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OIL SHALE UTILIZATION FOR POWER PRODUCTION IN THE HASHEMITE KINGDOM OF JORDAN

VOLUME V OF VI - APPENDIX 6
ORNL STUDY

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JORDAN OIL SHALE TO POWER
PREFEASIBILITY STUDY

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AN ASSESSMENT OF USING OIL SHALE FOR POWER PRODUCTION IN THE HASHEMITE KINGDOM OF JORDAN

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ABSTRACT

AN ASSESSMENT OF USING OIL SHALE FOR POWER PRODUCTION IN THE HASHEMITE KINGDOM OF JORDAN

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Up until the present, Jordan has relied almost exclusively on imported petroleum for its primary energy requirements. Encouraged by emerging technologies and recent fossil fuel discoveries, Jordanians are seriously examining exploitation of their own indigenous energy resources to meet projected mid-and long-term power requirements. These resources include (1) potentially significant amounts of natural gas and some crude oil (both only recently discovered and not yet adequately quantified); (2) large oil shale deposits in at least four sites; and, to a lesser extent, (3) renewable energy forms, including wind, sun, and biomass. Planning for future capacity expansion in the power sector is particularly difficult in Jordan because of uncertainties about the extent of its oil and gas reserves, the costs of exploiting its large oil shale reserves, and the future price of petroleum.

This report addresses the oil shale-for-power-production option in Jordan. Under consideration are 20- and 50-MW demonstration units and a 400-MW, commercial-scale plant. The report emphasizes four areas: (1) the need for power in Jordan, (2) environmental aspects of the proposed oil shale-for-power plant(s), (3) the engineering feasibility of using Jordan's oil shale in a circulating fluidized bed combustion (CFBC) boiler, and (4) the economic feasibility of the proposed plant(s).

Assessing Jordan's future power needs is complicated by the possibility of power imports from and exports to neighboring Arab countries, by demand-side management activities, and by uncertainty about growth prospects for the Jordanian economy. Thus, there is no "best" projection of future power demand in Jordan. Laboratory analyses of the ash left from a recent test burn of the Jordanian shale suggests that there are no severe environmental concerns about leachates and that sulfur emissions would be neutralized by the carbonate in the shale. Based on results of the test burn and recent improvements and experience with CFBC technology, it appears from a technical perspective that Jordanian shale could be successfully exploited.

A sensitivity study was conducted to determine the economic feasibility of the proposed plant(s) under different cost assumptions and revenue flows over the plant's lifetime. The results suggest that the 20-MW plant is not an economically attractive option under any circumstances. Under the rate level in existence for 1987 and most of 1988, the 50-MW option is not an attractive alternative either. Under this rate structure, the returns for the 400-MW plant approach or exceed Jordan Electricity Authority's opportunity cost of capital under only the most favorable cost and operating assumptions. Increasing the tariff level results in more favorable conclusions for the 50- and 400-MW options under various input assumptions. The sensitivity results are extended to include the major extra-firm benefits of the shale-for-power option: (1) foreign exchange savings from using domestic energy resources, (2) aggregate income effects of using Jordan's indigenous labor force, and (3) a higher level of energy security.

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MEASURES AND ABBREVIATIONS USED

AFUDC	allowance for funds used during construction
AID	U.S. Agency for International Development, USAID or A.I.D.
bbl	barrel
bbls/d	barrels per day
Btu	British thermal unit (1005 Joules or 0.293×10^{-3} kWh)
c	capita, person
¢	cent, 10^2 ¢ = 1 U.S. dollar($)
CFB	circulating fluidized bed
CFBC	circulating fluidized bed combustion
d	day
D/E	debt to equity ratio
DSM	demand-side management
EPA	(U.S.) Environmental Protection Agency
EPRI	Electric Power Research Institute (a private, non-profit U.S. research organization whose activities are funded by U.S. electric utilities
fils	fils, 10^3 fils = 1 J.D.
ft	foot, 12 in; 0.3048 m
GDP	Gross Domestic Product
GNP	Gross National Product
GOJ	Government of Hashemite Kingdom of Jordan
GWh	gigawatt-hour, 10^9 W-hours
h	hour
ha	hectare, 10^5 m^2; 1 ha = 2.469 acres
hp	horsepower; 745.7 W per minute
HTPS	Hussein Thermal Power Station
IDC	interest during construction
IDECO	Irbid District Electric Company
in	inch, 2.54 cm
IRR	internal rate of return
J.D.	Jordanian dinar, JD, the national currency of Jordan, 10^3 fils; U.S.$3.00 at time of staff visit in April 1988; $2.13 in December 1988
JEA	Jordan Electricity Authority
JEPCO	Jordan Electric Power Company
JPMC	Jordan Phosphate Mining Company, Ltd.
JPRC	Jordan Petroleum Refining Company
kV	kilovolts, 10^3 V
kW	kilowatt, 10^3 W
kWh	kilowatt-hour, 10^3 W-hour
L	liter, 0.264 U.S. gallons
lb	pound, 453.59237 grams
L/c/d	liters per capita per day
m^3	cubic meter, 264 U.S. gallons; 1.308 cubic yards
m^3/s	cubic meters per second (22.8 million gallons per day)
mbar	millibar (also often shown as mb); 10^{-3} bars; 9869×10^{-4} atmospheres (1 atmosphere = 76.0 cm Hg or 1,013 mb)
MEMR	Ministry of Energy and Mineral Resources
MOP	Ministry of Planning
Mm^3	million cubic meters
MMSCFD	million standard cubic feet (of natural gas) per day

M&I	municipal and industrial
MBtu	thousand British thermal units (10^3 Btu)
MW	megawatt (electric), MWe, 10^3 kW, 10^6 W, all measurements in this report expressed as MW are considered MWe unless designated MWt (MW thermal)
μ	micron, 10^{-6} m; micro- 10^{-6}
NPV	net present value
NO_x	nitrogen oxides
NRA	Natural Resources Authority of the GOJ
ORNL	Oak Ridge National Laboratory; Oak Ridge, Tennessee, USA
∇p	CFB bed pressure
PV	photovoltaics
ppm	parts per million
psia	pounds/in^2/atmospheric pressure
RCRA	(U.S.) Resource Conservation and Recovery Act
$	U.S. dollar, national currency of the United States of America, 10^2 ¢
s	second
SO_2	sulfur dioxide
t	1 metric tonne, 10^3 kg, 2204.6 pounds
ton	2000 pounds, 0.907 tonnes
TW	terawatt, 10^{12} W
tpy	tonnes per year, t/y
TOE	tonnes of oil equivalent; 44.76 x 10^9 Joules,
U.S.	United States of America
w	Watt
WAJ	Water Authority of Jordan
y	year

EXECUTIVE SUMMARY

AN ASSESSMENT OF USING OIL SHALE FOR POWER PRODUCTION IN THE HASHEMITE KINGDOM OF JORDAN

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Energy planning in Jordan is complicated by uncertainties surrounding the extent of indigenous petroleum and natural gas resources and, given these uncertainties, the optimal use of its sizeable oil shale resources. Jordan is currently producing approximately 1,000 barrels per day (bbls/d) of crude **petroleum**; its total petroleum needs, however, exceed 60,000 bbls/d. There is ongoing exploration by three international oil companies which took petroleum concessions in 1986. The prospects for discovering significant amounts of crude oil, however, are still uncertain at the present time. Similar to the uncertainty surrounding petroleum resources, there are insufficient geological data to speculate on the extent of **natural gas** reserves at the present time. The Government of Jordan has two gas wells presently in operation at Risha in the northeastern part of the country that have been tested at 20 MMSCFD (million standard cubic feet per day). Based on this optimistic finding, the government is committed to installing 2 X 30-MW gas turbines at the Risha site (to be completed by late 1988 or early 1989) and to constructing a 132-kv transmission line over the 334 km from the capital at Amman to the Risha fields. The government may ultimately add up to 4 x 30-MW gas turbines at the Risha fields, reaching the capacity of the 132-kv transmission line.[1] Four **oil shale** sites have been cored, drilled, and studied to date, with resulting data published for three of these. The three sites comprise nearly one-half of the country's proven geological reserves of more than 10 billion tons. Possibilities for exploiting the shale include indirectly using it (retorting) for producing a liquid fuel and directly using it as a high residual ash fuel in power production. Both options are currently being explored by the Jordanian government.

In this report, we address the oil shale-for-power-production option. Specifically, the feasibility of 20- and 50-MW demonstration units and a 400-MW commercial-scale plant are considered. The study addresses four areas: (1) the need for power in Jordan over the next two decades; (2) environmental aspects of the proposed plant(s); (3) the engineering feasibility of using Jordanian oil shale in a circulating fluidized bed (CFB) combustor; and (4) the economic feasibility of the proposed plant(s) and mining operations.

Projected Power Needs in Jordan

The power sector in Jordan has grown rapidly over the past two decades, especially in the late 1970s and early 1980s when an economic boom led to increased demand for electricity

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[1] PetroCanada is currently conducting a reservoir study to ascertain the size of the reserves at the Risha site. The study is expected to be completed by early 1989.

and a consequent increase in generating capacity. From 1975 to 1987, electricity consumption increased at an average annual rate of 20.2 percent. Generating capacity in the country increased to 979 MW by the end of 1987. More recently, however, growth in electricity consumption has slowed. In the two-year period from 1985-1987, consumption grew at an average annual rate of "only" 10.8 percent.

An important question for power planning in Jordan is the future growth of electricity demand. Estimates of future capacity requirements to meet expected load growth until the year 2005 range from 543 MW to more than 1,500 MW, assuming a 30 percent reserve margin. Three aspects of the Jordanian economy and power subsector make evaluation of future electricity consumption especially difficult:

- There is a great deal of uncertainty about the net impact on electricity sales of the potential interconnections among the national power systems of Jordan, Syria, Egypt, and Saudi Arabia. Currently, Jordan exports power to Syria. However, in September 1988, the governments of Jordan and Egypt signed a technical protocol for constructing a transmission line linking the power systems of both countries, with implementation expected to commence in early 1989. Also, Jordan and Egypt agreed to study the feasibility of connecting both their national grids to Saudi Arabia.

- Uncertainty surrounds the impact of both implemented and implementable demand-side management programs on future electricity demand.

- There is uncertainty about the future growth of the Jordanian economy. For one, the country's population is growing at an unusually high 3.8 percent annual rate, and not expected to decline to a still-high rate of 3.2 percent until around 2010. Historically, remittances by Jordanians employed in other Middle Eastern countries have accounted for a large share of gross income in the economy. With the recent decline in international petroleum prices, however, construction programs have been cancelled or delayed, jeopardizing future income from an historically important source. Uncertainty also surrounds the future growth of the industrial sector; it currently accounts for 40 percent of electricity demand. Large industrial power users in five industries, producing largely for export markets, account for more than 75 percent of this total. Future export markets for these industries are uncertain.

Projected Major Environmental Affects of the Proposed Oil Shale-for-Power Project

The major environmental affects of the proposed project revolve around control of the enormous quantities of waste ash and overburden that would be generated from a 400-MW facility over a 25-30 year period. This control effort takes two forms: (1) control of the fugitive dust from shale oil mining, transport, and crushing, and from disposal of the overburden and the ash itself; and (2) control of the final disposition of the ash in terms of groundwater protection. There are minor concerns about general water availability. The concerns about dust control are both in terms of occupational safety and in terms of the surrounding residents and the immediate biota.

Jordan has no comprehensive environmental standards regulating industrial development such as the proposed oil shale plant. Absent comprehensive standards to guide industrial development, the GOJ relies on the Department of Environment in the Ministry of Interior

to monitor and sometimes prevent the more egregious affronts to the environment. For major projects such as the proposed oil shale plant, the Department of the Environment would look to U.S. standards and World Bank guidelines in the interim until the country adopts its own regulatory standards and procedures.

The materials handling problems associated with moving vast quantities of rock and shale encompass several major environmental issues. As mentioned in the Bechtel Group's project plan, the need for a 50-MW step is more for answering questions centered on "design issues for optimizing a 100-MW plant, in particular materials flow, rather than any need to prove the technology feasibility." At peak, operation of the 400-MW plant would generate approximately 1000 tonnes per hour of wetted residual ash for disposal.

Conclusions about the different key concerns are:

Air quality and dust control

- Although there has been extensive work undertaken in the U.S. public and private sectors to determine the degree of pollution control that must be used by oil shale facilities to protect air quality, it is not possible to predict with confidence what precise impacts oil shale mining and CFBC technology would have on air quality at various levels of shale oil production because no large-scale facilities exist to date and because the proposed Jordanian project employs an innovative technology.

- The incidence of respiratory diseases in other minerals extraction industries indicates that exposure to the shale dusts and ashes at the Sultani project could be hazardous.

- Exhaust gases from the plant's boilers would likely be within limits to control emissions and ambient concentrations of SO_2 and NO_x.

- The dust particles from the ash or from the raw oil shale fines would likely be low in silica content (except when cherty materials would be run through the boilers), therefore minimizing the threat of silicosis to plant and mine workers.

Groundwater protection

- According to laboratory analyses of the leachate from the ash obtained from the test burn, ash disposal from the proposed facility may pose some risk of groundwater contamination.

- Jordan has very real water resource problems facing it. There are significant current and future demands placed on the limited groundwater resources in the Sultani area.

- The Sultani area, while seemingly remote, would likely play a secondary role in helping major municipalities meet their municipal and industrial water needs as early as the late 1990s.

- There likely would be adequate groundwater of sufficient quality and at reasonable pumping depths for operation of the proposed plant/mine/waste disposal complex and for meeting future competing needs.

- Groundwater flow regimes in the Upper Wadi Mujib drainage suggest that leachate from the fly ash that enters the water table with inadequate filtration and dilution could cause drinking water problems with municipal users in Amman or Karak, now and increasingly in the future.

- Care must be taken in the fly ash waste disposal and reclamation engineering to optimize filtration of fly ash leachate through replaced overburden before it can infiltrate the Amman Wadi Sir groundwater.

- Monitoring wells and instrumentation or regular sampling are required to assure that water safe from chromium and/or selenium contamination is being pumped from the Sultani and Qatraneh well fields.

Land reclamation

- There is ample surface area available at the Sultani site for permanent storage of mine and plant wastes.

- The land reclamation program proposed for the Sultani project is generally reasonable and responsible.

- Consideration of using the fly ash as an amendment to cement, asphalt, or other construction materials both as a profitable venture and as a means to decrease the quantities of materials to be disposed is premature at this stage of the analysis.

Erosion and sedimentation control

- Erosion and sedimentation controls, both short- and long-term, during mining and waste disposal appear adequate.

Engineering Feasibility of the CFB Combustion Technology

While fluidized bed boilers have been available for decades, they have started to make headway in commercial applications in recent years because of their high efficiency, clean burning characteristics, and ability to burn a variety of fuels. Rising oil prices over the past 15 years have contributed much to fluidized bed technologies' marketplace penetration. Throughout the world, there are 52 manufacturers of three types of fluidized boilers: bubbling bed, circulating, and pressurized.

Circulating fluidized bed (CFB) is a second-generation technology wherein the boilers are designed to burn low-cost, high sulfur coal or other waste products, producing steam and electricity without the need for expensive treatment of the exhaust stream. In a CFB boiler, high velocity air "fluidizes" a crushed fuel mix in the combustion chamber, transporting the solids up the chamber, where waterwalls are heated. Large, hot cyclones return the unfired fuel and other solids to the combustor chamber where they will, on the average, make several passes through the system before leaving as flue gases or as ash. Low operating

temperatures minimize NO_x emissions, and the use of limestone (where needed) can reduce SO_2 sufficiently to avoid having to use costly scrubbers.

First introduced beginning in 1979, there have been about 75 CFB boiler plants built worldwide. They have been designed to burn a wide variety of fuels: wood waste, peat, lignite, bituminous coal, coal washery tails, anthracite culm, industrial wastes and sludges, petroleum coke, and others.

The technology appears to have been successfully demonstrated in units as large as 60 MW. There are no indications that there will be any problems in successfully demonstrating larger plants.

