporizers and associated ancillary equipment located on the vaporization deck. LNG booster pumps, fuel gas compression, fire suppression and fire fighting systems, and remote sensing and control equipment will be installed in this area. Locating the vaporizers in this area ensures a short length of gas pipe from process to riser.

The LNG is pumped, as liquid, up to the 1,500 psig natural gas send out pressure and maintained at that pressure through the vaporization process. The vaporization portion of the process re-gasifies the LNG. The process will consist of eight submerged combustion vaporizers (SCVs). Each will have a maximum capacity of 198 short tons per hour of LNG vaporized. The SCVs will superheat the resultant natural gas to a temperature of about 41 °F at a pressure of about 1,500 psig. No compression of the natural gas is required. Combustion of natural gas provides the submerged combustion vaporization process with heat for re-gasification. The combustion vaporization process is thermally stabilized by submersion in a water bath. The LNG and natural gas flow are contained within process piping submerged in the water bath. Neither LNG nor natural gas is directly released into the water bath, but combustion exhaust gas does bubble through the water bath. Water for the bath is freshwater generated by collection of condensed water formed from the natural gas fuel burned in the SCV. Moisture in the exhaust gas will condense on cold LNG piping. The water bath provides stable heat transfer to the LNG and natural gas, with the water bath cooled as the natural gas absorbs heat from it. The normal re-gasification capacity will be between 579 and 821 tons per hour, and the maximum re-gasification will be 1,450 tons per hour. The quality, temperature, and pressure of regasified natural gas will be suitable for send out and delivery into the receiving natural gas transmission system in California.

No circulating seawater is required for the submerged combustion vaporization process. The water bath and excess freshwater are generated from condensation of moisture from the combustion exhaust.

2.5.5.3.3 Venting

The FSRU will be equipped with a cold stack that will be used only in the event of an emergency that requires venting natural gas vapors. The cold stack will be provided with an electric heating system to re-gasify any emergency LNG releases. The cold stack, if used, would discharge natural gas to the atmosphere without the use of a pilot light or other device to initiate combustion. The cold stack height and diameter will be designed to safely disperse the natural gas, considering the presence of the FSRU and an adjacent LNG carrier. The cold stack height, pending final design, will be approximately 250 feet above the water line, and approximately 80 feet above the top of the storage tanks, elevated personnel walkway and elevated piping along the tops of the tanks.

2.5.5.3.4 Fiscal Metering

The LNG tanks will be fitted with a radar type gauging system. This system is approved for custody transfer application and is fitted with a separate monitor in the control room. For metering of send-out gas two in-line gas flow meters of ultrasonic type will be used. One unit will handle the peak gas flow with the other unit as a stand-by. Flow, temperature and pressure signals will be transmitted to a flow computer with display and printer located in the control room, which can transmit to shore if desired. The system will be supplied with a certificate for fiscal accuracy and be periodically re-evaluated for accuracy.

2.5.5.3.5 Utility and Potable Water Systems

A utility area near the stern of the FSRU, below the crew quarters, will include the onboard electric power generation equipment. Three natural gas-fired generator sets, one dual fuel diesel/gas generating set and one diesel emergency generator set will generate the onboard electric power. Each of the three primary gas fired units will have power output of 7,400 kilowatts (kW) at 6.6 kilovolts (kV), and the dual fuel unit an output of 5,700 kW, for a total power plant generating capacity of approximately 28 megawatts. The diesel fuel unit used for emergency duty will have a power output of 4,000 kW at 6.6 kV.

Additional natural gas from BOG or the send-out line will be sent as fuel to the SCV to provide heat to regasify LNG.

All the required motor control centers, substations, cabling and lighting systems will be arranged in accordance with applicable regulations and standards (listed below) regarding protection, insulation and general safety. All electrical equipment within gas-dangerous zones will be designed, installed and supplied with certificates to show that it is rated for hazardous area conditions.

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

Potable water will be supplied from condensation of moisture out of the air at the SCV units or via marine type flash evaporators situated in the aft machinery space. Fresh water from the SCV condensation will be used to mix a urea solution for injection into air pollution control systems. Excess fresh water from condensation will be used to maintain pressure in the hydrant system, and would ultimately be discharged.

2.5.5.3.6 Nitrogen Generation and High Pressure Storage

Nitrogen, for inert gas purging, will be generated on board the FSRU, through the installation of nitrogen generators using a process that separates nitrogen from the air. Nitrogen will not be imported onto the FSRU from onshore.

2.5.5.3.7 Fuel Gas System

During initial startup (commissioning of the FSRU), the dual fueled generator set will be operated on diesel fuel to provide electricity for startup operations, until BOG can be utilized from LNG unloading.

2.5.5.3.8 Diesel Fuel

The diesel fuel storage system will consist of:

- 1,000 m^3 diesel storage tank with internal level gauge
- Diesel transfer skid

Diesel fuel will be delivered to the FSRU by supply boat. The boat will deliver standard size tank containers of low sulfur marine gas oil (diesel). The containers will be lifted onto the aft deck of the FSRU and fastened down within a spill containment area. The fuel would be gravity drained from the container tank to the fuel storage tank via fixed piping and a connection hose to the tank container.

2.5.5.3.9 Accommodations

An accommodation deck house with all facilities for a permanent crew of up to 30 persons with temporary accommodations for another 20 persons in fold-down bunks, and a helideck, will be fitted at the aft end in a non-gas dangerous zone. One free-fall lifeboat and two large life rafts complete with escape chutes will be fitted at the stern of the terminal for evacuation during an emergency. The supply vessel from shore for provisions and crew changes will also be berthing / de-berthing at the aft section of the terminal.

A multipurpose control room will be installed in the accommodations to control and monitor all aspects of the terminal's operations, and will utilize remote monitoring of the normally unmanned process area and utility equipment.

2.5.5.3.10 Material Handling

Electro-hydraulic-powered cranes will be installed on the FSRU in various areas to offload materials and supplies from the supply boat and to handle equipment on deck. Cranes situated in hazardous areas will have electrical equipment that has suitable hazardous area ratings. Fork lifts or hand trucks that may be required will also be hazardous area rated electric-powered vehicles.

2.5.5.4 Component Design Criteria

The project design criteria are defined in the Project engineering design document (refer to Section 4.4).

2.5.5.5 Design Standards and Codes

The FSRU has been designed in accordance with codes and standards applicable to LNG carriers and terminals as follows:

- DNV rules for classification of ships (liquefied gas carriers),

- International Maritime Organization (IMO) International Gas Carrier (IGC) Code 1993,
- Industry standards (such as American Petroleum Institute, American Society of Mechanical Engineers, and the International Organization for Standardization),
- Oil Companies International Marine Forum—Standardization of Manifolds for LNG,
- Society of International Gas Tankers and Terminal Operators,
- International Convention for Safety of Life at Sea, and
- International Convention of Load Lines.
- American Petroleum Institute Guidelines and Regulations
- International Electrical Commission Codes & Guidelines
- American Society of Mechanical Engineers Codes & Guidelines
- ASME B1.20.1, Pipe Threads, General Purpose
- ASME B16.5, Pipe Flanges and Flanged Fittings, NPS ½ through 24
- ASME B16.9, Factory Made Wrought Steel Butt-Welding Fittings
- ASME B31.3, Process Piping
- ASME Boiler and Pressure Vessel Code
  - Section V, Non-Destructive Examination
  - Section VIII, Rules for the Construction of Pressure Vessels
  - Section IX, Welding & Brazing Qualifications
- American Petroleum Institute (API)
- API 610, Centrifugal Pumps for Petroleum, Heavy-duty Chemical, and Gas Industry Services
- API 618 – Reciprocating Compressors for General Refinery Services
- API 520 – Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries
- API 521 – Guide for Pressure Relieving and Depressuring Systems
- International Electrotechnical Commission (IEC)
- IEC 60034, all relevant Parts, Rotating Electrical
- IEC 60079-0, Electrical Apparatus for Explosive Gas Atmospheres, General Requirements
- API RP 14E
- API RP 2A
- ASME B31.3
- ASME B31.4
- DnV Posmoor
- API 5LB
- API RP75
- API RP 2FPS
- API RP 14J
- API RP 2SM

The standards described below also have been satisfied in the design.

NFPA 59A, developed by the National Fire Protection Association (NFPA), specifies siting, design, construction, equipment, and fire protection requirements that apply to new LNG facilities and to existing facilities that have been replaced, relocated, or significantly altered. The standard covers design, location, construction, and operation of facilities at any location for the liquefaction of natural gas and storage, and for vaporization, transfer, handling, and truck transport of LNG. The LNG storage and LNG process areas of the FSRU are designed to comply with this NFPA standard.

49 Code of Federal Regulations (CFR) Part 193, as administered by the U.S. Department of Transportation (USDOT), sets forth criteria for pipeline safety and transportation of natural gas and LNG. Subpart B specifically discusses LNG facility siting requirements. Although these siting requirements are not directly applicable to the offshore mooring point for the FSRU, these siting requirements make the proposed location preferable over the Project alternatives.

33 CFR Part 127 is under the jurisdiction of the U.S. Coast Guard (USCG) and is specifically related to waterfront LNG handling facilities. While the FSRU is not a waterfront LNG facility, the LNG transfer equipment will meet USCG requirements. An FSRU Operations Manual and an FSRU

Emergency Manual will be prepared and submitted for USCG approval prior to receipt of LNG, in accordance with 33 CFR Part 127.019.

The Seismic Review of LNG Facilities (NBSIR 84-2833) is a requirement for onshore LNG facilities, and is not specifically applicable to the floating offshore terminal. Although the Project involves an offshore facility, consideration of seismic concerns and tsunami potential will be considered for the FSRU and its mooring point. DNV issued a review of technical requirements for the FSRU design in July 2001 [provided in *Confidential-Sensitive Information Document*]. The DNV Report identified the standards to which the FSRU and its mooring should be designed. The DNV Report states that:

"The design is to be documented to survive two main scenarios, which are:

- The 100-year extreme environment event for the vessel moored alone, and
- The maximum operating environment for the vessel moored with an LNG carrier."

The DNV report states that "design documentation should also include the anchoring system covering both the structural and geotechnical strength." Further, the DNV report states that the operator normally specifies the design environment and also supplies the geotechnical data.

The design process of all elements of the Project will address the seismic issues as recommended by DNV. In addition to requirements identified by DNV, the potential impact of the maximum credible earthquake will be considered. The potential for a tsunami wave and its impact on the FSRU, the mooring system, and the side-by-side configuration with the LNG Carrier will be addressed. In these deep-water depths the tsunami wave does not build up to any significant height, so little impact is expected.

2.5.5.6 Installed Equipment

2.5.5.6.1 Navigational Lighting

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

- Navigation warning lights on the FSRU mast mounted on the upper most deck of the accommodation block. Typically, the lighting will consist of two white lights separated by a red light. These lights will be visible all around (360°) the horizon and have a range of at least ten nautical miles.

- Searchlights on top of the accommodation block for scanning the approaches to the FSRU.

- Additional lights (flood) at regular intervals around the deck and berthing area such that all areas of the deck, equipment and re-gasification units are clearly illuminated. Flood lights will also be installed at deck level at each corner of the FSRU and in the berthing/manifold areas.

- Deck lighting around the deck, accommodations block, process area, and at walkways, ladders, and above all exit doors.

- An AIS (Automatic Identification System) which is triggered by other vessels radar.

2.5.5.6.2 Safety Equipment

The overall layout and general arrangement of the terminal reflect safety considerations. The general design concept separates the process area from the accommodation area. Likewise, the LNG storage tanks, mooring, and risers are separated from the process area. Explosion-proof covers will be installed to protect the tank facing the process area. Personnel will be able to evacuate to abandon ship muster area, located aft, from all parts of the FSRU.

The FSRU will be equipped and designed to provide a high level of protection to the personnel present, the unit itself, and the environment, against the effects of an uncontrolled release of hydrocarbons or other process gases.

The safety systems will include the following:

- Emergency shutdown on two levels—The pneumatically operated trip system based on a pipe loop that will extend throughout the LNG storage and process area. Thermal fuse plugs which detect heat from a fire and manual release valves will be located at strategic positions on the pneumatic pipe loop, including tank domes, loading arm areas, and the process area. This pneumatically operated trip system will initiate an ESD-2 through the electronic Fire & Gas panel. An emergency shutdown will also be able to be manually activated from the control room on either a berthed LNG carrier or the FSRU. The two ESD levels are ESD-1 and ESD-2. ESD 1 means the entire system is shutdown, including pumps and ESD valves on a berthed LNG carrier. ESD 2 also triggers the loading arm release valves and mooring line hooks, and initiates departure of the LNG carrier.

- Emergency depressurizing and venting system—The FSRU will be equipped with a cold stack that will be used only in the event of an emergency that requires venting natural gas vapors. The cold stack will be provided with an electric heating system to vaporize any emergency LNG releases. The cold stack, if used, would discharge natural gas to the atmosphere, without a pilot light or other device to initiate combustion. The cold stack height and diameter will be designed to safely disperse the natural gas, considering the presence of the FSRU and an adjacent LNG carrier. The cold stack height, pending final design, will be approximately 250 feet above the water line, and approximately 80 feet above the top of the storage tanks, elevated personnel walkway and elevated piping along the tops of the tanks.

- Nitrogen, for inert gas purging, will be generated on board the FSRU, using a process that separates nitrogen from the air.

- Gas detection systems—The FSRU will be equipped with a stationary gas detection system suitable for continuous operation on a fixed offshore production facility. The gas detection system will consist of continuously operating catalytic type detectors and an infrared line of site detectors that are connected to the FSRU's electronic Fire & Gas panel. The gas detection system will sound audible alarms, as well as initiate the shutdown of appropriate equipment and systems, dependent upon the logic within the electronic Fire & Gas panel. Gas detection will be provided for the regasification plant, other deck areas, and machinery spaces where high pressure gas is piped and the ventilation air inlets to safe spaces, including the accommodation. Handheld and personnel gas detection systems are also provided.

2.5.5.6.3 Lifesaving Equipment

A minimum of one freefall lifeboat will be installed on the FSRU. These lifeboats will be the primary means of emergency egress from the aft structure; there will be a minimum of four life rafts on the perimeter of the FSRU. The final layout for the safety equipment will be based on a safety and risk analysis.

2.5.5.6.4 Fire Fighting Equipment

The primary protection and fire-fighting philosophy on the FSRU is avoid fires through the use of preventative measures. In the event of a fire, the following fixed protection facilities will prevent further escalation:

- A main seawater deluge system—A system that uses on seawater will be installed to cool exposed surfaces in the cargo, deck, and process areas in the event of a fire emergency. The system will be dimensioned and arranged with hose stations and monitors located in accordance with IMO IGC Code 1993 requirements for coverage of horizontal and vertical surfaces. The deluge hydrant system also must be pressurized according to the IGC. Pressurized hydrant systems typically maintain pressure by circulation of seawater, with some continuous discharge and replenishment of the circulating water. The FSRU is expected to generate excess freshwater in the submerged combustion vaporization process described below and may circulate and discharge freshwater from the deluge hydrant system.

- Dry Powder - A fire-fighting-foam system will be arranged for the cargo and process areas. The dimensions and arrangement of fire-fighting systems throughout the cargo and process areas will comply with the IMO IGC Code (1993). A dry powder fixed system shall be installed in the galley and galley venting system.

- Carbon dioxide systems - CO_2 fire suppression systems will be arranged for machinery spaces. The dimensions and arrangement of CO_2 fire suppression systems will comply with the IMO IGC Code (1993).

- Fire Detection - Smoke and heat detection sensors throughout the accommodation, machinery and storage spaces. In addition, machinery spaces shall have an oil mist detection system.

- Water Sprinkler System - A low volume high pressure water mist sprinkler system shall be fitted throughout the accommodation block.

- Foam Fire fighting systems - Installed at the helideck and regasification deck.

A detailed layout of each of these fire protection systems, showing the location of fire water pumps, piping, hydrants, hose reels, foam systems, CO_2 systems, and auxiliary or appurtenant service facilities, is included in Appendix E, FSRU Design Drawings of the EA**.**

2.5.5.6.5 Pollution Prevention and Removal Equipment

Primary containment, the storage tanks, are described above. The LNG cargo will be stored in three 91,000 m^3 cargo tanks. Secondary containment will be designed in areas with a greater risk of LNG release, such as the loading arm area. Secondary containment for LNG releases has two purposes, to safely contain any LNG that escapes from primary containment, and to protect the FSRU from potential damage due to direct exposure to cryogenic temperatures

An inventory of approximately 1,000 m^3 of diesel fuel will be maintained on board the FSRU. Diesel fuel will be utilized in the dual fuel emergency service generator and lifeboat engines. Diesel fuel would be managed in accordance with U.S. Environmental Protection Agency (USEPA) and State of California requirements, including a Project specific Spill Prevention, Control and Countermeasure (SPCC) Plan as required for Deepwater Port Act Facilities under 40 CFR 112.1(a)(1). The SPCC Plan will outline emergency procedures, operating procedures, training of employees and engineering controls (e.g. secondary containment) necessary to prevent spills, overflows, or other incidents that may discharge hazardous materials to the environment.

Urea will be used in lieu of aqueous ammonia for selective catalytic reduction (SCR) air emission control. Dry urea will be delivered in a special container to the FSRU on a supply boat, and stored onsite in a dry contained area. The urea will be mixed with water available from the vaporization process into an aqueous form prior to injection into the exhaust upstream of the catalyst in the SCR system. Alternatively, premixed urea in aqueous form may be delivered to the FSRU on a supply boat in special container. The use of urea reduces the inherent risk of handling aqueous or anhydrous ammonia.

In order to deliver natural gas that is suitable for the existing natural gas distribution system, the gas will be odorized at the landfall, eliminating the need to store mercaptan gas on the FSRU.

Incoming supplies and outgoing wastes will be transferred by boat. A supply boat visit will occur once a week during normal operations. Supplies would range from food, toiletries, and office supplies for crew use in the living quarters to tools, small parts, dry or aqueous urea for NOx control of the generator engines, and other maintenance and repair materials. Solid wastes from the FSRU would be containerized for transfer to the supply vessel. Liquid sanitary wastes (black water) from the FSRU would also be containerized for transfer to shore via the supply vessel. Supply and waste transfers would be made by crane lifts from a supply vessel moored to the aft of the FSRU.

Three Moss spherical tanks will provide primary containment for the LNG. They will be built as independent Type B tanks in accordance with the IMO IGC Code. The containment concept is based on the "leak before failure" principle with implementation of a partial secondary barrier as required by the regulations. The tanks will be installed in separate cargo holds protected above deck by separate tank covers.

2.5.5.6.6 Waste Treatment Equipment

Gray water (from showers and sinks) will be treated to NPDES standards prior to discharge utilizing filtration and ultra violet (UV) oxidation. Black water (liquid sanitary wastes) will be transferred to onshore for disposal in standard tank containers.

2.5.6 Offshore Pipeline

It is anticipated that a 200-foot-wide right-of-way will be set aside, for both the construction and permanent rights-of-way, in all offshore areas in which the 30-inch pipeline is to be laid. The resulting new offshore right-of-way area, based on the 21.1-mile length and 200-foot width, will be approximately 511 acres. Approximately 412 acres of this right-of-way will be in Federal waters, and approximately 99 acres will be in California state waters. The send out pipeline will permanently occupy an area of approximately 10 acres, based upon the total pipeline length and diameter.

2.5.6.1 Description and Preliminary Design Drawing

The installation of the offshore portion of the proposed send out pipeline will follow site-specific pre-installation surveys. The installation sequence will be preparation, horizontal directional drilling (HDD), pipe fabrication, non-destructive examination (NDE), coating of completed welds, pipeline lowering, hydrostatic testing, and dewatering the pipe. In addition, offshore construction requires specific techniques for sandbagging and placement of concrete mats where the pipeline crosses existing cables. Preliminary design data are presented in Document No. 2935376 in the *Confidential-Sensitive Information* document.

This send out pipeline will be permitted as part of a Deepwater Port Act (DWPA) facility under the jurisdiction of, and subject to approval by, the USCG. The Mineral Management Service (MMS) and the USDOT have a history of jurisdiction over comparable pipelines, and have developed design standards for comparable pipelines. In addition the California Coastal Commission (CCC) has reviewed cable and pipeline projects that have beach crossings. The existing MMS and DOT standards and CCC precedent have been considered in the design of this pipeline.

The MMS regulations require that the pipeline be lowered 3 feet below the sea floor where water depths are less than 200 feet, except in congested or seismically active areas. In depths greater than 200 feet, the pipeline may be laid directly on the sea floor surface. USDOT requires lowering to the mudline in waters up to 200 feet deep. USDOT has a waiver process and does grant waivers from the lowering requirement in seismically active areas. The proposed pipeline will be laid on the sea floor except for the nearshore and onshore segment, which will be buried.

Although offshore construction procedures may vary to meet different construction situations or constraints, typically three different techniques are used depending on water depth and other site-specific conditions: burial, lowering, or laying. Burial includes trenching or HDD. Lowering includes trenching and laying the pipeline in the trench. The open trench is left to be filled in over time by natural sedimentation processes. Laying involves laying the pipeline on the sea floor without trenching or cover. This project includes only burial or laying; no lowering is proposed.

2.5.6.2 Design Criteria, Standards, Codes and Recommended Engineering Practices

The pipeline 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

Additional design criteria, standards and codes are presented in Document No. 1209-DR-0012 and Document No. 293-5376 located in the *Confidential-Sensitive Information* document.

2.5.6.3 Metering System

Natural gas from the vaporizers will be metered before entering the pipeline using a custody transfer metering station. Metering capacity will be 1.5 billion SCFD. 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 send out 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.

Remote Operated Vehicles (ROV's) and divers will be used to locate and monitor these pipeline crossings during construction of the pipeline.

The send out 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 pipeline and existing pipelines. Sandbags and/or concrete mats will be used to ensure 18 inches of separation between the pipeline 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 to 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 only onshore component of the Project is a subsurface 0.65-mile segment of the send out pipeline, which interconnects with the SoCalGas distribution system.

2.5.8 Miscellaneous Components

2.5.8.1 Description of Communications Systems

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

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

2.5.8.2 Description of Radar Navigation System

At least three (3) radars will be installed on the mast above the Moss tanks. One radar will be an X-band (3cm) connected to a traffic management monitoring system in the control room. An S-band (10cm) radar shall provide back-up for the X-band radar. A dopler radar shall be fitted to monitor weather out to a range of 90 miles.

The small range radar (1.5cm) will monitor all vessels operating and/or transiting in the near vicinity of the FSRU's exclusion zone. 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 x-band 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 FSRU

2.5.8.3 Mooring of Vessels

The typical normal mooring scenario, with favorable open water sea conditions, is expected to require at least two suitably powered tugs to be made fast alongside the LNG ship. All tugs will be designed and configured for continuous operation in the Deepwater Port site's open waters and fitted with heavy all-around fendering. They will employ joystick controlled propulsion systems consisting of a combination of twin steering nozzles and a bow thruster. This system will allow for excellent maneuverability while still retaining complete pushing and towing capability. Preliminary plans call for the tugs to have an estimated minimum average bollard pull of 75 tons, but the final plans will employ tugs capable of efficiently pushing, berthing and towing the largest expected LNG carrier calling at the Deepwater Port's FSRU.

The tug taking position alongside the aft part of the ship may also be directed as necessary during the maneuvers to move aft of the ship. A tow line from the tug to the ship's stern can then be used so the tug may act as a brake and heading stabilizer as the ship approaches the vicinity of the berth, if necessary. The specific positioning and use of the tugs to assist the LNG ship to safely berth will be decided and controlled by the Pilot/Mooring Master, in close consultation with the LNG ship's Master, as part of his advisory duties for the LNG ship before and during its approach to the FSRU and berthing evolution. The LNG ship is also expected to have a working bow thruster of suitable power ready to assist in the berthing operation as necessary.

The FSRU will employ its azimuthing thrusters to adjust its heading to a relative angle with the wind and sea that will allow an optimum angle of approach to its alongside berth by the LNG ship. The LNG carrier will then approach the berth with a speed and relative angle appropriate for the weather, sea conditions, and the heading of the FSRU.

When the bow of the LNG carrier passes abeam of a designated point near the FSRU's midship section, two messenger lines will be transferred from the FSRU deck to the LNG carrier's forward mooring station, via a line boat. At least two of the LNG carrier's forward mooring lines will then be connected to each messenger line and retrieved by the FSRU's mooring crew.

By the time the ship's forward mooring lines have been hauled aboard the FSRU, the ship should be stopped in the water and positioned at least one hundred feet off the FSRU's starboard side. Its heading should then be adjusted by using the tugs so as to be close to parallel with the berth side of the FSRU and with its cargo manifold close to being lined up with the FSRU's loading arms.

As soon as the first forward mooring lines are safely connected to the FSRU's quick-release mooring hooks, the LNG carrier's crew will proceed to heave in the slack lines as instructed by the ship's bridge command. At the same time the excess slack is being taken from the forward mooring lines, the assisting tugs will carefully push the LNG carrier alongside and parallel to the FSRU berth in a well-controlled manner. The FSRU's fendering system is designed to absorb energy from a landing speed of 0.6 meters per second for the largest LNG carrier.

While being held alongside the FSRU by the tugs and the already connected forward mooring lines, all other ship's mooring lines, in accordance with the mooring arrangement and any necessary adjustments to the mooring operations plan, will then be passed to the FSRU via heaving line and/or messenger line, with the line boat assisting as necessary. After final fore and aft positioning of the ship to properly line up the ship's manifold with the FSRU's loading arms, all mooring lines will then be heaved tight and secured as soon as safely possible.

The Pilot/Mooring Master will board the incoming LNG carrier at an individually designated "Pilot Boarding" position approximately two to three miles from the FSRU. This pilot rendezvous position may vary, as it will depend upon the local wind and sea conditions affecting the final approach to the FSRU berth. He will transfer to the ship from one of the attending mooring assist tugs.

The LNG carrier will not be permitted to approach the FSRU or berth alongside without a Pilot/Mooring Master onboard and all required tugs in attendance.

The Pilot/Mooring Master will advise the Master of the LNG carrier on operational and ship maneuvering control matters that are peculiar to the area and the FSRU. Information concerning items such as local navigational aids, depth of water, current characteristics, and sea condition effects within and around the maneuvering area, mooring equipment, mooring plan and procedures, tugs, the ship's characteristics, and the Deepwater Port's vessel traffic control and reporting procedures will be discussed, agreed and confirmed with the Master of the LNG carrier before proceeding inbound.

In addition to assisting in berthing the LNG carrier, the Pilot/Mooring Master will be responsible for ensuring the vessel is securely moored to the terminal and in correct position for connecting the cargo loading arms of the FSRU to the LNG carrier's cargo manifold.

After the vessel is securely moored to the FSRU, the Pilot/Mooring Master will then be assigned to remain aboard the LNG ship as Loading Master. He will supervise the cargo manifold connection.

He will monitor, advise, and be the liaison between the ship's command staff and the FSRU for all LNG cargo transfer related functions, including maintaining safe mooring at the berth.

After the LNG carrier is securely moored and the tugs are released from alongside the ship, one tug will remain in the area to patrol the exclusion zone and act as the standby vessel. The other tug will be released to perform other operations, go to port or to anchor, but will always remain available to return promptly to the FSRU for assisting with the unmooring of the LNG Carrier, or for any other service required.

If for any reason the LNG Carrier requires its main propulsion to be disabled while alongside the terminal (such as for urgent repairs), then both tugs will remain within the Deepwater Port's exclusion zone. One of the released tugs may be recalled to assist the stand-by tug during the un-berthing of the LNG carrier. Off-duty tugs will be able to be quickly contacted and will be stationed in a nearby port.

2.5.8.4 Support and Servicing Vessels

An FRC (Fast Rescue Craft) will be installed at the aft 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's primary function is to recover personnel who may fall overboard. It may also be used as for waterline inspections, diving support and as a safety boat for over the side operations. It will also be outfitted to deploy a light containment boom in the event of a small oil spill.

Four diesel-powered tugs (anchor handling tug supply, or AHTS) will be utilized during construction to assisting the pipelaying barges. One tug will assist with towing and two tugs with placement of the FSRU. Two tugs will be utilized during operations to assist in mooring of LNG carriers.

2.5.8.5 Shorebased Support Facilities for Support and Servicing Vessels

Tugs used during LNG carrier mooring assistance will be located at Port Hueneme and will be rated at about 5,000 horsepower. Support and servicing vessels will be located at Port Hueneme and will be used to facilitate the movement of personnel, equipment, supplies, and disposable materials between the Cabrillo Port Terminal and shore.

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 one mile intervals beginning at the safety zone leading to the FSRU maneuvering area and an AIS (radar identification) device installed on the FSRU. 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 FSRU will have a minimum of four mechanical foghorns (Diaphones). 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 floating terminals. Hand held fog horns will be stored onboard in the event of a power failure.

2.6 Operations Manual

2.6.1 Marine Operations Manual

A copy of the Marine Operations Manual is included in the *Confidential-Sensitive Information* document. The manual will be finalized after the detailed FSRU design is completed and the results of several operations and safety studies are completed.

Insert Figure 2.1-1 Project Vicinity Map

Insert Figure 2.2-1 Profile of Facilities

Insert Figure 2.2-2 Southern California Coastal Region Map

Insert Figure 2.3-1 FSRU Plan and Elevation Diagram

Insert Figure 2.5-1 LNG Carrier Berthing

Section

3

3 Financial Information

3.1 Annual Financial Statements

BHP Billiton LNG International Inc. is a new entity with no operating history and is a wholly owned subsidiary of BHP Holdings (Resources) Inc. whose ultimate parent company is BHP Billiton Ltd.; and the financial data presented herein is that of the ultimate parent (BHP Billiton Ltd.). Detailed financial reports are shown in Attachment 2.

3.2 Annualized Projections or Estimates

The Applicant is submitting annualized projection information in the *Confidential-Sensitive Information* document.

The Project will be operated under a tariff structure that obligates firm capacity holders on a “take or pay” basis, whereby capacity holders will be responsible to pay for their capacity rights whether or not they actually utilize them.

3.3 Management and Financing

Capital contributions from the applicant's ultimate Parent or its subsidiaries will provide the necessary equity contributions for the construction of the Project. To date there are no agreements, contracts or commitments entered into by the Applicant for the management and financing of the Project; this is inclusive of throughputs, loans, equity investments, leases, charters, or guarantees.

3.4 Total Capacity and Demand

The Project will provide services for the receipt, storage and re-gasification of LNG. The resulting natural gas will be transported via the associated send out pipeline to shore and the California markets. The Project will not provide long-term storage services as is sometimes customary at land based facilities. LNG receipts for the first two years of service are projected at 675-800 MMscf/d on an annual average basis. Thereafter, it is expected that the LNG receipts may increase modestly on an annual basis.

While natural gas demand in the United States is forecasted to increase significantly during the next 20 years, domestic natural gas production is expected to decline within that same time frame. The Energy Information Agency of the U.S. Department of Energy (USDOE) has forecasted that United States natural gas demand will reach 27 trillion cubic feet by 2010 and 35 trillion cubic feet by 2025; representing more than a 30% increase over current consumption levels.

Electric power generation is a significant factor for the projected increase in natural gas demand in the United States. Most of the new electric generation projects in recent years have been natural gas fired, a trend which is unlikely to abate as natural gas has become the fuel of choice insofar as it produces fewer pollutants and emissions as compared to other hydrocarbon based fuels.

The Project will provide a significant new source of natural gas to the southern California region, an area notable for its lack of interstate gas pipeline capacity. Due to the lack of adequate interstate pipeline capacity into the State of California, California consumers do not reap the benefits of a competitive natural gas marketplace and the supply options that such a market offers. The Project will provide an important new means for bringing natural gas into the region, with minimal adverse environmental impact, in effect adding a new diversified supply into the California market, not reliant upon existing interstate pipelines.

Section 4

4 Engineering and Construction Costs, Contracts, and Studies

4.1 Construction Costs

Construction costs for the Project are presented in the *Confidential-Sensitive Information* document.

4.2 Completion Dates

First deliveries of LNG are scheduled for 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

Completed studies showing the engineering planning or design approach for the Project are provided in the *Confidential-Sensitive Information* document.

4.5 Construction Procedures

4.5.1 Cabrillo Port FSRU

The FSRU will be fabricated on land then towed into place and moored, utilizing anchor handling and tug supply vessels. It is the intent that FSRU will be completely constructed and all systems pre-commissioned prior to its departure from the building facility. The FSRU is designed to be moored to a single, turret-style mooring point in water depths greater than 20 meters (66 feet). The bow of the FSRU will be moored, and the aft will be free to circle about the mooring point in accordance with wind, wave, and current conditions, but stern thrusters will be provided to allow some degree of heading control to optimize the motion characteristics. Upon arrival, the turret will be tied-in to the mooring system anchor cables, and the flexible risers will be connected.