Combustion tests of Jordan's oil shale were conducted in the Ahlström CFB test unit at their R&D Center in Karhula, Finland from January 11-20, 1988. The test program consisted of a series of runs in which one or more of the key operating parameters was changed for each run so that the effects on the combustion performance could be determined. Conclusions are:

- The Jordanian oil shale, because of its high ash content, is a more challenging fuel than, say, bituminous coal for use in scaling up to larger plants. The large quantities of ash which would be circulated through the combustor and returned by the hot cyclone would place a heavy demand on the return leg and loop seal.

- The Sultani oil shale's high volatile content should make it easy to start and would burn generally well even down to low loads.

- Low SO_2 and NO_x emission levels would likely be achievable in the circulating fluidized bed combustor, utilizing the calcium present in the shale and requiring no sorbent or chemical additives.

- The primary potential problem areas associated with the high ash content would be (1) bottom ash removal from the combustor, (2) high flow rate of recycle solids through the hot cyclone and return leg, (3) fly ash deposition and erosion of the convection tube banks, and (4) erosion of superheater tubes in the combustor.

Technical risks associated with each of the proposed unit sizes are:

- The technical risk should be fairly low for a 20-MW demonstration plant. Eighteen plants of this size or larger have been built by Ahlström or its subsidiaries; these plants have operated for a year or longer and have experienced availabilities of 95 percent or more.

- The technical risk is moderate for a 50-MW plant. There is some operating experience with plants of this capacity firing coal or other low- to medium-ash fuels, but there is not yet any experience with high-ash fuel in plants this large.

- The technical risk is fairly high to build a 100-MW plant as the first unit. There is no plant this large operating or under construction which is designed to operate on high-ash fuel.

Economic Feasibility of the Proposed Oil Shale-for-Power Project

The economic analysis consists of a series of sensitivity studies for 20-MW, 50-MW, and 400-MW options, calculating the present values of net benefits and the internal rates of return. For each plant size, the sensitivity studies included different assumptions about the operating characteristics of the plant: (1) capacity factor (50 percent, 60 percent, and 75 percent);[2] (2) average price of electricity, 6.0 ¢/kWh obtained by JEA in 1987[3] and two alternatives (7.5 and 9.0 ¢/kWh); (3) mining/processing and residual ash disposal (a 50/50 and 80/20 debt/equity ratio);[4] and (4) five capital expenditure scenarios, a base case provided by the Bechtel Group (noted Base) and four alternatives: an assumed 25 percent reduction in the base [Base(0.75)], a 25 percent increase [Base(1.25)], and 50 and 100 percent increases [Base(1.50) and Base(2.00)].[5] A total of 270 sensitivity studies were conducted, 90 for each plant size. Four major conclusions were drawn from the study:

- The 20-MW plant is not an economically attractive option for Jordan under any of the scenarios considered in the study.
- Under the tariff level currently in existence (6 ¢/kWh in average revenues), the 50-MW option is not economically attractive.
- Under the current tariff level, the 400-MW option is attractive, contingent on assumptions made about the operating characteristics of the plant (Table S.1, discussed below).
- Increasing JEA's current tariff level by 25 percent to 7.5 ¢/kWh makes the 50-MW option economically attractive under only the most favorable operating assumptions (Table S.2, discussed below).

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[2]The economic analysis here is not being conducted in tandem with a least cost capacity expansion planning model such as WASP III. An analysis such as this is beyond the scope of this prefeasibility assessment. In the event that a feasibility study is undertaken, a capacity expansion planning model would presumably be used. A model such as WASP would estimate the actual utilization (running time) of 20-, 50-, and 400-MW plant options based on minimizing system cost, given assumptions about (1) the operating characteristics of all other plants in JEA's system and the shale alternatives, (2) projected fuel costs, and (3) forecasted electricity demand. In the present study, we simply assume three different capacity factors for each of the three plant sizes.

[3]Most recently, electricity prices were lowered for at least some customer classes as part of an austerity program announced by the government on November 6, 1988. See *The Wall Street Journal* and *New York Times*, November 7, 1988.

[4]The debt/equity ratios refer to the assumed capitalization of the mining/processing and residual ash disposal operations. The 80/20 debt/equity assumption implies a lower cost of capital because the cost of debt is assumed smaller than the return required for equity capital.

[5]The ±25 percent scenarios are commonly used in sensitivity analyses. The +50 and +100 percent scenarios were included because estimates of capital expenditures for power plants are notoriously uncertain, especially when operating in a foreign environment. Another important consideration is the foreign exchange needed to import materials for constructing the plant. Most recently, the Jordanian Dinar has been depreciating in international exchange markets, increasing the cost of importing materials for constructing power plants. On December 31, 1987, the Jordanian Dinar was worth $3.04. The exchange rate stayed fairly stable during the first third of 1988, equalling $2.95 at the end of April 1988. However, since then it has steadily declined to the point where on December 15, 1988 it was $2.13.

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Table S.1 provides results for the 400-MW option, using the average revenue realized by JEA on its electricity sales in 1987 (6 ¢/kWh) and the most favorable assumption about the capital structure of the mining/processing and ash disposal operations (80/20 debt/equity ratio). The results show that, assuming a very low capital cost of the plant [Base(0.75)], the returns for the 60 and 75 percent capacity factor scenarios exceed JEA's opportunity cost of capital (which is 9 percent). The same is true under the Base scenario, assuming a 75 percent capacity factor. The results deteriorate substantially assuming higher capital expenditures on the plant.

Table S.1
Selected Sensitivity Results under Current Tariff Structure[a]
By Capacity Factor and Capital Expenditure Scenarios
400-MW Option
(In percentages)[b]

Capacity Factor	Base(0.75)	Base	Base(1.25)	Base(1.50)	Base(2.00)
75%	13.41	9.77	7.33	5.54	3.02
60%	9.75	6.66	4.57	3.00	0.77
50%	7.01	4.30	2.43	1.02	.

Source: Chapter 9

[a] The current tariff structure yields on average 6.0 ¢/kWh for electricity sales. Also, the results include the 80/20 debt/equity assumption for the capital structure of the mining/processing and spent ash disposal operations.

[b] A "." signifies that the internal rate of return is less than zero.

Increasing average revenues improves the results. Table S.2 presents the results under the 7.5 ¢/kWh assumption for both the 50- and 400-MW options under different scenarios. *Assuming that the average revenue received by JEA for its electricity sales were increased by 25 percent from 6.0 ¢/kWh to 7.5 ¢/kWh,* Table S.2 shows that the 50-MW option would be economically attractive (IRR approaching or exceeding 9 percent) only under the most favorable conditions: very low capital expenditures [Base(0.75)] and high running rate (75 percent capacity factor). Because of scale economies, the results for the 400-MW option are significantly better. Assuming a 75 percent capacity factor, the simulated returns for the 400-MW option exceed 9 percent in all cases except under the most unfavorable assumption about the cost of the plant [Base(2.00)]. Assuming a 50 percent running rate, the returns approach or exceed 9 percent under the two most favorable assumptions about the cost of the plant.

The sensitivity analysis conducted in this study was undertaken at the individual firm level, that of JEA. There are three important extra-firm benefits -- benefits that accrue to the economy or society as a whole -- that must also be considered when evaluating the oil shale-for-power option. One of the most important is the foreign exchange savings resulting from using indigenous oil shale in comparison with importing petroleum or coal. Second, mining and processing the oil shale and disposing of the residual ash in

comparison with importing coal and/or petroleum will have a significant net impact on employment in the country. Finally, there is an energy security benefit to Jordan in terms of using domestic energy in comparison to importing petroleum. If the proposed plant were not economically attractive from the standpoint of the electricity authority, the premium that policymakers place on this difficult-to-quantify, energy security benefit – and the foreign exchange and employment benefits – will determine if the plant should be built.

Table S.2
Selected Sensitivity Results under an Assumed Tariff Increase[a]
By Capacity Factor and Capital Expenditure Scenarios
50- and 400-MW Options
(in percentages)[b]

Capacity Factor	50 MW[c]					400 MW[c]				
	0.75	1.00	1.25	1.50	2.00	0.75	1.00	1.25	1.50	2.00
75%	9.16	6.15	4.08	2.54	0.31	19.92	15.18	12.07	9.83	6.73
60%	5.92	3.32	1.51	0.14	.	15.43	11.46	8.82	6.90	4.20
50%	3.40	1.09	.	.	.	12.17	8.72	6.40	4.69	2.27

Source: Chapter 9

[a] The current tariff structure yields on average 6.0 ¢/kWh for electricity sales. This scenario assumes that average revenues were increased by 25 percent to 7.5 ¢/kWh. Also, the results include the 80/20 debt/equity assumption for the capital structure of the mining/processing and spent ash disposal operations.

[b] A "." signifies that the internal rate of return is less than zero.

[c] Number headings refer to the five capital expenditure scenarios.

1. INTRODUCTION

1.1 HISTORY OF PROJECT

In Spring 1986, the Bechtel Group, Inc. completed a cursory examination of building a 20-MW demonstration oil shale-for-power production plant in western Jordan. Based on this study, the U.S. Agency for International Development (AID) agreed to fund through the government of Jordan a more rigorous study of the potential for using oil shale for power production. ORNL was asked to participate in four areas of the study: (1) an assessment of the need for power, (2) a review of environmental aspects of the proposed plant and mining operations, (3) an assessment of the technical feasibility of using circulating fluidized bed (CFB) combustion technology, and (4) a financial and economic assessment of the project. The study was led by the Bechtel Group, Inc. with input provided by the Pyropower Corporation and ORNL.

The first major activity of the study was the shipment of a sample of the Sultani oil shale to Pyropower's parent company, the Ahlström Corporation, in Finland for a test burn under a variety of combustion environments. The results of the test burn proved encouraging. Eleven tons of the residual ash were shipped to ORNL for testing and evaluation of the ash's potential for use as an amendment to construction or paving materials. Tests for carcinogenic, acidity, caustic, or other residual ash characteristics potentially hazardous to human health or the environment were also encouraging (Chapter 7) in light of negative findings. Simultaneous to the testing of the ash, a team visited Jordan in April 1988 to discuss engineering, environmental, and economic aspects of the proposed plant. The team consisted of representatives of the Bechtel Group, Pyropower, AID's Office of Energy in Washington, and ORNL.

1.2 PAST OIL SHALE STUDIES IN JORDAN

Industries involved in oil shale have existed in 14 countries at one time or another, some existing prior to the discovery of oil in 1859. Known oil shale deposits exist in many countries with the full extent of reserves in each as yet unknown.

1.2.1 Global Use of Oil Shale

At present, commercial quantities of oil shale are mined and used for power production through direct combustion in the Soviet Union, China, and Sweden. In Sweden, however, shale is used primarily for uranium preparation. The Soviet Union is the leader in utilizing oil shale directly in boilers for power production. Besides power production, the Soviet Union uses oil shale to obtain petroleum feed stocks and for combined power generation and industrial processing. Annual production of oil shale in the Soviet Union is 35 million tons, with three-quarters of this used as a fuel input for power production. The power plants using oil shale are located in the Baltic Republics. Two of the largest are the Estonian Power Plant (1600 MW) and the Pribaltiiskaya Plant (1450 MW).

Serious U.S. experience with exploitation of the vast U.S. reserves of oil shale (an estimated 630 billion bbls of oil) began in the late 1970s with the establishment of the Synfuels Corporation. Created by the U.S. Congress under the U.S. Energy Security Act, the Synfuels Corporation subsidized development of new technologies for exploiting

unconventional fuel sources. After the price of oil peaked in 1981, the impetus to seek alternative or innovative sources of fuels waned and Congress eventually shut down the Corporation in 1985. To maintain progress after that time in understanding and surmounting the obstacles to successful commercialization of these technologies, Congress guaranteed price supports for fuels being produced from four plants, one an oil shale plant producing liquid fuel through a retort process. The Unocal Corporation's Parachute Creek plant in Colorado has produced more than 600,000 bbls of synthetic oil, while so far reaching only half of its 10,000 bbls/d production capacity. The U.S. government's subsidy to Unocal (it currently guarantees Unocal $46.50/bbl) amounted to $17.4 million in 1987, and will extend to $400 million or 10 years, whichever comes first.

1.2.2 Jordanian Experience with Oil Shale

Jordan's oil shale reserves are estimated to be more than 10 billion tons. The use of shale in Jordan dates back to the beginning of this century. A production plant using Jordanian oil shale to feed a primitive retorting process provided oil fuel for locomotives prior to World War I — before such processes were even tried in Europe or the United States.

More recently, studies of the potential for using the El Lajjun deposit (Figure 1.1) as a source of petroleum fuels were started in 1968 by the Natural Resources Authority (NRA) of the Government of Jordan (GOJ). The studies involved core drilling and laboratory analyses using the Fischer Assay procedure for determining oil yields. Other analyses included determination of the inorganic constituents of the ore and its calorific value and identification of trace elements. NRA consulted British, West German, and U.S. oil shale experts in conjunction with conducting the studies. The studies were terminated in 1969 because the estimated cost of oil shale processing greatly exceeded the then current and projected cost of using imported petroleum. In the 1968-69 period, 53 boreholes were drilled.

The NRA reopened the investigation of the El Lajjun deposit in early 1979 because of the precipitous increase in the cost of imported petroleum and Jordan's rapidly increasing petroleum needs. The NRA's current program at El Lajjun — an assessment of the retort potential of the shale oil — is being assisted by West Germany. In the 1980s, the NRA began to study the Sultani site in detail for the feasibility of using oil shale in a direct combustion process to provide power generation in Jordan.

1.3 LOCATION OF PROPOSED OIL SHALE PLANT(S)

The Sultani site is located approximately 102 km south of Amman, the capital of Jordan, just off the main north-south Desert Highway (see Figure 1.1). The highway connects Jordan's northern neighbors with Mecca, the Holy City of the Islamic world. The proposed oil shale plant, although seemingly in a remote location, would have high visibility in Jordan.

1.4 ORGANIZATION OF REPORT

This draft prefeasibility assessment of the proposed oil shale power plant in Jordan contains eight additional chapters. The next chapter presents an overview of the Jordanian energy sector, including primary energy sources, energy conversion facilities, and final energy demand. It also discusses regulatory institutions in the energy sector of the economy. Section 3 addresses the need for power in the Jordanian economy over the

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next two decades. The discussion includes a description of electricity consumption over the past decade and two sets of forecasts of electricity demand. Three complicating factors in evaluating future electricity demand are then discussed: (1) the possibility of interconnections with – and power exports to – neighboring Arab countries; (2) the potential effect that price- and nonprice-induced demand-side management measures could have on electricity demand; and (3) the future economic growth of the economy, including growth prospects for major industrial electricity consumers. Given these uncertainties in evaluating future electricity demand, three forecasts of load growth are presented and the implied amount of additional generating capacity required in Jordan to service that load growth is computed.

The fourth chapter discusses Jordan's indigenous energy resources which could potentially be used to meet future power requirements. The candidates are crude oil, natural gas, shale, and renewables. Chapters 5 and 6 present technical aspects of the proposed plant. They include a description of the circulating fluidized bed (CFB) combustion technology that would be used in the proposed plant(s) and brief technical descriptions of the plant and mining operations. Much of what was originally Chapter 6 has been withheld because of its proprietary nature. Details may be pursued with the Pyropower Corporation. Chapter 7 discusses potential environmental effects of the plant and mine. Of particular importance here are discussions of the results of the chemical analyses of the residual ash produced from burning the shale, of the availability of water, and of the relationship of ash leachate to groundwater resources. Chapter 8 provides a technical risk assessment of the proposed CFB combustion technology; it is in part based on observing the technology in operation at Colorado UTE, a rural electric cooperative in the United States. The final section contains a financial/economic analysis of the proposed oil shale plant(s), including sensitivity studies of 20-MW, 50-MW, and 400-MW options.

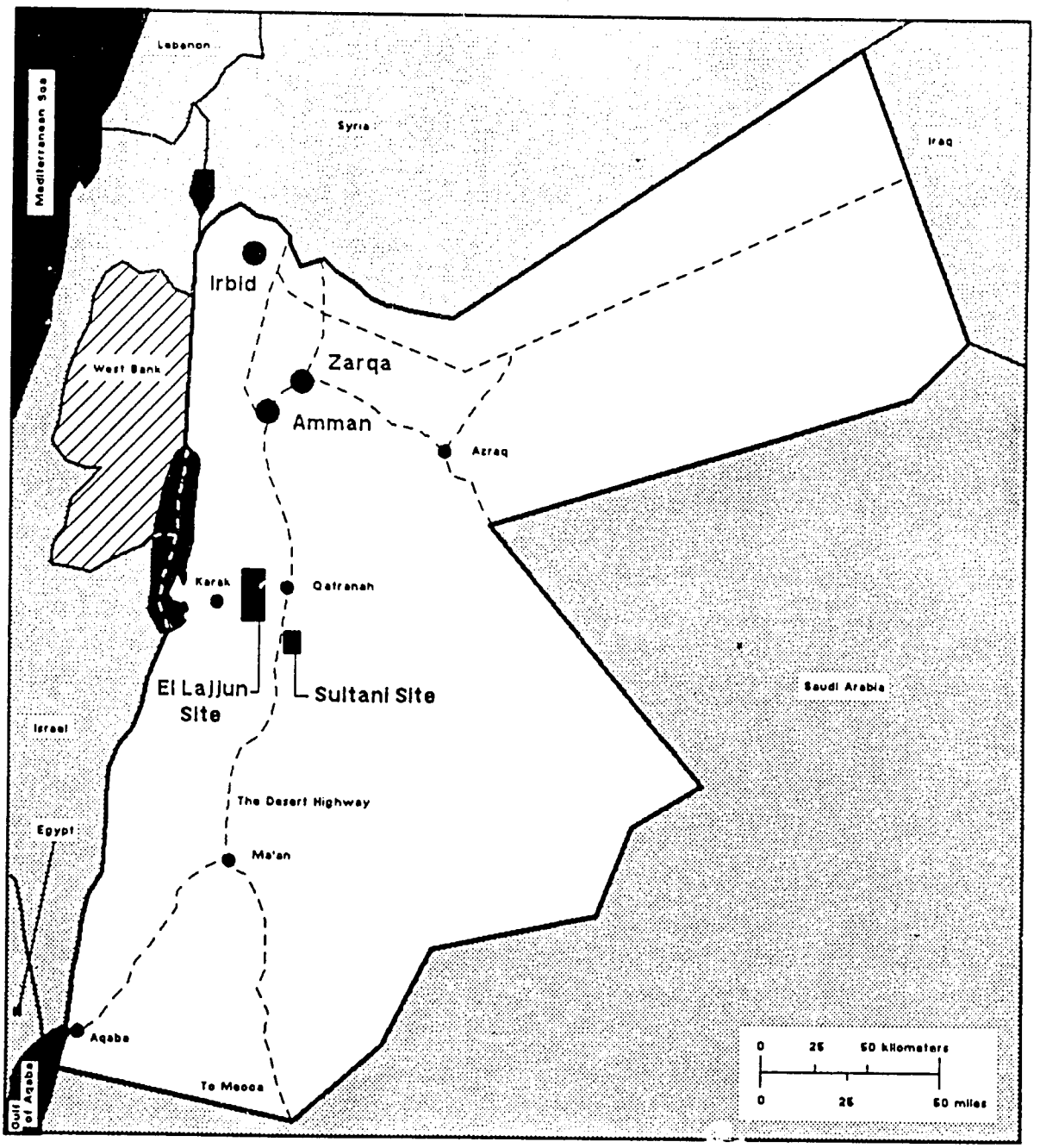

Figure 1.1
Location of Sultani and El Lajjun oil shale deposits

2. AN OVERVIEW OF THE JORDANIAN ENERGY SECTOR

The most salient characteristic of the Jordanian energy economy is its historical reliance on imported petroleum. With the exception of a nominal amount of hydropower and renewable energy sources, Jordan has historically relied on Middle Eastern oil-exporting countries for its energy. Jordan does have indigenous energy resources, but it did not begin intensively studying the extent and economic feasibility of using them until a decade ago.[1] A precipitous increase in Jordan's fuel import bill in the 1970s and early 1980s – caused by the rapid increase in the international price of petroleum and Jordan's robust economy – led policymakers to give indigenous energy development a high priority in economic planning. Emerging technologies have also played a role in studying the feasibility of using Jordan's energy resources. That is especially true for oil shale. The primary reason for this study – examining the feasibility of using oil shale for power generation using a circulating fluidized bed combustion process – was prompted by the emergence of an improved boiler technology for burning high-ash fuels of relatively low energy content. Besides oil shale, Jordan has a number of other potential energy resources which could significantly lessen the historical foreign exchange burden of oil imports. Although not presently tapped to any significant extent, there is a promise for the use of renewable energy in Jordan. More important, recent discoveries of crude petroleum and natural gas in Jordan offer the hope of even more significant foreign exchange savings.

This chapter lays the foundation for the remainder of the study by providing a background on the Jordanian energy sector, emphasizing energy institutions and capacity. Figure 2.1 provides a schematic representation of the Jordanian energy sector as of the end of 1987.[2] Sources of primary energy include petroleum and a limited hydropower potential. The Jordan Petroleum Refining Company (JPRC) is the sole user of the crude oil imported by the government, refining it and selling products to end users.[3] JPRC also sells diesel and fuel oil for electricity production to (1) the Jordan Electricity Authority (JEA), the primary generator of electricity in the country, (2) the Irbid District Electric Company (IDECO), (3) municipalities, and (4) various industrial users for self power generation. Although JEA sells some power to end users, it sells a large portion of the power it produces to the primary distributors in the country – IDECO and the Jordan Electric Power Company (JEPCO). Besides generating their own power, large industrial users also purchase power from the central grid. The largest end user of energy is the transport sector. Each of the three activities depicted in Figure 2.1 (primary energy supply, conversion, and consumption) is discussed in detail below.

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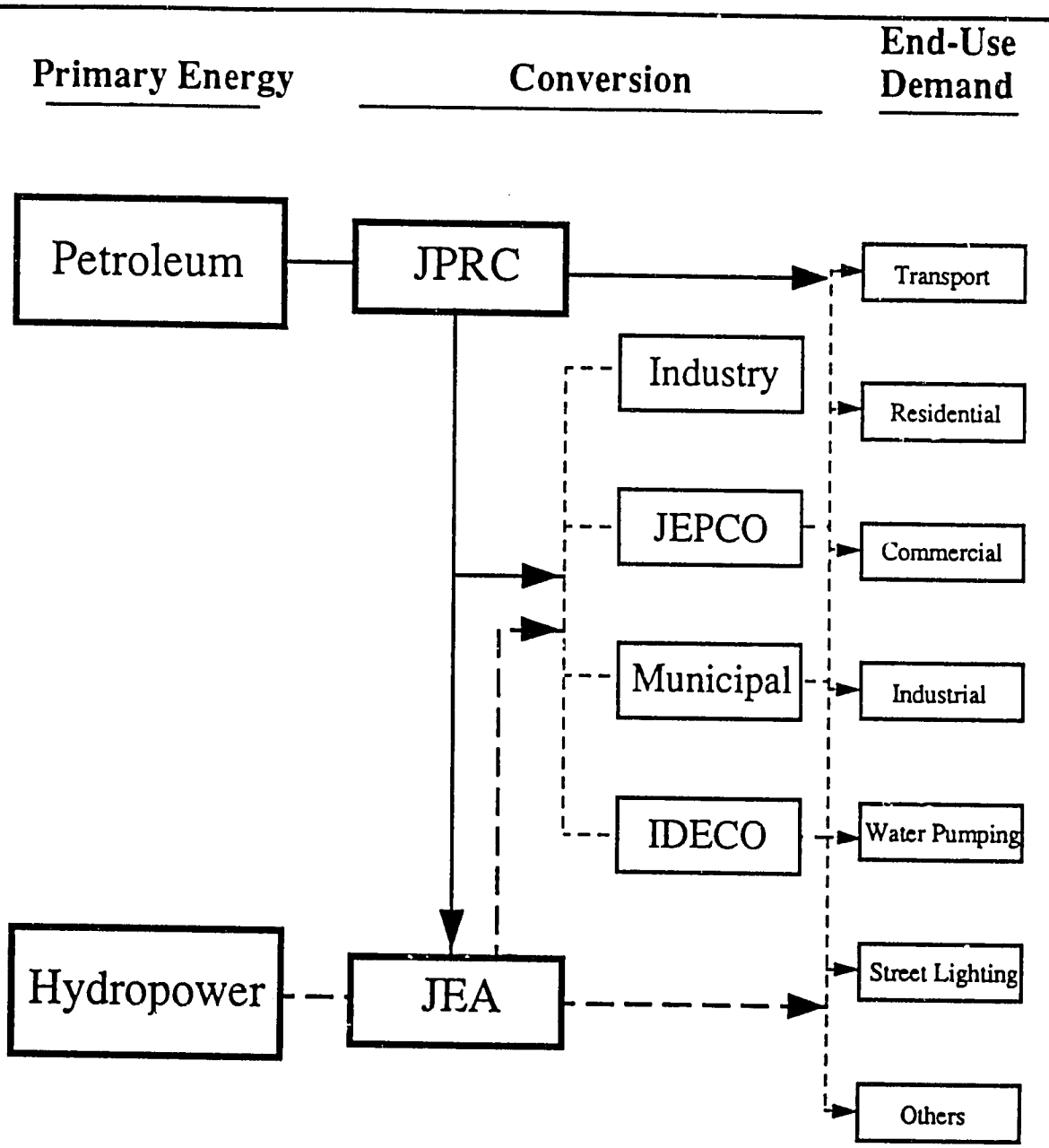
[1] Jordan's oil shale was used to a limited extent prior to World War I. Oil and gas exploration began after World War II, but the international oil companies abandoned Jordan because they believed that it did not have sufficiently large fields to rival those of other Middle Eastern countries. A further discussion of Jordan's indigenous energy resources is provided in Chapter 4.

[2] For clarity of presentation, the use of renewables has been excluded from Figure 2.1.

[3] A portion of Jordan's refined petroleum requirements is not attributable to the output of JPRC, but is imported.



JPRC	- Jordan Petroleum Refining Company	———	Oil Products
JEA	- Jordan Electricity Authority	— — — —	Electricity
IDECO	- IRBID District Electric Company	- - - - - - -	Oil Products and/or Electricity
JEPCO	- Jordan Electric Power Company		

Figure 2.1
Schematic representation of the Jordanian energy sector

2.1 PRIMARY ENERGY SOURCES

Table 2.1 displays the supply of primary energy to Jordan for 1976 and 1986, divided between domestic sources and foreign imports. Total primary energy consumption increased by more than two and one-half times in the decade from 1976 to 1986 (from 1.1 million TOE to 3.0 million TOE), reflecting substantial increases in total economic activity in the country.

Table 2.1
Primary Energy Supply in Jordan
1976 and 1986
(amounts in thousands of TOE)

	1976		1986	
Source	Amount	%	Amount	%
Domestic:				
Crude Oil	0	0.0	15	0.5
Hydro	0	0.0	31	1.0
Subtotal	0	0.0	46	1.5
Foreign:				
Crude Oil	1,112	100.0	2,282	76.9
Fuel Oil	0	0.0	582	19.6
Diesel	0	0.0	51	1.7
LPG	0	0.0	8	0.3
Subtotal	1,112	0.0	2,923	98.5
Total Supply	1,112	0.0	2,969	100.0

Source: World Bank and Government of Jordan, Ministry of Energy and Mineral Resources

In 1976, all primary energy supply was obtained from foreign sources. Domestic sources of energy accounted for only 1.5 percent of primary energy requirements in 1986. Of this amount, a nominal amount of crude oil production from the Amzah region accounted for 0.5 percent and hydroelectric production only 1.0 percent of primary domestic energy supply. Hydropower potential in Jordan is limited to 24 MW (87 GWh/y); an additional 7 MW are currently developed: 4 MW at the King Talal dam on the Zarqa River and 3 MW of the 20 MW potential at the Maqarin Dam on the Yarmuk River. Foreign imports of petroleum accounted for the majority of primary energy supply in 1986, comprising 98.5 percent of the total. Crude oil imports accounted for 76.9 percent of total supply, while fuel oil accounted for 19.6 percent. The remainder was provided by imports of diesel and LPG.

2.2 ENERGY CONVERSION

The petroleum sector in Jordan involves JPRC and the government. JPRC is a privately owned firm. The government, however, holds 12 percent of its stock. It operates the sole petroleum refinery in the country, and is located 35 km north of Amman. It has sole responsibility for refining the crude oil purchased for it by the government. It is also responsible for distributing and marketing all of the refined products. JPRC is regulated by the Ministry of Energy and Mineral Resources (MEMR) in accordance with a concessionary agreement which ensures that the company earns a fair return on investment.

The power sector as it is presently organized in Jordan is a relatively recent phenomenon. JEA was established by enactment of an electricity law in 1967. The purpose of the legislation was to centralize responsibility for power provision, with JEA acting as the coordinator. Under the legislation, JEA could designate existing power stations to operate under its direction, acquire the stations if it was deemed appropriate, and abandon uneconomic power generation facilities. However, JEA did not initially function as a utility. It acted as a conduit for government loans for power development to the existing electric distribution companies. The role of JEA was delineated in 1976 with enactment of the General Electricity Law. According to the statute, JEA is a financially and administratively autonomous electric utility. Its responsibilities include power generation, transmission, and distribution in addition to its responsibility as regulator of power consumption in the country. JEA is governed by an eight-member board appointed by the government and responsible to it for formulating JEA's general policy direction, including the setting of tariffs. JEA is also responsible for the formulation of the national rural electrification program in consultation with MEMR and the Ministry of Planning (MOP).

The legislation allows local distribution systems to operate and to be owned by private investors, but JEA regulates the distribution utilities. JEA, however, may take over the local distribution systems through mutual agreement, subject to the government's approval.

In addition to JEA, which sells some power at low voltage besides its bulk sales to distributors, there are presently two distribution companies operating through concessions from the government. JEPCO is a private company, owned by the public (77 percent), JEA (13 percent), and the municipalities (10 percent). It has responsibility for electricity distribution in the city of Amman and its environs.[4] IDECO is a semi-private company owned by JEA (46.5 percent), the municipalities of the Irbid governate (42.5 percent), and private investors (11 percent). It is responsible for power distribution in the governates of Irbid and Mafraq, with the exception of the Jordan Valley area.[5]

The government agency presently responsible for the energy sector is the MEMR. Created in November 1984, it formulates the overall energy strategy of the country, including

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[4] JEPCO used to be both the largest power generator and distributor in Jordan prior to formation of JEA. JEPCO was formed in 1963 as a result of a merger between Jordan Central Electric Company (distributor in the Zarqa concessionary area) and the Transjordan Electric Power Company, Ltd. The latter company was formed in 1947 as a result of the unification of several small electric power companies which were operating independently in Amman and its environs.

[5] IDECO was created as a private company in Irbid in 1957. In 1961, IDECO was converted to a public company and granted its present concession.

pricing policies in the petroleum and power subsectors. It is also responsible for coordinating activities in the energy sector.

As depicted in Figure 2.1, there are a number of non-utility generators of power in Jordan, including private industrial generators, mining interests, and municipalities. Table 2.2 shows the extent of private ownership of power production facilities in Jordan at the end of 1987 by ownership type and prime mover. Of the 979 MW of total capacity in the country, JEA owned 869 MW or 88.8 percent of the total in 1987. Of the other power generators in Jordan, the diammonium phosphate fertilizer company had the largest amount of capacity, 44 MW in 1987. Two of the other electricity generators were interconnected with the national grid in 1987: the potash mine and IDECO. Their 21 MW of generating capacity combined with 869 MW owned by JEA totals 890 MW of capacity on the interconnected, national grid.