Drag anchors will be placed on the seabed and positioned to within the design limit requirements. Drag anchors will require using a three-way tensioner system or laying an opposite leg to each of the three anchor leg clusters. The laying of the anchor leg will follow the anchor installation. The leg will be laid within a specific pre-surveyed corridor. At the end of the anchor leg, a retrieval pendant wire and buoy will be installed for future use. All nine-anchor legs will be installed and buoyed off accordingly, in anticipation of installation of the FSRU. Upon arrival of the FSRU, each of the anchor legs will be retrieved by surface vessels for connection. The FSRU will arrive in the field with the mooring turret and anchor pulling equipment pre-installed. Hook-up vessels will make the final connection between the FSRU and the anchor leg, and then lower the leg back to the seabed.

After final tensioning adjustment of the anchor legs, all risers will be installed using the pull-in equipment provided on the FSRU turret and the support of a dive crew to make connections to the pipeline ending manifold (PLEM). Three 16” diameter risers will connect to the one 30” diameter send out pipeline through the PLEM. The PLEM tie-in positions will maintain separation between the three 16” flexible risers. Each flexible riser will tie-in to the PLEM via 20” shutdown valves (SDV) in series. The PLEM will also have one 30” SDV at the tie-in for the 30” diameter send out pipeline.

4.5.2 Pipeline

After all right-of-way easements, grants, and required permits and clearances have been obtained, pipeline construction will begin.

The installation of the offshore portion of the pipeline system will follow site-specific pre-installation surveys. The installation sequence will be preparation, trenching, horizontal directional drilling (HDD), pipe fabrication, non-destructive NDE, coating of completed welds, pipeline lowering, hydrostatic testing, and dewatering the pipe. In addition, offshore construction requires specific techniques for sandbagging and placement of concrete mats where the pipeline crosses existing cables.

Preparation of the offshore pipeline right-of-way prior to the arrival of the pipe-laying equipment currently is expected to be limited to locations of cable crossings, and preparation of the exit hole location where HDD will be performed.

Crossings of existing cables will be protected by installing sandbags, concrete mats, and/or “sleepers.” Sleepers are fabricated steel pipe supports designed to hold the pipeline off the sea floor while protecting against sagging and abrasion of the pipe walls. ROVs, as well as divers, will be used to locate and monitor these cable crossings, especially during installation.

The shore crossing, where the proposed marine-to-shore transition between the offshore portion and the onshore portion occurs, will be installed by HDD. Before starting a HDD, the Applicant will identify buried utilities at the onshore work site and flag them accordingly. The One-Call system in southern California will be contacted.

Preparation of the predetermined HDD exit hole location will be required prior to HDD. The exit hole location will be dredged out to provide a low point for accumulation of drill cuttings. Onshore HDD entry locations require a staging area for the drill rig and drill pipe, which will be located approximately 0.3 miles inland. The pipeline will be pulled from the exit hole back to the shore. The pipeline will be installed by trenching from the HDD staging area to the SoCalGas tie-in.

Prior to shipment offshore, the joints of pipe to be installed offshore will be coated with fusion-bonded epoxy (FBE) to protect the steel from corrosion. Sacrificial anodes will be added for cathodic protection. The quantity of pipe joints equipped with anodes and their spacing will be determined by engineering calculations. Each joint of pipe also will receive concrete weight coating prior to delivery to the lay barge, in order to add weight to the installed pipe. After application of the FBE and weight coating to the pipe joints, the pipe will be loaded and secured onto material barges, and then towed to the location of the lay vessel.

The lay vessel has several welding stations, an NDE station, and a field joint-coating station. During pipe fabrication on the lay vessel, the ends of the pipe joints will be cleaned, a lineup clamp will align the ends of the pipe joints, and the first welding passes will be made. In the standard pipe-laying mode, once the initial welding passes have been completed in the lineup station, the lay barge will be moved forward, thus incrementally moving the barge beneath the pipe string. The new field joint effectively will be "moved" to the next station in the pipeline assembly line until the entire welding procedure has been completed. The field joint then will pass through the NDE station, where qualified personnel will examine the completed weld to verify its quality. If the weld contains an unacceptable defect, the defect will be removed, repaired, and re-examined.

After completion of the NDE, the field joint will be corrosion coated with a coating system compatible with that applied onshore. The coating of all field welds will be visually inspected and examined with an electronic device to detect coating defects. All coating defects will be repaired prior to the pipe entering the water. Concrete or polyurethane foam also will be applied to the field joint to make the outside diameter of that area flush with the concrete coating, in order to facilitate the passage of the pipeline over support rollers.

The buried portion of the pipelines from approximately 0.3 miles onshore at Ormond Beach out to 13 meters water depth will be installed using the HDD technique. Specific HDD alignments and site planning will be finalized based on site-specific core sampling. The Project will use HDD borings to cross the beach and continue out to sea. Marine-to-shore HDD typically uses an HDD rig located onshore and involves drilling from onshore to a predetermined exit hole in the ocean floor offshore. A receiving barge attends the exit hole location, where there is a transition zone from the HDD arc to the next segment of the pipeline. After drilling the bore hole, the pipeline either can be pulled from shore through to the exit hole using barge-mounted pulling equipment, or it can be pulled back from the barge to the onshore drill site using onshore pull-back equipment. The Project will use HDD in lieu of marine-to-shore trenching in order to minimize environmental impacts, including disruption of habitat for endangered shore birds. The remaining section of buried pipeline from approximately 0.3 miles onshore to the SoCalGas tie-in will be installed by trenching. This area contains no sensitive habitat or wetland areas (unvegetated) and has historically been industrial in nature (former location of storage tank facility) .

Laying will be used outside the 13-meter water depth. In these offshore areas, burial is not required because the Project is within a seismically active region; consequently, the pipe will be laid directly on the sea floor. For this offshore segment, a dynamically positioned pipe-laying vessel will be used to install the pipeline.

Underwater flange make-ups between the flexible risers and PLEM, and between the send out pipeline and the PLEM, with diver assist will be required. These flange connections will be designed for simple, effective connection in the subsea environment.

Prior to hydrostatic testing, a sizing plate will be installed on a pig and pushed through the pipeline to verify pipeline integrity. Filtered seawater will propel the sizing plate pig and fill the pipeline for the hydrostatic test. Test water intake and discharge will comply with all applicable state and Federal discharge regulations. Test water will be drawn only from appropriate and approved sources, including the Pacific Ocean, and will be screened to prevent entrainment of fish. After the testing is complete, the water in the pipeline will be discharged with two or more dewatering pigs.

The Applicant will not chemically treat the hydrostatic test water for sections of the pipeline where the residence time of the water in the pipeline is less than 10 to 14 days. Because that duration is expected to be sufficient for all pipeline segments, no chemical addition is proposed. If a longer residence time is required, only oxygen scavengers and biocides that have been proven to be non-detrimental to the environment will be added to the hydrostatic test water, to limit corrosion and marine growth. Oxygen scavengers will be removed by aeration during discharge, allowing the oxygen in the air to nullify the scavenging effect. The percentage of biocide will be kept sufficiently small and the residence time in the pipeline kept sufficiently long to render the biocide no longer harmful to sea life upon discharge.

4.6 Estimated Decommissioning Cost

The estimated cost for decommissioning of the Project is 10 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 Analysis (EA)

The information in this section of the application summarizes more detailed information contained in the Applicant's Environmental Analysis (EA) in the following sections:

Section 3, Project Description

Section 4, Alternatives

Section 5.1, Terrestrial and Freshwater Biology

Section 5.2, Marine Biology

Section 5.3, Agricultural Resources and Soils

Section 5.4, Geological Resources

Section 5.5, Oceanography and Water Quality

Section 5.6, Hazards and Hazardous Materials

Section 5.7, Air Quality

Section 5.8, Traffic and Transportation

Section 5.9, Noise

Section 5.10, Cultural Resources

Section 5.11, Aesthetics

Section 5.12, Land Use

Section 5.13, Socioeconomics

Section 5.14, Environmental Justice

Section 5.15, Recreation

Section 5.16, Energy and Mineral Resources

5.1 Alternatives (see Section 4.0)

The Project has been designed to avoid or minimize adverse impacts to the biological, physical, and socioeconomic environment. Significantly, the offshore location will result in avoidance of many of the substantial environmental impacts typically associated with large land based LNG facilities, as well as safety and security concerns associated with the siting of land-based terminals in populated areas.

This section summarizes the screening of alternatives against the Purpose and Need. The results of the screening are three alternatives that are analyzed in this EA: 1) No Action; 2) Santa Barbara Channel Alternative; and 3) technology alternative of intermediate fluid vaporizers rather than submerged combustion vaporizers.

The selection of the Project location, including the send out pipeline route, was the result of a comprehensive evaluation process, that took into account many factors including LNG carrier access, access to regional natural gas transmission systems and proximity to a region of high natural gas market demand, while maintaining safe clearance from shipping lanes, residential and recreational areas, and other existing uses.

Prime operational functions of the unit are as follows:

- Receipt of LNG from LNG carrier
- Storage of LNG
- Regasification of LNG
- Send-out of natural gas via pipeline

The selection of the Cabrillo Port FSRU location and pipeline route was determined as a result of an alternative analysis considering technical requirements, environmental impact assessment and preliminary input received from state and local agencies and other parties. Alternatives will be further considered during the public scoping meetings, open houses, and written comment period during the public permitting process.

The analysis of potential alternatives, included an examination of regional alternatives, local alternatives, and technology alternatives. An initial screening of regional alternatives was performed, evaluating several regions along the West Coast of the United States and Mexico. Local alternatives to the Project were then evaluated to determine whether they would be logistically and environmentally preferable to the proposed Project. These include alternative mooring point locations, alternative shore crossing locations, major pipeline route alternatives, and pipeline route variations. Finally, technology alternatives were considered for the FSRU and for the pipeline, based upon relative environmental impacts, safety, reliability and other factors.

The evaluation criteria for selecting potentially environmentally preferable alternatives include:

- Ability to satisfy Project purpose and need.
- Technical and economic feasibility and practicality.
- Significant environmental advantage over the proposed Project.

5.1.1 No-Action and Postponed Action Alternative

Deferral of the Project could stimulate other LNG and natural gas import projects in the region, including on-shore LNG terminals, which could result in greater adverse environmental impacts than the Project. Deferral of the Project could also result in restricted natural gas supplies and higher natural gas prices during the period of deferral, if the natural gas to be supplied by the Project cannot be derived from other new natural gas sources.

The EIA projects that natural gas demand in the United States will rise by two percent a year through 2020, while domestic production will only rise by one percent each year during the same period. Given this mismatch between projected U.S. supply and demand, a significant percentage of U.S. natural gas demand will necessarily be satisfied through gas imports. In this regard, overseas exploration has developed significant natural gas resources. Much of this gas has no local market due to lack of demand and infrastructure, and/or ability to pay for the gas. Without access to export markets, this gas is effectively stranded.

The no-action alternative would avoid the environmental impacts immediately associated with the Project. However, since the Project would be unavailable to meet anticipated growth in energy demand in the California market, this demand would need to be met by other alternatives. These alternatives include:

1. Local and regional energy alternatives including oil, coal, nuclear, and other fuels that are not "clean burning" and present additional environmental and economic impacts, particularly to air quality and transportation.

2. Development of additional renewable energy sources such as solar and wind, which present their own environmental issues and which are not able to adequately supply the projected energy demand. Wind energy expansion requires suitable acreage in a location that has appropriate wind conditions. While wind energy can be a valuable supplemental source of electric power, it is subject to significant fluctuations and is not a reliable primary source of energy to replace natural gas. While solar energy has applications in building-specific water heating and electric power generation, it is not available as a significant source of electric power and, like wind energy, can not be relied on to replace natural gas.

3. Construction of other LNG handling facilities that do not provide the environmental advantages of the Project. Extensive alternatives analysis has shown that an offshore, floating regasification unit tied in to an existing natural gas distribution system provides significant environmental advantages over other options.

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 proposed Project.

5.1.2 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.

Local and regional energy alternatives to the natural gas supply from the proposed project include oil, coal, nuclear, and alternative fuels that are present in the area. The potential impacts associated with using these alternative fuels rather than natural gas include impacts on air quality (oil or coal vs. natural gas), on transportation (coal vs. natural gas), and relative environmental and economic impacts associated with the construction of natural gas-based facilities vs. alternative fuel-based facilities. The use of less-clean burning alternative fuels would decrease air quality by increasing emissions of sulfur dioxide (SO_2) and other priority pollutants.

5.1.2.1 Alternative Offshore Projects

There are no existing offshore natural gas projects receiving LNG. Proposed offshore projects have been considered by others in the industry and three alternative concepts were examined by the Project as discussed in Section 5.1.4. Other concepts located at alternative sites could be used for offshore LNG FSRUs. Based upon our studies for the Project, the alternatives would not meet Project objectives and/or would incur greater environmental impact.

5.1.2.2 Existing or Proposed Onshore Facilities

Existing or proposed onshore facilities are considered as alternatives to the import and delivery capacity that would be provided by the Project. However, there are no existing or proposed onshore facilities in the West Coast Region. The Gulf Coast and East Coast have the following existing and proposed onshore facilities:

- Elba Island Terminal – Chatam County, Georgia
- Cove Point Terminal – Calvert County, Maryland
- Cameron LNG L.L.C. (formerly Hackberry Terminal) – Hackberry, Louisiana
- Everett LNG Terminal – Boston, Massachusetts
- CMS Lake Charles Terminal – Calcasieu Parish, Louisiana
- Port Pelican Terminal (proposed) – Gulf of Mexico
- Freeport LNG - Freeport, Texas

None of these onshore facilities could easily receive LNG carriers from the Pacific Basin.

5.1.3 Alternative Natural Gas Pipeline Systems

Alternative natural gas pipeline systems are pipelines that could replace all or part of those that would be used to transport gas from the Project to onshore connections to intrastate pipelines.

Pipeline route alternatives from the Santa Barbara Channel and Anacapa alternative mooring locations were considered but are not relevant because those mooring points were found to be unsuitable. Three pipeline route alternatives, between the proposed Project mooring point and the proposed shoreline crossing at Ormond Beach were evaluated. In all cases the shore crossing would be installed using HDD to avoid beach impacts that would be caused by trenching. Pipeline route alternatives were evaluated based upon the following criteria:

- *Seafloor Slope*

The mooring point is beyond the continental shelf in 2,900 feet of water. The climb from the seafloor up to the OCS includes steep slopes and canyons. For the greatest stability the pipelines should be routed directly up the slope, perpendicular to contour lines, and should be routed along the mildest slopes possible.

- *Slides, Faults and other Geologic Hazards*

The Project is located in a region of seismic activity. The pipeline routing should avoid directly crossing active faults and areas of historic slide activity. The pipeline route alternatives all assume that the pipelines will be laid upon the seafloor instead of buried to reduce the risk of damage from seismic activity.

- *Existing Cables and Pipelines*

The send out pipeline may present a reduced environmental impact, or at least can take less right-of-way space on the seafloor if it is routed along existing lines and shares overlapping rights-of-way. When cables or pipelines are crossed it is best to cross perpendicular to the existing line. Pipeline and cable crossings require protective concrete mats or other methods to maintain adequate clearance and prevent damage.

- *Buoys, Anchorages and Other Nautical Hazards*

A buffer of at least one quarter-mile should be maintained between pipeline routes and buoys to prevent the buoy from interfering with barges, lay vessels and other equipment during pipeline construction. Designated anchorages must be avoided to prevent third party impact to subsea pipelines. Ports, harbors and channel crossings may present a risk of third party damage to an unburied pipeline due to anchor dragging.

- *Constructability*

The pipeline route must be constructed using existing, available technology and equipment. Constructability issues may be related to factors such as pipeline burial depth, water depth, and seafloor slope. Nautical hazards such as shipping lanes may present complex logistical challenges during pipeline construction.

- *Pipeline Length*

Increased pipeline length may pose a greater risk if a natural gas release occurs because the line would hold a greater volume of gas that could escape. Longer pipelines also carry some additional risk of third party impact simply because they cover more distance along the seafloor.

5.1.3.1 Alternative Route 1

This route was the initial route considered from the Project proposed mooring location to shore. Below 328 feet water depth, it runs between two small canyons through one of the safest possible paths across the continental slope. There are no major natural obstructions along the proposed pipeline route, but it runs parallel and in close proximity to, or across several known man-made structures and restricted areas. These include two surface-laid Navy cables (FOCUS and RELI), one potentially buried telecommunication cable (Global West Segment F), and a Navy cable corridor and firing range. The total length of Alternative Route 1 is 20.2 miles, about 0.9 miles shorter than the proposed route. After detailed route surveys and specific confirmation of cable locations, the crossings and the separation between the proposed pipelines and the existing cables would be adjusted to comply with cable industry standards. It is anticipated that the Navy may require burial of their cables prior to the installation of the pipeline at cable crossings. A requirement to obtain permits to cross the Navy cables and to run within the Navy cable corridor could severely impact upon the scheduling of the pipeline project. Due to the risk of Project delay related to pipeline routing in close proximity to navy cables, this alternative was considered unsuitable and was abandoned in favor of the proposed Project pipeline routing.

5.1.3.2 Alternative Route 2

Alternative Route 2 was designed to run to the west of the proposed pipeline route and west (as much as possible) of both the Navy cables and their safety corridor. From there the route runs toward the Navy cable corridor and across a relatively featureless seabed. At around 2,625 feet water depth, the route heads to the northwest and enters the Navy cable corridor. In order to ensure compliance with the anticipated Navy engineering requirements, this section of the route was planned to accommodate crossings of the RELI and FOCUS cables with an angle as close as possible to 90°. At around 1,969 feet water depth the route leaves the Navy cable corridor and enters Hueneme Canyon. The alternate route runs through this feature, in a manner not always perpendicular to the slope, to a water depth of approximately 984 feet. Slope gradients in this area are likely greater than 10° in places, and possibly more. For this reason, and because this study has shown that the canyon is still active and may be affected by slope failure, slides and turbidity currents (particularly in the event of an earthquake), the pipeline is likely at greater risk in this area and this alternative route was deemed unsuitable. The total length of Alternate Route 2 is 23.6 statute miles long, i.e., about 2.5 statute miles longer than the proposed route.

5.1.3.3 Alternative Route 3

Alternative Route 3 was designed to avoid the Navy cable corridor as much as possible by staying to the east of the navy cables, except for the crossing point. From the mooring point the route follows Alternative Route 1 to the northwest for about 4 miles, then runs to the north. The route crosses the Global West cable at a water depth of approximately 2,625 feet. It then climbs up the continental slope in an area with maximum gradients of about 6°, along a smooth and wide ridge between Mugu Canyon and a smaller channel to the west. In the upper part of the slope, between 131 and 197 feet water depth, the route passes 2,297 to 2,625 feet to the east of a buoy testing area. Alternate route 3 then turns to the west to cross the Navy cable corridor and to avoid the head of Mugu Canyon. Alternate Route 3 runs between the two navigation buoys, through the Navy cable corridor and across both the RELI and FOCUS cables. This route crosses portions of the navy cables that have been buried to a depth of 1 to 2 feet. The total length of Alternate Route 3 is 20.9 statute miles, or 0.2 statute miles shorter than the proposed route. This route runs parallel to the beach and in shallow waters over a long distance. At this depth, the pipeline would likely be exposed to wave surge during large storms. Running the pipeline parallel to the shoreline could exacerbate this hazard. This is likely to be a problem in terms of permitting issues and may receive strong opposition from the Navy and from coastal communities. In addition, the route runs relatively close to the head of Mugu Canyon, which is a site of high activity during periods of flooding and strong storms and, therefore, could present additional hazards to the pipeline. For these reasons, Alternative Route 3 is not suitable and is not preferred compared to the proposed route.

5.1.3.4 Technology Alternatives

Technology alternatives are alternatives to the proposed Project that would make use of other existing, modified, or proposed LNG terminal and pipeline technologies to meet the stated objectives of the proposed Project. Technology alternatives vary from using an entirely different approach to meeting the Project objectives, such as use of a fixed, on-shore LNG receiving terminal. Technology alternatives may also be related to specific aspects of the proposed Project such as LNG vaporizer technology.

5.1.4 Alternative LNG FSRU Technology (see Section 4.0)

5.1.4.1 Fixed offshore LNG terminal alternative

Two basic offshore design concepts include fixed or floating offshore terminals. Fixed terminal designs include gravity-based structures (GBSs). Floating terminal designs such as that in the proposed project, include a floating, storage and regasification unit (FSRU) or a shuttle and regasification vessel. Factors influencing the concept decision include constructability, weather, safety, shipping, environmental setting and regulatory permitting.

A GBS would be built either on foundation piles that would be driven or drilled into the seabed, or a stabilized pad of soil material would have to be established. A major limitation of the GBS concept is that it needs to be installed in shallow water, typically less than 100 feet, which generally means closer to shore. The overall construction schedule for the proposed FSRU would be shorter than that for a GBS, because the fabrication process is very similar to that of standard LNG tankers built in dry-docks. A GBS could also be built in a dry dock and floated into place, however, no such facilities exist in the nearby vicinity for such construction and no GBS has ever been subjected to a long ocean tow in the past. The GBS would require much more extensive work onsite to complete installation and commissioning. Upon decommissioning, the GBS would again require much more work than the proposed FSRU. The GBS, after shutdown and purging, would have to be partially dismantled and re-floated for removal. The foundation piles would have to be cut at the seafloor. If a stabilized pad were employed, dredging may be required to recover pad material. The GBS foundation and support structure, during its operating life, may provide some artificial reef benefit for fish and haul-out areas for marine mammals, and removal of those benefits would be an impact upon decommissioning. The mooring procedures for mooring an LNG carrier next to a GBS or an FSRU are near equal. In either case the relative motion between the terminal and the LNG carrier would require careful analysis and detailed design for mooring and LNG transfer systems. Assuming comparable LNG storage capacity, the visual impact of a GBS would be comparable to or greater than that of the proposed FSRU. The visual impact would be greater if the fixed facility was designed and built completely above the waterline, similar to most fixed oil and gas production platforms. Because the profile of the FSRU is ship-shaped, and because of the more expedient fabrication and commissioning time, the GBS alternative does not present and significant environmental benefit compared to the proposed FSRU.

5.1.4.2 Flow-through regasification facility alternative

In lieu of a facility that provides LNG storage, an LNG terminal, fixed, floating, or on-shore, could be designed simply to receive and regasify the LNG, immediately sending out natural gas. An advantage of this alternative is the absence of LNG storage tanks, which would reduce visual impact. The impacts of this alternative, though, compared to the proposed FSRU would be partially dependent upon the regasification technology used. This approach requires the LNG carrier to remain moored for a longer period of time. With the proposed FSRU the LNG carrier can rapidly offload LNG at high flow rates, with an estimated 20-hour span between berthing and de-berthing. In a separate operation LNG is then regasified at a rate dependent upon the demand in the marketplace. With a flow-through facility there is little to no ability to store LNG, so the LNG carrier would offload LNG at a rate comparable to the market-driven natural gas send-out rate. This alternative approach requires longer mooring times for the LNG carrier, which increases the risk of mooring incidents and LNG transfer incidents. This alternative approach is also problematic for customers because the natural gas flow is interrupted in between LNG carrier berthings. This flow interruption would not satisfy the project objectives. Finally, in order to maximize natural gas delivery time and minimize downtime, LNG carriers would be sequenced with narrow time windows between departure of one carrier and arrival of another carrier. This close spacing of LNG carriers increases maritime risk. The close spacing of LNG carriers also offsets the benefit of reduced visual impact of the terminal, because the duration of LNG carrier presence would be increased relative to the FSRU. The flow-through approach does not appear to provide any environmental benefits sufficient to offset the increased commercial, safety and maritime risks associated with this alternative.

5.1.4.3 Flow-through mooring point, on-board regasification alternative

Another technology alternative to the proposed FSRU is a flow-through mooring point. The concept provides for an offshore mooring point that rests on the sea floor when inactive. LNG carriers with regasification equipment on board would tie-in to the mooring point, which can be raised to the surface when desired. After mooring, the LNG carrier would initiate regasification, with the natural gas being sent out through the mooring point to a send out pipeline. This alternative further reduces visual impacts, essentially leaving only the LNG carrier with no visible terminal equipment. The impact of this alternative relative to the proposed FSRU is dependent upon the regasification technology used. This alternative also has the drawbacks of the flow-through facility alternative discussed above, with intermittent natural gas flows, LNG carrier offloading at the rate determined by market conditions, extended mooring time, and a need to tightly sequence LNG carriers to maximize operations time. The duration of LNG carrier moorings and the tight sequencing of LNG carrier visits would present a visual impact comparable to that of the proposed FSRU.

5.1.5 Alternative Regasification Technologies (see Section 4.0)

The regasification process requires a heat source. The LNG would be pumped through some heating system, where it would absorb heat and vaporize, or regasify, into natural gas. The dominant technologies used for heating are intermediate fluid vaporizers (IFV), open rack vaporizers (ORV) and SCVs. IFV and ORV use seawater, and SCV uses natural gas combustion. The IFV and ORV alternatives would require about 50 million gallons of seawater per day. That seawater would flow through the vaporizers and then would be returned to the ocean at a lower than ambient temperature. The primary benefit of IFV and ORV relative to the proposed SCV is lower air emissions.

SCV burns natural gas equivalent to 2% of the LNG throughput to generate heat. The combustion process relies on natural gas from LNG, so it is a clean fuel. With SCV the exhaust gases also flow directly through a water bath, which acts as a quench and abatement system. The SCV air emissions will include oxides of nitrogen (NO_x), and carbon dioxide (CO_2). NO_x is a regulated ozone precursor, and CO_2 is a non-regulated greenhouse gas.

IFV and ORV would introduce some air emissions, which are of an order of magnitude less than SCV's because of the incremental electricity necessary to operate the large seawater pumps. The use of this large quantity of seawater raises concerns over entrainment and impingement of marine species, thermal plumes, turbidity, treated water discharge and noise. Impingement could occur when fish and other aquatic life are trapped against the IFV water intake screens. These screens prevent marine organisms and debris from entering and interfering with the IFV process. Entrainment occurs when aquatic organisms, including eggs and larvae, are drawn into the IFV water intakes, through the facility, and then pumped back out. Thermal plumes could result from the constant discharge of large quantities of relatively cold, and therefore relatively dense, water. The proposed mooring location is of sufficient depth that a thermal plume would not be likely to impact the seafloor. Turbidity would be a result of a thermal plume disturbing seafloor sediments. The IFV and ORV alternatives would periodically use sodium hypochlorite or another oxidizer to control the growth of marine organisms in the IFV and ORV equipment. Discharge of the residual sodium hypochlorite in IFV and ORV water could impact marine organisms, and would require a water discharge permit. Noise would be generated by the large seawater pumps required for the IFV alternative.

In general, the use of IFV would be difficult to permit and operate because of water discharge rules and restrictions and impacts to marine biota. The use of SCV would produce air emissions that could be minimized by emission control technology. The IFV alternative does not provide a clear environmental benefit.

5.1.6 Alternative Construction Methods

The FSRU will be fabricated on-land, towed into place and installed in 2,900 feet of water, thus avoiding construction impacts to marine physical and biological resources that would be associated with in-place construction of the FSRU. Impacts on marine resources from FSRU installation will be avoided to the extent possible, but there will be some unavoidable permanent impacts within the footprint. Short-and long-term impacts to biota will occur at the perimeter of the moorings and along the pipeline construction right-of-way.

5.1.6.1 Alternative Offshore Pipeline Installation Methods

5.1.6.1.1 Dual 24-inch pipe alternative

The dual pipe alternative would follow the proposed pipeline route but would lay two 24-inch diameter pipelines instead of a single 30-inch diameter pipeline as proposed. Two 24-inch pipelines would be necessary to satisfy the Project objectives. Dual pipelines would cover a larger amount of the seafloor, and thus would have a proportionately larger impact on the seafloor. Dual pipelines may also increase the construction duration, especially at the shoreline crossing, because two HDDs would be required. These potential disadvantages are offset by several factors. Dual pipelines offer operational flexibility. When shut down for periodic internal inspection, or for other reasons, flow of natural gas to the marketplace could be directed to the other pipeline. Construction of a 24-inch diameter pipeline requires smaller barges, cranes, and other equipment. Equipment capable of laying 24-inch diameter pipelines is generally available on the west coast and would not have to be brought in from the Gulf of Mexico or from across the Pacific, at substantial cost and delay for the Project. Implementation of a shoreline crossing HDD for a 24-inch diameter pipeline is substantially less difficult than implementation of HDD for 30-inch diameter pipelines. Substantial construction and logistics issues associated with the dual pipe alternative do not outweigh any potential benefits

5.1.6.1.2 Trenching Alternative

The Project will utilize HDD to cross the shoreline. Trenching is an alternative technology for crossing the shoreline and for continuing to bury the pipelines out to the 43-foot water depth. HDD may require 24-hour a day operation once the drilling is initiated, to reduce the likelihood of the borehole collapsing. Trenching could be performed on a daytime-only schedule, to reduce the noise level. Trenching would, however, be substantially more disruptive to beach and seafloor habitat.

5.1.7 Siting (see Section 4.0)

5.1.7.1 Site Selection

Nine possible sites were considered acceptable for the proposed location of the Project:

- Columbia River, Washington
- Eureka, California
- San Francisco, California
- Monterey Bay, California
- Ventura, California
- Port Hueneme, California
- Long Beach, California
- San Diego, California
- Rosarito, Mexico

Initial site selection screening criteria included:

- Proximity to Gas Consuming Region
- Proximity to Existing Gas Transmission Systems

- Site Safety
- Site Security
- Carrier Ingress / Egress
- Special interest groups

Several possible sites were considered acceptable for the proposed location of the FSRU. The site selected for the Project provides the safest and shortest routing for an LNG carrier approaching from the shipping channels and the most acceptable foundation sediments. 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.
- Accessibility to SoCalGas systems.

The specific location of the Project FSRU in the waters off of Ventura County, the specific location of the shoreline crossing and tie-in to the natural gas transmission systems, and the specific route of the send out pipeline were selected after consideration of several alternatives, as discussed below.

5.1.7.2 FSRU Mooring Location Alternatives

The alternatives assessment used criteria to judge safety, security, environment and community. The alternative mooring points were evaluated based on the following criteria:

- *Distance from Shipping Lanes*

The mooring point should be at least three nautical miles from the centerline of the nearest shipping lane. A Project-specific risk analysis that was performed included an assessment of the risk of impact from a vessel that has lost power and is drifting. The risk analysis determined that with a three nautical mile buffer the risk would be negligible.

- *Distance from Shore*

The mooring point should be several miles from shore to mitigate visual impact and the perceived risk of fire related to an LNG release. Visual impact is a qualitative judgment. The degree of impact may be influenced not only by distance from shore and size of the Project, but also by the setting and receptors.

- *Subsurface Slope*

The mooring point should be over an area of relatively smooth bottom and relatively flat slope. The mooring cables will spread over a seafloor area with a radius of almost 1 mile [pending re-design for water depth]. The mooring cables and mooring anchors will be designed in accordance with bottom conditions, but design can be simplified if the bottom conditions are flat.

- *Existing Facilities*

The mooring point should be at least two nautical miles from existing offshore oil production platforms. The clearance is to provide a safety buffer for the LNG carriers that will visit the FSRU three time per week, and to prevent any serious fire incidents on one facility from spreading to another facility. Existing cables and pipelines crossed by the send out pipeline will have to be protected from damage prior to laying the send out pipeline.

- *Ferry Routes*

Ferry routes and other designated routes for smaller vessels and vessels carrying passengers should be avoided to the extent possible. A buffer of four statute miles was used for siting purposes. This buffer is greater than the buffer for established coastal shipping lanes because the routes are designated as single lines, rather than lanes, with some variance allowed off the line.

- *Fishing and Recreation Areas*

Areas known for specific commercial or recreational uses that are not designated on navigation charts were assessed only to the extent to which they were known. General data on commercial fishing fleet catches by region, and number of boats by region was considered. Recreational boating activities were estimated using charter operation and boat registration data.

- *Jurisdictional Boundaries*

The boundaries of national marine sanctuaries, military use areas, and state waters limits were considered in the local alternatives analysis. Jurisdictional boundaries and their relevance to mooring point locations were considered on a case by case basis.

5.1.7.3 Santa Barbara Channel Alternative

The Santa Barbara Channel Alternative mooring point location is about 8.5 statute miles offshore from Rincon Beach, and about midway between the existing Grace and Habitat production platforms in the Santa Barbara Channel. The alternative mooring location is specifically located at latitude 34^o 14.410' N longitude 119^o 30.916' W. This alternative meets all of the criteria for clearances from shipping lanes, and existing facilities. It is inland, about 5.8 nautical miles from the coastal shipping lanes and over 4.2 nautical miles from the nearest offshore production platform. There are a number of concerns with this alternative including visual impact. Visual impact is perhaps lessened because of the presence of existing oil platforms. However, due to the population density along the wide sweep of the coast from which the FSRU would be visible, this alternative was found to be unsuitable. The viewshed of a very large number of receptors would be impacted.

5.1.7.4 Anacapa Alternative

The Anacapa Alternative mooring point location is about 16 statue miles offshore from Point Mugu, and about 11 miles from Anacapa Island, which is part of the Channel Islands National Park. The coordinates for this mooring alternative are 33^o 52.20000' N and 119^o 04.01100' W. This alternative location is inside the limits of the Pacific Missile Range, but meets other location criteria. Visual impact is mitigated by the distance from the mainland, the distance from Anacapa Island, and the low population density in the areas from which the mooring location could be viewed. This alternative was found to be unsuitable because of the risks associated with the Pacific Missile Range.

5.1.7.5 Shoreline Crossing Alternatives

One Alternative location for the shoreline crossing of the FSRU was assessed. This location was adjacent to the Mandalay Power Generating Station. The alternatives assessment used criteria to judge safety, security, environment and community. The alternative shoreline crossing was evaluated based on the following criteria:

- *Access to SoCalGas Natural Gas Transmission System*

The shoreline crossing should be at a location that provides existing access to the SoCalGas pipelines, or access with limited improvement of existing SoCalGas facilities. The required SoCalGas improvements should avoid areas of high population density.

- *Population Density*

Many shoreline areas have been developed into high density residential areas where the noise and traffic associated with construction work could be considered a nuisance and the installation of high pressure natural gas pipelines would be considered a hazard to the community.

- *Sensitive Habitat*

Shorelines offer unique habitats that may be home to endangered species such as the snowy plover. Sensitive habitats should be avoided, or work may have to be scheduled to avoid certain seasons when species of concern are present.

5.1.7.6

The Mandalay Power Generating Station Alternative would have a shoreline crossing adjacent to the Mandalay Gas Plant. Existing pipelines from the Gina and Gilda platforms already cross the shoreline here. The natural gas from the Project would be delivered into a tie-in with the SoCalGas system at the gas plant. To accommodate the natural gas flow from the project, a new 30-inch diameter pipeline would have to be installed alongside the existing pipeline from the Gas Plant to the SoCalGas Center Road Station. This alternative is unsuitable because the new SoCalGas pipeline would go through high density residential areas, presenting significant disruption during construction and a community hazard during operation. This shoreline alternative was deemed unsuitable based upon preliminary discussions with SoCalGas.

5.2 Net Environmental Impacts and Mitigation

5.2.1 Sea Bottom Characteristics (see Section 5.4)

The offshore portion of the project is located on the Southern California Continental Borderland, an irregular complex of basins, shelves, banks, islands, and submarine canyons of sedimentary and igneous rocks. From the shore, the Project pipeline will extend offshore through the Hueneme-Mugu Shelf, to the Hueneme-Mugu Slope (consisting of south-trending submarine canyons and intervening slopes), and finally into the Hueneme Fan. The FSRU will be moored on the fringe of the Hueneme Fan in the Santa Monica Basin.

Although the Project will not cross any active or potentially active faults, there is a high seismic risk throughout California from several large faults including the San Andreas Fault. Due to this risk, severe ground shaking could potentially impact the Project pipeline. Although the Project has been, to the greatest extent possible, sited to avoid steep slopes and canyons, potential hazards exist. These hazards include: slope failure, liquefaction of sediments and soils due to the presence of loose sandy material along the offshore portion of the Project; and the possible presence of shallow gas seeps that could potentially damage the pipeline. Design of every component of the Project to date has taken these hazards into close consideration. Surveys that will be conducted of the Project area will clearly identify existing geologic hazards, and the Project siting and design will be modified accordingly. No significant impacts to bottom topography, sediment transport, and natural shoreline erosional processes in the Southern California Bight are expected to result from construction or operation of the Project.

5.2.2 Natural Environment

5.2.2.1 Biota (see Section 5.1 and 5.2)

The Project will cross several marine habitats including sandy intertidal, sandy or rocky subtidal, deep soft sediment, and open water habitats. The Project pipeline will cross several marine habitats, including sandy intertidal, sandy or rocky subtidal, deep soft sediment and open water habitats before its nearshore underground segment. The underground portion of the Project pipeline resurfaces where it interconnects with the SoCalGas distribution system. This location is near the 217-acre Ormond Beach wetland complex and lagoon, as well as neighboring agriculture and urban land.

Although few impacts on marine birds, invertebrates and fish are expected from the Project, more susceptible marine mammals and sea turtles could be affected. Impacts could result from the unlikely event of a release of LNG, fuel, or lubricating oils from the FSRU or shuttle tankers. Additional impacts could result from construction activities, noise levels during construction, and potential contact of a Project vessel or mooring line with a marine mammal or turtle. Onshore, grading and excavation, lighting, dust and airborne emissions, noise, and additional traffic during construction of the Project have the potential to affect onshore plant and wildlife resources. Noise levels, lighting, and traffic resulting from both construction and operation of the Project, though, are not expected to significantly exceed current background levels present near Ormond Beach. In addition, the Project will use HDD in lieu of marine-to-shore trenching in order to minimize environmental impacts, including disruption of habitat for endangered shore birds. Trenching activities that will occur from the HDD staging area approximately 0.3 miles onshore to the SoCalGas tie-in will occur in an industrial area significantly bare of vegetation and outside all wetland and sensitive habitat areas.

A marine mammal observer and monitor will be aboard each vessel servicing or providing support to the FSRU during times that marine mammals are likely to be present in the Project area. Offshore construction will be timed to avoid the gray whale migration period. Additional spill prevention, control, and countermeasure plans and marine mammal contingency plans will be developed to avoid LNG, fuel or oil spills and affects to marine mammals and turtles. A Biological Resources Mitigation Implementation and Monitoring Plan will also allow avoidance and minimum disruption of special status species when possible. The U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service, Minerals Management Service, and/or California Department of Fish and Game will be consulted to ensure that these measures are adequate.

The Project will not adversely impact any commercially or recreationally important species.

5.2.2.2 Littoral Processes, Currents, and Wave Patterns (see Section 5.5)

Ventura County is part of the South Coast littoral cell. A littoral cell is a section of coastline where the transport of sediment is isolated from adjacent sections of the coastline. A cell is composed of one or more sediment sources, and sediment sinks. The beach acts as a conduit between the sources and sinks. The South Coast littoral cell runs from the mouth of the Santa Ynez River, north of Point Conception, to the Mugu Submarine Canyon, near the mouth of Mugu Lagoon.

In addition to littoral drift, there is an onshore-offshore movement of sand. Waves that are small or spaced far apart tend to move sand from the ocean bottom towards the beach, building it out. Large, closely spaced waves tend to cut back the beach and move the eroded sand seaward, forming sand bars in shallow water.

Sandy sediments may be transported on the offshore Oxnard Shelf as traction load sediments via submarine currents. However, relatively slow currents (less than 1 knot) on the Oxnard shelf are not expected to result in significant sediment transport by this mechanism. Severe storms can cause intense disturbances to regional circulation, resulting in short-term increases in currents and the rate of surface sediment transport.

The shoreline in the vicinity of the onshore pipeline crossing is a sandy beach. Installation of the onshore pipeline crossing by HDD may temporarily result in erosion of the exposed sediment and increased turbidity in the vicinity of the drilling. However, it is expected that the extent of sediment exposed to waves would be minimal, therefore~~,~~ the impact is expected to be less than significant.

Because the Project will be located approximately 13.9 miles offshore, there will be no effect on natural littoral processes from operation of the FSRU, nor will sedimentation and erosion along the shoreline will be effected.

The scale of the FSRU structure will produce only localized effects on current and wave patterns. None of the effects will approach the 500-meter radius safety zone around the FSRU.

5.2.2.3 Sea Bottom Sediments and Features (see Section 5.4)

Impacts to the sea bottom sediments and features will take place during construction and will be temporary in nature. Anchored structures disturb the sea bottom beneath and adjacent to the structure. Impacts from bottom area disturbance are of concern near sensitive areas such as topographic features, chemosynthetic communities, and archaeological sites.

Sediment displacement is also expected to occur during pipe laying activities. Pipe laying barges use an array of eight 9.9-ton 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.

No permanent impacts to sediments or sea bottom features are expected from the Project. Surveys of the sea bottom in the Project area will be analyzed to avoid hazardous areas and potential construction impacts.

5.2.2.4 Infrastructure Considerations

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

- Existing international onshore fabrication yards used for the fabrication of the FSRU.
- The PLEM and pipeline will connect to an existing onshore natural gas pipeline system.
- Existing port facilities will be used for support of FSRU operations.

The only new infrastructure created by this project is the FSRU, the PLEM, and pipeline connecting the FSRU to the existing gas-gathering infrastructure. The sites selected for these Project elements were selected with the intent to minimize environmental impacts and to ensure safe operation.

5.2.2.5 Potentially Important Uses (see Section 5.16)

Energy and mineral resources within the Project vicinity consist largely of offshore oil and gas fields. In the Project vicinity, there are currently three oil and gas fields in production (Hueneme Field, Santa Clara Field, and Sockeye Field), and one potentially developable oil field (Cavern Point).

The FSRU would be moored southeast of Anacapa Island, about 13.9 miles offshore on an unleased site. The potential for mineral resources exploration and production at the site or along the pipeline is insignificant because of the moratorium in California on new drilling leases.

There are no known energy or mineral resources present at or in the vicinity of the onshore portions of the Project. There is no commercial production of minerals, including the production of sand and gravel that occurs within the onshore portions of the Project area**.**

5.2.2.6 Sediment Quality Considerations (see Section 5.5)

Sediment and water quality within the Project area is impacted by various pollution sources. Agricultural, commercial, and industrial activities impact groundwater resources. Coastal runoff and discharges from industrial, commercial, and municipal facilities impact nearshore and offshore surface water bodies.

Studies show that the sediment in the Project vicinity consists of very fine to medium sand with some gravel, muddy sand, and mud. Deeper escarpment and basin sediments consist primarily of very fine silts and clays. Concentrations of contaminants such as metals, PCBs, bacteria, petroleum hydrocarbons, and pesticides in the sediments surrounding the Project area are typical of the Southern California Bight.

Any accidental release of LNG associated with the Project is not expected to significantly impact sediment quality due to the high vapor pressure and high solubility of methane, ethane, and propane in the LNG. These compounds would volatize relatively quickly following contact with seawater. The FSRU, LNG carriers, and supply vessels will carry varying amounts of petroleum hydrocarbon products, urea, and small amounts of other hazardous materials, including paints and solvents. Most of these compounds will be in such small amounts as to not significantly affect sediment quality. The 30,000 gallons of diesel fuel stored on the FSRU, for emergency power generation, as well as fuel stored in LNG carriers could, if spilled significantly affect sediment quality. A comprehensive Spill Prevention, Control, and Countermeasure Plan will be developed for LNG, natural gas, and all oil and hazardous compounds associated with the Project to avoid spills and response and cleanup in the event of a release.

5.2.2.7 Groundwater Resources (see Section 5.5)

The landfall of the Project will be located at Ormond Beach on the Oxnard Plain. A complex aquifer system underlies the plain, generally these aquifers can be divided into an upper and lower aquifer system. The upper system consists of flat-lying alluvial deposits, that comprise a shallow, unconfined perched aquifer and the Oxnard and Mugu aquifers. The perched aquifer is situated 80 to 100 feet below the ground surface. This aquifer is exposed immediately offshore along the coast and is underlain by a clay deposit, which separates this unit from the Oxnard and Mugu aquifers. Groundwater within these aquifers is used for agricultural uses and water supply. The Oxnard and Mugu aquifers crop out in the Hueneme and Mugu submarine canyons less than one-quarter mile offshore. The lower aquifer system consists of alternating layers of alluvial sand and clay and includes the Hueneme and Fox Canyon (or Grimes Canyon) aquifers. These aquifers contain relatively fresh water, except in areas of saltwater intrusion near to the coast and in the Project area. No groundwater wells used for public, domestic, or agricultural supply are in the area of the Project.

5.2.2.8 Cultural Resources (see Section 5.10)

The South Central Coastal Information Center in Fullerton, California conducted a record search of the Ventura Project area. The search included a review of all recorded prehistoric and historic archaeological sites within a one-quarter mile radius of the project area as well as a review of all known cultural resource reports. In addition, the staff reviewed historic maps, listings in the California Points of Historical Interest, the listings of the California Historical Landmarks (CHL), the National Register of Historic Places (NRHP), and the California State Historic Resources Inventory for the Project area.

5.2.3 Design, Construction and Operation

5.2.3.1 Effluents and Water Quality (see Section 5.5)

The only expected discharges from the FSRU are gray and black water from the quarters and other areas, runoff from the deck of the FSRU, excess freshwater from the SCVs, and water used for hydrostatic tests. Gray water will be treated in chemical or biological sanitary waste systems prior to discharge. Black water will be contained and shipped to shore on the supply boat, for disposal. Runoff from the deck of the FSRU will be treated using an oily water treatment system. The resulting discharge will contain less than 20 ppm of oil. BHPB will seek permits for these discharges from the USEPA and Los Angeles Regional Water Quality Control Board.

Any accidental release of LNG associated with the Project is not expected to significantly impact water quality due to the immediate evaporation at ambient temperature because of its high vapor pressure. The FSRU, LNG carriers, and supply vessels will carry varying amounts of petroleum hydrocarbon fuels and lubricants, urea, and small amounts of other hazardous materials, including paints and solvents. Most of these compounds will be in such small amounts as to not significantly affect water quality. The diesel fuel stored on the FSRU, though, for emergency power generation, as well as fuel stored in LNG carriers could potentially significantly affect water quality. A comprehensive Spill Prevention, Control, and Countermeasure Plan will be developed for LNG, natural gas, and all oil and hazardous compounds associated with the Project to avoid spills and response and cleanup in the event of a release.

5.2.3.2 Air Emissions and Air Quality (see Section 5.7)

During construction, the dynamic positioned lay vessel 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 carbon monoxide (CO), and small amounts of volatile organic compounds, respirable particulate matter (PM_{10}) and SO_2 from diesel fuel usage. 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.

During operations onboard the FSRU, the generator engines and SCVs will be the greatest source of air emissions, predominately NO_x, but will be mitigated by control technology if required. The fuel gas compressor, BOG compressor, various pumps, heaters, scrubbers, and utility equipment will be electric powered. This equipment will generate no air emissions. Periodic use of diesel-powered equipment (firewater pumps, and emergency back-up generator) will generate additional air emissions.

The LNG carriers and assist vessels operating within a 25-mile radius of the FSRU will produce NO_x and CO, as well as smaller amounts of other regulated air pollutants. Natural gas fuel will be used to the extent possible to mitigate these emissions.

5.2.3.3 Noise (see Section 5.9)

Generally, the equipment on the FSRU will be operated at a noise level of about 75 dBA (A-weighted decibels). Additionally, a LNG carrier moored at the FSRU could emit noise levels in the 85-120 dBA range during offloading operations. However, since the FSRU is anticipated to operate at about 75 dBA levels, the LNG carrier may be expected to operate at a similar noise level during unloading. Conservatively, if both vessels operate at 85 dBA during unloading, the total noise level from the FSRU and the LNG carrier would be about 90 dBA. FSRU noise abatement features include sound enclosures and acoustic walls. The nearshore and onshore pipeline will be buried and its operation would not be a significant source of noise to the surrounding environment.

Onshore, HDD (to be conducted around the clock until complete) and trenching during construction may create relatively high noise levels. Noise control measures should reduce temporary drilling operation noise to 70 dBA or below. Construction of the onshore meter and pigging station will be conducted during daytime hours.

5.2.3.4 Spills and Releases (see Section 5.6)

Potential sources of spills and releases from FSRU operations will be:

- Spills of LNG, lubricants or fuels (primarily diesel) from operational equipment.
- Spills of diesel 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 FSRU will be LNG, which consists predominately of methane. The LNG is received at the FSRU in a liquid state at a temperature of approximately -260° 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 FSRU 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 on skids with drain pans designed to hold any potential hydrocarbons and rainwater.

Spills, wash water, and rainwater within coamed areas and from equipment skid sumps will drain to a collection tank for suitable treatment where water and hydrocarbon will be separated. The hydrocarbons will be collected in a waste oil tank and the water will be discharged in accordance with NPDES permit requirements.

Project maintenance procedures will address hydraulic and lube oil spill cleanup from mobile equipment in areas of the FSRU that are not fitted with coaming.

The 1,000 m^3 diesel tank will be located within a secondary containment area. The tank will have an automatic level control to prevent overfilling. 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.

The FSRU 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 Project. (Except as defined under the NPDES permit). No maintenance dredging around the FSRU will be required.

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

- Maintenance wastes (oily rags, etc.) will be generated intermittently.
- Garbage (paper waste, packaging wastes, etc) will be generated at a rate of 145 lb./day (29 persons at five lbs./day per persons).
- Waste solvent drums, paint cans, hazardous solids, etc. will be generated intermittently.

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

The FSRU design will include the necessary secure storage areas, paint lockers, transfer dollies, etc. for safe storage of hazardous materials and the safe transport of hazardous wastes to shore for final disposal. Using the following techniques will minimize hazardous wastes:

- Standardized lubricants, solvents, and hazardous materials will be used where appropriate.

- Non-hazardous materials will be substituted for hazardous materials where possible.

- Solvents and hazardous materials will be recycled, reused, or regenerated where possible.

5.2.4 Land Use and Coastal Zone Management (see Sections 5.11 - 5.15)

The Channel Islands National Marine Sanctuary encompasses 1,252 square nautical miles of water surrounding Anacapa, Santa Barbara, Santa Cruz, Santa Rosa and San Miguel Islands extending from mean high tide to 6 nautical miles offshore around each of the five islands. The National Oceanic and Atmospheric Administration (NOAA) designated the Channel Islands National Marine Sanctuary in 1980 to protect marine resources of national and global significance.

The Project will be located outside the Channel Islands National Marine Sanctuary, about 18 miles southeast of Anacapa Island.

The FSRU will be permanently moored 13.9 miles offshore of Ventura County in about 2,900 feet of federal OCS waters, located at Latitude 33 51.512 N and Longitude 119 02.015 W. The FSRU will be surrounded by an exclusion zone of 1,640 feet, and will be connected to the landfall at Ormond Beach by one 21.1-mile pipeline. No other onshore land use will be required for the Project. There will be no long-term impacts to the coastal zone.

Some of the potential negative impacts to recreation from the FSRU could include reduced fish catches, disturbed fish habitats (both commercial and recreational) and 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 FSRU safety zone might present a potential navigational barrier for deep-sea fishers.

No significant long-term impacts upon land use, population and housing, or recreational resources, except for visual impacts described below, have been identified or projected as a result of construction or operation of the FSRU. The FSRU will be operated under a BHPB operations management system incorporating compliance with the international environmental management standard ISO 14001.

The onshore facilities would be located near an existing industrial setting where the addition of another industrial feature, amongst existing industrial components, would not result in a visual impact. The offshore FSRU would be located approximately 13.9 miles from the nearest shore between Point Mugu and Leo Carrillo State Beach. Recreationists at sites in the Santa Monica Mountains and residents living in the foothill areas near Santa Barbara would be able to see a greater proportion of the FSRU than viewers at sea level. For some visually sensitive viewers (such as residents living in foothill locations and some recreationists), the FSRU will degrade the existing visual character or quality of the site and its surroundings. However, as a proportion of the region's total population (e.g., residents of Oxnard, Ventura, Port Hueneme, outlying residents near Santa Barbara, visitors to the Santa Monica Mountains) the proportion of visually sensitive visitors and residents is likely to be very small.

There will not be substantial damage to scenic resources within the scenic highway corridor along Highway 1 because only a very small portion of the FSRU would be visible when viewed at sea level. The color of the vessel and the shape of the LNG tanks and hull should minimize the appearance of the FSRU as a “developmental” feature. It is likely that the majority of viewers will perceive the FSRU to be a ship, rather than an LNG processing facility.

Section

6

6 Regulatory Compliance and Federal and State 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 / California Environmental Quality 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's need to comply with NEPA. The EA is included to aid in conducting this review and for preparation of the EIS. 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.

The California Environmental Quality Act (CEQA) was modeled after NEPA. CEQA requirements are integrated with other planning and environmental laws to encourage concurrent review and processing. Its purpose is to disclose to the public and to decision-makers the significant environmental effects of a proposed project, and to identify ways to avoid or reduce environmental damage. The main objective of CEQA is to prevent environmental damage by requiring implementation of feasible alternatives or mitigation measures. This process is very similar to the NEPA EIS process, but the resulting product is called an Environmental Impact Report (EIR). Because the Project will be located in Federal OCS with pipeline connections through the waters of the State of California, both EIS and EIR processes must be undertaken. The process will be conducted as a joint EIS/EIR.

6.3 Federal Water Pollution Control Act (Clean Water Act)

Although the Project is considered a “new source” for purposes of the Federal Water Pollution Control Act (FWPCA), the USEPA has not promulgated performance standards for deepwater ports. Therefore, the FSRU is not subject to new source performance standards (NSPS) under the FWPCA.

6.3.1 Section 401(a)(1) Certification

Section 401 of the Clean Water Act (CWA) requires that the discharge of dredged or fill material into the waters of the United States does not violate state water quality standards. Generally, no CWA Sec. 404 permits will be issued until the State has been notified and the applicant has obtained a certification of state water quality standards.

The Army Corp of Engineers has jurisdiction for over Section 401 permitting.

6.3.2 National Pollutant Discharge Elimination System (NPDES) Short Form D Information

The NPDES permit is the water quality permit for the Project, as required by the DWPA. A pre-filing draft of the NPDES application is included as Attachment 4 of this document. The application will be completed and is expected to be filed prior to operations. The USEPA-Region 9 will review the application and confer with Army Corp of Engineers regarding discharge into waters of the state.

By Federal law every applicant for a Section 404 Federal permit for an activity which may result in a discharge into a water body must request a State certification that the proposed project will not violate State and Federal water quality standards. Certification is based on a finding that the proposed Section 404 discharge will comply with all pertinent water quality standards. In order to allow certification, conditions are required by the Regional Water Quality Control Board to remove or mitigate potential impacts to water quality standards.

6.4 Coastal Zone Management Act

6.4.1 Section 307 Certification

The Project will be located approximately 14 miles offshore of Ventura County and will not impact the coastal zone. Section 307 certification of compliance with the Federal Coast Zone Management Act will be obtained from the California Coastal Commission through the California State Lands Commission for the onshore and state water portion of the pipeline.

The California Coastal Commission defines the "coastal zone" as the area of the state which extends three miles seaward and generally about 1,000 yards inland. In particularly important and generally undeveloped areas where there can be considerable impact on the coastline from inland development, the coastal zone extends to a maximum of 5 miles inland from mean high tide line. In developed urban areas, the coastal zone extends substantially less than 1,000 yards inland.

6.5 Dredge and Fill Data

6.5.1 U.S. Army Permit Requirements

Section 404 of the Clean Water Act (CWA) establishes a program to regulate the discharge of dredged and fill material into waters of the United States, including wetlands. Activities regulated under this program include fills for development, water resource projects (e.g., dams and levees), infrastructure development (e.g., highways and airports), and conversion of wetlands to uplands for farming and forestry.

6.6 Clean Air Act

The Project is considered a “new source” for purposes of the Clean Air Act (CAA). As a new source, the FSRU will be subject to New Source Review (NSR) regulations under the CAA. 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). The FSRU will be located in an attainment area and as such may be subject to PSD preconstruction review by the USEPA Region 9, who will have air quality jurisdiction over the Port.

The USEPA is divided into ten regions, where each Regional Office is responsible within its states for the execution of the Agency's programs. Region 9 of the USEPA covers Arizona, California, Hawaii, Nevada, the Pacific Islands subject to U.S. law, and approximately 140 Tribal Nations. USEPA works with state, local, and tribal governments within the region to carry out the nation's environmental laws.

The air impacts analysis may require modeling of the FSRU emissions with a view toward effects on coastal air quality. It is not anticipated that emissions from the FSRU will have any significant effect on coastal air quality within the meaning of the CAA and will not violate any state or national ambient air quality standards.

The Port will also require a Federal Operating Permit under Title V requirements of the CAA. The Applicant will submit the application for a Title V Operating permit to USEPA Region 9, who will administer the permit under 40 CFR Part 71. The Port will also comply with applicable NSPS.

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, the MPRSA 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." These materials include, but are 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.

The Applicant will comply with this Act through compliance with the Clean Water Act. In addition, Project 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 FSRU may create short term “harassment” conditions to sensitive species. Consultation with National Marine Fisheries Services (NMFS), SUFWS, and California Department of Fish and Game (CDFG) staff will be done during preparation of the detailed design. Necessary approvals or permits will be obtained if required before installation.

The California Endangered Species Act (Fish & Game Code §§2050, et seq.) generally parallels the main provisions of the Federal Endangered Species Act and is administered by the CDFG.

State lead agencies, in this case the California State Lands Commission, are required to consult with CDFG to ensure that any action it undertakes is not likely to jeopardize the continued existence of any endangered or threatened species or result in destruction or adverse modification of essential habitat.

CDFG will provide review of records to determine whether state species of concern may be present in the project area.

6.9 Marine Mammal Protection Act

Under the Marine Mammal Protection Act (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 NMFS. 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 FSRU. The Applicant 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 (NHPA), as amended, requires agencies to take into account the effect of their undertakings on properties in or eligible for listing in the NRHP and to afford the Advisory Council on Historic Preservation (ACHP) an opportunity to comment on the undertaking. The Applicant will assist 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 FSRU or the pipeline, 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 will be notified immediately to ascertain the possible cultural significance of the feature encountered.

Section 106 of the National Historic Preservation Act (16 U.S.C. 470(f)) requires that a Federal agency involved in a proposed project or activity is responsible for initiating and completing the review process. Therefore, the USCG must confer with the State Historic Preservation Officer (an official appointed in each State or territory to administer the National Historic Program) and the NHPA.

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 FSRU and proper operation of the FSRU 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 (NGA) as amended, the importation of natural gas into the US requires approval from the U. S. Department of Energy (USDOE). The USDOE is responsible for issuing licenses to import natural gas and LNG from foreign countries. The Office of Fossil Energy (within USDOE) 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 by the Project from foreign sources, an import license may be required at some point in the future by the entity holding title to the gas at the time of its importation. The Applicant does not anticipate applying for an import license at this time, but rather, the LNG importer will apply for an import license at the appropriate time.

6.13 Outer Continental Shelf Lands Act

Under the Outer Continental Shelf Lands Act, the Secretary of the Department of the Interior 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). However, MMS does not have jurisdiction because the Project will not include exploration and production of mineral resources.

Regulatory processes and jurisdictional authority concerning pipelines on the OCS and in coastal areas are shared by several federal agencies, including the U.S. Department of Transportation (USDOT), U.S. Army Corps of Engineers, and 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 is responsible for promulgating and enforcing safety regulations for the transportation in or affecting interstate commerce of 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 USDOT has been designated as having the authority to grant a license for the siting, construction, and operation of a Deepwater Port. The USCG has been designated as the responsible agency under the Act. They in turn will issue regulations for the construction and operation of the Project, including any appurtenant pipelines.

6.14 California Department of Transportation

The California Department of Transportation (Caltrans) is the agency responsible for protecting the public's investment in the State highway system. Caltrans may require written authorization for the use of California State highways for other than normal transportation purposes in the form of an encroachment permit submitted to the offices of Caltrans District 07 in Los Angeles. Caltrans reviews all requests from utility companies, developers, volunteers, nonprofit organizations, etc., desiring to conduct various activities within the right of way, including construction.

6.15 California State Lands Lease

The California State Lands Commission (CSLC) is responsible for classifying any or all state land for its different possible uses, and may require other state agencies to make such classifications. The Mineral Resources Management Division (MRMD) of the CSLC manages the use of energy and mineral resources and leases covering state-owned lands. The MRMD ensures public safety and protects the environment. Public and private entities must apply to the CSLC for leases or permits on State lands for many purposes including tanker anchorages.

For work in harbors and waterways, dredging permits are issued to both public and private parties by the Commission. If the dredged material is to be used for a commercial purpose, a royalty is charged by the Commission.

The Applicant will submit a land lease application to the CSLC for the pipeline in state waters, beginning at high tide water line and extending to three miles offshore. Completed applications submitted to the CSLC are reviewed in conjunction with the EA prior to issuance of a land lease. CSLC staff also makes recommendations for action based upon their review of the Environmental Impact Report.

Section

7

7 Certification Statement

7.1 Statement of Veracity

State of Delaware)
) ss:
)

Stephen F. Billiot, being first duly sworn on his oath disposes and says that he is Vice President of BHP Billiton LNG International Inc., 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.

____

Stephen F. Billiot
Vice President
BHP Billiton LNG International Inc.

Sworn to and subscribed before me this __ day of __, 2003.

____

Notary public _______________

My Commission Expires:

____

ATTACHMENT 1

INCORPORATION DOCUMENTS

ATTACHMENT 2

ANNUAL FINANCIAL STATEMENTS

Date 7 August 2002

Number 47/02

BHP BILLITON FULL YEAR RESULTS FOR THE YEAR ENDED 30 JUNE 2002

Please find attached BHP Billiton's full year results for the year ended 30 June 2002.

Karen Wood
Company Secretary

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Further information can be found on our Internet site: http://www.bhpbilliton.com

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A member of the BHP Billiton group which is headquartered in Australia

BHP BILLITON
FULL YEAR RESULTS FOR THE YEAR ENDED 30 JUNE 2002

- EBITDA robust at US$4.9 billion despite lower revenues.
- Operating cash flow (after interest and tax) maintained at US$3.9 billion despite difficult conditions.
- EBIT US$3.2 billion, attributable profit US$1.9 billion, earnings per ordinary share 32.1 US cents (all excluding exceptional items).
- Merger benefits of US$220 million delivered (before one-off costs).
- Steel demerger completed.
- Exploration successes for Petroleum.
- Quality portfolio offers more stable cash flows in an uncertain world economy.

Year ended 30 June	2002 US$M	2001 US$M	Change %
Turnover (1)	**17 778**	19 079	-6.8%
EBITDA (1)(2)(5)	**4 915**	5 299	-7.2%
EBIT (1)(3)(5)	**3 188**	3 627	-12.1%
Attributable profit			
- excluding exceptional items	**1 934**	2 189	-11.6%
- including exceptional items	**1 690**	1 529	10.5%
Operating cash flow including dividends from joint ventures and associates and after net interest and tax	**3 918**	3 837	2.1%
Basic earnings per share (US cents)			
- excluding exceptional items	**32.1**	36.8	-12.8%
- including exceptional items	**28.0**	25.7	8.9%
EBITDA interest coverage (times) (4)(5)	**11.0**	8.5	29.4%

(1) Including the Group's share of joint ventures and associates.
(2) EBITDA is profit before net interest, taxation, and depreciation and amortisation (excluding impairments).
(3) EBIT is profit before net interest and taxation.
(4) For this purpose, net interest includes capitalised interest and excludes the effect of discounting on provisions and exchange differences arising from net debt.
(5) Excluding exceptional items.

The above financial results are prepared in accordance with UK generally accepted accounting principles (GAAP). Financial results prepared under Australian GAAP are provided on page 26.

All references to the corresponding period are to the year ended 30 June 2001.

PRELIMINARY ANNOUNCEMENT OF RESULTS

FOR THE YEAR ENDED 30 JUNE 2002

CHIEF EXECUTIVE'S REVIEW

The Merger

The merger of BHP Limited and Billiton Plc on 29th June 2001 established a new leader in the global resources sector, one seeking superior shareholder returns as the world's premier supplier of natural resources and related products and services. Merger integration via the "Dual Listed Companies" structure was swift, with the key business units being organised immediately into 6 Customer Sector Groups, supported by 2 marketing hubs - one in The Hague, and one in Singapore. Virtually from the outset, the executive group functioned as a unified team, and performed effectively in the challenging market conditions of the past year.