Table 2.2
Installed Electric Generating Capacity in Jordan
By Owner and Prime Mover
December 31, 1987
(MW)

Category	Steam	Gas	Diesel	Hydro	Total
Total	696	182	94	7	979
JEA	623	182	57	7	869
Others:	73	0	37	0	110
Refinery	14	2			16
Arab Potash[a]	15				15
Fertilizer	44				44
IDECO[a]			6		6
Cement (Ferheis Plant)			9		9
El Hasa Phosphate			12		12
Municipalities			8		8

Source: Jordan Electric Authority, *Annual Report, 1987*

[a] Part of the interconnected national power system

2.3 FINAL ENERGY CONSUMPTION

Table 2.3 provides the end-use consumption and percentage composition of all energy consumed in 1976 and 1986 by sector. Energy use in the transport sector – 475,000 TOE in 1976 and 1.11 million TOE in 1986 – accounted for the most energy consumed, comprising over one-half of total energy consumption. The household sector consumed 15.1 percent of all energy in 1986, down from 20.7 percent in 1976. The industrial sector consumed less than 20 percent. However, as the next chapter shows, the industrial sector accounted for nearly 40 percent of total end-use electricity consumption in Jordan in 1987.

Table 2.3
End-Use Energy Consumption in Jordan
1976 and 1986
(amounts in thousands of TOE)

Sector	1976 Amount	1976 %	1986 Amount	1986 %
Household	189	20.7	330	15.1
Transport	475	52.1	1,110	50.7
Industry	184	20.2	421	19.2
Other	64	7.0	195	8.9
Nonenergy Use	0	0.0	132	6.9
Total	912	100.0	2,189	100.0

Source: World Bank and Government of Jordan, Ministry of Energy and Mineral Resources

3. THE NEED FOR POWER

The scope of this prefeasibility study does not encompass developing an electricity demand forecast for the Jordanian electricity subsector. However, two electricity demand forecasts have recently been prepared: (1) the annual Jordan Electricity Authority (JEA) forecast developed as part of its planning process and (2) projections of electricity demand made by Meta Systems/Hagler-Bailly/Bechtel in March 1988.[1] These two electricity demand projections will serve as the basis of the discussion on the need for power.

Before addressing the question of future electricity requirements in Jordan, however, it is instructive to look at historical electricity consumption. Electricity consumption from 1975 through 1987 is the topic of the next section. After reviewing the electricity demand projections of JEA and the Meta Systems *et al.* study in Section 3.2, the discussion turns to complicating factors in assessing the electricity demand forecasts in the subsequent section. Economic projections are notoriously uncertain, contingent on specifying assumptions about the future state of domestic and international economies. Section 3.3 discusses some complicating factors relevant to assessing the future electricity growth in the Jordanian economy. These factors include (1) actual and planned power interconnections between Jordan and neighboring Arab countries, thereby creating the possibility of increased power exports by Jordan; (2) more efficient use of electricity created by both price- and nonprice-induced demand-side management programs; and (3) future growth of the Jordanian economy. The latter includes a discussion of the major industrial users of electricity. The chapter concludes with an evaluation of the need for power in Section 3.4.

3.1 HISTORICAL GROWTH IN ELECTRICITY CONSUMPTION

Table 3.1 summarizes total electricity consumption in Jordan for selected years from 1975 through 1987 and the percentage compostion by sector. Total electricity consumption increased more than ten-fold from 1975 through 1987, progressing from 236 GWh in 1975 to 2,668 GWh in 1987. On a sectoral basis, electricity consumption in the residential sector accounted for a little less than 40 percent of the total in 1975, declining to 28.5 percent in 1987. The industrial sector is the largest user of electricity, increasing from 19.1 percent of total electricity consumption in 1975 to almost 40 percent in 1987. Electricity used to pump water increased significantly in the past three years. In 1985, water pumps accounted for 10.0 percent of total electricity consumption. The percentage climbed to 15.6 two years later.

The significance of electricity use for water pumping is further quantified in Table 3.2. The table provides the average annual percentage growth in electricity consumption by sector and in total over the 1975-1987 period, by various subperiods. Over the total 12-year period from 1975 to 1987, the average annual growth in electricity was 20.2 percent. The industrial sector grew the fastest, increasing at an annual rate of 26.4 percent over the period. The rate of increase of electricity use for water pumping was the second fastest, increasing at 22.2 percent per year.

Disaggregating these results into different time periods, however, shows a declining trend in electricity growth. Total electricity consumption grew the fastest in the 1975-1980 period.

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[1] Meta Systems, Hagler-Bailly, Bechtel, *Report on Long Term Energy Policy and Investment*, March 22, 1988.

It increased at an annual rate of more than 26 percent over that period, spurred in large measure by 38.3 percent average annual growth in the industrial sector.

Table 3.1
Jordanian Electricity Consumption
Amount and Percentage Composition by Sector
Selected Years, 1975-1987

Year	Total (GWh)	Percentage Composition by Sector					
		Domestic	Commercial	Industrial	Water Pumps	Street Lighting	Other
1975	236	39.0	16.9	19.1	12.3	4.2	8.5
1980	877	36.6	12.2	34.9	8.7	1.8	5.8
1985	2,151	30.4	12.5	42.0	10.0	2.1	3.0
1987	2,668	28.5	10.6	39.9	15.6	2.5	2.9

Source: Jordan Electricity Authority, *Annual Report*, various years.

Table 3.2
Jordanian Electricity Consumption
Average Annual Growth by Subperiods
1975-1987
(percent)

Year	Domestic	Commercial	Industrial	Water Pumps	Street Lighting	Other	Total
1975-87	17.6	16.3	26.4	22.2	15.7	11.1	20.2
1975-80	25.0	19.7	38.3	19.3	9.4	18.7	26.3
1980-85	14.3	18.4	21.6	20.8	21.1	4.5	17.9
1985-87	7.4	2.9	8.2	33.1	18.0	8.6	10.8

Source: Computed from Jordan Electricity Authority, *Annual Report*, various years.

In the 1980s, growth has slowed. In the first five years of the decade, the growth in total consumption declined to 17.9 percent per annum. In the most recent two years, growth was under 11 percent. Growth in the industrial sector slowed considerably, declining from 38.3 percent in the last half of the 1970s to 8.2 percent in the 1985-1987 period.[2] The rate of growth in the residential and commercial sectors also declined from historical levels in the most recent two-year period.

[2] The industrial sector will be discussed in greater detail in the next section.

The annual rate of growth of electricity use for water pumping, however, has increased over the past decade. From 1985-1987, electricity use increased by more than 33 percent per annum. Electricity use for water pumping is expected to grow in the future. Water resources are becoming increasingly scarce in the Amman region. North Jordan has at least 95 percent of the country's population (Amman accounts for 70 percent of the country's water demand), but has only 55 percent of its surface area. Groundwater and surface water supplies in the North are extensive, but are insufficient to meet all of the competing demands (irrigation, domestic, and industrial applications). Groundwater resources in the southeastern part of the country are extensive, but remote from demand centers. Water requirements for irrigation in 2015 are estimated to be only 6 to 15 percent higher than the 1986 level; however, municipal water requirements are expected to triple over the next 30 years. Higher usage levels and remoteness of supplies portend larger electricity requirements for pumping.[3]

Especially important for a need for power analysis is the peak load of the system. In Jordan, the peak is usually in September. Table 3.3 provides the peak load and its growth for selected years from 1975 through 1987. The peak grew at an average annual rate of 16.0 percent from 1975-80, reflecting the rapid increase in electricity growth, but substantially below the electricity demand growth rate of 26.3 percent over the same period (see Table 3.2). From 1980-85, the growth rate in peak load increased slightly. Most recently, peak load growth slowed considerably. From 1985-87, it grew at an average annual rate of 11.1 percent. However, the percentage growth in peak in 1987 was only 6.1 percent.

Table 3.3
Peak Electricity Load in Jordan
Selected Years, 1975-1987

Year	Peak[a] (MW)	Growth[b] (percent)
1975	88	
		16.0
1980	196	
		17.7
1985[c]	475	
		11.1
1987[c]	593	

Source: Jordan Electric Authority, *Annual Report*, various years

[a] Peak for all Jordan: interconnected system and others
[b] Average annual growth rate
[c] Includes the amount for exports

[3] Issues associated with water availability are discussed at length in Chapter 7.

The combination of 979 MW of installed capacity (Table 2.2) and a peak load of 593 MW (Table 3.3) for 1987 indicates a significant reserve margin on Jordan's electric system.[4]

3.2 FORECASTS OF ELECTRICITY DEMAND

As part of its corporate planning effort, JEA forecasts electricity demand annually. The methodology used to forecast electricity demand by JEA does not involve executing an energy demand model integrated with a model of the rest of the economy. Rather, it is a sector-specific approach, taking the forecast results of six sectors and then aggregating to total electricity demand. The six sectors are domestic, commercial, industrial, water pumping, institutions, and others. Within each of these sectors different methodologies are used to forecast demand. The three most common are simple extrapolation of historical trends, market surveys, and specification of econometric models. Extrapolation involves examining historical trends and projecting into the future. A market survey approach is used for bulk-supply industrial customers. The difference between electricity needs and self-generation by these customers is determined by on-site visits and interviews with knowledgeable engineers. An econometric approach consists of specifying equations with independent variables theorized to influence the consumption of electricity for specific sectors (electricity price, income).

Table 3.4 summarizes the annual forecasts of demand made in consecutive years from 1982 to the most current period, 1987. The table highlights the declining growth rates projected by JEA over the decade of the 1980s. In 1982, forecasted annual growth was 9.2 percent over the 1985-2000 period, reaching 9,935 GWh of consumption in the year 2000. However, since that period, the forecasted growth rate over the 1985-2000 period has declined with the exception of the most recent forecast made in 1987. The 1987 forecast shows electricity consumption increasing at an average annual rate of 6.9 percent from 1985 to 2000, reaching 7,639 GWh in the year 2000.

Besides the forecasts of electricity demand provided by JEA, there have been a number of other demand studies conducted. The most recent, completed in March 1988, was undertaken by a Meta Systems/Hagler Bailly/Bechtel team. The study team used an energy-economy model which was developed earlier, modified, and then transferred to MEMR. It is a general equilibrium model of the Jordanian economy, capturing the interrelationships between the energy subsectors in Jordan and other sectors of the Jordanian economy.[5]

Use of the model requires a number of exogenous assumptions about economic conditions both external to Jordan (the world price of oil, for example) and internal to the Jordanian economy such as policy instruments (tax policy, for example). The authors posited a number of assumptions to project energy demand under 12 scenarios, including assumptions about both domestic and international conditions to the year 2000. Their base case scenario was developed by the project team and various ministries of government

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[4] The reason for this large margin could be a lack of demand, a capacity requirement to cover nonscheduled downtime on the system, or a combination of the two. It is not possible to determine from data made available to the study team what the specific reason(s) were.

[5] A detailed description of the model is beyond the scope of this study. The interested reader is referred to *Energy Economy Model of Jordan: Impact Analysis Using the Model*, Meta Systems, Inc., Study 117, March 1988.

to reflect what the planners believe is a reasonable set of domestic and foreign conditions that Jordan will confront over the forecasting horizon.

Table 3.4
Jordan Electricity Authority
Summary of Electricity Demand Forecasts
1982-1987
(percent)

Year[a]	1985-1990	1990-1995	1995-2000	2000-2005	1985-2000
1982	11.7	9.1	7.0		9.2
1983	9.9	8.8	6.9		8.5
1984	10.7	7.7	6.8		8.4
1985	9.9	6.8	5.8		7.5
1986[b]	9.1	5.7	4.2	3.9	6.1
1987[c]	9.7	6.9	5.2	4.3	6.9

Source: Computed from Jordan Electricity Authority, *Annual Report*, various years

[a] The year of the annual report in which the forecast appeared

[b] Includes one actual year and four forecasted years. The 15-year forecast from 1985-2000 includes forecasts for 14 years from 1986 through 2000.

[c] Includes two years actual and three forecasted years. The 15-year forecast from 1985-2000 includes forecasts for 13 years from 1987 through 2000.

Table 3.5 summarizes the forecasts of electricity demand from the base case and, for the sake of comparison, presents JEA's most recent forecast of electricity demand over the same period that was provided in Table 3.4. Table 3.5 shows a significant difference between the most recent JEA forecast and that of Meta Systems *et al.* Over the 1986-2000 planning horizon, JEA projected a 6.9 percent average annual growth rate in electricity consumption in comparison with a forecast by Meta Systems *et al.* of 4.2 percent. The growth rates in subperiods presented in Table 3.5 are correspondingly different.

Besides the base case scenario presented in Table 3.5, the Meta Systems *et al.* study projected electricity demand under 11 other scenarios, comparing the results of different exogenous assumptions on future macroeconomic conditions, world oil prices, and the treatment of domestic energy prices (adjusting to changing international prices or not). The highest annual growth rate of electricity demand over the 1986-2000 period under any of these scenarios was 5.3 percent. In this particular scenario, the most optimistic assumptions about future macroeconomic conditions were invoked, a gradual increase in the international price of petroleum was assumed, and domestic energy prices were assumed to remain constant. Under the worst case scenario for electricity demand growth, the base case macroeconomic assumptions were assumed, there were fluctuating changes in the international price of petroleum, and domestic energy prices were adjusted instantaneously to reflect the international price changes. In this scenario, the average annual growth rate in electricity demand over the 1986-2000 period was projected to be 3.6 percent.

Table 3.5
Comparison of Electricity Demand Forecasts
1986-2000
(percent)

Source	1986-1990	1990-2000	1986-2000
JEA[a]	9.7	6.0	6.9
Meta Systems, *et al.*	4.9	3.9	4.2

Source: Computed from Jordan Electricity Authority, *Annual Report*, 1987, and Meta Systems, Hagler-Bailly, Bechtel, *Report on Long Term Energy Policy and Investment*, March 1988

[a] Includes the actual amount for 1987 and three forecasted years. The 14-year forecast from 1986-2000 includes forecasts for 13 years from 1987 through 2000.

3.3 COMPLICATING FACTORS IN ASSESSING FUTURE ELECTRICITY DEMAND

Energy demand forecasts are replete with assumptions on future economic conditions which are highly uncertain. The preceding forecasts of electricity demand in Jordan are no exception. There are a number of especially uncertain aspects of the Jordanian economy and power subsector which must be considered when evaluating future power requirements. With respect to electricity demand, three are important. First, potential further interconnections of the national power systems of Jordan, Syria, Egypt, and Saudi Arabia could significantly affect electricity sales. Currently, Jordan exports power only to Syria. Another area of uncertainty is the extent to which demand-side management programs (including price reform and conservation activities) will affect future electricity demand. Jordan revised its electric power tariffs in 1986. However, a recent study showed that there still is room for using the tariff structure to increase the efficiency of electricity consumption. Nonprice demand-side activities include the possibility of significant energy savings in the transport and manufacturing sectors through appropriate conservation measures. The final area of demand uncertainty is the growth of the economy itself. Of particular importance here is the future growth of the industrial sector in Jordan. As discussed above, the industrial sector currently accounts for 40 percent of electricity demand in Jordan. The remainder of this section will address each of these issues in more detail.

3.3.1 Power Interconnections and Exports

Jordan is currently exporting a nominal amount of power to Syria after constructing tie lines to connect with Syria's grid. Power exports to Syria began in 1985 with a total of 20 GWh. In 1986 and 1987, the amount of power exported was 214 and 334 GWh, respectively. The level of these sales to Syria in the future is uncertain. However, JEA has expanded the capacity of the electrical interconnection with Syria in the recent past. And, JEA plans to undertake a feasibility study with the goal of synchronizing the electrical interconnection between the Jordanian and Syrian systems.

The Syrian interconnection is the first phase of what is anticipated to be multi-country interconnections in the 1990s. Exploratory discussions on future interconnections with

other neighboring Arab countries are ongoing. In concert with other power parastatals in the Arab world, JEA formed the Arab Union of Producers, Transporters, and Distributors of Electricity. The goal of the union is to promote cooperation between Arab countries in developing generation, transmission, and distribution facilties in the Arab world. As part of this increased emphasis on cooperation, the union's goal is to coordinate electricity-related activities of the members, including the interconnection between national grids of the Arab countries.