Along with the smooth integration, five highlights stand out:

- the successful demerger of BHP Steel;
- the approval of 12 new projects involving aggregated capital investments of US$2.9 billion;
- a string of remarkable successes by our Petroleum exploration teams;
- the delivery of merger benefits of $220 million (before one-off costs); and
- the publication of our Strategic Framework in April this year, which detailed the key value drivers which distinguish us from our competitors, the strategic imperatives which will realise our full potential, and 8 performance measures against which we have invited the market to judge us.

The financial results achieved by the management team during the 2002 financial year, BHP Billiton's first as a combined group, are set out below.

Stability and Growth

The central tenet of the BHP Billiton business model is that its diversified portfolio of high quality assets provides more stable cash flows and greater capacity to drive growth than the traditional resource cyclicals. The results of the past year provide striking support for that thesis. Despite price weakness in many of our products, despite currency fluctuations, and canny cut-backs at some of our major operations, our Earnings before Interest, Tax, Depreciation and Amortisation (EBITDA) held steady at around US$1.2 billion in every quarter. Aggregated over the year, EBITDA was US$4,915 million, down only 7.2% on last year's record level notwithstanding much weaker commodity markets.

Even more dramatic was the underlying stability of our operating cash flows (after interest and tax) which held steady at US$3,918 million, despite the generally lower prices.

These strong financials were reflected in other measures: EBITDA interest cover rose from 8.5 times in 2001 to 11.0 times in the reporting year; gearing (net debt to net debt plus equity) declined from 38.4% to 35.0%; and net debt at 30 June 2002 was US$6,822 million, a reduction of US$499 million over the year.

Our robust cash flows left us well placed to proceed methodically with the new growth projects that we flagged to shareholders at the time of the merger. A full list of projects approved this year, totalling US$2.9 billion, is attached.

The Income Statement

The difficult market conditions that prevailed throughout the year were reflected in Group turnover, which fell by 6.8% to US$17,778 million, due to lower commodity prices (for crude oil, aluminium, copper, nickel, chrome, alumina, silver and zinc), lower sales volumes (from Escondida (Chile), Tintaya (Peru), energy coal, crude oil at Bass Strait (Australia), Laminaria (Australia), Griffin (Australia), Samarco (Brazil), manganese and titanium minerals) and lower contributions from ceased and sold operations. These factors were partly offset by contributions from new and acquired operations (including the first full year's results from the various Rio Algom businesses, the energy coal operations in Colombia, the additional 29% interest in Ekati™ diamond mine (Canada) and the additional 56% interest in Worsley alumina refinery (Australia)).

Earnings before interest and tax (EBIT), excluding exceptional items, was US$3,188 million compared with US$3,627 million last year, a reduction of 12.1%. This decline was caused by the lower commodity prices, lower profits from ceased, sold and discontinued operations, increased exploration expenditure, and the impact of inflation on operating costs. Offsetting factors were profits from new and acquired operations, the favourable effect of exchange rate movements, lower price-linked costs, and increased profits from asset sales.

Net interest expense (before exchange gains on net debt) fell to US$429 million from US$625 million in the corresponding period. In fact, net interest including capitalised interest and excluding discounting on provisions, fell from US$625 million to US$445 million. That reduction of US$180 million (28.8%) was principally driven by an improved credit rating, lower average debt levels and lower market interest rates.

Exchange gains on net debt were US$180 million compared with US$149 million in the corresponding period, arising primarily on the year end translation of Rand denominated debt of companies which account in US dollars as their functional currency. The Rand depreciated by 21% during the current period compared with the 16% depreciation in the corresponding period. Approximately Rand 2.9 billion of debt was repaid during the year.

The tax charge for the year (excluding exceptional items) was US$958 million, representing an effective rate of 32.6%. Excluding the impact on tax of non tax-effected foreign currency gains and other functional currency translation adjustments, the effective rate was 32.7%. This rate is above the nominal rate of 30%, mainly due to non tax-effected losses in the current year, non-deductible accounting depreciation and amortisation, and secondary taxes on dividends paid and payable by South African entities, partly offset by the recognition of prior year tax losses.

Attributable profit (excluding exceptional items) was US$1,934 million, down 11.6% from the US$2,189 million of last year. Basic earnings per share was 12.8% lower at 32.1 US cents.

Exceptional Items

Exceptional items totalling US$212 million (before tax) were expensed at year end. These included one-off costs of US$80 million relating to the merger and restructuring of the Group during the year.

Following a reassessment of the Group's asset disposal and closure plans relating to its South West Copper business in the US (where the Group ceased operations in 1999), impairment provisions, principally related to the San Manuel smelter, were increased by US$171 million. This was offset by a reduction of US$70 million in provisions relating to the expected timing of site restoration expenditure.

Sulphide operations at Tintaya (Peru) have been suspended until at least January 2003. An exceptional charge of US$31 million recognised the costs of the suspension and a write-down of obsolete equipment.

In June 2002 a change in legislation increased the corporation taxation rate for oil and gas companies in the United Kingdom from 30% to 40%, resulting in deferred taxation balances being restated, with an adverse impact of US$56 million on the full year's results. The tax effects of other exceptional items were a benefit of US$24 million.

After accounting for these exceptional items, the remaining attributable profit was US$1,690 million, 10.5% higher than the US$1,529 million of last year. Basic earnings per share, including exceptional items, was 28.0 US cents, 8.9% higher than the 25.7 US cents of the corresponding period.

Cash Flows

Capital expenditures and financial investment totalled US$2,621 million for the year. Expenditure on growth projects amounted to US$1,590 million, including Escondida Phase IV, the ROD oil and Ohanet wet gas projects in Algeria, Mozal II and Petroleum projects in the Gulf of Mexico. Maintenance capital expenditure of US$891 million was US$31 million lower than in the previous year. Exploration expenditure was US$390 million, an increase of US$49 million.

Net cash outflow from acquisitions and disposals was US$38 million, including additional investments in Colombian coal assets and Ekati™, less the proceeds from the sale of PT Arutmin (Indonesia).

After dividend payments of US$811 million (up from US$751 million in the prior year), net cash flow (before management of liquid resources and financing) amounted to US$448 million. This inflow compares to an outflow of US$1,977 million in the corresponding period, which included the acquisitions of Rio Algom and the additional 56% interest in the Worsley alumina refinery.

Dividends

An interim dividend of 6.5 US cents per fully paid ordinary share was paid in December 2001 and a final dividend of 6.5 US cents per fully paid ordinary share was paid in July 2002, bringing the total for the year to 13.0 US cents. The BHP Billiton Limited dividends were fully franked for Australian taxation purposes.

The corresponding period for BHP Billiton Limited shareholders included an unfranked interim dividend of 12.1 Australian cents per fully paid share (adjusted for merger bonus issue) and a fully franked final dividend of 12.6 Australian cents per fully paid share (adjusted for merger bonus issue).

The corresponding period for BHP Billiton Plc shareholders included an interim dividend of 4.0 US cents per share and a final dividend of 8.0 US cents per share.

Dividends for the BHP Billiton group are determined and declared in US dollars. However, BHP Billiton Limited dividends are mainly paid in Australian dollars and BHP Billiton Plc dividends are mainly paid in pounds sterling to shareholders on the UK section of the register and South African Rand to shareholders on the South African section of the register. The rates of exchange applicable two business days before the declaration date were used for conversion.

Portfolio Management

The demerger of BHP Steel in July 2002 was a landmark event, severing a link of many decades. The outcome was embraced by both organisations, launching BHP Steel as an independent, world-class steel business and releasing BHP Billiton to focus on its upstream interests. Strong demand for the BHP Steel shares, which were sold through the Sale Facility to participants under the Retail and Institutional offers, took the final price to A$2.80 per BHP Steel share. The 6% retained by BHP Billiton and sold through the Sale Facility brought a cash benefit of US$75 million in July 2002. Accounting rules will see the difference between this selling price and the book value - some US$19 million - appear as a loss in the 2003 financial statements. BHP Billiton Plc shareholders received approximately 149 million bonus shares to match the demerger value distributed to BHP Billiton Limited shareholders.

During the year, we also finalised our responsible exit from the Ok Tedi copper mine in Papua New Guinea, in the process establishing a fund to support the future social and economic development of the people of Papua New Guinea and, in particular of the Western Province. We also announced the sale of our interest in the PT Arutmin Indonesia energy coal operations, and the acquisition, in conjunction with our partners, of the 50% interest in Cerrejon Zona Norte energy coal mine in Colombia, bringing our interest to 33%.

Capital Management

A US$2.5 billion syndicated multi-currency revolving facility was completed in September 2001. This facility replaced the US$1.2 billion credit facility of BHP Billiton Limited and the US$1.5 billion and US$1.25 billion credit facilities of BHP Billiton Plc. The facility includes a US$1.25 billion 364-day revolving credit component, and a US$1.25 billion five-year revolving credit component.

In October 2001, BHP Billiton increased its A$ Commercial Paper Program limit from A$1 billion to A$2 billion. During November 2001, the Group issued A$1 billion in debt securities in two tranches: A$750 million of 7 year, 6.25% notes maturing August 2008; and A$250 million of 3 year, floating rate notes maturing November 2004. In addition a US$1.5 billion Euro Medium Term Note (EMTN) programme was established during June 2002.

In accordance with the announced share buyback program, BHP Billiton Limited re-purchased 4,134,622 shares during the year at a weighted average price of A$8.83 per share. The buyback program allows for the purchase of either BHP Billiton Limited or BHP Billiton Plc shares, up to a limit of 186 million shares.

Merger Benefits and Further Cost Savings

An important target announced at the time of the merger was the pursuit of ongoing benefits of US$270 million (before one-off costs) by the end of financial year 2003. Good progress was made towards this goal, with US$220 million being delivered in the year ended 30 June 2002. These benefits arose in a number of different areas, including Operating Excellence initiatives, strategic sourcing, changes to our marketing activities, access to lower cost finance and widespread operational savings. One-off costs of US$115 million were incurred to deliver the benefits, of which US$80 million has been expensed as an exceptional item.

A further target of US$500 million of cost savings and efficiency gains has been set for the next three years. A major part of this is expected to be delivered through the continuance of our Operating Excellence initiatives, together with savings from simplified structure and processes, economies of scale from centrally-focused marketing activities, and from productivity improvements at ongoing operations.

Exploration Progress for Petroleum

Our Petroleum exploration shows particular promise. We invested US$287 million in exploration and appraisal activities during the year, and were rewarded with a finding cost of US$1.59 per barrel of oil equivalent and a capitalisation rate of 47.4%. Both represent top tier performance.

In the Gulf of Mexico, appraisal wells at Mad Dog and Atlantis were successfully completed, leading to sanction of both projects. The near field discovery at Boris will be tied back to the Typhoon facility. Encouraging discoveries were made at Cascade and Neptune, and will now be further appraised.

In Trinidad, the Kairi and Canteen wells built on our original exploration success in the Angostura field and development work is well advanced to sanction this project during the coming year.

Further leases were acquired in both the Gulf of Mexico and Trinidad whilst new leases were obtained offshore Brunei, South Africa and Brazil.

Corporate Governance

From 1 July 2002, I assumed the role of CEO and Managing Director, replacing Paul Anderson who retired from his executive role on the same date, but who remains on the Board until completion of the Annual General Meetings in November 2002. The Board will pay him tribute at an appropriate function for his outstanding service to this Group.

Messrs. Ben Alberts, John Conde, Derek Keys and Barry Romeril retired from the Board at the end of June 2002. All four contributed much to the decisions of the Group, and particularly to those related to the merger.

The Annual General Meetings of BHP Billiton Limited and BHP Billiton Plc will both be held on Monday 4 November 2002. The meetings will be held in Melbourne and in London simultaneously and will be linked by video.

Outlook

There is cause for concern about the global economy. Although OECD industrial production continues to post small monthly rises, it remains below the levels of a year ago. After some early gains, the US economy is struggling to maintain momentum; growth prospects across Europe remain subdued; and a rising Yen threatens to derail Japan's export led recovery. Business investment and non-residential construction remain weak in the developed economies. Only across Asia does production continue to improve, particularly in South Korea and China where annual growth is approaching eight percent.

In recent weeks extreme volatility in equity markets, falling business and consumer confidence, and heightened risk aversion have cast a pall over the global economic outlook. In reaction, the prices of many traded commodities have fallen to or near multi-month lows. In these circumstances, the executive team will concentrate on the sound management of our businesses, while remaining alert for opportunities that might arise from the turmoil.

Whilst our short-run profits may show volatility due to movements in foreign exchange rates, our accounting practices provide balance sheet stability and proper management of our costs over the long-run. Additionally, our diversified portfolio of high quality assets provides more stable cash flows, leaving us well placed to prosper where others might not.

TRADING REVIEW

EBIT

The following table details the approximate impact of major factors affecting EBIT for the year ended 30 June 2002 compared with the corresponding period.

	Total US$M	Merger benefits included US$M
EBIT for the year ended 30 June 2001	**3,627**	
Change in sales prices	(665)	20
Change in volumes	(165)	5
Price linked costs	270	
Inflation on costs	(210)	
Costs	80	110 (a)
New and acquired operations	185	15
Ceased, sold and discontinued operations	(255)	
Exchange rates	375	
Asset sales	45	
Exploration	(45)	
Other items	(54)	
EBIT for the year ended 30 June 2002	**3,188**	150 (b)

(a) Gross savings of US$145 million, net of one-off costs of US$35 million

(b) Other non-EBIT merger benefits totaling US$35 million were achieved during the year.

Prices

Lower prices for crude oil, aluminium, copper, nickel, chrome, alumina, diamonds, silver and zinc decreased turnover by approximately US$1,035 million. This decrease was partly offset by higher prices for metallurgical coal, energy coal, and gas prices which increased turnover by approximately US$370 million.

Volumes

Lower sales volumes from Base Metals, Carbon Steel Materials, petroleum products, Energy Coal and Titanium Minerals businesses were partly offset by higher sales volumes from the Stainless Steel Materials businesses, resulting in a net volume impact on EBIT of a loss of approximately US$165 million.

Costs

Cost reductions increased EBIT by approximately US$350 million compared with the corresponding period. Lower price linked costs of approximately US$270 million were mainly due to lower royalties and taxes for petroleum products together with lower costs for London Metals Exchange (LME) listed commodities partially offset by increased royalty costs at metallurgical coal operations mainly reflecting higher metallurgical coal prices.

Merger benefit initiatives generated net cost savings of approximately US$110 million during the year.

Costs increased at Escondida (Chile) mainly reflecting the decision to reduce production in response to weaker base metals markets and increased costs at metallurgical coal operations (Australia) and energy coal operations (New Mexico) were due to operational issues. These factors were partly offset by lower operating costs at Liverpool Bay (UK) and Hillside (South Africa), primarily reflecting higher maintenance activities in the corresponding period, cost reductions at the Gulf of Mexico (US) petroleum operations mainly due to increased productivity, and savings at WA Iron Ore operations (Australia) due to lower port and rail costs.

Inflation increased costs by approximately US$210 million.

New and acquired operations

New and acquired operations increased EBIT by approximately US$185 million compared with the corresponding period mainly due to, commencement of production of petroleum from Typhoon (America), Zamzama (Pakistan) and Keith (North Sea), increased ownership interests in the Worsley alumina refinery (Australia) together with the fully commissioned Mozal aluminium smelter (Mozambique), the acquisition of an additional 29% interest in the Ekati™ diamond business, a full years contribution from Rio Algom base metals businesses and the first full year contribution from Carbones del Cerrejon and Cerrejon Zona Norte Coal (Colombia). These factors were partially offset by a downturn in the Integris (formerly Metals Distribution) (US) business compared with the corresponding period.

Ceased, sold and discontinued operations

Steel profits (excluding OneSteel Limited) reduced by approximately US$130 million. The corresponding period included contribution to EBIT of approximately US$125 million from a higher ownership interest in metallurgical coal (Queensland), the sale of Buffalo oilfield (Australia), spun-out steel operations (OneSteel Limited), and the Ok Tedi copper mine (PNG), partly offset by losses from HBI Venezuela. The current period included a lower contribution from PT Arutmin Indonesian energy coal operations due to sale of the business in November 2001.

Foreign exchange

Foreign currency fluctuations had a favourable effect of approximately US$375 million mainly due to the impact of lower Rand/US$ (US$265 million) and A$/US$ (US$85 million) exchange rates on related operating costs and the conversion of monetary assets and liabilities, including provision balances, and reduced losses on legacy A$/US$ currency hedging.

Asset sales

Profits from asset sales were approximately US$45 million higher than the corresponding period mainly due to the profit on sale of PT Arutmin Energy Coal operations in Indonesia.

Exploration

Exploration charged to profit was approximately US$45 million higher than the corresponding period mainly due to the write-off of La Granja copper exploration activities (Peru), together with increased petroleum activity in the Gulf of Mexico.

CUSTOMER SECTOR GROUP SUMMARY

A detailed explanation of the factors influencing EBIT, including joint ventures and associates (excluding exceptional items) by Customer Sector Group, is as follows:

Aluminium

Aluminium contributed EBIT of US$492 million, down from US$523 million, a decrease of 5.9% compared with the corresponding period.

The EBIT reduction was mainly attributable to the lower average LME price for aluminium, down US$180 per tonne or 11.7%, and the decline in production from Alumar and Valesul (Brazil) due to power curtailments.

These factors were partially offset by higher alumina production from Worsley (Australia) following the acquisition of an additional 56% interest in January 2001 together with increased production and profits from the fully commissioned Mozal (Mozambique) aluminium smelter. Lower operating costs were mainly due to the decrease in LME linked production costs together with the favourable effect on related operating costs due to US dollar exchange rate movements against the South African Rand and Brazilian Real.

Base Metals

Base Metals contributed EBIT of US$200 million, down from US$462 million, a decrease of 56.7% compared with the corresponding period.

The EBIT reduction was mainly due to a significant decline in the average realised copper price to US$0.69/lb compared to US$0.78/lb in the corresponding period together with lower volumes at Escondida and Tintaya, reflecting the decision to temporarily reduce production in reaction to the global deterioration of base metals markets. In addition, the current period was adversely impacted by the write-off of the La Granja (Peru) exploration activities.

These factors were partly offset by a full year's contribution from the various Rio Algom operations (Cerro Colorado, Antamina and Highland Valley Copper) which were acquired in October 2000, as well as higher silver and lead volumes at the Cannington (Australia) silver mine resulting from a revision of the mine's production strategy.

Carbon Steel Materials

Carbon Steel Materials contributed EBIT of US$1,084 million, up from US$918 million, an increase of 18.1% compared with the corresponding period.

The increase in EBIT was attributable to increased volumes and higher prices for metallurgical coal, lower operating costs at Mt Whaleback (Australia) iron ore operations due to improved waste ore ratios, and improved operating performance over the year and lower capital expenditure (which is charged to profit) at Boodarie™ Iron (Australia). Operating costs across West Australian iron ore operations were further reduced by improved ship loading rates at Port Hedland (Australia), reflecting the successful application of the Operating Excellence methodology. The favourable effect of the lower A$/US$ and Rand/US$ exchange rates reduced related operating costs.

These factors were partially offset by higher costs at metallurgical coal operations in Queensland due to increased stripping costs at Goonyella, Blackwater, Saraji and Peak Downs, adverse roof conditions at Crinum between August 2001 and December 2001, together with higher royalty costs and higher demurrage costs. Reduced market demand for manganese ore and alloy products, as well as Samarco pellets, resulted in lower sales and prices for these commodities compared with the corresponding period.

On 26 March BHP Billiton declared "force majeure" on sales contracts and some supply contracts at the Boodarie™ Iron Plant. The declaration followed the temporary suspension of work at the plant following a tube failure in a gas re-heating furnace. Production re-commenced in one train on 18 July 2002, with the remaining three trains planned being progressively back on line during the September 2002 quarter.

Agreement was reached in May 2002 with Nippon Steel Corporation (Japan) and Kawasaki Steel Corporation (Japan) for the prices of Mt Newman (West Australia) Iron Ore from the period commencing 1 April 2002. The agreed prices are :-

- Mt Newman Fines – 28.28 US cents per dry long ton unit – a decrease of 2.4%.
- Mt Newman Lump – 36.13 US cents per dry long ton unit – a decrease of 5.0%.

Commercial terms have been settled for the majority of annually priced coking coal contracts relating to the BHP Billiton Mitsubishi Alliance (BMA) and BHP Billiton Mitsui coal operations in Queensland (Australia) and the BHP Billiton Illawarra coal operations (Australia):

- FOB prices for premium hard coking coals have increased to a range of US$48.00 – US$50.00/t across all markets, reflecting strong supply/demand fundamentals following the reduction in export volumes from a number of US operations in 2001/02.
- FOB prices for semi-soft and PCI coals have decreased to a range of US$32.00 - US$33.00/t across all markets. The lower prices largely reflect pressure from Chinese supply and a weaker thermal coal market.
- Volumes are expected to remain steady.

The majority of prices settled with customers are retrospective to 1 April 2002.

Stainless Steel Materials

Stainless Steel Materials contributed EBIT of US$3 million, down from US$72 million, compared with the corresponding period.

The EBIT reduction was driven by lower realised prices for nickel and cobalt by-product, down 17% and 33% respectively, together with lower prices for ferrochrome products due to producers liquidating stock holdings to reduce inventory levels. Ferrochrome prices were also adversely impacted by the devaluation of the South African Rand against the US dollar.

These factors were partly offset by the favourable effect of the lower Rand/US$ exchange rate on related operating costs and the favourable impact from nickel due to increases in production, mainly from the continued ramp-up of Cerro Matoso Line 2, which commenced production on 1 January 2001.

Energy Coal

Energy Coal contributed EBIT of US$536 million, up from US$382 million, an increase of 40.3% compared with the corresponding period.

The increase in EBIT was attributable to a significant increase in export market prices during the first six months of the year, with annual average prices well above prior periods despite a downturn in market conditions in the second half of the year. The benefit of higher priced longer term contracts offset the weakness in spot prices. The current period included the profit on disposal of PT Arutmin (Indonesia) effective 30 November 2001 together with the inclusion of profits from Cerrejon operations (Colombia). An overall reduction in unit cash costs were achieved through cost improvement initiatives despite inflationary pressure in South Africa and reduced production volumes predominantly in South Africa and the United States. In addition, a benefit was derived from the favourable effect of lower Rand/US$ exchange rates on related operating costs and net monetary liabilities.

These factors were partially offset by lower export volumes due to the disposal of PT Arutmin together with weakening of European markets after an unseasonably warm winter and low natural gas prices.

Diamonds and Specialty Products

Diamonds and Specialty Products contributed EBIT of US$272 million, up from US$188 million, an increase of 44.7% compared with the corresponding period.

The increase in EBIT was primarily due to increased profits from Ekati™ diamond mine (Canada) mainly reflecting the acquisition of an additional 29% interest in June 2001 together with increased production due to higher ore grade and higher recoveries of lower quality diamonds. The increase in carat production has been driven by the introduction of the Misery Pipe (higher grade and lower value stones) and the continued optimisation of the process plant. These factors were partially offset by lower diamond prices mainly due to a general downturn in the global economy and lower volumes from the titanium minerals operations primarily reflecting weaker market conditions in the US and Japan.

Petroleum

Petroleum contributed EBIT of US$1,073 million, down from US$1,407 million a decrease of 23.7% compared with the corresponding period.

The reduction in EBIT was due to a lower average realised oil price of US$22.58 per barrel compared to US$28.04 per barrel in the corresponding period together with a lower average realised liquefied petroleum gas (LPG) price US$214.62 per tonne compared to US$299.18 per tonne in the corresponding period. The current period was impacted by reduced crude oil volumes primarily due to natural field decline in the Laminaria, Bass Strait and Griffin oil fields, which were partially offset by infill programs in Bass Strait and Griffin. The corresponding period benefited from a gain on the sale of the Buffalo oil field in March 2001.

These factors were partly offset by inclusion of profits from the Typhoon (US) oil field and the Zamzama gas field (Pakistan), which commenced operations in July 2001 and March 2001 respectively. Natural gas volumes were higher than the corresponding period due to improved performance at Liverpool Bay (UK) together with the commencement of Zamzama operations.

During the year, BHP Billiton sanctioned two oil and gas projects in the Gulf of Mexico (US). The Mad Dog development (BHP Billiton 23.9%) will have a gross design capacity of 80,000 barrels of oil per day and 40 million standard cubic feet of gas per day and contains estimated reserves in the range 200 to 450 million barrels of oil equivalent (mmboe) gross. First production is expected by the end of 2004 calendar year. The Atlantis development (BHP Billiton 44%) has estimated gross proven and probable reserves of 575mmboe making it the third largest field in the Gulf of Mexico deepwater. First production is expected by the end of calendar year 2005.

Steel (Discontinued)

BHP Steel Limited (BHP Steel) legally separated from the BHP Billiton Group on 22 July 2002, having listed on the Australian Stock Exchange on 15 July 2002.

As at 30 June 2002, BHP Steel was a business unit of the BHP Billiton Group and its 2002 and comparative financial results are reflected in the BHP Billiton combined group results. However, the Steel Segment reported does not reflect the demerged BHP Steel results due to the Steel Segment being reported under UK GAAP, in US dollars.

Steel contributed EBIT of US$101 million, down from US$270 million, a decrease of 62.6% compared with the corresponding period.

The EBIT reduction was mainly due to lower international prices for steel products and the exclusion of operating profits from disposed businesses (primarily OneSteel Limited) which were included in the corresponding period.

These factors were partly offset by stronger Australian domestic demand for value added coated products and the profit on sale of the Australian and US strapping businesses.

Group & Unallocated Items

The net costs of Group and Unallocated Items, excluding losses from legacy A$/US$ currency hedging was, US$242 million compared with US$235 million in the corresponding period.

Group and Unallocated Items includes losses on legacy A$/US$ currency hedging of approximately US$331 million compared with losses of US$360 million in the corresponding period. These losses mainly reflect the lower value of hedge settlement rates compared with hedge contract rates for currency hedging contracts settled during the year.

GROWTH PROJECTS

BHP Billiton has committed approximately US$2.9 billion to new growth projects since the merger was consummated on 29 June 2001.

All references to production volumes and capital expenditure are BHP Billiton's share, unless otherwise stated.

Customer Sector Group	Project	Capital Expenditure US$M	Production	Completion
Aluminium	**Mozal 2 expansion** Mozambique BHP Billiton 47.1%	405	120,000 tonnes per annum of aluminium metal	Initial production late 2003
	Hillside 3 expansion South Africa BHP Billiton 100%	449	132,000 tonnes per annum of aluminium metal	Initial production mid 2004
Carbon Steel Materials	**Mining Area C** Australia BHP Billiton 85%	181	15 million tonnes per annum of iron ore by 2011 (100%)	Initial production late 2003
	Port & capacity expansion Australia BHP Billiton 85%	299	Increase in port capacity to 81 millions of tonnes per annum by 2004 (100%)	Late 2004
	Dendrobium Australia BHP Billiton 100%	170	5.2 million tonnes per annum of raw metallurgical coal	Initial production mid 2005
Energy Coal	**Mt Arthur North** Australia BHP Billiton 100%	411	12.1 million tonnes per annum of saleable energy coal	Initial production late 2003
Petroleum	**Mag Dog oil and gas field** US BHP Billiton 23.9%	335	20,000 boe/day	Initial production late 2004
	Atlantis oil and gas field US BHP Billiton 44%	355	66,000 boe/day	Initial production late 2005
	Gulf of Mexico transportation system US BHP Billiton 22-25%	100	Pipeline capacities (100%) Oil - 450,000 bbls per day Gas - 500,000 million standard cubic feet per day	Commissioning late 2004
	Minerva gas field Australia BHP Billiton 90%	123	150 terrajoules of gas per day	Initial production early 2004
	Zamzama gas field Pakistan BHP Billiton 47.5%	40	300 million cubic feet of gas per day	Initial production mid 2003
	Bream gas pipeline Australia BHP Billiton 50%	50	15 million bbls over 10 years	Initial production mid 2003
		2,918		

FINANCIAL INFORMATION

The financial information in this document for the year ended 30 June 2002 is unaudited, has been derived from the draft financial statements of BHP Billiton Plc and does not constitute the statutory accounts of BHP Billiton Plc for that year.

With effect from 1 July 2001, the majority of BHP Billiton Limited's businesses changed their functional currency to US dollars, the functional currency of the combined BHP Billiton Group. This is consistent with BHP Billiton Plc's previous policy and is the basis on which the combined BHP Billiton Group manages its businesses. Most BHP Billiton commodities are sold in US dollars and are predominantly destined for export markets. BHP Billiton's reporting currency is US dollars.

Concurrent with this change, the BHP Billiton Group has changed its policy regarding the treatment of foreign exchange gains or losses on local currency site restoration provisions held in the accounts of entities using US dollar functional currencies. Under the previous policy, the foreign exchange gains and losses on site restoration provisions were recognised in the profit and loss account. Under the revised policy, such foreign exchange gains and losses are treated as part of the revision to the estimated future restoration cost and are included in the cost of tangible fixed assets. The revised policy has been adopted as it better matches the ultimate cost of site restoration charged in the profit and loss account to the profit earned. The impact in the year ended 30 June 2002 has been the capitalisation to tangible fixed assets of foreign exchange losses of US$40 million. The application of the revised policy to prior periods does not have a material impact on the comparative profit and loss account or balance sheet figures and no prior period adjustment has been made.

In the opinion of the Directors, the financial information for the year ended 30 June 2002, presents fairly the financial position, results of operations and cash flows for the periods in conformity with UK generally accepted accounting principles. The financial information for the year ended 30 June 2001 has been derived from the audited financial statements of BHP Billiton Plc for that period as filed with the Registrar of Companies and does not constitute the statutory accounts of BHP Billiton Plc for that period. The auditors' report on the statutory accounts for the year ended 30 June 2001 was unqualified and did not contain statements under Section 237 (2) (regarding adequacy of accounting records and returns) or under Section 237 (3) (provision of necessary information and explanations) of the United Kingdom Companies Act 1985. The statutory accounts for the year ended 30 June 2002 will be finalised on the basis of the financial information presented by the Directors in this preliminary announcement and will be delivered to the Registrar of Companies following the Annual General Meeting.

The combined results for the year ended 30 June 2002, prepared in accordance with UK GAAP, are generally consistent with the combined results under Australian GAAP as required by the Australian Securities and Investments Commission in respect of dual listed companies. However, in contrast to UK GAAP, Australian regulatory requirements do not allow the combination of the results of BHP Billiton Limited with those of BHP Billiton Plc for periods prior to consummation of the DLC merger on 29 June 2001. Financial results prepared in accordance with Australian GAAP are provided on page 26.

Consolidated Profit and Loss Account

for the year ended 30 June 2002

	Note	Year ended 30 June 2002			Year ended 30 June 2001		
		Excluding Exceptional Items US$M	Exceptional Items (Note 1) US$M	Including Exceptional Items US$M	Excluding Exceptional Items US$M	Exceptional Items (Note 1) US$M	Including Exceptional Items US$M
Turnover (including share of joint ventures' and associates' turnover)	3	**17 778**	-	**17 778**	19 079	-	19 079
Less: share of joint ventures' and associates' turnover included above		**(1 872)**	-	**(1 872)**	(1 290)	-	(1 290)
Group turnover		**15 906**	-	**15 906**	17 789	-	17 789
- continuing operations		**13 562**	-	**13 562**	14 771	-	14 771
- discontinued operations	2	**2 344**	-	**2 344**	3 018	-	3 018
Net operating costs		**(13 192)**	**(212)**	**(13 404)**	(14 551)	(60)	(14 611)
Group operating profit		**2 714**	**(212)**	**2 502**	3 238	(60)	3 178
- continuing operations		**2 655**	**(212)**	**2 443**	3 005	(38)	2 967
- discontinued operations	2	**59**	-	**59**	233	(22)	211
Share of operating profit/(loss) of joint ventures and associates [a]		**340**	-	**340**	281	(634)	(353)
Operating profit (including share of profit of joint ventures and associates)		**3 054**	**(212)**	**2 842**	3 519	(694)	2 825
Income from other fixed asset investments - continuing operations		**37**	-	**37**	28	-	28
- discontinued operations	2	**1**	-	**1**	4	-	4
Profit on sale of fixed assets - continuing operations		**13**	-	**13**	71	128	199
- discontinued operations	2	**15**	-	**15**	1	-	1
Profit on sale of subsidiaries - continuing operations		**68**	-	**68**	4	-	4
Loss on termination of operations - continuing operations [b]		-	-	-	-	(430)	(430)
Merger transaction costs - continuing operations		-	-	-	-	(92)	(92)
Net interest and similar items payable - Group	4	**(212)**	-	**(212)**	(407)	(6)	(413)
- Joint ventures and associates	4	**(37)**	-	**(37)**	(63)	-	(63)
Profit before taxation	3	**2 939**	**(212)**	**2 727**	3 157	(1 094)	2 063
Taxation	5	**(958)**	**(32)**	**(990)**	(943)	132	(811)
Profit after taxation		**1 981**	**(244)**	**1 737**	2 214	(962)	1 252
Equity minority interests		**(47)**	-	**(47)**	(25)	302	277
Profit for the financial period (attributable profit)		**1 934**	**(244)**	**1 690**	2 189	(660)	1 529
Dividends to shareholders		**(784)**	-	**(784)**	(754)	-	(754)
Retained profit for the financial period		**1 150**	**(244)**	**906**	1 435	(660)	775
Earnings per ordinary share (basic) (US cents) [c]		**32.1**	**(4.1)**	**28.0**	36.8	(11.1)	25.7
Earnings per ordinary share (diluted) (US cents) [d]		**32.1**	**(4.1)**	**28.0**	36.6	(11.0)	25.6
Dividend per ordinary share							
BHP Billiton Plc (US cents)				**13.0**			12.0
BHP Billiton Limited (US cents)				**13.0**			
BHP Billiton Limited (Australian cents) [e]							24.7

[a] In the year ended 30 June 2001, the exceptional share of operating losses of joint ventures and associates includes the impairment of HBI Venezuela (US$520 million).