Besides the power sales to Syria, another concrete example of this cooperation involving Jordan is the feasibility study of connecting the national power grids of Jordan and Egypt. JEA and the Egyptian Electricity Authority, through a joint technical committee, conducted a prefeasibility study of interconnecting the power systems of the two countries. Based on the favorable conclusions of the prefeasibility study, Jordan and Egypt (aided by France) conducted a technical and economic feasibility study of constructing a marine power transmission line from the southern part of Jordan along the Gulf of Aqaba to Egypt. The interconnection project entered the executive stage in late August when the Ministers of Energy of both countries met in Cairo.[6] A technical protocol for cooperation in energy-related matters was signed by the ministers of the two countries. Egypt and Jordan agreed to exchange expertise and information to determine the route of the marine cable linking the power systems of the two countries. They also agreed to cooperate in jointly seeking out funding sources for the project. It is expected that implementation of the link will commence in early 1989 after additional technical studies are completed.[7]

The impact of constructing the marine transmission line between Jordan and Egypt on the power sales of Jordan is uncertain. Because the peak power load periods of the two countries differ (Egypt in October, Jordan in September), one possibility would be load shaving for both power grids. However, with the uncertainty associated with Egypt's power system, the effect may be a significant amount of net sales of power to Egypt from Jordan.

Another complicating factor is the possibility of an interconnected grid between Jordan, Syria, Egypt, and Saudi Arabia. As part of the aforementioned feasibility study of connecting the Jordanian and Egyptian power grids, the participants also agreed to include a study of the feasibility of connecting the power grid in Saudi Arabia. With Jordan's current transmission link with Syria, the impending link with Egypt, and the possibility of connecting with Saudi Arabia, the goal of a pan-Arab electrical connection is closer to fruition. Here again, while the purpose would be in part peak load shaving for each of the countries, the net impact on Jordanian power sales is uncertain.

Finally, there is a possibility of linking an interconnected Arab power system with the systems of Europe. Discussions among Middle Eastern Arab countries are under way on the possibility of linking Arab power grids with those of Turkey and other European countries in the early 1990s.[8] Here again, the net impact of these possibilities on the Jordanian power system cannot be determined with any degree of certainty.

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[6] *The Egyptian Gazette*, August 31, 1988.

[7] *The Egyptian Gazette*, September 2, 1988.

[8] *The Egyptian Gazette*, August 31, and September 1, 1988.

3.3.2 Demand-Side Management

One of the ways in which JEA can meet its future load requirements is by reducing electricity consumption through demand-side measures. Demand-side management (DSM) refers to the intervention of a utility to influence its load curve.[9] Broadly defined, the types of interventions include both technical and behavioral ones. Examples of technical interventions include providing efficient equipment for energy conservation and energy demand control equipment. Innovative pricing strategies and public relations campaigns for efficient energy use are examples of behavioral measures which a utility can undertake to influence energy consumption.

The Jordanian government has undertaken both technical and behavioral measures to various degrees as part of their demand-side program. With the creation of the Ministry of Energy and Mineral Resources (MEMR) in 1984, Jordan has proceeded on an intensive program to quantify the potential role of conservation measures to rationalize energy use. Before creating MEMR, GOJ proceeded on a course to raise energy prices (both petroleum and electricity prices) to levels approaching the economic cost of supply. At present, however, there is still room for both technical and behavioral DSM programs to improve the efficiency of energy use. Each of the measures will be discussed in detail below.

3.3.2.1 Energy pricing

Over the past decade, Jordan has moved toward correcting pricing inefficiencies in both its petroleum and power subsectors. The rationalization of petroleum prices was important for the power sector because of Jordan's total reliance on petroleum for power generation. As with many developing countries, the petroleum subsector of Jordan was a net contributor to revenue generation of the government prior to the first international oil price shock in 1973 because of the amount of taxes levied on gasoline and diesel. However, the petroleum subsector was subsidized by the national government as a result of the precipitous increase in international petroleum prices in 1973; international price increases were not passed on to Jordanian petroleum users for political, economic, and social reasons. By the end of 1978, the subsidy to the petroleum subsector amounted to $66 million. After the second oil price shock in 1979, the government's policy changed. It concluded that, if the price increases were not passed on to consumers, the impact on the government budget would be profound. Therefore, the government decided to gradually phase out the subsidy to petroleum consumers. Since the first petroleum price increase in July 1979, there have been seven further adjustments (February 1980, February 1981, April 1981, November 1981, February 1983, December 1984, and June 1986).

Because of the recent decline in the international price of petroleum, the price of each individual petroleum product in Jordan is above its economic cost of supply. This is the case even though in order to promote economic competitiveness, the government decided to pass along price decreases to certain customer classes (large industrial users and the power sector) through its tariff revision in June 1986.

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[9] DSM activities have six generic load shape objectives: conservation, peak clipping, valley filling, load shifting, load growth, and flexible load shape. The objectives are not mutually exclusive. For example, a utility may desire both to clip its peak and shift load to improve load factor on the system. The objective of any individual parastatal depends on conditions in its power supply system at any given time (using excess capacity, shedding load, eliminating brownouts, and the like).

Electricity prices followed a similar pattern. The average annual real increase in electricity rates was only one percent from 1975 to 1981. During that same period, JEA's fuel bill increased at an average annual real rate of 10 percent. JEA was not allowed to pass along the petroleum price increases of 1981 to consumers because of social and political considerations. A rapid increase in electricity prices was perceived as a threat to civil order.

In the past decade there have been four tariff changes in the power sector (March 1977, February 1980, December 1984, and June 1986). Presently, JEA's tariff structure consists of demand rates and time of day rates for large-volume sales (bulk sales) to distribution companies and large and medium industries, increasing block rates for residential and public buildings, flat rates for commercial consumers, and a declining block rate for small industrial consumers. A fixed charge per month is levied on residential and small industrial consumers. With the tariff change in June 1986, the government reduced the prices to certain customer classes. This came in conjunction with the reduction in petroleum prices. The petroleum price decrease reduced the fuel oil bill to JEA by about 21 percent.

The World Bank estimated that as of 1987 the current overall price of electricity in Jordan is 85 percent of the estimated economic cost of supply. Although this is favorable in comparison with many other developing countries, the government agreed to a marginal cost pricing study to determine the extent of the subsidy to individual sectors and, if warranted, to adjust tariffs to economic levels. Of particular concern is that electricity prices to bulk consumers, medium industry, and small industry are only 75 percent of their estimated economic cost of supply, based on the analysis conducted by the World Bank. The results of the marginal cost pricing study were to supposedly serve as the basis for adjusting electricity tariffs further.[10]

3.3.2.2 Conservation

Since its creation in 1984, MEMR has been actively involved in promoting energy conservation. Several studies and programs have been initiated.

For general energy conservation activities, two conservation centers have been established to promote and technically support more efficient energy use. The centers have benefitted from the financial assistance of USAID. The first, the Energy and Electricity Information and Advisory Center (EEIAC), is located in Amman and is sponsored by MEMR and JEA. The second center, located in Irbid, is sponsored by MEMR and IDECO. One of the primary functions of the conservation centers is to inform the public about energy savings by collecting and disseminating information about energy conservation. Activities include

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[10] The marginal cost pricing study entitled "Long Run Marginal Cost Analysis and Electricity Pricing" was completed by Meta Systems and Hagler-Bailly in March, 1988. The study made a number of recommendations for changing the level and structure of electricity prices in Jordan. However, by the authors' own admission, the study did not include the impact on net revenues of changing electricity tariffs for both JEA and Jordan's other electric utilities (the preceding chapter discusses the power system in Jordan). This proved to be one of the primary problems of the study. Although the results of the study were generally perceived as reflecting a "theoretically correct" rate structure, the decision to propose it to higher management was postponed because it did not present the impact of the structure on revenues. JEA is especially mindful of its self-financing covenant with the World Bank, which targets an annual self-financing ratio for the Jordanian electric system of 25 percent of all capital expenditures.

holding seminars, advertising, and preparing and distributing publications on energy conservation. A second major activity of the centers is conducting energy audits and providing technical advice based on on-site inspections. The advice has encompassed using thermal insulation, designing passive-solar-heated buildings, installing solar water heaters, and using electrical equipment more efficiently.

Besides the conservation centers, MEMR is engaged in sector-specific activities. In the residential sector, the most important activity is promoting the use of solar water heaters. Presently, 25 percent of houses use solar water heaters in comparison to less than 5 percent before 1980. In addition to promoting the use of solar heaters, the MEMR is engaged in establishing standards (design specifications) for the technical quality of solar heaters to improve their performance. Related to this is a program to enhance the technical know-how of workers engaged in the manufacture of solar water heaters. Another major conservation activity in the residential sector is related to windows. A study was conducted to determine the optimal design of windows to prevent air infiltration.

In the industrial sector, MEMR contracted with the Bechtel Group, Inc. for a study of potential energy savings through conservation measures in large industries. The study, conducted in conjunction with Technical Audit, Ltd. of England, was carried out in 1985.[11] A three-step procedure was used to identify individual industrial plants for intense scrutiny, resulting in detailed audits of 14 industrial plants. Included in the plants chosen for detailed audits were the oil refinery, cement plants, phosphate mines, and a fertilizer plant, which accounted for nearly 60 percent of the total amount of electricity used in the industrial sector in 1987. Electricity use by major industrial users will be discussed in detail in the next section.

The results showed that 80 percent of the total potential energy savings from the 14 audited plants comes from petroleum refining, the fertilizer plant, and phosphate mining. For electricity consumption, the estimated savings for phosphate mining was approximately 10 percent of total 1985 consumption in the mines.

In the transport sector, an energy conservation study was conducted for the five largest transport companies--Jordan Syrian Land Transport Co., Jordan Iraqi Land Transport Co., Public Transport Corporation, Royal Jordanian, and JPRC. The results show that conservation measures could save between 7 to 15 percent of total energy consumption; valued at 4.5 million JD per annum. An economic feasibility study for establishing a center for training drivers in energy efficiency was also conducted. The center would be set up in cooperation with the vocational training corporation.

3.3.3 Economic Growth

Table 3.6 provides the growth rates for Gross Domestic Product (GDP) and Gross National Product (GNP) for selected periods from 1975 to 1987. From 1975-1980 economic growth in the Jordan economy was more than 14 percent annually as measured by both GDP and GNP. In the early 1980s, growth slowed considerably, falling as low as 2.4 percent per annum in 1987. The rapid increase in total economic growth during the 1975-1980 period explains in large measure the prolific growth in electricity demand during that period (26.3 percent per annum from 1975-1980 from Table 3.2).

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[11] Overseas Bechtel, Inc. and Technical Audit, Ltd., *Energy Conservation Study in Jordan*, 1985.

Table 3.6
Average Annual Growth in GDP and GNP
1975-1987
(percent)

Period	GDP	GNP
1975-80	14.7	14.1
1980-85	5.0	3.7
1985-86	2.6	3.9
1986-87	NA	2.4

Source: Central Bank of Jordan, *Monthly Statistical Bulletin*, January 1988

The primary reason for the difference in growth rates between GDP and GNP is the amount of remittances to the Jordanian economy. Table 3.7 provides an analysis of the historical importance of remittances[12] to the Jordanian economy from 1976 through 1986. In Table 3.7, Gross National Product is comprised of Gross Domestic Product and net factor income. The latter is composed of foreign remittances and net investment income earned abroad.

Table 3.7
Analysis of Gross National Product
Selected Years, 1976-1986
(millions of current JD)

	1976	1980	1981	1984	1985	1986
Gross Domestic Product	421.6	984.3	1164.2	1499.4	1573.3	1613.6
Factor Income – Net:						
Remittances – Net	131.3	190.7	288.9	377.5	310.0	366.0
Investment Income	9.5	15.1	29.6	-22.4	-34.1	-62.2
Gross National Product	562.4	1190.1	1482.7	1854.5	1849.2	1917.4
Remittances – % of GDP	31.1	19.4	24.8	25.2	19.7	22.7
Remittances – % of GNP	23.3	16.0	19.5	20.4	16.8	19.1

Source: Central Bank of Jordan, *Monthly Statistical Bulletin*, January 1988

[12] Remittances are factor (labor) income earned by Jordanians working abroad and sent back to Jordan.

The table illustrates the large share of GNP accounted for by remittances to the Jordanian economy. In 1976, remittances accounted for nearly one-quarter of GNP. However, the percentage is substantially lower in recent years. These remittances have been historically important in explaining the large rate of growth in electricity demand over the past decade. However, the future amount of these remittances to the Jordanian economy is uncertain. It is contingent on events in the international economy which are largely beyond the control of the Jordanian government. The majority of remittances have historically been derived from Jordanians working in the Middle East. The infusion of "petrodollars" associated with the large increases in petroleum revenues of Middle East oil-exporting countries during the 1970s led to large-scale construction projects, inducing Jordanian workers to seek employment in the oil-exporting countries. The level of these remittances in the future is tied to the international price of petroleum. With the recent decline in international crude oil prices, many construction projects have been cancelled in the Middle East, leading to a decline of foreign remittances to the Jordanian economy.

The amount of remittances is only one uncertain factor in estimating future growth in the Jordanian economy. Both domestic and international conditions will impinge on that growth. Meta Systems *et al.* simulated the performance of the economy over the 1986-2000 period under different assumptions about both domestic and international economic conditions, using a general equilibrium model of Jordan's economy. A base case scenario was executed along with 11 other sensitivity studies. The base case scenario reflected "reasonable" assumptions about the international economy, energy supply conditions, and economic policy until the year 2000. International petroleum prices were assumed to increase gradually, while domestic energy prices were assumed to adjust instantly in the base case scenario. Forecasted growth in GDP under this scenario is 3.4 percent annually over the 1986-1990 period and 5.2 percent per annum from 1990-2000. Average annual growth of GDP over the entire period was simulated to be 4.7 percent. This rate approaches the actual growth of GDP from 1980-1985, but is significantly above the most recent growth in the 1985-1987 period (see Table 3.6).

The other 11 scenarios bracket the base case, ranging from an average annual growth of 4.1 percent over the 1986-2000 period on the low end and 5.6 percent using the most optimistic set of exogenous assumptions. On the low end, the forecasted annual growth rate of 4.1 percent is less than what was experienced by the Jordanian economy from 1980-1985, but significantly higher than the 1986 growth rate (Table 3.6). On the high end, the forecasted growth is larger than that experienced over the 1980-1985 period. The 4.1 percent growth rate was derived from the same macroeconomic assumptions as used in the base case, but, in contrast to the base case, international oil prices were assumed to rise rapidly in the forecast horizon and domestic energy prices were assumed to be constant. The scenario with the most optimistic forecasted growth of 5.6 percent annually included very favorable exogenous macroeconomic assumptions with a gradual rise in international petroleum prices and domestic energy prices adjusting to the increases.

An important consideration in assessing the future growth of the Jordanian economy and, hence, future electricity requirements, is growth prospects for the major industrial users of electricity. Table 3.8 presents total industrial electricity consumption and the percentage composition of large users of electricity in the industrial sector by industry and the total amount and percentage composition of electricity used by small and medium industries for selected years from 1977 through 1987.

The last entry in the table reproduces the information contained in Table 3.1, indicating the percentage of total electricity sales accounted for by sales to industrial consumers. The table shows that industrial users of electricity in recent years accounted for 40 percent of total electricity consumption. The share of total industrial electricity consumption accounted for by large-volume users increased from 59.4 percent in 1977 to 75.6 percent in 1987. The increase is due in large part to the introduction of potash mining and fertilizer production since 1980. The production of cement has historically accounted for a large portion of industrial electricity sales. In 1977, more than one-third of total industrial electricity use was accounted for by cement production, declining to a third in 1980, and, most recently, falling to 26.0 percent of total industrial consumption in 1987. The use of electricity by small and medium industries as a percentage of total industrial electricity consumption declined from 40.6 percent in 1977 to 24.4 percent in 1987, reflecting in large measure the introduction of potash mining and fertilizer production in the Jordanian economy since 1980.

Table 3.8
Industrial Electricity Consumption
Amount and Percentage Composition by Source
Selected Years, 1977-1987

	1977		1980		1985		1987	
Source	GWh	%	GWh	%	GWh	%	GWh	%
Oil Refining	20	11.4	26	8.5	66	7.3	68	6.4
Cement	63	36.0	102	33.3	253	28.0	276	26.0
Potash	0	0.0	0	0.0	153	16.9	188	17.7
Phosphate	21	12.0	47	15.4	81	9.0	99	9.3
Fertilizer	0	0.0	0	0.0	136	15.1	147	13.9
Total – Large	104	59.4	175	57.2	689	76.3	802	75.6
Small/Medium	71	40.6	131	42.8	214	23.7	259	24.4
Total Industry	175	100.0	306	100.0	903	100.0	1061	100.0
Industry (% of total)		34.1		34.9		42.0		39.9

Source: Computed from Jordan Electricity Authority, *Annual Report*, various years.

Prospects for future growth in the industrial sector are uncertain. Initially, we examine output by the major industrial users over the past decade and then look at future prospects. Table 3.9 quantifies the recent activity of major industrial electricity users, presenting their output for selected years from 1977 through 1987. The output of cement increased at an average annual rate of 14.8 percent between 1977 and 1987. However, in recent years the growth has not been favorable. Although production increased by nearly 28 percent in 1987, it declined by 12.0 percent in 1986 and, although not contained in Table 3.9, declined by 0.2 percent in 1985. Future prospects are uncertain. Middle East

markets for cement have diminished considerably with the reversal of the "petrodollar" construction boom in the area. Other international markets will have to be tapped if petroleum prices continue at their depressed level.

Table 3.9
Output of Major Jordanian Electricity Users
Selected Years, 1977-1987
(thousand tonnes)

Year	Cement	Potash	Phosphates	Fertilizer
1977	538	0	1769	0
1980	913	0	3911	0
1985	2023	908	6067	510
1986	1795	1102	6249	551
1987	2372	1203	6845	604

Source: Central Bank of Jordan, *Monthly Statistical Bulletin*, January 1988.

The second major industrial user of electricity in Jordan, potash mining, faces a similar uncertain future. Potash production increased by 19.3 percent in 1986 and 8.8 percent in 1987. Jordan increased its potash exports in 1986, a year in which the international potash industry was depressed. The increase was attributable to increased exports to East Asia (primarily China), Brazil, and India. However, the increase to these regions was partially offset by the loss of some markets in East and South Asian markets to Canada. Even though the total volume of potash sales increased in 1986, the average price per tonne decreased, leading to a decline in total revenues. The future for the potash industry is clouded, but it is conceivable that Jordan could lose more of its Asian markets to Canada and, possibly, to Israel.

Phosphate production increased at an average annual rate of 13.5 percent over the 1977-1987 period. Most recently, production has slowed over the historically high levels, growing by 3 percent in 1986 and 9 percent in 1987. The Jordan Phosphate Mining Company (JPMC) has two markets for its output. The first is its newly acquired diammonium phosphate fertilizer division. Sales to this division have been increasing in recent years. Production for export markets is the second use of JPMC's phosphate production, accounting for more than five-sixths of JPMC's sales. Most recently, Jordan has increased its market share for phosphate exports. Its principal markets are in Eastern Europe, East Asia, and South Asia. Jordan has recently increased its exports to Eastern Europe by extending more generous credit terms to Yugoslavia and Poland. It has also attempted to gain new markets (Western Europe, Canada, and Mexico) by expanding into areas previously dominated by Morocco and the United States. The expansion of exports is not costless. Nearly one-third of Jordan's phosphate exports go to Romania, Poland, and Yugoslavia in Eastern Europe. Since each of these countries has foreign exchange shortages, Jordan must accept inferior goods as partial payment for its exports. Also, by infringing on markets formerly dominated by Morocco, JPMC has seen retaliation by Morocco in its lucrative South and East Asian markets.

JPMC commenced operations of its diammonium phosphate fertilizer plant in 1982. Every year since it began producing fertilizer, it has operated at a loss. Since beginning production, it has had to periodically shut down because of surplus inventories with inadequate storage capacity. Most recently, JPMC has changed its business strategy for fertilizer production and exports. It has decided to operate the plant at near capacity and conduct a bold marketing effort to increase exports, hoping to reduce the average fixed cost per unit of fertilizer sales and thereby reduce its losses. In the process, it has diversified its geographical source of exports, emphasizing Western European markets at the expense of ones in South Asia. Although the largest individual market for exports is India, the largest regional market is now Western Europe (more than a third of total exports), displacing South Asia as the most important regional market. Also as a part of its new business and marketing strategy, JPMC is negotiating bilateral trade and counterpurchase agreements to obtain cheaper sulfur and ammonia which are important inputs in the production of diammonium phosphate fertilizer.

The future growth of the Jordanian economy and, hence, electricity demand growth depends in large measure on both the performance of the cement, potash, phosphate, and fertilizer industries and the ability of Jordan to develop new export industries. With respect to the latter, a key problem is that the Jordanian economy is relatively small and unable to absorb the output of many manufacturing industries. To achieve the economies of scale required to be competitive in many of these industries, export markets must be developed. Jordan has a number of advantages to accomplish this. One of the most important advantages is that it is geographically close to the lucrative Middle Eastern markets with which the Jordanians share similar ethnic and cultural backgrounds. Another important advantage is that Jordan has a relatively good infrastructure with a fairly well developed transport network and reliable electricity and telephone service. Still, given these advantages, it remains uncertain whether Jordan can develop and maintain economically viable export industries to sustain strong economic growth. In a recent study, the World Bank examined the prospects for small- and medium-scale enterprises for Jordan over the short- and long-run time frames.[13] The study concluded that prospects in the short run are not favorable. However, over the longer run small and medium industries could contribute significantly to economic growth if a series of reforms to promote growth are undertaken in the economy. The suggestions include reform of trade laws and the investment licensing system and a number of institutional improvements in the economy.

3.4 ASSESSMENT OF THE NEED FOR POWER

The power sector in Jordan has grown very rapidly over the past two decades, especially in the late 1970s and early 1980s when an economic boom saw electricity demand growth rates exceeding 20 percent per annum. However, growth has recently slowed and, based on demand projections by Meta Systems *et al.*, will not exceed 5 percent per annum the rest of this century. These projections are based, however, on a well-defined set of assumptions about the future course of economic events which may or may not transpire. Demand-side management, including both electricity pricing and conservation measures, will rationalize the use of electricity in the future. The future price of oil is indeterminate, and its effect on the growth of the Jordanian economy – and electricity demand – has been and will be significant. The export markets and growth potential for major domestic industrial users of electricity are uncertain. International prices of crude oil will be a

[13] World Bank, *Jordan: Policies and Prospects for Small and Medium Scale Manufacturing Industries*, January 1988, No. 6848-JO.

significant factor for the future growth of the cement industry in Jordan. Perhaps even more significant for electricity growth is the potential effect that electricity interconnections between Jordan and other Arab countries (especially Syria, Egypt, and Saudi Arabia) will have on the Jordanian power system. These interconnections could potentially affect Jordan in several ways. They could conceivably be a future source of demand, requiring capacity growth, or they could contribute to load shedding on the Jordanian system in the 1990s and beyond, improving Jordan's load factor with a concomitant decrease in capacity requirements to meet peak load.

Although all utility systems face uncertainties, the ones confronting Jordan on the demand side are especially acute. On one hand, failure to anticipate growth in electricity demand can stifle overall economic growth in the economy; on the other, building excess power production capacity carries with it a high economic opportunity cost in terms of other investment alternatives which may be taken by the economy in place of power generating facilities.

Given these demand uncertainties, evaluating the need for power in Jordan is an extremely delicate problem. The uncertainties with circumstances that may impinge on electricity demand growth in the future strongly suggest that there is no "best" forecast of load growth over the next twenty years. At one extreme, however, it is fairly certain that historical electricity growth rates will not be equalled or exceeded in Jordan for any lengthy period in the future. The 26.3 percent and 17.9 percent average annual growth rates in electricity consumption over the 1975-1980 and 1980-1985 time periods occurred during periods in which domestic and international economic conditions were amenable to load growth in Jordan. At the other extreme, the growth in electricity demand is difficult to call.

Given these uncertainties, we choose here to bound the problem of determining load growth by using JEA's 1987 forecast of peak load to provide an indication of the range of capacity requirements that may be needed on the Jordan power system over the next two decades.[14] As discussed earlier, JEA produces an annual forecast of electricity demand and peak load growth under three scenarios (low, medium, and high) that reflect a range of assumptions about future domestic and international conditions which may influence electricity demand. Table 3.10 presents JEA's forecasted peak loads for the interconnected power system (excluding exports of power to Syria) under the three scenarios for five-year increments beginning in 1986 and extending to 2005, along with an analysis of required capacity additions over that period.

For the sake of clarity of presentation, the implied annual average growth rates for the levels of forecasted peak load over the 1986-2005 time period are not included in the table. They are 4.5 percent, 6.0 percent, and 7.4 percent for the low, mid, and high scenarios, respectively. Each of the forecasted growth rates in peak load is significantly below the experiences of the last decade (Table 3.3 above). Most recently, peak load has grown at an annual average rate of 11.1 percent from 1985-1987. The associated annual average growth rates in electricity demand for the low, mid, and high scenarios are 4.7 percent, 6.3 percent, and 7.6 percent, respectively. The low growth scenario with a forecasted annual growth in electricity demand of 4.7 percent most closely corresponds to the growth rates produced in the Meta Systems *et al.* study.

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[14] The Meta Systems *et al.* study of energy demand did not produce forecasts of peak load.

Table 3.10
Jordan Power System
Forecasted Peak Load, Required Capacity, and New Capacity
Thirty Percent Reserve Margin
1986-2005
(MW)

Year	Peak Load Forecast			Required Capacity[a]			Existing Capacity[b]	Incremental Capacity		
	Low	Mid	High	Low	Mid	High		Low	Mid	High
1986	458	458	458	595	595	595	880	0	0	0
1990	582	655	721	757	852	937	877	0	0	60
1995	737	903	1075	958	1174	1398	852	106	322	485
2000	896	1147	1435	1165	1491	1866	848	211	321	472
2005	1070	1422	1855	1391	1849	2412	848	226	358	546
							Total	543	1001	1564

[a] Assumes reserve margin of 30 percent for all periods

[b] Capacity existing in 1987 less scheduled retirements through 1997. Retirements beyond 1997 are unknown.

The required capacity figures in Table 3.10 are simply 30 percent larger than the peak load forecasts, corresponding to the 30 percent reserve margin used by JEA in its planning.[15] The existing capacity is simply the amount that existed on Jordan's interconnected system in 1986, less JEA's planned retirements. It is the basis from which capacity planning begins. The incremental capacity provided in the last category of information in Table 3.10 is simply the amount of required capacity less capacity existing in 1986. It is the estimated amount of additional generating capacity needed to be constructed in the various time frames.

The results in Table 3.10 indicate that, under the high growth scenario, Jordan will need 60 MW of additional capacity by 1990. In addition, another 485 MW, 472 MW, and 546 MW will be needed by the years 1995, 2000, and 2005, respectively, totalling 1,546 MW of total additional capacity by the year 2005. At the other extreme, Table 3.10 shows that no additional capacity will be needed by 1990 under the low growth scenario and, over the 20-year period, only 543 MW will be needed in total. With total capacity requirements under the mid growth scenario estimated to be 1,001 MW, there is a significant variation in generating requirements with nearly a three-fold difference between the low and high estimates. Satisfying this capacity requirement is the subject of the next chapter.

[15] Note that a 30 percent reserve margin to meet peak load does not necessarily imply a 70 percent capacity factor. The relationship between the two depends on the load factor of the system.

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4. ACCOMMODATING FUTURE CAPACITY REQUIREMENTS

4.1 THE JORDANIAN POWER SYSTEM

The national power system in Jordan is thermally dominated, using primarily heavy fuel oil and, to a lesser extent, diesel as primary fuels.[1] At the end of 1987, there was 979 MW of installed capacity in Jordan. Of this total, 869 MW was owned by the Jordan Electricity Authority (JEA) and the remainder by private companies, municipalities, and other power distribution companies in Jordan.[2] An additional 21 MW of capacity is connected to JEA's system, bringing the total capacity of the interconnected system to 890 MW at the end of 1987.

Figure 4.1 characterizes the interconnected power system in Jordan.[3] It consists of the main power generating stations and a theoretically plausible 400-kV transmission line from Aqaba on Jordan's southern coast to the Amman South station near the capital city, Amman. At present, the 400-kV line operates at 132 kV. JEA placed a tender for upgrading the line to 400 kV, but the 132/400-kV substations were postponed because of the delay in construction of the 2 x 130-MW units at Aqaba.[4] In addition to the main north-south transmission link from Amman South to Aqaba, the grid extends up to Irbid in the North with a 132-kV tie line. From Irbid, two tie lines (one a 66-kV line, the other 230 kV) connect Jordan's national grid with that of Syria's. Besides these north-south ties, Figure 4.1 shows that two 132-kV tie lines are presently under construction. The first in the northern part of the country will connect the Amman South station with Risha in the East. The latter is the site of the natural gas discovery in Jordan.[5] In addition to transmitting power produced at the well-sites to the main consumption centers in Jordan, it will serve to electrify some remote areas along its route. The line is expected to be completed at the end of 1988 or early 1989 to transmit power from the 2 x 30-MW gas turbines at Risha. The second 132-kV transmission line under construction links Ma'an with Shidiya in the southeastern part of the country. Shidiya is the site of the new phosphate mine in Jordan. The line is expected to be completed in late 1988 or early 1989.

Figure 4.1 shows the main thermal power generation sites at Aqaba in the southern-most part of the country; Zarqa (the Hussein Thermal Power Station) which is 35 km north of Amman; Marka, just north of Amman; Amman (South); and Karak, which is east of the

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[1] There is a nominal amount of hydroelectric power generation with 7 MW of capacity at the end of 1987. Renewable energy plays a minor role in the power system. Its role will be discussed below.

[2] A thorough discussion of the relationship of JEA to the two other power distribution companies (the Irbid District Electric Company and the Jordan Electric Power Company) and private power producers is presented in Chapter 2.

[3] For clarity of presentation in the figure, we include only JEA's steam, gas turbine, and diesel power generating stations and two private generators which are part of the interconnected grid. The hydroelectric capacity is not included. The capacity of other power generators was presented in Table 2.2 of Chapter 2.

[4] The two units at Aqaba were to be the second stage of capacity expansion at the Aqaba port. The first stage was completed in 1986. The reasons for its delay will be discussed below.

[5] Natural gas will be discussed at length below.