[b] In the year ended 30 June 2001, the exceptional loss on termination of operations relates to the Ok Tedi copper mine.

[c] The calculation of basic earnings per ordinary share is based on earnings after tax and minority interests of US$1,690 million (30 June 2001: $1,529 million) and the weighted average number of ordinary shares outstanding of 6,029 million (30 June 2001: 5,944 million).

[d] The weighted average number of shares used for the calculation of diluted earnings per share has been adjusted for the effect of Restricted Share Scheme awards, Co-Investment Plan awards, Employee Share Plan options and Executive Share Scheme partly paid shares, to the extent they were dilutive at balance date. Performance based rights and options are excluded, except where an issue of shares is expected to occur.

[e] The BHP Billiton Limited dividend for the year ended 30 June 2001 was declared in Australian cents. The amounts shown above are adjusted for the BHP Billiton Limited bonus issue effective 29 June 2001.

Consolidated Statement of Total Recognised Gains and Losses
for the year ended 30 June 2002

	Year ended 30 June 2002 US$M	Year ended 30 June 2001 US$M
Attributable profit for the financial period	**1 690**	1 529
Exchange gains and losses on foreign currency net investments	**25**	(763)
Total recognised gains for the period	**1 715**	766

Consolidated Balance Sheet
as at 30 June 2002

		Note	As at 30 June 2002 US$M	As at 30 June 2001 US$M
Fixed assets				
Intangible assets	- goodwill		**42**	95
	- negative goodwill		**(33)**	(36)
			9	59
Tangible assets			**20 179**	19 231
Investments	- joint ventures		**1 468**	1 011
	- share of gross assets		**2 902**	2 816
	- share of gross liabilities		**(1 434)**	(1 805)
	- associates		**85**	58
	- loans to joint ventures and associates and other investments		**987**	911
			22 728	21 270
Current assets				
Stocks			**1 457**	1 675
Debtors			**3 751**	3 583
- amounts due within one year			**2 554**	2 547
- amounts due after one year			**1 197**	1 036
Investments			**117**	215
Cash including money market deposits		7	**1 499**	1 285
			6 824	6 758
Creditors: amounts falling due within one year			**(6 229)**	(5 235)
Net current assets			**595**	1 523
Total assets less current liabilities			**23 323**	22 793
Creditors: amounts falling due after more than one year			**(5 987)**	(7 054)
Provisions for liabilities and charges			**(4 654)**	(4 019)
Net assets			**12 682**	11 720
Equity minority interests			**(326)**	(380)
Attributable net assets			**12 356**	11 340
Capital and reserves				
Called up share capital - BHP Billiton Plc			**1 160**	1 160
Share premium account - BHP Billiton Plc			**592**	592
Contributed equity - BHP Billiton Limited			**3 143**	3 039
Profit and loss account			**7 461**	6 549
Equity shareholders' funds		6	**12 356**	11 340

Consolidated Statement of Cash Flows
for the year ended 30 June 2002

	Year ended 30 June 2002 US$M	Year ended 30 June 2001 US$M
Net cash inflow from Group operating activities (a)	**4 641**	4 805
Dividends received from joint ventures and associates	**149**	154
Interest paid	**(496)**	(587)
Dividends paid on redeemable preference shares	**(35)**	(69)
Interest received	**156**	132
Other dividends received	**38**	39
Dividends paid to minorities	**(20)**	(50)
Net cash outflow from returns on investments and servicing of finance	**(357)**	(535)
Taxes paid	**(606)**	(587)
Refund of taxes paid	**91**	-
Taxation	**(515)**	(587)
Available cash flow	**3 918**	3 837
Purchases of tangible fixed assets	**(2 481)**	(3 038)
Exploration expenditure	**(390)**	(341)
Disposals of tangible fixed assets	**200**	339
Purchase of investments and funding of joint ventures	**(182)**	(677)
Sale of investments and repayments by joint ventures	**232**	82
Capital expenditure and financial investment	**(2 621)**	(3 635)
Investment in subsidiaries	**(45)**	(1 567)
Sale of subsidiaries	**190**	372
Net cash acquired with subsidiary	**-**	117
Cash transferred on disposal	**(45)**	(61)
Investment in joint ventures	**(208)**	(482)
Disposal of joint ventures	**70**	193
Acquisitions and disposals	**(38)**	(1 428)
Equity dividends paid	**(811)**	(751)
Net cash flow before management of liquid resources and financing	**448**	(1 977)
Management of liquid resources	**157**	242
Debt due within one year – repayment of loans	**(1 344)**	(668)
Debt due within one year – drawdowns	**1 657**	849
Debt due after one year – repayment of loans	**(2 722)**	(998)
Debt due after one year – drawdowns	**2 318**	2 072
Finance lease obligations	**(28)**	(4)
Redeemable preference shares	**(423)**	(425)
Net cash (outflow)/inflow from debt and lease financing	**(542)**	826
Share buyback scheme - BHP Billiton Plc	**-**	194
Share repurchase scheme - BHP Billiton Limited	**(19)**	-
Issue of shares	**104**	743
Net cash (outflow)/inflow from financing	**(457)**	1 763
Increase in cash in the period	**148**	28

Consolidated Statement of Cash Flows (continued)
for the year ended 30 June 2002

Reconciliation of net cash flow to movement in net debt	Year ended 30 June 2002 US$M	Year ended 30 June 2001 US$M
Increase in cash in the period	**148**	28
Cash flow from debt and lease financing	**542**	(826)
Cash flow from management of liquid resources	**(157)**	(242)
Change in net debt arising from cash flows	**533**	(1 040)
Money market deposits and loans acquired with subsidiaries	**-**	(665)
Exchange adjustments	**(34)**	476
Movement in net debt	**499**	(1 229)
Net debt at start of period	**(7 321)**	(6 092)
Net debt at end of period	**(6 822)**	(7 321)

(a) Net cash inflow from Group operating activities

Operating profit	**2 502**	3 178
Merger transaction costs	**-**	(92)
Depreciation and amortisation	**1 727**	1 672
Impairment of assets	**272**	34
Employee share awards	**28**	46
Net exploration charge (excluding impairment of assets)	**243**	250
Loss on sale of fixed assets	**-**	21
Payments relating to HBI Venezuela guarantee	**-**	(310)
Decrease in stocks	**7**	41
Increase in debtors	**(346)**	(141)
Increase in creditors	**292**	115
(Decrease)/increase in provisions	**(119)**	28
Other movements	**35**	(37)
Net cash inflow from Group operating activities	**4 641**	4 805

1. Exceptional items

Year ended 30 June 2002	Gross US$M	Tax US$M	Net US$M
Base Metals:			
Impairment of South West Copper assets	(171)	-	(171)
Reassessment of South West Copper closure provisions	70	-	70
Charges associated with suspension of Tintaya sulphide operations	(31)	9	(22)
Change in UK taxrate on petroleum operations	-	(56)	(56)
Merger restructuring costs and provisions	(80)	15	(65)
Total by category	(212)	(32)	(244)
Exceptional items by segment			
Aluminium	(4)	-	(4)
Base metals	(145)	10	(135)
Carbon steel materials	(6)	1	(5)
Stainless steel materials	(3)	-	(3)
Energy coal	(5)	1	(4)
Diamonds and specialty products	(6)	2	(4)
Petroleum	(4)	1	(3)
Group and unallocated items	(39)	9	(30)
Taxation	-	(56)	(56)
Total by customer sector group	(212)	(32)	(244)

Year ended 30 June 2001	Gross US$M	Tax US$M	Net US$M
Profit on sale of fixed assets (equalisation of Queensland Coal interests)	128	-	128
Termination of operations (Ok Tedi copper mine)	(430)	14	(416)
Merger transaction costs	(92)	-	(92)
Taxation (income tax audit)	-	(33)	(33)
Sale of Mozal II expansion rights [(a)]	61	(21)	40
Merger and other restructuring costs and provisions [(a)(b)]	(64)	16	(48)
Employee share awards accelerated by the merger [(a)]	(37)	10	(27)
Write down in carrying value of assets (Lakes Mines) [(a)]	(26)	6	(20)
Write down in carrying value of assets and provisions (HBI Venezuela) [(c)]	(520)	110	(410)
Write down in carrying value of assets (Columbus JV) [(c)]	(114)	30	(84)
Total by category	(1 094)	132	(962)
Exceptional items by segment			
Aluminium	53	(19)	34
Base metals	(8)	2	(6)
Carbon steel materials	126	2	128
Stainless steel materials	(123)	31	(92)
Energy coal	(34)	8	(26)
Diamonds and specialty products	(13)	3	(10)
Steel [(b)]	(22)	7	(15)
Group and unallocated items [(d)]	(1 067)	98	(969)
Net interest	(6)	-	(6)
Total by customer sector group	(1 094)	132	(962)

(a) Included in operating profit with the exception of charges of $6 million (no tax effect) of merger and other restructuring costs in 2001 which were charged against net interest and other similar items payable.
(b) Includes amounts attributable to discontinued operations of US$22 million (US$15 million after tax).
(c) Included in share of operating profit/(loss) of joint ventures and associates.
(d) Includes exceptional items in relation to HBI Venezuela and Ok Tedi which were previously reported in Carbon Steel Materials and Base Metals, respectively.

2. Discontinued Operations

Due to the demerger of the BHP Steel business in July 2002, BHP Steel's results have been reported as discontinued operations, together with the results of the OneSteel business which was demerged from BHP Billiton in October 2000.

The profit and loss impact of these businesses, as included in the BHP Billiton financial statements is detailed below. As BHP Billiton operate treasury and tax functions on a Group basis, disclosure of net interest and tax expense information for the BHP Steel results is not meaningful and has therefore not been included. These businesses comprise the majority of the Steel segment (refer Note 3).

Profit and Loss Account	2002 US$M	2001 US$M
Turnover (including share of joint ventures and associates)	**2 550**	3 213
Less: share of joint ventures and associates turnover included above	**(206)**	(195)
Group turnover	**2 344**	3 018
Net operating costs *	**(2 285)**	(2 807)
Group operating profit	**59**	211
Share of operating profit of joint ventures and associates	**11**	2
Operating profit (including share of profit of joint ventures and associates)	**70**	213
Income from other fixed asset investments	**1**	4
Profit on sale of fixed assets	**15**	1
Profit before net interest and taxation	**86**	218

* Included within operating costs in 2001 is a charge for exceptional items of US$22 million (before tax) relating to restructuring costs and provisions. There were no exceptional items in 2002.

The BHP Billiton Group demerged the BHP Steel business in July 2002 as follows:

- A capital reduction and a transfer to BHP Billiton Limited shareholders of 94% of the shares in BHP Steel;
- A bonus issue of BHP Billiton Plc shares to BHP Billiton Plc shareholders as a Matching Action to ensure economic benefit equality to shareholders of both BHP Billiton Limited and BHP Billiton Plc (the bonus issue was one BHP Billiton Plc share for approximately each 15.6 BHP Billiton Plc shares held); and
- The sale by the BHP Billiton Group of the remaining 6% of BHP Steel shares held by the Group.

The impact of these steps (which have been recorded in July 2002) is:

- The BHP Billiton Group's capital was reduced by approximately US$1,501 million, including approximately US$19 million of costs directly associated with the demerger;
- A cash inflow of approximately US$369 million, representing net US$294 million from the settlement by BHP Steel of intercompany loans, together with US$75 million from the sale of the 6% of BHP Steel; and
- A loss of approximately US$19 million (no tax effect) relating to the sale of the 6% of BHP Steel.

BHP Steel is the leading steel company in Australia and New Zealand, specialising in the production of flat steel products, including slab, hot rolled coil, plate and value-added metallic coated and pre-painted steel products. The company supplies customers in Australia, New Zealand, Asia, the US, Europe, the Middle East and the Pacific. Key steel-making assets are the low-cost global scale Port Kembla Steelworks (Australia), BHP New Zealand Steel and North Star BHP Steel (USA). A network of metallic coating and coil painting facilities operates in Australia, New Zealand and South East Asia.

The attributable net assets of BHP Steel as included in the BHP Billiton Group's 30 June 2002 balance sheet is provided below. In addition, the estimated net assets demerged in July 2002 are provided, after allowing for the settlement of intercompany loans by BHP Steel to the BHP Billiton Group.

Balance Sheet	2002 US$M
Tangible Assets	**1 881**
Investments	**91**
Current Assets	**759**
Creditors falling due within one year	**(345)**
Creditors falling due after more than one year and provisions	**(495)**
	1 891
Equity minority interests	**(21)**
Attributable net assets as at 30 June 2002	**1 870**
Net payments to the BHP Billiton Group by BHP Steel to settle intercompany loans (post 30 June 2002)	**(294)**
Estimated attributable net assets of BHP Steel to be demerged	**1 576**

3. Segmental analysis by business

Turnover	Year ended 30 June 2002 US$M	Year ended 30 June 2001 US$M
Aluminium	**2 857**	2 971
Base metals	**1 821**	1 719
Carbon steel materials	**3 306**	3 349
Stainless steel materials	**868**	994
Energy coal	**1 919**	1 982
Diamonds and specialty products	**1 480**	1 318
Petroleum	**2 815**	3 361
Steel	**2 785**	3 760
Group and unallocated items	**495**	209
Intersegment	**(568)**	(584)
	17 778	19 079

Profit before taxation

Aluminium	**492**	523
Base metals	**200**	462
Carbon steel materials	**1 084**	918
Stainless steel materials	**3**	72
Energy coal	**536**	382
Diamonds and specialty products	**272**	188
Petroleum	**1 073**	1 407
Steel	**101**	270
Group and unallocated items	**(573)**	(595)
Exceptional items	**(212)**	(1 088)
	2 976	2 539
Net interest	**(249)**	(476)
	2 727	2 063

Net operating assets

Aluminium	**4 727**	4 730
Base metals	**4 077**	3 795
Carbon steel materials	**2 573**	2 387
Stainless steel materials	**1 663**	1 736
Energy coal	**2 092**	1 986
Diamonds and specialty products	**1 620**	1 488
Petroleum	**2 865**	2 504
Steel	**2 044**	2 130
Group and unallocated items	**644**	956
	22 305	21 712

Trading activities included above

Turnover

Aluminium	**1 006**	1 014
Base metals	**24**	13
Carbon steel materials	**22**	40
Stainless steel materials	**9**	6
Energy coal	**108**	100
Diamonds and specialty products	**823**	797
Petroleum	-	-
Steel	-	-
Group and unallocated items	-	-
	1 992	1 970

Profit before taxation

Aluminium	**13**	14
Base metals	-	-
Carbon steel materials	**3**	1
Stainless steel materials	**1**	-
Energy coal	**4**	6
Diamonds and specialty products	**9**	23
Petroleum	-	-
Steel	-	-
Group and unallocated items	-	-
	30	44

3. Segmental analysis by business (continued)

A new segment, Diamonds and Specialty Products, has been created encompassing Diamonds, Titanium Minerals, Integris (metals distribution) and Exploration & Technology. As a consequence, the former Exploration, Technology and New Business and Other Activities segments ceased to exist and any remaining portions have been included in Group and Unallocated Items. In addition, HBI Venezuela and Ok Tedi, previously reported in Carbon Steel Materials and Base Metals, respectively, are now included in Group and Unallocated Items. Comparatives have been restated accordingly.

4. Net interest and similar items payable

	Year ended 30 June 2002 US$M	Year ended 30 June 2001 US$M
On bank loans and overdrafts	**(161)**	(236)
On all other loans	**(311)**	(339)
Finance lease and hire purchase interest	**(5)**	(9)
	(477)	(584)
Dividends on redeemable preference shares	**(39)**	(83)
Discounting on provisions	**(42)**	(39)
Less amounts capitalised	**58**	39
	(500)	(667)
Share of interest of joint ventures and associates	**(71)**	(94)
	(571)	(761)
Other interest receivable	**142**	136
	(429)	(625)
Exchange differences on net debt - Group	**146**	118
- Joint ventures and associates	**34**	31
	180	149
Net interest and similar items payable (a)	**(249)**	(476)

(a) Disclosed in the Consolidated Profit and Loss Account as:

Net interest and similar items payable - Group	**(212)**	(413)
- Joint ventures and associates	**(37)**	(63)
Net interest and similar items payable	**(249)**	(476)

5. Taxation

	Year ended 30 June 2002 US$M	Year ended 30 June 2001 US$M
Profit before taxation	**2 727**	2 063
Taxation on profit @ 30%	**818**	619
Permanent differences:		
Investment and development allowance	**(10)**	(19)
Non-tax effected capital gains	**(12)**	(63)
Recognition of prior year tax losses	**(103)**	(133)
Tax rate differential	**(1)**	57
Non-tax effected operating losses	**69**	47
Prior year adjustments / under or over provisions	**(23)**	5
Non-deductible accounting depreciation and amortisation	**54**	32
Foreign expenditure including exploration not presently deductible	**16**	57
Non-deductible dividends on redeemable preference shares	**13**	24
South African secondary tax on companies	**48**	46
Foreign exchange gains and other translation adjustments	**(2)**	(113)
Tax rate changes	**59**	(22)
Investment and asset impairments	**32**	176
Non-deductible merger transaction costs	**-**	28
Other permanent differences	**32**	70
Permanent differences	**172**	192
Timing differences	**(218)**	50
Current taxation charge for the period	772	861
Timing differences	**218**	(50)
Taxation charge for the period (including exceptional items)	**990**	811

6. Reconciliation of movements in shareholders' funds

	Year ended 30 June 2002 US$M	Year ended 30 June 2001 US$M
Profit for the financial period	**1 690**	1 529
Other recognised gains and losses	**25**	(763)
Total recognised gains	**1 715**	766
Dividends	**(784)**	(754)
Issue of ordinary shares for cash	**104**	744
Capital reduction on OneSteel spin-out	**-**	(650)
Share buy-back scheme - BHP Billiton Plc	**-**	194
- BHP Billiton Limited	**(19)**	-
Transfer to profit and loss account (goodwill)	**-**	4
Net movement in shareholders' funds	**1 016**	304
Shareholders' funds at start of period	**11 340**	11 036
Shareholders' funds at end of period	**12 356**	11 340

7. Analysis of movement in net debt

	As at 1 July 2001 US$M	Acquisitions & disposals US$M	Cashflow US$M	Other non-cash movements US$M	Exchange movements US$M	**As at 30 June 2002 US$M**
Cash at bank and in hand	836	(45)	411	-	(3)	**1 199**
Overdrafts	(287)	-	(218)	-	(4)	**(509)**
	549	(45)	193	-	(7)	**690**
Redeemable preference shares	(890)	-	423	-	17	**(450)**
Finance lease obligations	(63)	-	28	-	-	**(35)**
Other debt due within one year	(1 432)	-	(313)	(574)	43	**(2 276)**
Other debt due after one year	(5 934)	-	404	574	(95)	**(5 051)**
	(8 319)	-	542	-	(35)	**(7 812)**
Money market deposits	449	-	(157)	-	8	**300**
	(7 321)	(45)	578	-	(34)	**(6 822)**
The balance sheet movement in cash including money market deposits is as follows:						
Cash at bank and in hand	836	(45)	411	-	(3)	**1 199**
Money market deposits	449	-	(157)	-	8	**300**
	1 285	(45)	254	-	5	**1 499**

BHP Billiton Group Financial Results under Australian GAAP

Year ended 30 June 2002	**US$ Million**
Revenue from ordinary activities	
Sales	15 896
Other revenue	1 166
	17 062
Profit from ordinary activitites before depreciation, amortisation and borrowing costs	4 852
Deduct: Depreciation and amortisation	1 753
Borrowing costs	449
Profit from ordinary activities before tax	2 650
Deduct: Tax expense attributable to ordinary activities	955
Net profit	1 695
Outside equity interests in net profit	(47)
Net profit attributable to members of combined BHP Billiton Group	**1 648**
Basic earnings per fully paid ordinary share (cents)	27.3

Basis of Preparation

The results of the BHP Billiton Group, comprising BHP Billiton Limited and BHP Billiton Plc, for the year ended 30 June 2002 have been prepared in accordance with Australian GAAP and Practice Note 71 'Financial reporting by Australian entities in dual listed company arrangements' issued by the Australian Securities and Investments Commission (ASIC). Australian regulatory requirements do not allow the combination of the results of BHP Billiton Limited with those of BHP Billiton Plc for periods prior to consummation of the DLC merger on 29 June 2001.

The financial information has been prepared using the same accounting policies as were used in preparing the results for the BHP Billiton Limited Group as presented in the BHP Billiton Limited financial statements for the year ended 30 June 2001, except as noted below.

With effect from 1 July 2001, the majority of BHP Billiton Limited's businesses changed their functional currency to US dollars, the functional currency of the combined BHP Billiton Group. This is consistent with BHP Billiton Plc's previous policy and is the basis on which the combined BHP Billiton Group manages its businesses. Most BHP Billiton commodities are sold in US dollars and are predominantly destined for export markets. BHP Billiton's reporting currency is US dollars.

Concurrent with this change, the BHP Billiton Group has changed its policy regarding the treatment of foreign exchange gains or losses on local currency site restoration provisions held in the accounts of entities using US dollar functional currencies. Under the previous policy, the foreign exchange gains and losses were recognised in the profit and loss account. Under the revised policy, such foreign exchange gains and losses are treated as part of the revision to the estimated future restoration cost and are included in the cost of property, plant and equipment. The revised policy has been adopted as it better matches the ultimate cost of site restoration charged in the profit and loss account to the profit earned. The impact in the year ended 30 June 2002 has been the capitalisation to property, plant and equipment of foreign exchange losses of US$40 million.

The results are subject to audit.

BHP BILLITON FULL YEAR REPORT 30 JUNE 2002
SUPPLEMENTARY INFORMATION

Customer Sector Group Results

Yearly Comparison 30 June 2002 vs 30 June 2001

BHP BILLITON GROUP

Year ended 30 June 2002

	US$ Million							
	Turnover (1)	EBIT (2) excluding exceptional items	Exceptional items	EBIT (2) including exceptional items	Net operating assets	Capex (3)(4)	Exploration gross (5)(6)	Exploration to profit (6)
Aluminium	2 857	492	(4)	488	4 727	291	-	-
Base metals	1 821	200	(145)	55	4 077	630	20	53
Carbon steel materials	3 306	1 084	(6)	1 078	2 573	284	8	8
Stainless steel materials	868	3	(3)	-	1 663	84	7	16
Energy coal	1 919	536	(5)	531	2 092	295	5	-
Diamonds and speciality products	1 480	272	(6)	266	1 620	165	62	59
Petroleum	2 815	1 073	(4)	1 069	2 865	711	288	151
Steel	2 785	101	-	101	2 044	100	-	-
Group and unallocated items (7)	495	(573)	(39)	(612)	644	261	-	-
BHP Billiton Group	**17 778**	**3 188**	**(212)**	**2 976**	**22 305**	**2 821**	**390**	**287**

Year ended 30 June 2001

	US$ Million							
	Turnover (1)	EBIT (2)(8) excluding exceptional items	Exceptional items	EBIT (2)(8) including exceptional items	Net operating assets	Capex (4)	Exploration gross (5)(6)	Exploration to profit (6)
Aluminium	2 971	523	53	576	4 730	1 635	1	1
Base metals	1 719	462	(8)	454	3 795	2 103	56	19
Carbon steel materials	3 349	918	126	1 044	2 387	383	5	5
Stainless steel materials	994	72	(123)	(51)	1 736	212	7	4
Energy coal	1 982	382	(34)	348	1 986	545	6	2
Diamonds and speciality products	1 318	188	(13)	175	1 488	419	63	75
Petroleum	3 361	1 407	-	1 407	2 504	459	206	144
Steel	3 760	270	(22)	248	2 130	69	-	-
Group and unallocated items (7)	209	(595)	(1 067)	(1 662)	956	610	-	-
BHP Billiton Group	**19 079**	**3 627**	**(1 088)**	**2 539**	**21 712**	**6 435**	**344**	**250**

(1) Turnover does not add to the BHP Billiton Group figure due to inter-segment transactions.
(2) EBIT is earnings before net interest and taxation.
(3) Capex in aggregate comprises US$1,930 million growth and US$891 million sustaining.
(4) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(5) Includes US$147 million (2001:US$112 million) capitalised exploration.
(6) Includes US$44 million (2001:US$18 million) exploration expenditure previously capitalised, now written off.
(7) Includes consolidation adjustments and unallocated items.
(8) Certain items have been restated between Customer Sector Groups.

Customer Sector Group Results - Full Year Comparison

ALUMINIUM

Year ended 30 June 2002

	US $ Million							
	Turnover	EBITDA [1]	Depn & amortisation	EBIT [2]	Net Operating assets [3]	Capex [4][5]	Exploration gross	Exploration to profit
Alumina	661	278	106	172	2 210	37		
Aluminium	1 396	435	128	307	2 517	254		
Intra-divisional adjustment	(206)	-	-	-	-	-		
Third party products	1 006	13	-	13	-	-		
Total	**2 857**	**726**	**234**	**492**	**4 727**	**291**	**-**	**-**

Year ended 30 June 2001

	US $ Million							
	Turnover	EBITDA [1]	Depn & amortisation	EBIT [2]	Net Operating assets [3]	Capex [5]	Exploration gross	Exploration to profit
Alumina	520	260	72	188	2 190	1 525		
Aluminium	1 566	447	126	321	2 540	110		
Intra-divisional adjustment	(129)	-	-	-	-	-		
Third party products	1 014	14	-	14	-	-		
Total	**2 971**	**721**	**198**	**523**	**4 730**	**1 635**	**1**	**1**

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$230 million growth and US$61 million sustaining.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.

Production ('000 tonnes)	2002	2001	Change %
Alumina	3 942	2 938	34.2
Aluminium	992	984	0.8

Customer Sector Group Results - Full Year Comparison

BASE METALS

Year ended 30 June 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross (6)	Exploration to profit (7)
Escondida	658	242	101	141	1 899	388		
Tintaya	81	(1)	31	(32)	380	120		
Cerro Colorado	209	102	72	30	697	43		
Antamina (8)	181	22	-	22	718	52		
Alumbrera (8)	126	32	-	32	223	-		
Cannington	322	127	23	104	271	20		
Highland Valley Copper (8)	116	2	-	2	121	-		
Other businesses (9)	104	(93)	6	(99)	(232)	7		
Third party products	24	-	-	-	-	-		
Total	**1 821**	**433**	**233**	**200**	**4 077**	**630**	**20**	**53**

Year ended 30 June 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross (6)	Exploration to profit
Escondida	853	415	104	311	1 609	231		
Tintaya	157	26	29	(3)	284	47		
Cerro Colorado	167	86	49	37	694	2		
Antamina (8)	-	-	-	-	707	46		
Alumbrera (8)	44	22	-	22	273	-		
Cannington	302	110	25	85	260	11		
Highland Valley Copper (8)	46	3	-	3	131	-		
Other businesses (9)	137	16	9	7	(163)	16		
Third party products	13	-	-	-	-	-		
Total	**1 719**	**678**	**216**	**462**	**3 795**	**2 103**	**56**	**19**

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$465 million growth and US$165 million sustaining. Total capital expenditure for 2001 does not add to the Base Metals total as this reflects the acquisition of Rio Algom Limited for US$1,750 million (before deduction of assumed debt) which has not been allocated between the various operations.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(6) Includes US$2 million (2001: US$37 million) capitalised exploration.
(7) Includes US$35 million (2001: US$nil million) exploration expenditure previously capitalised, now written off.
(8) Equity accounted investments.
(9) Includes Selbaie, Pering and the North America copper mining and smelting operations (which ceased operations during the September 1999 quarter).

Production ('000 tonnes)	**2002**	**2001**	**Change %**
Payable metal in concentrate	586.6	578.0	1.5
Copper cathode	237.7	206.9	14.9

Customer Sector Group Results - Full Year Comparison

CARBON STEEL MATERIALS

Year ended 30 June 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross	Exploration to profit
WA Iron Ore	1 056	574	68	506	935	89		
Samarco (6)	170	55	-	55	314	-		
Total Iron Ore	1 226	629	68	561	1 249	89		
Queensland	1 193	531	67	464	697	118		
Illawarra	293	87	19	68	113	22		
Total Metallurgical Coal	1 486	618	86	532	810	140		
Manganese	509	148	29	119	373	23		
Boodarie™ Iron	133	(116)	-	(116)	(14)	32		
Divisional activities	(48)	(12)	-	(12)	155	-		
Total	**3 306**	**1 267**	**183**	**1 084**	**2 573**	**284**	**8**	**8**

Year ended 30 June 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (5)	Exploration gross	Exploration to profit
WA Iron Ore	1 059	524	80	444	877	27		
Samarco (6)	224	71	-	71	334	-		
Total Iron Ore	1 283	595	80	515	1 211	27		
Queensland	1 161	445	63	382	643	286		
Illawarra	257	73	17	56	105	12		
Total Metallurgical Coal	1 418	518	80	438	748	298		
Manganese	548	128	26	102	413	27		
Boodarie™ Iron	91	(136)	-	(136)	16	31		
Divisional adjustment	(31)	(2)	-	(2)	(1)	-		
Third party products	40	1	-	1	-	-		
Total	**3 349**	**1 104**	**186**	**918**	**2 387**	**383**	**5**	**5**

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$126 million growth and US$158 million sustaining.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(6) Equity accounted investment.
(7) Includes intra-divisional activities and third party products.

Production (Millions tonnes)	**2002**	**2001**	**Change %**
Iron ore	67.9	65.9	3.0
Metallurgical coal	35.5	37.1	(4.3)
Manganese alloys	0.619	0.644	(3.9)
Manganese ores	3.535	3.774	(6.3)

Customer Sector Group Results - Full Year Comparison

BASE METALS

Year ended 30 June 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross (6)	Exploration to profit (7)
Escondida	658	242	101	141	1 899	388		
Tintaya	81	(1)	31	(32)	380	120		
Cerro Colorado	209	102	72	30	697	43		
Antamina (8)	181	22	-	22	718	52		
Alumbrera (8)	126	32	-	32	223	-		
Cannington	322	127	23	104	271	20		
Highland Valley Copper (8)	116	2	-	2	121	-		
Other businesses (9)	104	(93)	6	(99)	(232)	7		
Third party products	24	-	-	-	-	-		
Total	**1 821**	**433**	**233**	**200**	**4 077**	**630**	**20**	**53**

Year ended 30 June 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross (6)	Exploration to profit
Escondida	853	415	104	311	1 609	231		
Tintaya	157	26	29	(3)	284	47		
Cerro Colorado	167	86	49	37	694	2		
Antamina (8)	-	-	-	-	707	46		
Alumbrera (8)	44	22	-	22	273	-		
Cannington	302	110	25	85	260	11		
Highland Valley Copper (8)	46	3	-	3	131	-		
Other businesses (9)	137	16	9	7	(163)	16		
Third party products	13	-	-	-	-	-		
Total	**1 719**	**678**	**216**	**462**	**3 795**	**2 103**	**56**	**19**

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$465 million growth and US$165 million sustaining. Total capital expenditure for 2001 does not add to the Base Metals total as this reflects the acquisition of Rio Algom Limited for US$1,750 million (before deduction of assumed debt) which has not been allocated between the various operations.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(6) Includes US$2 million (2001: US$37 million) capitalised exploration.
(7) Includes US$35 million (2001: US$nil million) exploration expenditure previously capitalised, now written off.
(8) Equity accounted investments.
(9) Includes Selbaie, Pering and the North America copper mining and smelting operations (which ceased operations during the September 1999 quarter).