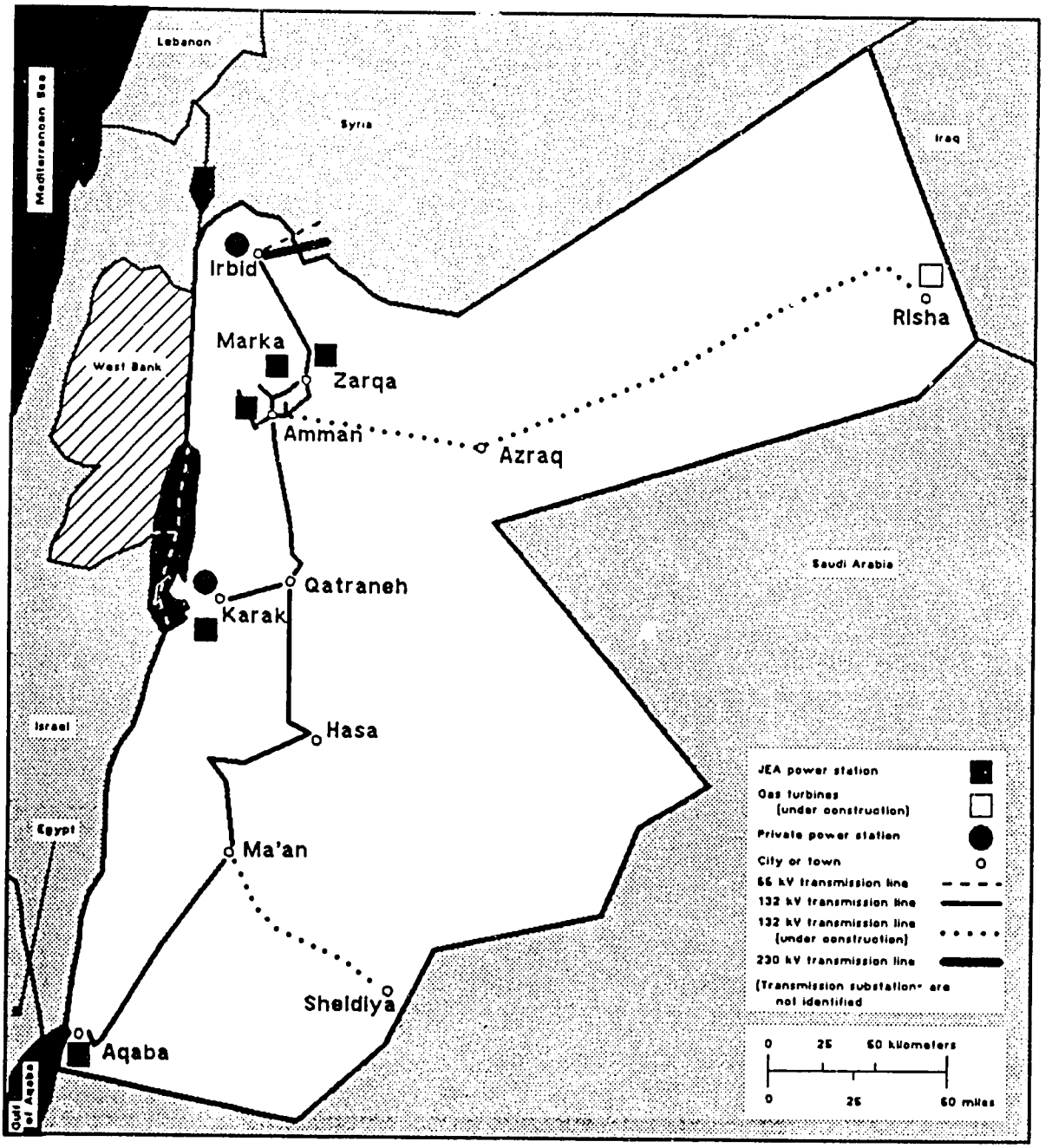

Figure 4.1
The Interconnected Power System in Jordan

southern part of the Dead Sea.[6] Table 4.1 provides JEA's capacity at each of the five generating sites by prime mover.

Table 4.1
Power Generating Stations
Jordan Electricity Authority
By Capacity and Prime Mover
December 31, 1987
(MW)

Site	Steam	Gas	Diesel	Total[a]
Aqaba	2 x 130		2 x 3.5	
			3 x 5	282
Zarqa[b]	3 x 33	1 x 14		
	4 x 66	1 x 18		395
Marka		4 x 18	30	102
Karak		1 x 18	3 x 1.5	23
Amman South		2 x 30		60
Total	623	182	57	862

Source: Jordan Electricity Authority, *Annual Report*, 1987 and information provided by the Jordan Electricity Authority.

[a] Does not include 7 MW of hydroelectric capacity.
[b] Also referred to as the Hussein Thermal Power Station (HTPS).

The 623 MW of steam generating capacity, using heavy fuel oil, represents the most economic units on the system. In terms of a theoretical loading order based on the economics of the units, the 2 x 130-MW units at Aqaba and the 4 x 66-MW units at Zarqa rank first and second. The 182 MW of gas turbines used diesel oil as their primary fuel in 1987. The 57 MW of diesel units used oil fuel as their primary fuel in 1987. The two oldest units on the system are the two gas turbines at HTPS, coming on line in 1975 and 1976. The newest units on the system are the 2 x 130-MW steam units at Aqaba.

Table 4.2 provides operating results for Jordan Electricity Authority's (JEA'S) power system for eleven months (January 1 through November 30) in 1987. In comparison with typical utility reporting in the United States, the data contained in Table 4.2 are homologous to the operating expenses of a utility. The capacity data listed in the table correspond in the aggregate to the amounts listed in Table 4.1 by type of prime mover. Thus, not only is the total capacity factor for JEA's entire system a weighted average across different units, but capacity factors for individual generating stations are weighted averages to varying degrees.

[6] Excluded from the discussion are the two hydroelectric sites: one at the King Talal Dam, the other at Aqaba.

Table 4.2
Operating Results for Generating Stations
Jordan Electricity Authority
Eleven Months
January-November, 1987

Category	Aqaba[a]	Aqaba[b]	Karak	Marka	Zarqa[c]	Other[d]	Total
Capacity (MW)	260	22	23	102	395	67	869
Generation (GWh)	1,160.3	36.2	10.6	50.0	1,609.7	4.7	2,871.6
Capacity Factor (%)[e]	55.7	23.8	5.6	5.7	50.7	1.0	41.2[f]
Cost (fils/kWh)							
Fuel	8.7	10.8	10.7	12.0	10.4	24.6	9.8
Depreciation	2.5	12.0	16.6	10.8	1.5	80.8	2.4
Other	0.8	6.4	9.0	10.7	0.9	83.0	1.3
Total	12.0	29.3	36.3	33.6	12.8	188.4	13.4
Cost (¢/kWh)[g]							
Fuel	2.6	3.3	3.2	3.6	3.1	7.4	2.9
Depreciation	0.8	3.6	5.0	3.3	0.4	24.2	0.7
Other	0.2	1.9	2.7	3.2	0.3	24.9	0.4
Total	3.6	8.8	10.9	10.1	3.8	56.5	4.0

Source: Data provided by Jordan Electricity Authority, April 1988

[a] Represents the Aqaba Thermal Power Station.

[b] Represents the Aqaba Central Power Station.

[c] Represents the Hussein Thermal Power Station.

[d] The category includes the Amman South Station (60 MW) and hydroelectric capacity (7 MW).

[e] The Capacity Factor is calculated as the ratio of actual generation of the plant expressed as a fraction of theoretically possible generation. The latter is determined by multiplying nameplate capacity times the total number of hours in any given time period. Because the data contained in the table are for an 11-month period, nameplate capacity was multiplied by 8,040 hours to determine the denominator of the equation.

[f] The Capacity Factor for the entire system represents the weighted average capacity factors for all stations on the system.

[g] Based on an exchange rate of $3 U.S. per Jordanian Dinar. There are 1,000 fils in each Dinar.

The most extreme example of this is the data listed for Zarqa (the Hussein Thermal Power Station). Here, as Table 4.1 shows, the 395 MW of capacity listed in Table 4.2 is divided between 3 x 33- and 4 x 66-MW steam units and 1 x 14- and 1 x 18-MW gas turbine units. Thus, the capacity factor of 50.7 percent shown for Zarqa in Table 4.2 is a weighted average of each of the individual units.[7]

The table shows that the 2 x 130-MW units at Aqaba, using heavy fuel oil, and the 395 MW of capacity at Zarqa had the highest capacity factor for the 11-month period at 55.7 percent and 50.7 percent, respectively. As mentioned above, the 2 x 130-MW units at Aqaba and the 4 x 66-MW steam units at Zarqa (264 MW out of a total of 395) are ranked one and two in the economic loading order of the system. In total, the 869 MW of capacity on JEA's system had a weighted average capacity factor of only 41.2 percent. Several comments are in order. First, the peak load on JEA's system – including exports to Syria – was 563 MW in 1987.[8] JEA's total capacity is 869 MW, indicating a substantial reserve margin to provide peaking power. The most plausible explanation as to why the system operates at such a low capacity is that the peak on JEA's system occurs in September and its load factor is substantially below unity. Second, the data in Table 4.2 do not say anything about availability of units. In its planning, JEA schedules 35 days of maintenance for the 2 x 130 units at Aqaba and 29 days for the 4 x 66-MW at Zarqa, the first two stations in the economic loading order. From the data provided to the study team, it is not possible to tell, however, the duration of forced and unforced outages on any part of the system.

Table 4.2 shows that the operating cost per kWh of generated electricity for the entire system over the 11-month period was 13.4 fils/kWh (1,000 fils equals a Jordan Dinar). Using an exchange rate of $3 U.S./JD, the average operating cost on the entire system was 4.0¢/kWh. Because of their positions in the economic loading order and their consequent capacity factors, the 2 x 130-MW units at Aqaba and those at the Zarqa power station (HTPS) had the lowest unit operating cost of any of the stations on the system, totalling 3.6¢/kWh and 3.8¢/kWh, respectively, which are both less than the average total system operating cost of 4.0¢/kWh.

4.2. CURRENT SYSTEM PLANNING

As part of the long-range planning process, JEA conducted a least-cost power generation expansion study in 1984. The generating alternatives which were considered in the study included gas turbines, combined cycle units, and thermal stations using coal, oil, or a combination of the two. The results of the study showed that, under both forecasts of fuel prices at the time and estimates of capital costs, the least-cost solution to JEA's capacity requirements was two 130-MW steam units to be located at the site of the 2 x 130-MW steam units which were under construction at Aqaba (the Aqaba Thermal Power Station) at the time and eventually came on line in 1986. The two additional units were anticipated to be on-line in 1991-92. These units were to be dual-fired: coal would be the primary fuel and oil the backup.

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[7] This problem cannot be avoided because the data presented in Table 4.2 are at the finest level of detail available to the study team.

[8] Note here that the peak of 563 MW does not correspond to the data presented in Table 3.3 of the previous chapter. The peak load listed there was 593 MW. Here, we are addressing only JEA's system – not the remainder of the interconnected system and private power generators.

Following the 1984 study, other studies continued to show that the additional 2 x 130-MW units at Aqaba would be sufficient to meet the power needs of the country. Therefore, the units were sent out for bid in 1987. Based on conditions existing at the time and a forecast of the relative costs of petroleum and coal, a decision was made to use coal as the primary fuel in the two units to minimize operating expenses. However, considering the up-front capital costs for coal handling and storage, the original decision was reversed; heavy fuel oil would initially be used for the additional 2 x 130-MW units designated Aqaba II to distinguish them from the 2 x 130-MW oil-fired units coming on line in 1986.

During this planning process, natural gas was discovered at Risha in the northeastern part of the country (see Figure 4.1 above). Although the extent of the gas reserves is unknown,[9] a decision was made in the middle of 1987 to construct 2 x 30-MW baseload gas turbines at Risha because it was believed that the reserves were sufficient to supply at least these units. The on-line date for the two units is expected to be late 1988 or early 1989. In JEA's loading order, the two units would be first in the economic loading order. With the decision to build 60 MW of capacity at Risha and the prospect of finding additional quantities of natural gas, JEA further delayed construction of the two additional units at Aqaba. The first unit at Aqaba II is delayed to the middle of 1992 and the second unit delayed until the end of 1992.[10]

A 132-kV transmission line from Risha to Amman South is currently under construction to transmit the power from the gas-fired units at Risha (see Figure 4.1 above). The capacity of the line can accommodate the 60 MW of power currently under construction at Risha and 120 MW of additional capacity. If natural gas reserves prove to be sufficient, the 2 x 30-MW of capacity at Risha can be supplemented by another 4 x 30-MW in the future.

Based on the most pessimistic projection of capacity requirements discussed in the previous chapter (543 MW of additional capacity by 2005, using a 30 percent reserve margin to meet the projected peak load of the system), Jordan cannot meet its power generation needs until 2005 by constructing the 6 x 30-MW gas-fired units at Risha and the heretofore "shelved" 2x130 dual-fired units at Aqaba II. This scenario is further complicated by a number of factors on both the demand and supply sides.

First, as the previous chapter pointed out, there are a number of complicating factors in the load projections for the Jordanian power system, including the imminent power interconnection with Egypt and potential power interconnections with other neighboring Arab countries and Eastern Europe; demand-side management activities, which at the very least could result in clipping the peak of power demand; and the uncertain future growth of the Jordanian economy which is affected by the future price of petroleum and the ability of large-volume, industrial electricity users to further exploit international markets for their output. Each of these factors has a potentially significant influence on future capacity requirements of the Jordanian power system. As the previous chapter pointed out, there is a wide range of projected capacity requirements.

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[9] Natural gas will be discussed in greater detail in the next section.

[10] The tone of conversations with staff members at JEA suggested that the delays may extend well beyond these "official" dates.

Second, in planning for capacity requirements into the next century, consideration must be given to the age and composition of the current power system. The oldest unit on JEA's system is a 14-MW gas turbine at Zarqa, which came on line in 1975. The newest are the two 130-MW thermal units at Aqaba which came on line in 1986. The majority of other units have commercial operating dates in the late 1970s and early 1980s. In the long-range planning context of this study, it might well be that some of these units will be retired within the planning horizon of this study.

Third, the 2 x 130-MW thermal units delayed at Aqaba (using heavy fuel oil and/or coal) may prove to be less economic than other generating options available to Jordan, including plants constructed to use indigenous energy resources. The two units at Aqaba, whether using coal or oil, require significant amounts of foreign exchange because the fuel inputs must be imported. And, depending on the extent of indigenous energy resources, it may prove economically feasible to replace other existing boilers which are presently not scheduled for retirement.

The remainder of this chapter looks at Jordan's indigenous energy resources. Jordan has a number of potentially attractive, but uncertain, options for meeting future power requirements through use of domestic fuel sources. The reserves of most of these resources are unknown at the present time, precluding a thorough analysis of the various options. However, the remaining sections review what is known about domestic energy resources – crude oil, natural gas, oil shale, and renewables – and provide a preliminary assessment of their potential use for power generation.

4.3. POTENTIAL DOMESTIC FUEL SOURCES FOR POWER GENERATION

4.3.1 Crude Oil

Approximately three-fourths of Jordan's land area is covered by sedimentary basins which are generally thought to be favorable for the existence of oil deposits. Exploration of these areas began in 1947 and, through the mid-1970s, U.S., German, Japanese, French, Dutch, British, and Yugoslavian petroleum interests have been involved. During this time, 14 exploratory wells were drilled. Although oil and gas were found to exist in several of the wells, the international petroleum interests concluded that the size of the fields were not likely to match the ones existing in neighboring Arab countries in the Middle East. By the mid-1970s, international petroleum interests ceased exploratory drilling in Jordan.

The Government of Jordan (GOJ), however, was not as discouraged. Despite the disappointing conclusion of the international oil companies, the GOJ embarked on an exploration program in 1976, funded from its own resources. Through its mining arm, the Natural Resources Authority (NRA), the Government examined historical geophysical data, generated new data, and marketed Jordan's potential for large-scale petroleum resources to international oil companies with the aid of British and French firms. In 1980, 20 companies were invited to review and purchase the new data. Only six companies purchased the data, but none opted for an exploration concession. The general belief was that the probability of finding a major field was small in comparison with other exploration opportunities.

Despite these negative responses from international petroleum interests, the GOJ has continued to maintain an ambitious oil exploration program funded out of general revenues. Expenditures for petroleum-related research were at the level of $20 million for

1982 and 1983. Under the current five-year plan, 34 million JD was budgeted for petroleum exploration.

Most recently, each of NRA's 17 wells in the Hamzah region have been found to contain some oil with production levels of approximately 1,000 bbls/d. However, Jordan's total petroleum needs are greater than 60,000 bbls/d. Even more encouraging to the government is its success in attracting the interest of three international oil companies (Amoco, Hunt, and Petrofina) to take petroleum concessions in 1986. Although the concessions are only one well plus seismic work, the interest shown by the three international oil companies is encouraging to the government. Clearly, the price of petroleum on international markets directly influences international exploration activity. When the concessions were taken the price did not favor intense oil exploration efforts. However, the prospects for discovering significant amounts of crude oil in Jordan are still uncertain at the present time.[11]

4.3.2 Natural Gas

Similar to crude oil, there are insufficient geological data to speculate on the extent of natural gas reserves in Jordan. NRA has two gas wells presently in operation at Risha in the northeastern part of the country (see Figure 4.1 above) which exhibit significant flow rates. One of the wells at Risha has been completed and tested at 20 MMSCFD (million standard cubic feet per day).