Production ('000 tonnes)	**2002**	**2001**	**Change %**
Payable metal in concentrate	586.6	578.0	1.5
Copper cathode	237.7	206.9	14.9

Customer Sector Group Results - Full Year Comparison

CARBON STEEL MATERIALS

Year ended 30 June 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross	Exploration to profit
WA Iron Ore	1 056	574	68	506	935	89		
Samarco (6)	170	55	-	55	314	-		
Total Iron Ore	1 226	629	68	561	1 249	89		
Queensland	1 193	531	67	464	697	118		
Illawarra	293	87	19	68	113	22		
Total Metallurgical Coal	1 486	618	86	532	810	140		
Manganese	509	148	29	119	373	23		
Boodarie™ Iron	133	(116)	-	(116)	(14)	32		
Divisional activities	(48)	(12)	-	(12)	155	-		
Total	**3 306**	**1 267**	**183**	**1 084**	**2 573**	**284**	**8**	**8**

Year ended 30 June 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (5)	Exploration gross	Exploration to profit
WA Iron Ore	1 059	524	80	444	877	27		
Samarco (6)	224	71	-	71	334	-		
Total Iron Ore	1 283	595	80	515	1 211	27		
Queensland	1 161	445	63	382	643	286		
Illawarra	257	73	17	56	105	12		
Total Metallurgical Coal	1 418	518	80	438	748	298		
Manganese	548	128	26	102	413	27		
Boodarie™ Iron	91	(136)	-	(136)	16	31		
Divisional adjustment	(31)	(2)	-	(2)	(1)	-		
Third party products	40	1	-	1	-	-		
Total	**3 349**	**1 104**	**186**	**918**	**2 387**	**383**	**5**	**5**

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$126 million growth and US$158 million sustaining.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(6) Equity accounted investment.
(7) Includes intra-divisional activities and third party products.

Production (Millions tonnes)	**2002**	**2001**	**Change %**
Iron ore	67.9	65.9	3.0
Metallurgical coal	35.5	37.1	(4.3)
Manganese alloys	0.619	0.644	(3.9)
Manganese ores	3.535	3.774	(6.3)

Customer Sector Group Results - Full Year Comparison

STAINLESS STEEL MATERIALS

Year ended 30 June 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross (6)	Exploration to profit (7)
Nickel	447	88	64	24	1 312	57		
Chrome	342	7	25	(18)	287	27		
Other (8)	70	(4)	-	(4)	64	-		
Third party products	9	1	-	1	-	-		
Total	**868**	**92**	**89**	**3**	**1 663**	**84**	**7**	**16**

Year ended 30 June 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (5)	Exploration gross (6)	Exploration to profit (7)
Nickel	457	133	52	81	1 300	169		
Chrome	375	32	30	2	298	43		
Columbus Stainless Steel	156	(11)	-	(11)	138	-		
Third party products	6	-	-	-	-	-		
Total	**994**	**154**	**82**	**72**	**1 736**	**212**	**7**	**4**

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$30 million growth and US$54 million sustaining.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(6) Includes US$nil (2001 : US$3 million) capitalised exploration.
(7) Includes US$9 million (2001:US$nil million) exploration expenditure previously capitalised, now written off.
(8) The Group's remaining interest in Columbus Stainless Steel and the investment in Acerinox SA. are accounted for as a fixed asset investment.

Production ('000 tonnes)	**2002**	**2001**	**Change %**
Nickel	68.9	60.8	13.3
Chrome Ores	2 451	3 158	(22.4)

Customer Sector Group Results - Full Year Comparison

ENERGY COAL

Year ended 30 June 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross (6)	Exploration to profit
Ingwe	983	419	117	302	970	85		
New Mexico	418	108	30	78	238	99		
Hunter Valley	132	44	17	27	265	110		
Indonesia	135	108	12	96	(6)	1		
Colombia (7)	129	35	-	35	642	-		
Divisional activities	-	(11)	-	(11)	(17)	-		
Third party products	122	9	-	9	-	-		
Total	**1 919**	**712**	**176**	**536**	**2 092**	**295**	**5**	**-**

Year ended 30 June 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (5)	Exploration gross (6)	Exploration to profit
Ingwe	1 039	328	105	223	1 131	105		
New Mexico	409	127	37	90	169	51		
Hunter Valley	129	26	14	12	176	17		
Indonesia	222	63	28	35	117	1		
Colombia (7)	83	16	-	16	393	371		
Divisional activities	-	-	-	-	-	-		
Third party products	100	6	-	6	-	-		
Total	**1 982**	**566**	**184**	**382**	**1 986**	**545**	**6**	**2**

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$226 million growth and US$69 million sustaining.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(6) Includes US$5 million (2001:US$4 million) capitalised exploration.
(7) Equity accounted investment.

Production (Millions tonnes)	**2002**	**2001**	**Change %**
Energy coal	82.8	92.8	(10.8)

Customer Sector Group Results - Full Year Comparison

DIAMONDS AND SPECIALTY PRODUCTS

Year ended 30 June 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (4)(5)	Exploration gross (6)	Exploration to profit
Ekati[TM]	393	249	69	180	976	152		
Other businesses (8)	1 076	173	5	168	683	4		
Exploration and Technology	11	(74)	2	(76)	(39)	9		
Total	**1 480**	**348**	**76**	**272**	**1 620**	**165**	**62**	**59**

Year ended 30 June 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (2)	Net operating assets (3)	Capex (5)	Exploration gross (6)	Exploration to profit (7)
Ekati[TM]	241	154	26	128	913	405		
Other businesses (8)	1 067	189	7	182	619	11		
Exploration and Technology	10	(117)	5	(122)	(44)	3		
Total	**1 318**	**226**	**38**	**188**	**1 488**	**419**	**63**	**75**

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$97 million sustaining and US$68 million growth.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(6) Includes US$3 million (2001:US$6 million) capitalised exploration.
(7) Includes US$nil (2001:US$18 million) exploration expenditure previously capitalised, now written off.
(8) Includes the titanium minerals businesses and Integris metals businesses (both equity accounted investments).

Production ('000 carats)	2002	2001	Change %
Ekati[TM] diamonds	3 650	1 429	155.4

Customer Sector Group Results - Full Year Comparison

PETROLEUM

Year ended 30 June 2002

	US$ Million							
	Turnover (1)	EBITDA (2)	Depn & amortisation	EBIT (3)	Net operating assets (4)	Capex (5)(6)	Exploration gross (7)	Exploration to profit
Australia/Asia	1 943	1 223	228	995	1 371	236		
Bass Strait	953	513	103	410	455	109		
North West Shelf	616	464	56	408	818	75		
Americas	262	223	139	84	621	186		
UK/Middle East	538	449	197	252	993	289		
Exploration/Business Development	-	(172)	-	(172)	-	-		
Other	72	(79)	7	(86)	(120)	-		
Total	**2 815**	**1 644**	**571**	**1 073**	**2 865**	**711**	**288**	**151**

Year ended 30 June 2001

	US$ Million							
	Turnover (1)	EBITDA (2)	Depn & amortisation	EBIT (3)	Net operating assets (4)	Capex (6)	Exploration gross (7)	Exploration to profit
Australia/Asia	2 583	1 647	262	1 385	1 346	111		
Bass Strait	1 149	633	91	542	422	55		
North West Shelf	731	535	54	481	850	43		
Americas	213	118	63	55	472	166		
UK/Middle East	508	421	166	255	614	173		
Exploration/Business Development	-	(144)	-	(144)	-	-		
Other	57	(135)	9	(144)	72	9		
Total	**3 361**	**1 907**	**500**	**1 407**	**2 504**	**459**	**206**	**144**

(1) Petroleum turnover includes: Crude oil US$1,757 million (2001:US$2,321 million), Natural gas US$418 million (2001:US$358 million), LNG US$274 million (2001:US$291 million), LPG US$153 million (2001:US$198 million) and Other US$213 million (2001:US$193 million).
(2) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(3) EBIT is earnings before net interest and taxation (excluding exceptional items).
(4) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(5) Capex in aggregate comprises US$529 million growth and US$182 million sustaining.
(6) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(7) Includes US$137 million (2001:US$62 million) capitalised exploration.

Production	2002	2001	Change %
Crude oil and condensate (Millions bbls)	78.5	79.1	(0.7)
Natural gas (bcf) (excluding liquefied natural gas)	223.9	205.1	9.2
Liquefied natural gas (bcf)	59.6	56.7	5.1

Customer Sector Group Results - Full Year Comparison

STEEL

Year ended 30 June 2002

	US$ Million							
	Turnover	EBITDA [1]	Depn & amortisation	EBIT [2]	Net operating assets [3]	Capex [4][5]	Exploration gross	Exploration to profit
Flat Products [6]	1 397	130	72	58	1 189	45		
Coated Products	1 635	133	58	75	950	51		
Discontinued operations	-	-	-	-	(78)	1		
Intra-divisional adjust	(727)	(8)	-	(8)	(26)	-		
Divisional activities	94	(37)	1	(38)	9	2		
Transport & Logistics	386	20	6	14	-	1		
Total	**2 785**	**238**	**137**	**101**	**2 044**	**100**	-	-

Year ended 30 June 2001

	US$ Million							
	Turnover	EBITDA [1]	Depn & amortisation	EBIT [2]	Net operating assets [3]	Capex [5]	Exploration gross	Exploration to profit
Flat Products [6]	1 485	131	80	51	1 233	35		
Coated Products	1 790	214	59	155	876	23		
Discontinuing operations [7]	498	47	20	27	(55)	8		
Intra-divisional adjust	(944)	28	-	28	(17)	-		
Divisional activities	40	(21)	1	(22)	(8)	-		
Transport & Logistics	891	45	14	31	101	3		
Total	**3 760**	**444**	**174**	**270**	**2 130**	**69**	-	-

Steel has been presented above in the same manner as it has been in previous reporting periods. Steel will be demerged effective 1 July 2002.
Details of the demerging BHP Steel business can be found in the BHP Billiton preliminary announcement for the year ending 30 June 2002.

(1) EBITDA is earnings before net interest, taxation, and depreciation and amortisation.
(2) EBIT is earnings before net interest and taxation (excluding exceptional items).
(3) Net operating assets comprises all assets and liabilities with the exception of balances related to net debt, taxation and dividends.
(4) Capex in aggregate comprises US$nil growth and US$100 million sustaining.
(5) Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.
(6) Includes North Star BHP Steel, an equity accounted investment.
(7) Includes the Long Products business (OneSteel Limited) which ceased to report results from November 2000 following spin-out.

Production ('000 tonnes)	2002	2001	Change %
Raw steel	5 306	5 432	(2.3)
Marketable steel products	5 381	5 507	(2.3)

(excluding discontinuing businesses)

Debt Analysis

The breakdown of net debt by currency is as follows:

	US$M
Net debt denominated in:	
US dollars	4 631
South African rand	348
Australian dollars	1 451
Canadian dollars	301
Other currencies	91
Net debt	**6 822**

	US$M
Debt maturity	
Matures < 1 year	1 205
Matures 1 - 2 years	136
Matures 2 - 5 years	4 234
Matures > 5 years	2 179
Total	7 754

Debt Rating

	Long Term	Short Term
Standard & Poors	A	A-1
Moody's	A3	P2

Currency

Currency fluctuations affect the profit and loss account in two principal ways.

Sales are predominantly based on US dollar pricing (the principal exceptions being Petroleum's gas sales, Steel's sales to Australian customers and Energy Coal's sales to South African domestic customers). However, a proportion of operating costs (particularly labour) arises in local currency of the operations, most significantly the Australian dollar and South African rand, but also the Brazilian real and Chilean peso and Colombian peso. Accordingly, changes in the exchange rates between these currencies and the US dollar can have significant impact on the Group's reported results.

Several subsidiaries hold certain monetary assets and liabilities denominated in currencies other than their functional currency (US dollars), in particular non-US dollar denominated debt, tax liabilities and provisions. Monetary assets and liabilities are converted into US dollars at the closing rate. The resultant difference are accounted for in the profit and loss account in accordance with UK GAAP.

The following exchange rates have been utilised in this report:

Versus US dollar	Year ended 31 June 2002 average	Year ended 31 June 2001 average	31 June 2002	As at 31 Dec 2001	31 June 2001
South African rand	10.03	7.16	10.25	11.89	8.08
Australian dollar	1.91	1.87	1.77	1.96	1.98
Brazilian real	2.50	2.01	2.82	2.32	2.30
Chilean peso	672.1	577.0	697.6	654.8	631.8
Colombian peso	2,487	2,233	2,399	2,310	2,297
Canadian dollar	1.56	1.52	1.50	1.58	1.52

ATTACHMENT 3

INTERIM FINANCIAL REPORT

Company Secretary

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24 February 2003

Australian Stock Exchange
Company Announcements Office
4th Floor, 20 Bridge Street
SYDNEY NSW 2000

BHP Billiton Limited – Australian GAAP Interim Report and Appendix 4B

Please find attached the Interim Report for BHP Billiton Limited for BHP Billiton Limited for the half year ended 31 December 2002 prepared in accordance with Australian Generally Accepted Accounting Principles (GAAP), which includes disclosures to satisfy Appendix 4B requirements.

Karen Wood
Company Secretary

Att

BHP Billiton Limited
Interim Report

For The Half Year Ended 31 December 2002

Prepared in Accordance with Australian Generally Accepted Accounting Principles (GAAP)

CONTENTS

Notes to financial statements

All amounts are expressed in US dollars unless otherwise stated.

DIRECTORS' REPORT

The Directors present their report together with the interim condensed financial statements for the half year ended 31 December 2002 and the auditors' review report thereon.

REVIEW OF OPERATIONS

Stability and Growth

These results build on the progress made since the merger and illustrate the continued success of the Customer Sector Group business model and the Company's strategy. In a period of global economic weakness and despite self imposed cut-backs at some of our operations, financial results have remained solid and cash flow generation from our portfolio of high quality assets is strong. We have exceeded our merger benefits target six months ahead of schedule and have delivered further cost savings against our additional target of US$500 million.

Strong operational cash flow (after interest and tax) of US$1,189 million has enabled us to proceed with sanctioned growth projects. Progress on all projects continues to be on or ahead of schedule and budget. Notable milestones were reached during the half year with the mechanical completion and commissioning of Escondida Phase IV (Chile), the commencement of operations at the San Juan underground project (US) and the commencement of natural gas flow through the Bream gas pipeline in Bass Strait (Australia). Currently 13 major capital projects are under development, including the recently approved Atlantis full field development in the Gulf of Mexico.

Strong cash flows enabled the Board to increase dividends paid to shareholders by 7.7% compared with the half year ended 31 December 2001 (the "corresponding period"). A dividend of 7.0 US cents per share was paid on 4 December 2002.

Financial Results

<u>Group Result</u>

The profit after tax attributable to BHP Billiton shareholders for the half year ended 31 December 2002 was US$891 million (31 December 2001 US$1,177 million). Basic earnings per share were 14.4 US cents (31 December 2001 19.5 US cents). This included the loss on sale of the remaining 6% interest in the Group's Steel business following demerger of that business in July 2002 which has been disclosed as a significant item in the half year ended 31 December 2002. The contribution of the Group's Steel business in the corresponding period has been disclosed as discontinued operations (Refer note 3 to the financial statements). There were no significant items reported in the half year ended 31 December 2001.

Revenue was US$7,277 million, compared with US$8,825 million for the corresponding period, mainly due to the demerger of the Group's Steel business in July 2002. For other information relating to revenue, refer below under Petroleum, Aluminium, Base Metals, Carbon Steel Materials, Stainless Steel Materials, Energy Coal, Diamonds and Specialty Products and Group and Unallocated Items.

Profit from ordinary activities before taxation was US$1,275 million compared with a profit of US$1,696 million for the corresponding period. There were a number of factors which affected the results for current half year including:

- Foreign currency fluctuations had an unfavourable effect of approximately US$450 million compared with the corresponding period. This was principally due to foreign exchange losses on conversion of Rand denominated monetary assets and liabilities at balance date, with the Rand appreciating by 16% during the current period compared with a depreciation of 47% in the corresponding period. The conversion of A$ denominated monetary assets and liabilities and the impact of the stronger A$/US$ exchange rates on operating costs also had an unfavourable impact on profit. This was partly offset by reduced losses on legacy A$/US$ currency hedging compared with the corresponding period and lower average Rand/$US and Colombian peso/US$ exchange rate impacts on operating costs.

- Inflationary pressures, principally in South Africa, increased costs by approximately US$140 million.

- Ceased, sold and discontinuing businesses had an unfavourable effect on profit before taxation of approximately US$135 million, mainly due to the demerger of the Group's Steel business, and the inclusion in the corresponding period of profits from PT Arutmin which was divested in November 2001 and the Rietspruit energy coal mine which was closed in May 2002.

- Increases in price linked costs depressed profits by approximately US$50 million, mainly due to higher royalties and taxes for petroleum products.

- The impact of asset sales is a reduction in profits of approximately US$60 million mainly from the divestment of PT Arutmin in the corresponding period and the loss on sale of 6% of the Group's Steel business in the current period.

These factors were partly offset by:

- Higher sales volumes of iron ore, energy coal, diamonds and aluminium partly offset by lower sales volumes of petroleum products, resulting in a positive net volume impact on profits of approximately US$130 million.

- Higher prices for petroleum products, nickel, copper, manganese, metallurgical coal and chrome increased turnover by approximately US$290 million. This increase was partly offset by lower prices for export energy coal, diamonds, iron ore and aluminium that decreased turnover by approximately US$230 million.

- Exploration expense was down by approximately US$90 million. The prior period included the write off of exploration expenditure at La Granja (Peru) and higher exploration expense in Petroleum.

- Favourable operating cost performance increased profits by approximately US$80 million compared with the corresponding period. The Group's cost reduction initiatives and reduced maintenance costs at Hillside (South Africa) lowered costs by approximately US$190 million. These factors were partially offset by higher costs at Escondida, due to voluntary restraints on production, maintenance outages and higher depreciation from the start-up of Phase IV. Higher operating costs at Bass Strait, increased depreciation charges in Energy Coal (as a result of a review of asset lives) and in Petroleum also had an unfavourable impact on operating costs.

Refer below to the discussions relating to the relevant Customer Sector Groups for other factors affecting the December 2002 results.

Depreciation and amortisation expense decreased US$77 million to US$807 million in the current half year. This was mainly due to the lower depreciation expense as a direct result of the demerger of the Group's Steel business in July 2002.

Borrowing costs decreased US$115 million to US$144 million in the current half year. Including capitalised interest, total borrowing costs decreased US$79 million to US$195 million, principally driven by lower market interest rates and lower average debt levels.

The tax expense for the period ended 31 December 2002 was US$367 million, compared with US$497 million for the period ended 31 December 2001. The effective taxation rate for the current half year was 28.8% compared with 29.3% in the corresponding period, while the nominal taxation rate was 30% for the current half year.

Segment Results

Petroleum

Petroleum contributed US$650 million to profit before tax, up from US$568 million, an increase of 14.4% compared with the corresponding period.

The increase in profit before tax was due mainly to a higher average realised oil price of US$27.19 per barrel compared to US$22.54 per barrel in the corresponding period, together with lower exploration costs in the current period and higher volumes at North West Shelf (Australia) due to timing of shipments and strong production.

These factors were partly offset by lower overall sales and production volumes at Liverpool Bay (UK) due to scheduled maintenance, and lower production at Bass Strait and Laminaria (Australia), due to natural field decline. An increase in price-linked costs (royalties and taxes), higher depreciation and an increase in costs at Bass Strait also had an unfavourable impact on profit before tax.

Aluminium

Aluminium contributed US$242 million to profit before tax, up from US$233 million, an increase of 3.9% compared with the corresponding period.

The increase in profit before tax was mainly attributable to improved operational cost performance at Hillside, Worsley and Alumar, resulting from increased production and reduced maintenance costs. Increased production at Hillside and Worsley was mainly attributable to the continued success of Operating Excellence projects and increased production at Alumar was due to the end of power restrictions in Brazil. Lower maintenance costs at Hillside were mainly a result of a lower number of pots being relined in the current period, combined with the absence of the net costs associated with the September 2001 power outage. The weakening of the Rand/US$ and Brazilian Real/US$ average exchange rates also had a favourable impact on operating costs.

These factors were partially offset by foreign exchange losses arising on conversion of Rand denominated tax provisions at balance date, compared with foreign exchange gains in the corresponding period. The lower average LME price for aluminium, down US$17 per tonne or 1.3% to US$1,332 per tonne and the strengthening of the A$/US$ exchange rate also had an unfavourable impact on profits.

Base Metals

Base Metals contributed US$53 million to profit before tax, up from US$51 million, an increase of 3.9% compared with the corresponding period.

The increase in profits was mainly attributable to lower exploration expense with US$38 million relating to the write off of La Granja included in the corresponding period. Also contributing to the increase in profits was the higher average realised copper price at US$0.68 per lb, for the half year ended 31 December 2002, compared to US$0.65 per lb in the corresponding period. Profits also benefited from a full six months of operations from Antamina. Commercial production at Antamina commenced in October 2001.

These factors were partially offset by increased unit costs at Escondida due to the ramp-up of Phase IV production and lower existing plant throughput resulting from maintenance outages. Production cutbacks at Escondida and Tintaya (Peru) were partially offset by the completion of the Phase IV expansion in October 2002.

Carbon Steel Materials

Carbon Steel Materials contributed US$490 million to profit before tax, down from US$550 million, a decrease of 10.9% compared with the corresponding period.

The decrease in profits was mainly attributable to the unfavourable impact of stronger A$/US$ exchange rates on operating costs compared to the corresponding period. Lower iron ore prices, following the contract settlements announced in May 2002, also unfavourably impacted profits.

These factors were partially offset by continued strong demand for Western Australian iron ore from Asian markets, which resulted in record production and shipping during the December 2002 half year. Increased demand during the current half year for Samarco (Brazil) pellets also had a favourable impact on profits.

Diamonds and Specialty Products

Diamonds and Specialty Products contributed US$84 million to profit before tax, down from US$144 million, a decrease of 41.7% compared with the corresponding period.

The decrease in profit before tax was mainly attributable to foreign exchange losses arising from conversion of Rand denominated tax provisions and debt at balance date, compared with foreign exchange gains in the corresponding period. Profits were also unfavourably impacted by lower average realised diamond prices (down 28%) as a result of a change in product mix compared with the corresponding period and during the current period Integris' volumes have been adversely affected by market conditions in North America.

These factors were partially offset by increased diamond production, mainly due to increased plant throughput and processing efficiencies. Cost efficiencies were achieved by Integris Metals (US) subsequent to the merger of BHP Billiton's and Alcoa Metals' metals distribution businesses on 1 November 2001.

Energy Coal

Energy Coal contributed US$94 million to profit before tax, down from US$391 million, a decrease of 76.0% compared with the corresponding period.

The decrease in profits was primarily due to the foreign exchange losses arising from conversion of Rand denominated monetary liabilities at balance date, compared with foreign exchange gains in the corresponding period, and a significant decline in export market prices. The divestment of PT Arutmin in November 2001 and the closure of the Rietspruit mine in May 2002 had an unfavourable impact on profits with both the exclusion of the results of these operations in the current period and the profit on sale of PT Arutmin recorded in the corresponding period. The unit cost impact from lower Colombian production volumes in response to depressed European market conditions, higher depreciation charges as a result of a review of asset lives and inflationary pressure on costs in South Africa and Colombia also had an unfavourable impact on profits.

These factors were partially offset by higher sales volumes at Ingwe (South Africa) and Hunter Valley (Australia), the inclusion of profits from the additional share of the Cerrejon Zona Norte operation and cost improvement initiatives across all Energy Coal operations.

Stainless Steel Materials

Stainless Steel Materials contributed US$58 million to profit before tax, compared with a loss of US$25 million in the corresponding period.

The increase in profits was driven by higher realised prices for nickel, up by 29%. In addition, a 12% increase in ferrochrome production, associated with the restart of idle furnaces in the period in response to increasing market demand, and a 15% increase in nickel production reflecting the continued ramp-up of production from Cerro Matoso Line 2 (Colombia) improved results. Benefits from ongoing improvement programs at both Cerro Matoso and QNI (Australia) and the impact of the weaker average Rand/US$ exchange rates on operating costs also had a favourable impact on profits.

Group and Unallocated

Corporate overheads for the half year decreased by US$24 million (after taking account of inflation and exchange impacts) to US$100 million. Losses on legacy A$/US$ currency hedging also decreased to US$95 million from US$176 million in the corresponding period, which were partly offset by the unfavourable impact of one-off items.

Equity Minority Interests

The share of net profit or loss attributable to equity minority interests was US$17 million compared with US$22 million in the corresponding period.

Dividend

On 4 December 2002, a dividend of 7.0 US cents per share was paid to BHP Billiton Limited and BHP Billiton Plc shareholders, which represents an increase of 7.7% compared with the corresponding period. The BHP Billiton Limited dividend was fully franked for Australian taxation purposes.

Dividends for the BHP Billiton group are determined and declared in US dollars. However, BHP Billiton Limited dividends are mainly paid in Australian dollars and BHP Billiton Plc dividends are mainly paid in sterling to shareholders on the UK section of the register and South African rand to shareholders on the South African section of the register.

Capital Management

The Group's inaugural Eurobond issue, under the US$1.5 billion Euro Medium Term Note programme established in June 2002, took place in early October 2002. The issue of €750 million five year notes, which were swapped into US dollars, was oversubscribed and priced at the lower end of market expectations. The success of this issue, in light of the then prevailing market conditions, is a clear reflection of the Group's strong credit profile.

The US$1.25 billion 364 day revolving credit component of the US$2.5 billion syndicated multi-currency revolving credit facility that was due for expiry in September 2002 was extended for a further period of 364 days to September 2003.

In October 2002, Moody's Investor Services upgraded the Group's long term credit rating to A2 from A3 and short term credit rating to P-1 from P-2. This upgrade reflects the successful combination of the Group's operations following the merger in June 2001, the benefit of a substantially diversified portfolio and our continued focus on maintaining disciplined financial policies. Standard & Poor's rating for the Group remains on positive watch after being upgraded in September 2001 to its current long term credit rating of A and short term credit rating of A-1.

Merger Benefits and Further Cost Savings

During the year ended 30 June 2002, merger benefits (before one-off costs) of US$220 million were delivered. A further US$65 million of merger-related benefits have been achieved during the six months to 31 December 2002, bringing the total to US$285 million. This exceeds our target for merger synergies, set at the time of the merger, of US$270 million by the end of financial year 2003, and has been achieved six months ahead of schedule. One-off costs of US$130 million in total were incurred to deliver these on-going annual benefits, US$15 million of which were incurred in the current period.

A further target, to achieve additional annual cost savings and efficiency gains of US$500 million by June 2005, was set in our Strategic Framework last April. This target, to be measured by looking at commodity based unit costs using the year ended 30 June 2001 as the base year, will be delivered through the continuation of our Operating Excellence programme and productivity improvements, ongoing strategic sourcing and marketing initiatives. During the six months to December 2002, we achieved savings and efficiency gains of US$70 million in addition to the merger benefits set out above, largely as a result of Operating Excellence initiatives in our Aluminium, Base Metals and Stainless Steel Materials CSGs and other productivity gains in our Aluminium and Diamonds and Specialty Products CSGs.

Cash Flows

Net operating cash flows (after interest and tax) remained strong at US$1,189 million.

Expenditure on growth projects and investments amounted to US$1,020 million, including Petroleum projects in the Gulf of Mexico, the Mt Arthur North energy coal project in Australia, the ROD oil and Ohanet wet gas projects in Algeria, the Mining Area C, Yandi and Port and

Capacity Expansion (PACE) iron ore projects in Australia, the Hillside 3 expansion in South Africa and the Mozal 2 expansion in Mozambique. Maintenance capital expenditure was US$223 million and exploration expenditure was US$130 million. These outflows were offset by the proceeds on demerger of the Group's Steel business of US$272 million, proceeds on the sale of the residual 6% share in BHP Steel after demerger of US$75 million, the repayment of loans by equity accounted associates of US$90 million, and proceeds from sale of property plant and equipment totalling US$33 million, contributed to an investing cash outflow of US$903 million. Whilst not reflected in cash flows, US$232 million of debt was retained by BHP Steel upon demerger.

After dividend payments of US$855 million (up from US$815 million in the prior half year), financing cash outflows were US$536 million.

Net debt comprises US$7,937 million of total debt offset by US$874 million of cash, including money market deposits.

Financial Ratios

At 31 December 2002 BHP Billiton's gearing ratio was 36.7% compared to 33.7% at 30 June 2002.

Based on earnings before interest and tax (EBIT), interest cover for the half year was 7.3 times compared to 7.2 times for the half year ended 31 December 2001. Based on earnings before interest, tax and depreciation (EBITDA), interest cover for the half year was 11.4 times compared with 10.4 times in the corresponding period.

Profit from ordinary activities before tax as a percentage of revenue was 17.5% for the half year ended 31 December 2002 compared with 19.2% for the corresponding period.

Net profit as a percentage of equity was 15.0% for the half year ended 31 December 2002 compared to 18.6% in the corresponding period.

Net tangible assets per fully paid share were US$1.84 as at 31 December 2002 compared with US$2.01 as at 31 December 2001.

Outlook

In general, London Metals Exchange commodity prices showed improvement during the December 2002 quarter. Prices continued to show some improvement in the opening weeks of calendar 2003. Prices for oil have risen as a result of the ongoing uncertainty in the Middle East and Venezuela, while steel making raw materials are well positioned to benefit from strong North East Asian and, in particular, Chinese demand.

The global economy continues to encounter both economic and geo-political tensions. Despite continued buoyancy in China, the Organisation for Economic Cooperation and Development (OECD) leading indicator is signalling continued weakness in global industrial production.

In the short term, the uncertainty regarding developments in the Middle East, continued high oil prices and weak global equity markets are weighing heavily on consumer and business sentiment with the latter delaying the new investment spending and employment growth needed before there will be any sustained improvement in the world economy. Demand in China, an important influence on many of our products, continues to be strong.

Despite this uncertain outlook, our diversified portfolio of high quality assets provides relatively stable cashflows, leaving us well placed to continue to invest in value adding opportunities and to prosper from any uptick in economic activity.

Significant Events After End of Half Year

No matter or circumstance has arisen since the end of the half year that significantly affected or may significantly affect the operations, the results of operations or state of affairs of the Group in subsequent financial periods.

BOARD OF DIRECTORS

The Directors of the Company in office during or since the end of the half year are:

Mr D R Argus – Chairman since April 1999 (on the Board of Directors since November 1996)

Mr D A Crawford – a Director since May 1994

Mr M A Chaney – a Director since May 1995

Dr D A Jenkins – a Director since March 2000

Dr J M Schubert – a Director since June 2000

Mr C W Goodyear – an Executive Director since November 2001

Mr B P Gilbertson – an Executive Director since June 2001, resigned 5 January 2003

Dr D C Brink – a Director since June 2001

Mr C A Herkströter – a Director since June 2001

Lord Renwick of Clifton – a Director since June 2001

Dr John Buchanan – a Director since February 2003

On 24 February 2003, the Board announced the appointment of Mr Miklos Salamon as an Executive Director to the Board of Directors, with immediate effect.

ROUNDING OF AMOUNTS

The Company is a company of a kind referred to in Class Order No. 98/0100 dated 10 July 1998 issued by the Australian Securities and Investments Commission. Amounts in this report, unless otherwise indicated, have been rounded in accordance with that Class Order to the nearest million dollars.

Signed in accordance with a resolution of the Board.

D R Argus

Chairman

Dated in Melbourne this 24th day of February 2003.

Interim Condensed Financial Statements
For The Half Year Ended 31 December 2002

Statement of Financial Performance

For the half year ended 31 December 2002

	Notes	**Half year ended 31 December 2002 US$M**	Half year ended 31 December 2001 US$M (a)
Revenue from ordinary activities			
Sales revenue	4	**7 056**	8 067
Other revenue	4	**221**	758
	8	**7 277**	8 825
deduct			
Expenses from ordinary activities, excluding depreciation, amortisation and borrowing costs	5	**5 140**	6 136
add			
Share of net profit of associated entities accounted for using the equity method	10	**89**	150
		2 226	2 839
deduct			
Depreciation and amortisation	6	**807**	884
Borrowing costs	7	**144**	259
Profit from ordinary activities before income tax	8	**1 275**	1 696
deduct			
Income tax expense attributable to ordinary activities		**367**	497
Net profit		**908**	1 199
deduct			
Outside equity interests in net profit of controlled entities		**17**	22
Net profit attributable to members of the BHP Billiton Group		**891**	1 177
Net exchange fluctuations on translation of foreign currency net assets and foreign currency interest bearing liabilities net of tax		**39**	26
Total direct adjustments to equity attributable to members of the BHP Billiton Group		**39**	26
Total changes in equity other than those resulting from transactions with owners		**930**	1 203
Basic earnings per share (US cents) (a) (b)		**14.4**	19.5
Diluted earnings per share (US cents) (a) (b)		**14.3**	19.5

(a) Effective July 2002, the BHP Steel business was demerged from the BHP Billiton Group. The Statement of Financial Performance for the half year ended 31 December 2001 includes results pertaining to BHP Steel. Refer note 3 "Discontinued Operations".

(b) Basic earnings per share are calculated based on 6 201 million (31 December 2001: 6 024 million) weighted average number of shares. Diluted earnings per share are calculated based on 6 219 million (31 December 2001: 6 040 million) weighted average number of shares.

Under the terms of the DLC merger, the rights to dividends of a holder of an ordinary share in BHP Billiton Plc and a holder of an ordinary share in BHP Billiton Limited are identical. Consequently, earnings per share has been calculated on the basis of the aggregate number of ordinary shares ranking for dividend. The weighted average number of shares used for the purposes of calculating basic earnings per share is calculated after deduction of the shares held by the share repurchase scheme and the Billiton Employee Share Ownership Trust.

The weighted average diluted number of ordinary shares has been adjusted for the effect of Employee Share Plan options, Executive Share Scheme partly paid shares and Performance Rights to the extent they were dilutive at balance date. Refer note 13 for details of shares issued under these plans.

The accompanying notes form part of these interim condensed financial statements.

Statement of Financial Position

As at 31 December 2002

	Notes	As at 31 December 2002 US$M	As at 30 June 2002 US$M (a)	As at 31 December 2001 US$M (a)
Current assets				
Cash assets	16	**874**	1 499	661
Receivables		**2 126**	2 294	2 048
Other financial assets		**107**	117	175
Inventories		**1 294**	1 509	1 550
Other assets		**163**	108	155
Total current assets		**4 564**	5 527	4 589
Non-current assets				
Receivables		**804**	889	661
Investments accounted for using the equity method		**1 538**	1 505	1 492
Other financial assets		**480**	581	505
Inventories		**51**	80	77
Property, plant and equipment		**16 086**	17 304	16 813
Exploration, evaluation and development expenditure	11	**2 180**	2 180	1 820
Intangible assets		**488**	513	536
Deferred tax assets		**434**	480	422
Other assets		**834**	803	717
Total non-current assets		**22 895**	24 335	23 043
Total assets		**27 459**	29 862	27 632
Current liabilities				
Payables		**2 072**	2 435	1 885
Interest bearing liabilities		**1 269**	1 797	1 217
Tax liabilities		**354**	493	270
Other provisions		**609**	1 116	512
Total current liabilities		**4 304**	5 841	3 884
Non-current liabilities				
Payables		**112**	121	131
Interest bearing liabilities		**6 668**	6 383	6 807
Deferred tax liabilities		**1 365**	1 600	1 355
Other provisions		**2 802**	2 764	2 462
Total non-current liabilities		**10 947**	10 868	10 755
Total liabilities		**15 251**	16 709	14 639
Net assets		**12 208**	13 153	12 993
Equity				
Contributed equity – BHP Billiton Limited	12	**1 759**	3 143	3 065
Called up share capital – BHP Billiton Plc	12	**1 752**	1 752	1 752
Reserves		**334**	471	479
Retained profits	14	**8 055**	7 455	7 369
Total BHP Billiton interest		**11 900**	12 821	12 665
Outside equity interest		**308**	332	328
Total equity	15	**12 208**	13 153	12 993

(a) Effective July 2002, the BHP Steel business was demerged from the BHP Billiton Group. The Statement of Financial Position as at 31 December 2001 and 30 June 2002 include BHP Steel assets and liabilities accordingly. Refer note 3 "Discontinued Operations".

The accompanying notes form part of these interim condensed financial statements.

Statement of Cash Flows

For the half year ended 31 December 2002

	Notes	**Half year ended 31 December 2002 US$M**	Half year ended 31 December 2001 US$M (a)
Cash flows related to operating activities			
Receipts from customers		**6 928**	8 411
Payments to suppliers, employees, etc.		**(5 228)**	(6 480)
Dividends received		**84**	69
Interest received		**6**	47
Borrowing costs		**(170)**	(298)
Other		**109**	134
Operating cash flows before income tax		**1 729**	1 883
Income taxes paid net of refunds received		**(540)**	(400)
Net operating cash flows		**1 189**	1 483
Cash flows related to investing activities			
Purchases of property, plant and equipment		**(1 191)**	(1 080)
Exploration expenditure		**(130)**	(202)
Purchases of investments and funding of joint ventures		**(52)**	(47)
Purchases of, or increased investment in, controlled entities and joint venture interests net of their cash		**-**	(45)
Investing cash outflows		**(1 373)**	(1 374)
Proceeds from sale of property, plant and equipment		**33**	144
Proceeds from sale or redemption of investments		**165**	36
Proceeds from sale, or partial sale, of controlled entities and joint venture interests net of their cash		**272**	130
Net investing cash flows		**(903)**	(1 064)
Cash flows related to financing activities			
Proceeds from ordinary share issues, etc.		**147**	31
Proceeds from interest bearing liabilities		**2 878**	3 659
Repayment of interest bearing liabilities		**(2 695)**	(3 511)
Redemption of secured Employee Share Plan program		**-**	(134)
Purchase of shares under Share Buy-Back program		**-**	(19)
Dividends paid		**(855)**	(815)
Other		**(11)**	11
Net financing cash flows		**(536)**	(778)
Net decrease in cash and cash equivalents		**(250)**	(359)
Cash and cash equivalents at beginning of the half year		**990**	998
Effect of foreign currency exchange rate changes on cash and cash equivalents		**18**	(6)
Cash and cash equivalents at end of the half year	16	**758**	633

(a) Effective July 2002, the BHP Steel business was demerged from the BHP Billiton Group. The Statement of Cash Flows for the half year ended 31 December 2001 includes cash flows pertaining to BHP Steel. Refer note 3 "Discontinued Operations".

The accompanying notes form part of these interim condensed financial statements.

Notes to Financial Statements

NOTE 1. BASIS OF PREPARATION OF INTERIM CONDENSED FINANCIAL STATEMENTS, DUAL LISTED COMPANY STRUCTURE AND ACCOUNTING POLICIES

Basis of preparation of interim financial statements

These statements are general purpose interim consolidated financial statements that have been prepared in accordance with the requirements of the Corporations Act 2001, Australian Stock Exchange Listing Rules, Australian Accounting Standard AASB 1029 “Interim Financial Reporting” and Urgent Issues Group Consensus Views, and give a true and fair view of the matters disclosed. These interim financial statements and reports should be read in conjunction with the annual financial statements for the year ended 30 June 2002 and any public announcements made by the BHP Billiton Group and its controlled entities during the half year in accordance with continuous disclosure obligations arising under the Corporations Act 2001 and Australian Stock Exchange Listing Rules. The notes to the financial statements do not include all information normally contained within the notes to an annual financial report.

Merger terms

On 29 June 2001, BHP Billiton Limited (previously known as BHP Limited), an Australian listed Company, and BHP Billiton Plc (previously known as Billiton Plc), a UK listed Company, entered into a Dual Listed Companies (DLC) merger. This was effected by contractual arrangements between the companies and amendments to their constitutional documents.

The effect of the DLC merger is that BHP Billiton Limited and its subsidiaries (the BHP Billiton Limited Group) and BHP Billiton Plc and its subsidiaries (the BHP Billiton Plc Group) operate together as a single economic entity (the BHP Billiton Group), with neither assuming a dominant role. Under the arrangements:

- The shareholders of BHP Billiton Limited and BHP Billiton Plc have a common economic interest in both groups;
- The shareholders of BHP Billiton Limited and BHP Billiton Plc take key decisions, including the election of Directors, through a joint electoral procedure under which the shareholders of the two companies effectively vote on a joint basis;
- BHP Billiton Limited and BHP Billiton Plc have a common Board of Directors, a unified management structure and joint objectives;
- Dividends and capital distributions made by the two companies are equalised; and
- BHP Billiton Limited and BHP Billiton Plc each executed a deed poll guarantee, guaranteeing (subject to certain exceptions) the contractual obligations (whether actual or contingent, primary or secondary) of the other incurred after 29 June 2001 together with specified obligations existing at that date.

If either BHP Billiton Limited or BHP Billiton Plc proposes to pay a dividend to its shareholders, then the other Company must pay a matching cash dividend of an equivalent amount per share to its shareholders. If either Company is prohibited by law or is otherwise unable to declare, pay or otherwise make all or any portion of such a matching dividend, then BHP Billiton Limited or BHP Billiton Plc will, so far as it is practicable to do so, enter into such transactions with each other as the Boards agree to be necessary or desirable so as to enable both Companies to pay dividends as nearly as practicable at the same time.

The DLC merger did not involve the change of legal ownership of any assets of BHP Billiton Limited or BHP Billiton Plc, any change of ownership of any existing shares or securities of BHP Billiton Limited or BHP Billiton Plc, the issue of any shares or securities or any payment by way of consideration, save for the issue by each Company of one special voting share to a trustee company which is the means by which the joint electoral procedure is operated. In addition, to achieve a position where the economic and voting interests of one share in BHP Billiton Limited and one share in BHP Billiton Plc were identical, BHP Billiton Limited made a bonus issue of ordinary shares to the holders of its ordinary shares.

NOTE 1. BASIS OF PREPARATION OF INTERIM FINANCIAL STATEMENTS, DUAL LISTED COMPANY STRUCTURE AND ACCOUNTING POLICIES continued

Treatment of the DLC merger for accounting purposes

In accordance with the Australian Investments and Securities Commission (ASIC) Practice Note 71 'Financial Reporting by Australian Entities in Dual-Listed Company Arrangements', and an order issued by ASIC under section 340 of the Corporations Act 2001 on 2 September 2002, this interim report presents the financial results of the BHP Billiton Group as follows:

- Results for the half years ended 31 December 2002 and 31 December 2001 are for the combined entity including both BHP Billiton Limited and its subsidiary companies and BHP Billiton Plc and its subsidiary companies; and
- Results are presented in US dollars unless otherwise stated.

Accounting policies

Accounting standards and policies have been consistently applied by all entities in the BHP Billiton Group in the half year ended 31 December 2002 and are consistent with those applied in the half year ended 31 December 2001 and the full year ended 30 June 2002.

As a consequence of the enactment of Australian tax consolidation legislation and since the consolidated tax groups within the BHP Billiton Group have not notified the Australian Taxation Office at the date of signing this report of the implementation date for tax consolidation, BHP Billiton Group has applied UIG 39 "Effect of Proposed Tax Consolidation Legislation on Deferred Tax Balances".

NOTE 2. SIGNIFICANT ITEMS

Individually significant items (before outside equity interests) included within the BHP Billiton Group net profit are detailed below.

Half year ended 31 December 2002	Gross US$M	Tax US$M	Net US$M
Loss upon sale of 6% interest in BHP Steel	(19)	–	(19)
Total by category	**(19)**	**–**	**(19)**
Discontinued Operations	(19)	–	(19)
Total by Customer Sector Group	**(19)**	**–**	**(19)**

No significant items are included in the results for the half year ended 31 December 2001.

NOTE 3. DISCONTINUED OPERATIONS

Effective July 2002, the BHP Steel business demerged from the BHP Billiton Group. The demerger of BHP Steel effectively brings to an end the BHP Billiton Group's involvement as a steel producer and follows the demerger of the OneSteel business in October 2000 and the disposal of other steel operations, such as the US West Coast Steel businesses in June 2000.

Prior to the demerger, BHP Steel was the leading steel company in Australia and New Zealand, specialising in the production of flat steel products, including slab, hot rolled coil, plate and value-added metallic coated and pre-painted steel products. The Company supplied customers in Australia, New Zealand, Asia, the US, Europe, the Middle East and the Pacific. Key steelmaking assets were the low-cost global scale Port Kembla Steelworks (Australia), BHP New Zealand Steel and North Star BHP Steel (US). A network of metallic coating and coil painting facilities operated in Australia, New Zealand and South East Asia.

The financial performance of the Discontinued Steel business (including the loss upon sale of 6% interest in BHP Steel retained by BHP Billiton), as included in the Statement of Financial Performance, is detailed as follows:

Discontinued Steel business	**Half year ended 31 December 2002 US$M**	Half year ended 31 December 2001 US$M
Financial Performance		
Revenue from ordinary activities before interest income	**75**	1 157
Expenses from ordinary activities, excluding borrowing costs	**(94)**	(1 131)
Profit from ordinary activities before net borrowing costs and income tax	**(19)**	26

While the BHP Billiton Group operates its treasury function on a Group basis, certain financing arrangements not reported in the Steel segment can be attributed to the discontinued Steel operations. Not included within revenue from ordinary activities is interest income of US$6 million. The borrowing costs associated with attributable debt instruments was US$8 million. The income tax expense related to the discontinued operation, including the tax impact on financing arrangements included above, was US$3 million.

The contribution to Group cash flows of these businesses, before consideration of borrowing costs and income tax, as included in the Statement of Cash Flows, is detailed as follows:

Discontinued Steel business	**Half year ended 31 December 2002 US$M**	Half year ended 31 December 2001 US$M
Cash Flows		
Net operating cash flows (excluding borrowing activities and income tax)	**–**	107
Net investing cash flows (a)	**74**	(5)
Net financing cash flows	**–**	25
Total cash flows provided by discontinued operations	**74**	127

(a) Includes US$75 million in proceeds from the sale of 6% of BHP Steel and US$1 million in costs associated with the sale.

NOTE 3. DISCONTINUED OPERATIONS continued

The attributable net assets of BHP Steel as included in the Statement of Financial Position is provided below. In addition, the net assets demerged in July 2002, which are equivalent to the balances held at 30 June 2002, are also provided, after allowing for the settlement of intercompany loans by BHP Steel to the BHP Billiton Group.

Discontinued Steel business	As at 31 December 2002 US$M	As at 30 June 2002 US$M
Financial Position (a)		
Total assets	–	2 732
Total liabilities	–	(841)
Outside equity interests	–	(21)
Total equity	–	1 870
Net payments to the BHP Billiton Group by BHP Steel to settle intercompany loans (post 30 June 2002)		(294)
Net assets of BHP Steel		1 576
Elimination of intercompany profits in inventory		(9)
Attributable net assets of BHP Steel demerged		1 567

(a) Includes certain assets and liabilities (primarily cash, interest bearing liabilities and taxation provisions), which are not allocated to Steel for segment reporting purposes.

The impact on the BHP Billiton Group of the demerger of BHP Steel business in July 2002 was as follows:

- The BHP Billiton Group's capital was reduced by US$1,489 million, including US$17 million of costs (net of tax; US$24 million before tax) directly associated with the demerger. The capital reduction takes into account the transfer to BHP Billiton Limited shareholders of 94 percent of the shares of BHP Steel. The remaining 6 percent of BHP Steel shares held by the Group were subsequently sold;
- A bonus issue of BHP Billiton Plc shares to BHP Billiton Plc shareholders as a Matching Action to ensure economic benefit equality between shareholders of both BHP Billiton Limited and BHP Billiton Plc. The bonus issue resulted in one BHP Billiton Plc share being issued for approximately each 15.6 BHP Billiton Plc shares held;
- A cash inflow of US$347 million, representing US$294 million from the settlement by BHP Steel of intercompany loans, less US$22 million demerger transaction costs paid. US$75 million from the sale of the 6 percent interest in BHP Steel is included in proceeds from sale or redemption of investments; and
- A loss of US$19 million (no tax effect) relating to the sale of the 6 percent of BHP Steel.

NOTE 4. REVENUE FROM ORDINARY ACTIVITIES

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
Sales revenue		
Sale of goods	**6 823**	7 896
Rendering of services	**233**	171
Total sales revenue	**7 056**	8 067
Other revenue		
Interest income	**29**	51
Dividend income	**14**	18
Proceeds from sales of non-current assets	**109**	655
Management fees	**1**	2
Other income	**68**	32
Total other revenue	**221**	758

NOTE 5. EXPENSES FROM ORDINARY ACTIVITIES, EXCLUDING DEPRECIATION, AMORTISATION AND BORROWING COSTS

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
Employee benefits expense	**769**	1 000
Raw materials and consumables used	**1 195**	1 330
External services (including transportation)	**1 336**	1 311
Costs relating to trading activities	**741**	933
Changes in inventories of finished goods and work in progress	**(97)**	(128)
Net book value of non-current assets sold	**116**	599
Foreign losses/(gains) on external debt and tax balances	**95**	(328)
Resource rent tax	**226**	203
Rental expense in respect of operating leases	**97**	118
Government royalties paid and payable	**162**	138
Other	**500**	960
Total expenses from ordinary activities, excluding depreciation, amortisation and borrowing costs	**5 140**	6 136

NOTE 6. DEPRECIATION AND AMORTISATION

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
Depreciation relates to		
Buildings	**52**	66
Plant, machinery and equipment	**585**	696
Mineral rights	**65**	50
Exploration, evaluation and development expenditure	**76**	45
Capitalised leased assets	**3**	4
Total depreciation	**781**	861
Amortisation relates to		
Goodwill (not tax-effected)	**26**	23
Total amortisation	**26**	23
Total depreciation and amortisation	**807**	884

NOTE 7. BORROWING COSTS

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
Borrowing costs paid or due and payable		
On interest bearing liabilities	**193**	270
On finance leases	**2**	4
Total borrowing costs	**195**	274
deduct		
Amounts capitalised	**51**	15
Borrowing costs charged against net profit from ordinary activities	**144**	259

NOTE 8. SEGMENT RESULTS

	Segment Revenue US$M	Profit before tax (a) US$M
Half year ended 31 December 2002		
Petroleum	**1 547**	**650**
Aluminium	**1 547**	**242**
Base Metals	**673**	**53**
Carbon Steel Materials	**1 647**	**490**
Diamonds and Specialty Products	**184**	**84**
Energy Coal	**855**	**94**
Stainless Steel Materials	**484**	**58**
Group & unallocated items (b)	**457**	**(262)**
Net unallocated interest	**29**	**(115)**
Discontinued Operations (b)	**75**	**(19)**
Intersegment	**(221)**	**-**
BHP Billiton Group	**7 277**	**1 275**
Half year ended 31 December 2001		
Petroleum	1 450	568
Aluminium	1 371	233
Base Metals	658	51
Carbon Steel Materials	1 527	550
Diamonds and Specialty Products	852	144
Energy Coal	1 220	391
Stainless Steel Materials	368	(25)
Group & unallocated items (b)	401	(57)
Net unallocated interest	49	(217)
Discontinued Operations (b)	1 189	58
Intersegment	(260)	-
BHP Billiton Group	8 825	1 696

(a) Before outside equity interests.

(b) For segment reporting, the results of operations formerly presented as the Steel segment have been split between Discontinued Operations and Continuing Operations. Discontinued Operations represents the part of the Steel business that was demerged in July 2002. Steel's Continuing Operations include the results of operations of Transport and Logistics, until 31 December 2001, and certain minor residual Steel assets and liabilities (that have not been demerged as part of BHP Steel) and are now included in Group and unallocated items.

NOTE 9. DIVIDENDS

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
BHP Billiton Limited (a)		
Interim dividends paid	**261**	241
BHP Billiton Plc		
Interim dividends paid	**173**	151
Total dividends paid or payable	**434**	392

(a) The dividend for the December 2002 half year of US$0.07 per share, paid on 4 December 2002, was fully franked (2001 – US$0.065 per share fully franked). For the purposes of AASB 1034, the Group has an adjusted franking account balance of US$176 million (A$310 million) at 31 December 2002. From 1 July 2002 the Australian Income Tax Assessment Act 1997 requires measurement of franking account balances based on the amount of income tax paid, rather than on after-tax profits. The current outlook is that dividends payable in the next twelve months will be fully franked.

NOTE 10. INVESTMENTS ACCOUNTED FOR USING THE EQUITY METHOD

	Ownership interest at BHP Billiton Group reporting date (a)		Contribution to operating profit after income tax	
Material interests in associated entities	**31 December 2002 %**	31 December 2001 %	**31 December 2002 US$M**	31 December 2001 US$M
Samarco Mineracao S.A.	50	50	22	10
Minera Antamina S.A.	34	34	(3)	(6)
Cerrejon Coal Corporation (b)	33	(b)	8	13
Highland Valley Copper	34	34	(3)	7
Minera Alumbrera Limited	25	25	15	5
Other (c)			50	121
Total			89	150

(a) Ownership interest reflects the interest held at the end of the half years ended 31 December 2002 and 2001 respectively. The proportion of voting power held corresponds to ownership interest.

(b) At 31 December 2001 the BHP Billiton Group had an ownership interest of 33% in Carbones del Cerrejon S.A. and 17% in Carbones Zona Norte S.A. Following the BHP Billiton Group's acquisition of an interest in Intercor LLC in February 2002, the BHP Billiton Group's existing interest in Carbones del Cerrejon S.A. was merged into Intercor LLC, which was subsequently renamed Carbones del Cerrejon LLC, in November 2002. The activities of Carbones del Cerrejon LLC and Carbones Zona Norte S.A. are managed as an integrated operation referred to as Cerrejon Coal Corporation. The BHP Billiton Group has an effective ownership interest of 33% in Cerrejon Coal Corporation.

(c) Includes immaterial equity accounted associates and the Richards Bay Minerals joint venture owned 50% (2001: 50%).

NOTE 11. EXPLORATION, EVALUATION AND DEVELOPMENT EXPENDITURE CAPITALISED

	As at 31 December 2002 US$M	As at 30 June 2002 US$M	As at 31 December 2001 US$M
Exploration, evaluation and development expenditures carried forward in areas of interest			
- now in production	**783**	986	877
- in development stage but not yet producing (a)	**999**	852	572
- in exploration and/or evaluation stage (b)	**398**	342	371
Total exploration, evaluation and development expenditure capitalised	**2 180**	2 180	1 820

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
(a) Details of movement in expenditure capitalised in development stage but not yet producing		
Balance at the beginning of the half year	**852**	393
Expenditure incurred during the half year	**141**	198
Transferred from exploration and/or evaluation	**11**	32
Transferred to production	**-**	(61)
Depreciation	**(1)**	(2)
Exchange fluctuations and other movements	**(4)**	12
Balance at the end of the half year	**999**	572
(b) Details of movement in expenditure capitalised in exploration and/or evaluation stage		
Balance at the beginning of the half year	**342**	386
Expenditure incurred during the half year	**141**	208
Expenditure expensed during the half year	**(83)**	(172)
Transferred to development	**(11)**	(32)
Depreciation	**(5)**	(10)
Exchange fluctuations and other movements	**14**	(9)
Balance at the end of the half year	**398**	371

NOTE 12. CONTRIBUTED EQUITY AND CALLED UP SHARE CAPITAL

	As at 31 December 2002 US$M	As at 30 June 2002 US$M	As at 31 December 2001 US$M
BHP Billiton Limited			
Paid up contributed equity			
3 741 863 290 ordinary shares fully paid (30 June 2002: 3 724 893 687; 31 December 2001: 3 706 520 347) (a)	**1 759**	3 143	3 065
260 000 ordinary shares (30 June 2002: 320 000; 31 December 2001: 340 000) paid to A$1.40 (30 June 2002 A$0.71; December 2001: A$0.71) (b)	**–**	–	–
1 265 000 ordinary shares (30 June 2002: 2 305 000; 31 December 2001: 3 153 500) paid to A$1.36 (30 June 2002 A$0.67; December 2001: A$0.67) (b)	**–**	–	–
1 Special Voting Share (30 June 2002: 1; 31 December 2001: 1) (c)	**–**	–	–
	1 759	3 143	3 065

	Number of shares		
	31 December 2002	30 June 2002	31 December 2001
Movements in ordinary fully paid shares			
Opening number of shares	**3 724 893 687**	3 704 256 885	3 704 256 885
Shares issued on exercise of Employee Share Plan options	**14 610 650**	22 955 508	5 716 946
Shares issued on exercise of Performance Rights	**918 120**	-	-
Partly paid shares converted to fully paid (b) (d)	**1 440 833**	1 815 916	681 138
Shares bought back and cancelled (e)	**-**	(4 134 622)	(4 134 622)
Closing number of shares	**3 741 863 290**	3 724 893 687	3 706 520 347

	As at 31 December 2002 US$M	As at 30 June 2002 US$M	As at 31 December 2001 US$M
BHP Billiton Plc			
Allotted, called up and fully paid share capital			
2 468 147 002 ordinary shares of US$0.50 each (30 June 2002: 2 319 147 885; 31 December 2001: 2 319 147 885)	**1 752**	1 752	1 752
	1 752	1 752	1 752

	Number of shares		
	31 December 2002	30 June 2002	31 December 2001
Movements in ordinary fully paid shares			
Opening number of shares	**2 319 147 885**	2 319 147 885	2 319 147 885
Bonus issue (a)	**148 999 117**	-	-
Closing number of shares	**2 468 147 002**	2 319 147 885	2 319 147 885

NOTE 12. CONTRIBUTED EQUITY AND CALLED UP SHARE CAPITAL continued

(a) Contributed equity decreased by US$1 456 million due to the demerger of BHP Steel Limited. This reflected a capital reduction of A$0.69 per share. The demerger resulted in BHP Billiton Limited shareholders being issued one BHP Steel Limited share for every five BHP Billiton Limited shares held. BHP Billiton Plc shareholders did not receive shares in BHP Steel Limited. To ensure the equality of treatment, BHP Billiton Plc shareholders received a bonus issue to reflect the market value of the BHP Steel shares being distributed. 148 999 117 bonus shares were issued to BHP Billiton Plc shareholders in July 2002.

(b) 60 000 shares (30 June 2002: 65 000, 31 December 2001: 45 000) paid to A$1.40 and 1 040 000 shares (30 June 2002: 1 351 500; 31 December 2001: 503 000) paid to A$1.36 were converted to fully paid during the half year ended 31 December 2002. There were no partly paid shares issued during the half years ended 31 December 2002 and 31 December 2001 or the year ended 30 June 2002. As a consequence of the BHP Steel Limited demerger, an instalment call of A$0.69 per share was made on partly paid shares which was then immediately replaced by the application of the capital reduction. During the period 1 January 2003 to 20 February 2003, 40 000 Executive Share Scheme partly paid shares were paid up in full and 4 320 261 fully paid ordinary shares (including attached bonus shares) were issued on the exercise of Employee Share Plan options.

(c) Each of BHP Billiton Limited and BHP Billiton Plc issued one Special Voting Share to facilitate joint voting by shareholders of BHP Billiton Limited and BHP Billiton Plc on Joint Electoral Actions.

(d) The DLC Merger bonus issue was accrued for Executive Share Scheme partly paid shares issued in 1996 and 1997 and as a result the number of shares converted from partly paid to fully paid will not necessarily be on a 1:1 basis because the conversion of some partly paid shares also attract the issue of bonus shares.

(e) During the year ended 30 June 2002, BHP Billiton Limited repurchased 4 134 622 shares (31 December 2001: 4 134 622) at a weighted average price of A$8.83 per share (31 December 2001: A$8.83 per share), in accordance with its announced share buy-back program. The buy-back program allows for the purchase of up to 186 million BHP Billiton Limited shares (adjusted for the bonus issue), less the number of BHP Billiton Plc shares purchased on market.

NOTE 13. SHARE OPTIONS

BHP Billiton Group share options

The following tables relate to share options issued under the Employee Share Plan, performance rights issued under the Performance Share Plan, awards issued under the Restricted Share Scheme, awards issued under the Co-Investment Plan and performance shares issued under the Group Incentive Scheme. Unless otherwise indicated details of the Plans, including comparatives, are presented including, where applicable, a bonus element to which the participant became entitled with effect from 29 June 2001, as a result of the DLC merger.

Month of issue	Number Issued	Number of recipients	Number Exercised (a)	Shares issued on exercise	Number lapsed	Awards outstanding at balance date	Exercise Price A$ (b)	Exercise period
Employee Share Plan options (c)								
September 2002	67 500	1	-	-	-	67 500	$8.26	Oct 2004 – Sept 2011
November 2001	6 870 500	113	138 587	138 587	187 413	6 544 500	$8.30	Oct 2004 – Sept 2011
November 2001	7 207 000	153	234 595	234 595	288 405	6 684 000	$8.29	Oct 2004 – Sept 2011
December 2000	3 444 587	67	81 500	168 306	15 432	3 260 849	$8.72	July 2003 – Dec 2010
December 2000	2 316 010	59	201 500	416 118	139 749	1 760 143	$8.71	July 2003 – Dec 2010
November 2000	1 719 196	44	106 500	219 933	136 675	1 362 588	$8.28	July 2003 – Oct 2010
November 2000	7 764 776	197	1 101 250	2 274 191	82 429	5 408 156	$8.27	July 2003 – Oct 2010
April 2000	61 953	3	-	-	-	61 953	$7.60	April 2003 – April 2010
April 2000	937 555	5	-	-	138 361	799 194	$7.60	April 2003 – April 2010
December 1999	413 020	1	-	-	-	413 020	$8.61	April 2002 – April 2009
December 1999	309 765	1	-	-	-	309 765	$7.50	April 2002 – April 2009
October 1999	123 906	6	50 000	103 255	20 651	-	$7.57	April 2002 – April 2009
October 1999	105 320	3	7 000	14 456	30 976	59 888	$7.57	April 2002 – April 2009
July 1999	206 510	1	-	-	-	206 510	$7.60	April 2002 – April 2009
April 1999	44 474 822	45 595	5 887 700	12 158 689	19 894 970	12 421 163	$6.93	April 2002 – April 2009
April 1999	16 901 398	944	2 522 800	5 209 834	6 231 749	5 459 815	$6.92	April 2002 – April 2009
April 1998	366 555	16	72 500	149 719	-	216 836	$6.45	April 2001 – April 2003
April 1998	289 114	23	113 000	233 356	10 326	45 432	$6.44	April 2001 – April 2003
November 1997	3 261 619	3 501	1 206 000	2 490 509	771 110	-	$6.84	Nov 2000 – Nov 2002
November 1997	16 336 800	16 411	6 614 100	13 658 778	2 678 022	-	$6.84	Nov 2000 – Nov 2002
October 1997	11 234 144	511	5 349 500	11 047 252	186 892	-	$6.73	Oct 2000 – Oct 2002
October 1997	8 243 879	379	3 788 500	7 823 631	420 248	-	$6.73	Oct 2000 – Oct 2002
July 1997	413 020	1	200 000	413 020	-	-	$8.49	July 2000 – July 2002
July 1997	816 747	36	326 000	673 222	143 525	-	$8.50	July 2000 – July 2002
						45 081 312		

NOTE 13. SHARE OPTIONS continued

Month of issue	Number Issued	Number of recipients	Number Exercised (a)	Shares issued on exercise	Number lapsed	Awards outstanding at balance date	Exercise Price A$ (b)	Exercise period
Performance Rights (c) (d)								
November 2001 (LTI)	4 770 800	110	188 117	188 117	236 983	4 345 700	–	Oct 2004 – Sept 2011
October 2001 (LTI)	162 200	2	-	-	-	162 200	–	Oct 2004 – Sept 2011
October 2001 (MTI)	222 892	6	-	-	-	222 892	–	Oct 2003 – Mar 2006
December 2000 (LTI)	387 601	11	-	-	-	387 601	–	July 2003 – Dec 2010
November 2000 (LTI)	4 143 278	104	673 111	1 390 042	169 385	2 583 851	–	July 2003 – Oct 2010
March 1999 (LTI)	2 141 100	1	1 000 000	2 141 100	-	-	–	Mar 1999 – Mar 2009
						7 702 244		
Restricted Share Scheme (c) (d)								
November 2001 (Share awards)	274 914	1	–	–	–	274 914	–	8 Nov 2004
October 2001 (Share awards)	4 178 100	197	51 320	51 320	222 880	3 903 900	–	1 Oct 2004
October 2001 (Options)	863 000	41	1 833	1 833	11 367	849 800	–	Oct 2004 – Sept 2008
						5 028 614		
Co-Investment Plan (c) (d)								
November 2001	94 851	1	–	–	–	94 851	–	Nov 2003 – Apr 2006
October 2001	866 791	125	6 131	6 131	15 505	845 155	–	Oct 2003 – Mar 2006
						940 006		
Group Incentive Scheme Performance Shares (e)								
November 2002	11 477 011	645	–	–	17 250	11 459 761	–	30 June 2005
						11 459 761		

(a) Represents the number of options and Performance Rights exercised or lapsed, and has not been adjusted to take into account the bonus shares issued on exercise of options.

(b) Although the exercise price of options was not affected by the bonus issue of shares, the exercise prices for options as stated have been adjusted to take into account the bonus issue of shares, which took effect 29 June 2001. Exercise prices were also reduced, where applicable, by A$0.66 (pre bonus issue) following the OneSteel Limited spin-out on 31 October 2000 and by A$0.69 following the BHP Steel Limited spin-out on 1 July 2002.

(c) Further details of the Plans can be found in note 31 of the "BHP Billiton Limited Combined Financial Statements 2002".

(d) Shares issued on exercise of Performance Rights and awards under the Restricted Share Scheme and Co-Investment Plan include shares purchased on market.

NOTE 13. SHARE OPTIONS continued

(e) The Group Incentive Schemes were approved by shareholders at the 2002 Annual General Meeting. The Group granted Performance Shares to participants in November 2002 under transition arrangements of the Schemes, subject to achievement of specified performance conditions. The Performance Shares granted are subject to meeting the three-year Total Shareholder Return and Earnings Per Share performance conditions as set out below. The exercise period for the Performance Shares will be from the date the performance conditions are met (if at all) to the date, which is three years after the start of the exercise period. The exercise or award of Performance Shares granted will be based on Earnings Per Share (EPS) growth and Total Shareholders Return (TSR) during the period from 1 July 2002 to 30 June 2005 (the Performance Period). Both EPS growth targets and minimum TSR targets will need to be reached in order for the conditions to be satisfied. The EPS growth threshold will be satisfied if the compound EPS growth for the Group during the Performance Period is equal to or greater than the higher of the increase in the Australian Consumer Price Index or the increase in the United Kingdom Retail Price Index, plus 2 per cent per annum, over the Performance Period. The TSR threshold is based on whether the total shareholder return achieved by the peer group companies is greater than the total shareholder return achieved by BHP Billiton Limited and BHP Billiton Plc over the Performance Period. In essence, TSR is measured by the sum of any increase in share price of, plus dividends paid by, the various companies.

NOTE 14. RETAINED PROFITS

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
Balance at the beginning of the half year	**7 455**	6 526
Dividends provided for or paid (a)	**(434)**	(392)
Aggregate of amounts transferred from reserves	**143**	77
BHP Billiton Limited share buy-back program (b)	**-**	(19)
Net profit	**891**	1 177
Balance at the end of the half year	**8 055**	7 369

(a) Refer note 9.

(b) Refer note 12 (e).

NOTE 15. TOTAL EQUITY

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
Balance at the beginning of the half year	**13 153**	12 232
Total changes in equity recognised in the Statement of Financial Performance	**930**	1 203
Transactions with owners – contributed equity	**72**	26
Dividends (a)	**(434)**	(392)
BHP Billiton Limited share buy-back program (b)	**-**	(19)
BHP Steel demerger (c)	**(1 489)**	-
Total changes in outside equity interests	**(24)**	(57)
Balance at the end of the half year	**12 208**	12 993

(a) Refer note 9.

(b) Refer note 12 (e).

(c) The BHP Steel business was demerged in July 2002 with a capital reduction of US$1 489 million, including approximately US$17 million of costs directly associated with the demerger. The capital reduction decreased Contributed equity by US$1 456 million and Reserves by US$33 million.

NOTE 16. NOTES TO THE STATEMENT OF CASH FLOWS

For the purpose of the Statement of Cash Flows, cash is defined as cash and cash equivalents. Cash equivalents include highly liquid investments, which are readily convertible to cash, bank overdrafts and interest bearing liabilities at call.

	As at 31 December 2002 US$M	As at 30 June 2002 US$M	As at 31 December 2001 US$M
Reconciliation of cash			
Cash and cash equivalents comprise:			
Cash assets			
Cash	**567**	1 199	485
Short-term deposits	**307**	300	176
Total cash assets	**874**	1 499	661
Bank overdrafts (a)	**(116)**	(509)	(28)
Total cash and cash equivalents	**758**	990	633

	Half year ended 31 December 2002 US$M	Half year ended 31 December 2001 US$M
Non-cash financing and investing activities		
Disposal of North American Metals Distribution assets to Integris Joint Venture	–	341
Employee Share Plan loan instalments (b)	**2**	12

(a) Included in the Statement of Financial Position as Interest Bearing Liabilities (Current)

(b) The Employee Share Plan loan instalments represent the repayment of loans outstanding with the BHP Billiton Group, by the application of dividends.

Disposal of Controlled Entities

Effective July 2002, the BHP Steel business demerged from the BHP Billiton Group. Refer note 3 "Discontinued Operations" for the details of the effect of the demerger. The inflow of cash as a result of the sale (net of cash disposed) was US$272 million.

During the half year ended 31 December 2001, BHP Billiton sold its investment in PT Arutmin Indonesia for proceeds of US$140 million. The net assets of the entity sold at the time of disposal were US$76 million. BHP Billiton recognised a profit on sale of PT Arutmin Indonesia of US$64 million during the half year ended 31 December 2001. The inflow of cash as a result of the sale (net of cash disposed) was US$141 million.

NOTE 17. CONTINGENT LIABILITIES AND CONTINGENT ASSETS

There have been no material changes in contingent liabilities or contingent assets that existed at 30 June 2002.

NOTE 18. SIGNIFICANT EVENTS AFTER END OF HALF YEAR

No matters or circumstances have arisen since the end of the half year that have significantly affected, or may significantly affect, the operations, results of operations or state of affairs of the BHP Billiton Group in subsequent accounting periods.

NOTE 19. STATEMENT OF FINANCIAL POSITION – AUSTRALIAN DOLLARS

For the convenience of the reader, an Australian dollar Statement of Financial Position of the BHP Billiton Group is detailed below. A convenience translation of amounts from US dollars into Australian dollars has been made at an exchange rate of US$0.5666 = A$1 at 31 December 2002, US$0.5664 = A$1 at 30 June 2002 and US$0.5114 = A$1 at 31 December 2001. These rates of exchange are based on the Hedge Settlement Rate ('HSR') on the last day of each financial period respectively. The HSR is calculated as the average of the spot US$/A$ rates of exchange quoted at 9.45am each business day by the top licenced foreign exchange dealers in the Australian market and is used as the basis for settling hedge contracts maturing on that day.

	As at 31 December 2002 A$M	As at 30 June 2002 A$M	As at 31 December 2001 A$M
Current assets			
Cash assets	**1 542**	2 646	1 293
Receivables	**3 752**	4 050	4 004
Other financial assets	**189**	207	342
Inventories	**2 284**	2 664	3 032
Other assets	**288**	191	303
Total current assets	**8 055**	9 758	8 974
Non-current assets			
Receivables	**1 419**	1 570	1 293
Investments accounted for using the equity method	**2 715**	2 657	2 917
Other financial assets	**847**	1 026	987
Inventories	**90**	141	150
Property, plant and equipment	**28 390**	30 551	32 877
Exploration, evaluation and development expenditure	**3 848**	3 849	3 560
Intangible assets	**861**	905	1 047
Deferred tax assets	**766**	847	826
Other assets	**1 472**	1 418	1 401
Total non-current assets	**40 408**	42 964	45 058
Total assets	**48 463**	52 722	54 032
Current liabilities			
Payables	**3 657**	4 300	3 685
Interest bearing liabilities	**2 239**	3 172	2 380
Tax liabilities	**625**	870	527
Other provisions	**1 075**	1 970	1 001
Total current liabilities	**7 596**	10 312	7 593
Non-current liabilities			
Payables	**198**	214	257
Interest bearing liabilities	**11 769**	11 269	13 310
Deferred tax liabilities	**2 409**	2 825	2 649
Other provisions	**4 945**	4 880	4 815
Total non-current liabilities	**19 321**	19 188	21 031
Total liabilities	**26 917**	29 500	28 624
Net assets	**21 546**	23 222	25 408
Equity			
Contributed equity – BHP Billiton Limited	**3 105**	5 549	5 994
Called up share capital – BHP Billiton Plc	**3 092**	3 093	3 426
Reserves	**589**	832	937
Retained profits	**14 216**	13 162	14 410
Total BHP Billiton interest	**21 002**	22 636	24 767
Outside equity interest	**544**	586	641
Total equity	**21 546**	23 222	25 408

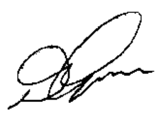
Directors' Declaration

I, Don R Argus being a Director of BHP Billiton Limited state on behalf of the Directors and in accordance with a resolution of the Directors that, in the opinion of the Directors -

(a) the accompanying financial statements set out on pages 9 to 26 are drawn up so as to give a true and fair view of the financial position as at 31 December 2002, and the performance for the half year ended 31 December 2002 of the Company;

(b) the interim consolidated financial statements have been made out in accordance with Australian Accounting Standard AASB1029: "Half Year Accounts and Consolidated Accounts" and other mandatory professional reporting requirements; and

(c) at the date of this statement there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.



D R Argus
Director

Dated in Melbourne this 24th day of February 2003

Independent review report to the members of BHP Billiton Limited

Statement

Based on our review, which is not an audit, we have not become aware of any matter that makes us believe that the interim condensed financial report, set out on pages 9 to 27 is not presented in accordance with:

- the Corporations Act 2001 in Australia, including giving a true and fair view of the financial position of the BHP Billiton Group (as defined in Note 1) as at 31 December 2002 and of its performance for the half-year ended on that date.
- Accounting Standard AASB 1029: Interim Financial Reporting and the Corporations Regulations 2001.
- Other mandatory professional reporting requirements in Australia.

This statement must be read in conjunction with the following explanation of the scope and summary of our role as auditor.

Scope and summary of our role

The financial report – responsibility and content

The preparation of the financial report for the half-year ended 31 December 2002 is the responsibility of the directors of BHP Billiton Limited.

The auditor's role and work

We conducted an independent review of the financial report in order for, and only for, the Company to lodge the financial report with the Australian Securities & Investments Commission. Our review has been undertaken so that we might state to the members of the Company those matters we are required to state to them in this report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the members of the Company for our review work, for this report, or for the conclusions we have reached. Our role was to conduct the review in accordance with Australian Auditing Standards applicable to review engagements. Our review did not involve an analysis of the prudence of business decisions made by the directors or management.

This review was performed in order to state whether, on the basis of the procedures described, anything has come to our attention that would indicate that the interim condensed financial report does not present fairly a view in accordance with the Corporations Act 2001 in Australia, Accounting Standard AASB 1029: Interim Financial Reporting and other mandatory professional reporting requirements in Australia, and the Corporations Regulations 2001, which is consistent with our understanding of the Group's financial position, and its performance as represented by the results of its operations and cash flows.

The review procedures performed were limited primarily to inquiries of company personnel and analytical procedures applied to financial data. The review has not involved a study and evaluation of internal accounting controls, tests of accounting records or tests of responses to inquiries by obtaining corroborative evidence from inspection, observation or confirmation. These procedures do not provide all the evidence that would be required in an audit, thus the level of assurance provided is less than that given in an audit. We have not performed an audit, and accordingly, we do not express an audit opinion.

Independent review report to the members of BHP Billiton Limited continued

Independence

As auditor, we are required to be independent of the Group and free of interests which could be incompatible with integrity and objectivity. In respect of this engagement, we followed the independence requirements set out by The Institute of Chartered Accountants in Australia, the Corporations Act 2001 and the Auditing and Assurance Standards Board.

In addition to our statutory audit and review work, we were engaged to undertake other services for the Group. In our opinion the provision of these services has not impaired our independence.

PricewaterhouseCoopers

Geoffrey M. Cottrell — Melbourne
Partner — 24 February 2003

KPMG

William J. Stevens — Melbourne
Partner — 24 February 2003

BHP BILLITON INTERIM REPORT 31 DECEMBER 2002
SUPPLEMENTARY INFORMATION

Customer Sector Group Results

The following notes and definitions are relevant to the table below and those on the following pages:
- Turnover is based on Group realised prices.
- EBIT is earnings before net interest and taxation.
- EBITDA is earnings before net interest, taxation, depreciation and amortisation.
- Capex includes capital and investment expenditure and excludes capitalised interest and capitalised exploration.

Half Year Comparison 31 December 2002 vs 31 December 2001

BHP BILLITON GROUP

Half year ended 31 December 2002

	US$ Million							
	Turnover [1]	EBIT excluding exceptional items	Exceptional items	EBIT including exceptional items	Net Operating Assets	Capex [2]	Exploration gross [3]	Exploration to profit [4]
Petroleum	1 511	660	-	660	3 227	479	95	50
Aluminium	1 535	266	-	266	4 907	217	-	-
Base metals	897	83	-	83	4 116	155	5	5
Carbon steel materials	1 747	506	-	506	2 583	159	2	2
Diamonds and specialty products	716	150	-	150	1 484	21	24	24
Energy coal	947	124	-	124	2 172	175	2	-
Stainless steel materials	491	61	-	61	1 709	50	2	2
Group and unallocated items [5]	424	(191)	-	(191)	602	12	-	-
	8 048	**1 659**	**-**	**1 659**	**20 800**	**1 268**	**130**	**83**
Discontinued Operations [6]	-	-	(19)	(19)	-	-	-	-
BHP Billiton Group	**8 048**	**1 659**	**(19)**	**1 640**	**20 800**	**1 268**	**130**	**83**

Half year ended 31 December 2001

	US$ Million							
	Turnover [1]	EBIT [7] excluding exceptional items	Exceptional items	EBIT [7] including exceptional items	Net Operating Assets	Capex	Exploration gross [3]	Exploration to profit [4]
Petroleum	1 434	576	-	576	2 722	298	143	74
Aluminium	1 371	191	-	191	4 773	117	-	-
Base metals	817	69	-	69	4 149	380	18	52
Carbon steel materials	1 660	565	-	565	2 407	95	1	1
Diamonds and specialty products	752	138	-	138	1 672	61	34	33
Energy coal	1 045	350	-	350	1 780	120	3	-
Stainless steel materials	449	(36)	-	(36)	1 747	39	3	12
Group and unallocated items [5]	378	(257)	-	(257)	956	29	-	-
	7 649	**1 596**	**-**	**1 596**	**20 206**	**1 139**	**202**	**172**
Discontinued Operations [6]	1 245	55	-	55	2 039	24	-	-
BHP Billiton Group	**8 894**	**1 651**	**-**	**1 651**	**22 245**	**1 163**	**202**	**172**

(1) Turnover does not add to BHP Billiton Group due to intersegment transactions
(2) Capex in aggregate comprises US$1,020 million growth and US$248 million sustaining.
(3) Includes US$47 million (2001: US$74 million) capitalised exploration.
(4) Includes US$nil (2001: US$44 million) exploration expenditure previously capitalised, now written off.
(5) Includes consolidation adjustments, unallocated items and the Group's freight, transport and logistics operations and associated trading activity, much of which is trading with other Customer Sector Groups.
(6) Discontinued operations includes BHP Steel, which was demerged from the BHP Billiton Group in July 2002.
(7) Certain items have been restated between Customer Sector Groups.

Quarterly Comparison 31 December 2002 vs 30 September 2002

BHP BILLITON GROUP

Quarter ended 31 December 2002

	US$ Million						
	Turnover [1]	EBIT excluding exceptional items	Exceptional items	EBIT including exceptional items	Capex [2]	Exploration gross [3]	Exploration to profit
Petroleum	694	276	-	276	240	58	29
Aluminium	758	131	-	131	118	-	-
Base metals	508	67	-	67	48	2	2
Carbon steel materials	896	239	-	239	120	1	1
Diamonds & specialty products	383	80	-	80	8	15	15
Energy coal	519	56	-	56	107	1	-
Stainless steel materials	271	38	-	38	24	2	2
Group and unallocated items [4]	239	(72)	-	(72)	8	-	-
	4 126	**815**	**-**	**815**	**673**	**79**	**49**
Discontinued Operations [5]	-	-	-	-	-	-	-
BHP Billiton Group	**4 126**	**815**	**-**	**815**	**673**	**79**	**49**

Quarter ended 30 September 2002

	US$ Million						
	Turnover [1]	EBIT excluding exceptional items	Exceptional items	EBIT including exceptional items	Capex	Exploration gross [3]	Exploration to profit
Petroleum	817	384	-	384	239	37	21
Aluminium	777	135	-	135	99	-	-
Base metals	389	16	-	16	107	3	3
Carbon steel materials	851	267	-	267	39	1	1
Diamonds & specialty products	333	70	-	70	13	9	9
Energy coal	428	68	-	68	68	1	-
Stainless steel materials	220	23	-	23	26	-	-
Group and unallocated items [4]	185	(119)	-	(119)	4	-	-
	3 922	**844**	**-**	**844**	**595**	**51**	**34**
Discontinued Operations [5]	-	-	(19)	(19)	-	-	-
BHP Billiton Group	**3 922**	**844**	**(19)**	**825**	**595**	**51**	**34**

(1) Turnover does not add to BHP Billiton Group due to intersegment transactions
(2) Capex in aggregate comprises US$550 million growth and US$123 million sustaining.
(3) Includes US$30 million (Sept 2002:US$17 million) capitalised exploration.
(4) Includes consolidation adjustments, unallocated items and the Group's freight, transport and logistics operations and associated trading activity, much of which is trading with other Customer Sector Groups.
(5) Discontinued operations includes BHP Steel, which was demerged from the BHP Billiton Group in July 2002.

Half Year Comparison 31 December 2002 vs 31 December 2001

PETROLEUM

Half year ended 31 December 2002

	US$ Million							
	Turnover [1]	EBITDA [2]	Depn & amortisation	EBIT [2]	Net Operating Assets	Capex [3]	Exploration gross [4]	Exploration to profit
Australia/Asia	1 120	732	116	616	1 424	158		
Bass Strait	546	307	51	256	469	80		
North West Shelf	376	292	22	270	882	55		
Americas	121	86	54	32	776	184		
UK/Middle East	237	197	95	102	1 053	137		
Exploration/Business Development	-	(60)	-	(60)	-	-		
Divisional activities	-	(31)	(1)	(30)	(26)	-		
Third party products	33	-	-	-	-	-		
Total	**1 511**	**924**	**264**	**660**	**3 227**	**479**	**95**	**50**

Half year ended 31 December 2001

	US$ Million							
	Turnover [1]	EBITDA [2]	Depn & amortisation	EBIT [2]	Net Operating Assets	Capex	Exploration gross [4]	Exploration to profit
Australia/Asia	1 012	649	112	537	1 384	100		
Bass Strait	515	273	53	220	415	48		
North West Shelf	325	257	27	230	864	34		
Americas	115	94	66	28	549	53		
UK/Middle East	272	230	101	129	871	145		
Exploration/Business Development	-	(83)	-	(83)	-	-		
Divisional activities	-	(32)	4	(36)	(82)	-		
Third party products	35	1	-	1	-	-		
Total	**1 434**	**859**	**283**	**576**	**2 722**	**298**	**143**	**74**

(1) Petroleum turnover includes: Crude oil US$967 million (2001:US$879 million), Natural gas US$217 million (2001:US$198 million), LNG US$153 million (2001:US$154 million), LPG US$112 million (2001:US$90 million) and Other US$62 million (2001:US$113 million).
(2) Excludes exceptional items.
(3) Capex in aggregate comprises US$435 million growth and US$44 million sustaining.
(4) Includes US$45 million (2001:US$69 million) capitalised exploration.
(5) Total barrels of oil equivalent (million) based on conversion rate of 6 billion standard cubic feet of gas per million barrels of oil equivalent.

Production	**2002**	**2001**
Crude oil, condensate and LPG (million barrels of oil equivalent)	39.3	43.3
Natural gas (bcf) (excluding liquefied natural gas)	109.8	115.2
Liquefied natural gas (bcf)	31.5	31.3
Total barrels of oil equivalent (million) [5]	63.1	67.9

Half Year Comparison 31 December 2002 vs 31 December 2001

ALUMINIUM

Half year ended 31 December 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (1)	Net Operating Assets	Capex (2)	Exploration gross	Exploration to profit
Alumina	335	125	54	71	2 166	24		
Aluminium	743	258	67	191	2 741	193		
Intra-divisional adjustment	(100)	-	-	-	-	-		
Third party products	557	4	-	4	-	-		
Total	**1 535**	**387**	**121**	**266**	**4 907**	**217**	-	-

Half year ended 31 December 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (1)	Net Operating Assets	Capex	Exploration gross	Exploration to profit
Alumina	333	131	51	80	2 240	16		
Aluminium	660	174	64	110	2 533	101		
Intra-divisional adjustment	(140)	-	-	-	-	-		
Third party products	518	1	-	1	-	-		
Total	**1 371**	**306**	**115**	**191**	**4 773**	**117**	-	-

(1) Excludes exceptional items.

(2) Capex in aggregate comprises US$201 million growth and US$16 million sustaining.

Production ('000 tonnes)	**2002**	**2001**
Alumina	2 029	1 929
Aluminium	534	479

Half Year Comparison 31 December 2002 vs 31 December 2001

BASE METALS

Half year ended 31 December 2002

	US$ Million							
	Turnover	EBITDA [(1)]	Depn & amortisation	EBIT [(1)]	Net Operating Assets	Capex [(2)]	Exploration gross [(3)]	Exploration to profit
Escondida	337	106	58	48	1 944	78		
Tintaya	25	3	19	(16)	421	22		
Cerro Colorado	92	45	35	10	672	12		
Antamina [(4)]	119	14	-	14	729	26		
Alumbrera [(4)]	64	19	-	19	211	-		
Cannington	154	57	12	45	254	12		
Highland Valley Copper [(4)]	55	(3)	-	(3)	96	-		
Other businesses [(5)]	45	(34)	1	(35)	(211)	5		
Third party products	6	1	-	1	-	-		
Total	**897**	**208**	**125**	**83**	**4 116**	**155**	**5**	**5**

Half year ended 31 December 2001

	US$ Million							
	Turnover	EBITDA [(1)]	Depn & amortisation	EBIT [(1)]	Net Operating Assets	Capex	Exploration gross	Exploration to profit
Escondida	306	115	51	64	1 800	219		
Tintaya	59	3	17	(14)	367	79		
Cerro Colorado	102	52	35	17	687	32		
Antamina [(4)]	51	2	-	2	800	40		
Alumbrera [(4)]	49	10	-	10	288	-		
Cannington	140	54	12	42	254	7		
Highland Valley Copper [(4)]	70	7	-	7	130	-		
Other businesses [(5)]	39	(56)	3	(59)	(177)	3		
Third party products	1	-	-	-	-	-		
Total	**817**	**187**	**118**	**69**	**4 149**	**380**	**18**	**52**

(1) Excludes exceptional items.
(2) Capex in aggregate comprises US$97 million growth and US$58 million sustaining.
(3) Includes US$nil (2001:US$1 million) capitalised exploration.
(4) Equity accounted investments.
(5) Includes Selbaie, Pering and the North America copper mining and smelting operations (which ceased operations during the September 1999 quarter).

Production ('000 tonnes)	2002	2001
Payable copper in concentrate	284.7	299.8
Copper cathode	125.4	123.4

Half Year Comparison 31 December 2002 vs 31 December 2001

CARBON STEEL MATERIALS

Half year ended 31 December 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (1)	Net Operating Assets	Capex (2)	Exploration gross	Exploration to profit
WA Iron Ore	567	266	32	234	1 019	101		
Samarco (3)	105	30	-	30	317	-		
Total Iron Ore	672	296	32	264	1 336	101		
Queensland	569	216	38	178	733	18		
Illawarra	173	66	12	54	154	22		
Total Metallurgical Coal	742	282	50	232	887	40		
Manganese	264	77	14	63	364	14		
Boodarie™ Iron	80	(45)	-	(45)	1	4		
Divisional activities	(22)	(6)	-	(6)	(5)	-		
Third party products	11	(2)	-	(2)	-	-		
Total	**1 747**	**602**	**96**	**506**	**2 583**	**159**	**2**	**2**

Half year ended 31 December 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (1)	Net Operating Assets	Capex	Exploration gross	Exploration to profit
WA Iron Ore	539	306	35	271	884	36		
Samarco (3)	77	20	-	20	333	-		
Total Iron Ore	616	326	35	291	1 217	36		
Queensland	597	252	28	224	679	31		
Illawarra	144	53	6	47	113	6		
Total Metallurgical Coal	741	305	34	271	792	37		
Manganese	236	73	18	55	372	8		
Boodarie™ Iron	78	(43)	-	(43)	26	14		
Divisional activities	(25)	(9)	-	(9)	-	-		
Third party products	14	-	-	-	-	-		
Total	**1 660**	**652**	**87**	**565**	**2 407**	**95**	**1**	**1**

(1) Excludes exceptional items.
(2) Capex in aggregate comprises US$116 million growth and US$43 million sustaining.
(3) Equity accounted investment.

Production (Million tonnes)	**2002**	**2001**
Iron ore	37.1	34.4
Metallurgical coal	17.0	17.2
Manganese alloys	0.4	0.3
Manganese ores	2.2	1.9

Half Year Comparison 31 December 2002 vs 31 December 2001

DIAMONDS AND SPECIALTY PRODUCTS

Half year ended 31 December 2002

US$ Million

	Turnover	EBITDA [1]	Depn & amortisation	EBIT [1]	Net Operating Assets	Capex [2]	Exploration gross [3]	Exploration to profit
Diamonds	172	97	34	63	905	18		
Other businesses [4]	538	110	-	110	585	-		
Exploration and Technology	6	(22)	1	(23)	(6)	3		
Total	**716**	**185**	**35**	**150**	**1 484**	**21**	**24**	**24**

Half year ended 31 December 2001

US$ Million

	Turnover	EBITDA [1]	Depn & amortisation	EBIT [1]	Net Operating Assets	Capex	Exploration gross [3]	Exploration to profit
Diamonds	165	114	34	80	911	54		
Other businesses [4]	582	93	5	88	769	3		
Exploration and Technology	5	(29)	1	(30)	(8)	4		
Total	**752**	**178**	**40**	**138**	**1 672**	**61**	**34**	**33**

(1) Excludes exceptional items.
(2) Capex in aggregate comprises US$14 million growth and US$7 million sustaining.
(3) Includes US$nil (2001:US$1 million) capitalised exploration.
(4) Includes Richards Bay Minerals and Integris Metals Inc (formerly Metals Distribution), which are equity accounted businesses.

Production ('000 carats)	2002	2001
Diamonds	2 025	1 695

Half Year Comparison 31 December 2002 vs 31 December 2001

ENERGY COAL

Half year ended 31 December 2002

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (1)	Net Operating Assets	Capex (2)	Exploration gross (3)	Exploration to profit
Ingwe	443	134	64	70	932	34		
New Mexico	218	60	13	47	193	21		
Hunter Valley	48	6	7	(1)	403	120		
Indonesia	6	(2)	-	(2)	(6)	-		
Colombia (4)	87	12	-	12	618	-		
Divisional activities	-	(5)	-	(5)	32	-		
Third party products	145	3	-	3	-	-		
Total	**947**	**208**	**84**	**124**	**2 172**	**175**	**2**	**-**

Half year ended 31 December 2001

	US$ Million							
	Turnover	EBITDA (1)	Depn & amortisation	EBIT (1)	Net Operating Assets	Capex	Exploration gross (3)	Exploration to profit
Ingwe	529	240	53	187	983	29		
New Mexico	211	53	16	37	202	68		
Hunter Valley	61	17	9	8	202	22		
Indonesia	120	108	11	97	(6)	1		
Colombia (4)	61	22	-	22	386	-		
Divisional activities	-	(4)	-	(4)	13	-		
Third party products	63	3	-	3	-	-		
Total	**1 045**	**439**	**89**	**350**	**1 780**	**120**	**3**	**-**

(1) Excludes exceptional items.
(2) Capex in aggregate comprises US$148 million growth and US$27 million sustaining.
(3) Includes US$2 million (2001:US$3 million) capitalised exploration.
(4) Equity accounted investment.

Production (Million tonnes)	**2002**	**2001**
Energy coal	40.1	43.0

Half Year Comparison 31 December 2002 vs 31 December 2001

STAINLESS STEEL MATERIALS

Half year ended 31 December 2002

	US$ Million							
	Turnover	EBITDA [1]	Depn & amortisation	EBIT [1]	Net Operating Assets	Capex [2]	Exploration gross	Exploration to profit
Nickel	285	90	35	55	1 336	35		
Chrome	203	21	15	6	293	15		
Other [3]	-	-	-	-	80	-		
Third party products	3	-	-	-	-	-		
Total	**491**	**111**	**50**	**61**	**1 709**	**50**	**2**	**2**

Half year ended 31 December 2001

	US$ Million							
	Turnover	EBITDA [1]	Depn & amortisation	EBIT [1]	Net Operating Assets	Capex	Exploration gross	Exploration to profit
Nickel	200	20	33	(13)	1 296	29		
Chrome	167	(2)	18	(20)	316	10		
Columbus Stainless Steel	79	(3)	-	(3)	135	-		
Third party products	3	-	-	-	-	-		
Total	**449**	**15**	**51**	**(36)**	**1 747**	**39**	**3**	**12**

(1) Excludes exceptional items.
(2) Capex in aggregate comprises US$9 million growth and US$41 million sustaining.
(3) The Group's remaining interest in Columbus Stainless Steel and the investment in Acerinox SA. are accounted for as fixed asset investments.

Production ('000 tonnes)	2002	2001
Nickel	38.5	33.4
Ferrochrome	468	413

PORTFOLIO RISK MANAGEMENT

This table summarises the next four quarters as at 31 December 2002 with respect to the BHP Billiton Group's significant derivative financial instruments used to hedge Australian dollar costs that are sensitive to changes in exchange rates for the forthcoming twelve months.

		Weighted average A$/US$ exchange rate			Contract amounts	
		Forwards	Call options	Put options	A$ million	US$ million
US dollars						
Q3 2003	- forwards	1.5489	-	-	325	210
	- collar options	-	1.4686	1.5363	29	20
	- Purchased options	-	-	-	-	-
	- sold options	-	-	-	-	-
Q4 2003	- forwards	1.6292	-	-	342	210
	- collar options	-	-	-	-	-
	- Purchased options	-	-	-	-	-
	- sold options	-	-	-	-	-
Q1 2004	- forwards	1.6515	-	-	297	180
	- collar options	-	-	-	-	-
	- Purchased options	-	-	-	-	-
	- sold options	-	-	-	-	-
Q2 2004	- forwards	1.5974	-	-	176	110
	- collar options	-	-	-	-	-
	- Purchased options	-	-	-	-	-
	- sold options	-	-	-	-	-

Commodity price risk

As at 31 December 2002 there were no significant commodity price derivative financial instruments outstanding.

Risk mitigation transactions

During the half year ended 31 December 2002, the BHP Billiton Group entered into forward contracts to hedge 80% of the committed portion of the BHP Billiton Group's share of Australian dollar capital expenditure in relation to the Mining Area C (MAC) and Port & Capacity Expansion (PACE) capital projects at Western Australian iron ore operations and the Dendrobium Coal capital project at Illawarra metallurgical coal operations. Total principal amounts in relation to these forward contracts are A$854 million, which are hedged at a weighted average exchange rate of 1.8804 Australian dollars to one US dollar. The contracts' expiry dates extend up to November 2004.

Strategic financial transactions

As at 31 December 2002 there were no strategic financial derivative transactions outstanding.

SHARE PRICE PERFORMANCE

	BHP Billiton Plc UK Pence	BHP Billiton Limited Australian dollars
Closing price at 31.12.02	331.8	10.15
Closing price at 28.06.02	335.9	9.63
Closing price at 31.12.01	327.9	9.82
High during the period	348.6(1)	10.50(3)
Low during the period	259.5(2)	8.30(4)

(1) on 8 July 2002
(2) on 5 August 2002
(3) on 9 July 2002
(4) on 6 August 2002
(5) the Highs and Lows disclosed above represent closing prices not intra-day trading

ATTACHMENT 4

NPDES SHORT FORM D INFORMATION