Based on this optimistic finding, the government has committed itself to installing 2 X 30-MW gas turbines (to be completed by late 1988 or early 1989) and to constructing a 132-kV transmission line over the 334 km from Amman to the Risha gas fields. In the event that the gas finds are sufficient, the government will add up to 4 x 30-MW gas turbines at the Risha fields until the 132-kV transmission capacity is reached.[12]

PetroCanada is currently conducting a reservoir study to ascertain the size of the reserves at the Risha site. The study is expected to be completed by early 1989. The results of the study are crucial for energy planning in Jordan. If the reserves prove to be large, a decision must be made on the use of natural gas reserves in excess of the amount required for power generation at the Risha site. There are several possibilities. The excess gas could be exported. Because the Risha site is far removed from economic centers in Jordan, this could be an attractive alternative. However, the lack of export markets in the region may

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[11] In their study of the energy sector in Jordan, Meta Systems *et al.* used three future oil scenarios. The authors acknowledged that the scenarios were not projections or probable outcomes, but were simply plausible, based on information available in late 1987. The scenarios were reviewed and approved by the Ministry of Energy and Mineral Resources (MEMR) for use in the study. The base case scenario assumes that none of the three existing concessions will make commercial discoveries of crude oil. The field currently producing 1,000 bbls/d for NRA is assumed to be depleted by the year 2000. An alternate scenario assumes that one of the current concessions finds a field of moderate size by 1990 – 6,000 bbls/d. Subsequent additions to capacity increase output to 30,000 bbls/d in 1995 and 40,000 bbls/d in 2000. The final scenario assumes that two fields will be developed, providing 40,000 bbls/d in 1995 and 90,000 bbls/d in 2000. The latter amount represents the capacity of the refinery.

[12] Constructing a 132-kV transmission line from Risha to Amman is an indication that the government is confident that there is at least enough natural gas in the Risha fields to supply 6 x 30-MW units – the 2 x 30-MW units currently under construction and 4 x 30-MW units to be constructed in the future.

preclude this possibility. Another alternative would be to transmit the gas by pipeline from Risha to the Amman area, where it could be used for industrial uses and power generation. Pipelines, however, are notoriously capital-intensive. The problem becomes even more complex when natural gas could be competing with other indigenous energy resources as a fuel source in Jordan; namely, petroleum and oil shale.[13]

4.3.3 Renewable Energy

Recent studies on renewable energy show that the potential for wind, solar, and biogas energy in Jordan is encouraging. It has been estimated that electricity generated by the wind could displace 3 percent of oil consumption in Jordan, while 8 percent could be replaced by solar water heaters and 1 percent by biogas electric generators.

The potential for wind energy in Jordan is significant.[14] Up until recently, wind energy has been used mainly for water pumping. However, a joint MEMR-JEA project has been initiated for establishing a pilot 300-kW wind farm for power generation. The farm is connected to the national grid and began generating electricity on an experimental basis in April 1988. It has been estimated that up to 10 percent of the demand for electricity in Jordan can be met through generation by wind turbines.

Because of the high cost of photovoltaics (PV), their use as a source of energy for electricity generation is ruled out for the near future. However, PV can and is used for water pumping and communications in remote areas where wind energy is not feasible. Several projects have been undertaken to pump underground water in desert areas where the construction of power lines is uneconomical.

In cooperation with the Royal Scientific Society, JEA electrified Jurf Aldaraweish, a rural village, using both wind and solar energy. The electrification is regarded as a test project to electrify remote villages which are a distance away from the national grid.

Biogas is currently used for electricity generation, lighting, cooking, and running agricultural motors as a substitute for diesel. The biogas sources include agricultural and animal wastes as well as left-over food.

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[13] The Meta Systems et al. study used four different scenarios for gas discovery, approved by MEMR for use in the study and developed to bracket scenarios developed by MEMR in 1987. The base case scenario had the 20 MMSCFD of current production reduced to zero by 1995. Another scenario had production expanded to 50 MMSCFD by 1990, increasing to 125 and 175 MMSCFD in 1995 and 2000, respectively. The third scenario had production reaching 100 MMSCFD by 1990, increasing to 125 MMSCFD in 1995 and 175 MMSCFD in 2000. The final scenario assumed that gas production would be sufficient to replace all fuel oil and provide supplies to serve the household and commercial sectors. Starting from 100 MMSCFD in 1990, production would increase to 175 MMSCFD in 1995 and 250 MMSCFD in 2000. The range of these scenarios encompasses every possible outcome for natural gas discoveries in Jordan.

[14] Jordan has been rated first among developing countries for developing its wind energy resources. See Strategies Unlimited, "Study of the Potential for Wind Turbines in Developing Countries," prepared for U.S. Department of Energy and World Bank, 1986.

4.3.4 Oil Shale

In 1979, the Jordanian Higher Committee on Energy made oil shale development the primary energy priority. A special department to administer development of petroleum, geothermal energy, and oil shale was established in the Natural Resources Authority.

In 1979, the NRA contracted with the West German government to study the oil shale at El Lajjun. The study concluded that the reserves were of high enough quality to justify indirectly using them for retorting and directly using them for power production. Since the Soviet Union has extensive experience with using shale for power production, the NRA contracted in September, 1980 with Technopromexport, a state-owned firm of the USSR, to carry out a feasibility study of directly using oil shale to fuel a 300 to 400-MW thermal power station. Also in 1980, a contract was awarded to Kloeckner/Lurgi, a West German firm, to study the feasibility of using oil shale in Lurgi's fluidized bed combustion technology and to determine the viability of building a retorting plant to convert the oil shale to a liquid. The German study concluded that Jordan should concentrate its efforts on retorting the shale at El Lajjun. More recently, the El Lajjun deposit was cored, drilled, and mapped in a joint study program sponsored by the Federal Republic of Germany. A two-phase feasibility assessment of syncrude oil production via mining, retorting, and oil upgrading by hydroprocessing was also conducted by the Germans and the NRA. The results of this study have not been published at this time.[15]

At the present time, three other shale deposits have been studied. They are the Sultani site, approximately 102 km south of Amman, the Jurf-ed Darawish site, approximately 35 km south of the Sultani site, and, most recently, a deposit north-northeast of Sultani. The four sites have proven geological reserves of more than 10 billion tons of shale. However, the estimated reserves exploitable by open-cast mining are significantly less: 1,165.9 million tons at El Lajjun, 942.1 million tons at Sultani, and 2,489.3 million tons at Jurf-ed Darwish. The four sites have been cored, drilled, and studied, but no data have been released about the most recently explored deposit. Possibilities for exploiting the shale include indirect use (retorting) for producing liquid fuel and direct use as a high-ash content fuel in power production. Jordan has been experimenting with both methods.

The remainder of this study addresses engineering, environmental, and economic aspects of using the oil shale at Sultani for producing power, using a circulating fluidized bed combustion technology developed by Pyropower. Implicit in the discussion of engineering and environmental aspects of the project is that additional power generating capacity is needed and oil shale is a candidate fuel to serve that need. In the economic discussion, the use of shale will be compared with other fuels for power generation, most notably the use of coal and/or oil at the delayed Aqaba II plant.

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[15] Although published data on the project are not available, some results were presented at a symposium held at JEA, April 10-11, 1988. The symposium, entitled *Groundwater and Mineral Resources — Examples of Jordanian-German Cooperation*, was sponsored by the Goethe Institute Amman and the Federal Institute for Geosciences and Natural Resources, Hannover, West Germany, and the Jordanian Ministry of Energy and Mineral Resources and the Ministry of Water and Irrigation.

5. CIRCULATING FLUIDIZED BED TECHNOLOGY

5.1 BASIC PRINCIPLES

Circulating fluidized bed (CFB) technology involves use of a special category of atmospheric fluidized bed combustor in which (1) the combustor is operated at a superficial gas velocity sufficiently high that the solid material is levitated and distributed throughout the height of the combustor with no discernible separation between a bed region and freeboard region, and (2) a hot cyclone separator is employed to return the circulating solids to the bottom of the combustor so that the solids will, on the average, make several passes through the system before leaving. In this high-velocity regime, a high degree of turbulence occurs with slip between the gas and solids and internal circulation within the combustor. This yields high combustion efficiency, low NO_x emission, good sulfur capture efficiency, and high heat transfer to the combustor waterwalls. The high turbulence promotes good mixing of the fuel over a relatively large bed area, so that a much smaller number of fuel feed points is required than for a bubbling fluidized bed boiler of the same output. No in-bed boiler tubes are employed in the circulating fluidized bed combustor, thus avoiding tube erosion problems.

The only significant disadvantages of the circulating type of system are that a greater fan power (than is required for a bubbling atmospheric fluidized bed combustor) is needed to maintain the pressure drop through the combustor and the capital cost is somewhat higher, primarily because of the hot cyclone separator which is inherent in the design.

5.2 TECHNOLOGY STATUS

First introduced beginning in 1979, there have been about 75 CFB boiler plants built worldwide. They have been designed to burn a wide variety of fuels: wood waste, peat, lignite, bituminous coal, coal washery tails, anthracite culm, industrial wastes and sludges, petroleum coke, and others. The thermal rating of the plants range from 2 MWt up to 290 MWt (110 MWe). About 30 of the plants are 20 MW or larger, while only 6 are above 150 MW. Ahlström and Pyropower, or through other subsidiary companies, have supplied the CFB boiler and associated equipment for about 40 of the plants which have been built. Ahlström has installed about 20 CFB boiler plants which are 20 MW or larger, and two of these are larger than 50 MW (55 and 110 MW). Six of the plants which are 20 MW or larger have been operating for two years or longer and 12 of them have been operating for about one year. The 55 and 110 MW plants have been operating for less than one year.

The operating experience with the Pyropower CFB boiler plants has been reported to be generally very good. The plants which have operated long enough to establish a record have demonstrated high availabilities, in excess of 95 percent. The technology appears to have been *successfully demonstrated* in units as large as up to about *60 MW*. There are no indications that there should be any problems in demonstrating successful operation of larger plants. The 55 MW plant was sold on a commercial basis, and it is anticipated that it will operate satisfactorily. The largest plant, 110 MW, is a utility demonstration plant at which the Electric Power Research Institute (EPRI) is conducting a 2-year test program to demonstrate the feasibility of CFB boilers for utility applications.

The Jordanian oil shale, because of its high ash content, is a more challenging fuel than, say, bituminous coal for use in scaling up to larger plants. The large quantities of ash which will be circulated through the combustor and returned by the hot cyclone will place a heavy demand on the return leg and loop seal. Also, there will be heavy fly ash loading in the flue gas passing through the convection tube banks, with increased potential for problems with erosion or deposition.

5.2.1 Plant Visits

In order to gain information on the operating experience of the Ahlström-Pyropower CFB plants, tours were taken of two plants: the 80 MWt (about equivalent to a 25 MWe plant) district heating plant at Espoo, Finland, and the 110 MW utility demonstration plant at Nucla, Colorado. The tour of the Espoo plant was at the invitation of Ahlström during the time that the fuel combustion evaluation team was present for the Jordanian oil shale combustion tests at Karhula, Finland.

5.2.1.1 Espoo plant

The boiler is rated at 80 MWt and produces hot water at 180°C and a pressure of 9 bar. The primary water is circulated through a heat exchanger where heat is transferred to water which is sent through the city district heating distribution system. The circulating fluidized bed combustor and boiler were designed and built by Ahlström. Coal is the fuel burned and limestone is added for SO_2 capture. The unit was commissioned in 1986 and has operated satisfactorily. It is an add-on unit to a larger pulverized coal-fired cogeneration steam plant for electric power and district heating which has remained in operation.

5.2.1.2 Nucla CFB demonstration plant

The plant is owned and operated by the Colorado UTE Electric Association and is a joint demonstration project with the Electric Power Research Institute (EPRI) and several cooperating sponsors. This is the world's largest operating CFB boiler. The three original coal-fired stoker boilers, each rated at 12 MW, have been retired in place. The new CFB boiler, rated at 110 MW, produces all the steam and a new 74 MW topping steam turbine-generator has been added to operate in series with the three original turbine-generators, rated at 12 MW each, to produce the full plant output.

The CFB boiler, designed and supplied by Pyropower Corp., produces 925,000 lb/h of superheated steam at 1510 psia and 540°C for the nonreheat steam turbine cycle.

The boiler has two combustion chambers, adjoining with a common center separation watertube wall, each a little more than 20-ft square and about 130-ft tall. Each combustion chamber has watertube walls and a superheater tube bank arranged around three of the four walls near the top of the combustion chamber. There is a hot cyclone separator for each of the two combustion chambers. The cyclone separators are designed to remove about 95 percent of the solid particles above 90 μ in diameter. The flue gas from the two cyclones flows to a single convection pass, where the gas flows down over final (tertiary) and primary superheater tube banks and then economizer tube banks. The flue gas then flows through the tube side of a vertical-tube air preheater and then to a baghouse.

Solids removed by the hot cyclones are returned to the bottom of the combustion chambers through loop seal legs which are fluidized by a number of air nozzles to maintain solids return flow.

Coal is fed through two feed-points on the front wall of each combustion chamber and at one feed-point on each of the solids return line just before the return entrance to the combustion chamber. Limestone is fed through four feed-points on the walls of each combustion chamber.

Primary (fluidizing) air is supplied to the bottom air plenum and enters the combustion chamber through a large number of fluidizing air nozzles which have several small holes drilled around the side of each nozzle. The floor of the combustion chamber (which also serves as the top of the air plenum) consists of a welded membrane watertube wall with the floor sloped toward two walls from the center, with the air nozzles attached to the membrane fins between water tubes. Secondary air is supplied through the wall to each combustion chamber at an elevation a few feet above the coal feed points. The ratio of primary/secondary air normally used at full load is 70:30. Overall, the excess air used is enough to yield about 3.5 percent O_2 in the flue gas, or about 17 percent excess air.

At full load, the combustor operates at a chamber pressure of approximately 35 to 40 in of H_2O at the bottom and a temperature of approximately 900°C. A combustion efficiency of 99 percent and a boiler efficiency of approximately 86 percent have been achieved. The environmental regulations require an SO_2 removal of 80 percent to stay under a limit of 0.3 lb/MBtu. Limestone is fed at a rate of approximately 0.1 ton/ton of coal with a mean particle size of approximately 150 μ to control SO_2 emissions. Low levels of NO_x emissions have been achieved.

Ash and spent limestone are discharged from the side of each combustion chamber into two ash-cooler-classifier-recycle units. Fluidizing air is supplied to these units which causes the finer particles to rise and return to the combustor. The larger particles travel down around watercooled tubes which permits useful recovery of heat from the ash into the water-steam cycle. The cooled ash falls through rotary valves and into water-cooled screw conveyors which feed it to the ash disposal system.

Coal and limestone are delivered by truck to the plant. The coal is sized about 2 in x 0 as received. The coal analysis is in this range:

HHV, Btu/lb	=	9400 - 10,400
% Sulfur	=	0.68 - 0.8
% Ash	=	20 - 23
% Moisture	=	5 - 10

Coal is crushed to 1/4 in x 0 and sent to the feed hopper. From the feed hopper it is fed by weighbelt feeder through a rotary valve into the combustion chamber. Coal consumption is about 62 tons/h at full load.

Limestone is received with a top size of 12 to 14 in. From the storage pile it is sent to a crusher where it is crushed to 150 μ mean size and dried with a gas-fired heater. It is sent to the feed hopper which discharges through four rotary valves into the four pneumatic feed

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lines to each combustion chamber. The limestone feed rate is metered by the time - differential weight of the feed hopper.

Gas burners are used for startup. Each combustion chamber has 3 startup gas burners through the wall and one duct gas burner for preheating the air during startup. They preheat the air to approximately 427°C with the duct burner. They use a startup bed of spent bed ash about 4 ft deep. They fire gas to make enough steam to get the turbine generators synchronized at minimum load and to get the bed temperature up to 510°C. At this temperature they begin feeding coal, and it lights off easily at that point. They can go from a cold start to operating solely on coal in about 12 h. The boiler is designed for a 3:1 turndown on coal firing. The steam exit temperature is controlled by attemperator water spray ahead of both the secondary and final superheaters.

Variable speed AC motor drives are used on the primary, secondary, and induced draft fans. The primary air fan has a 3500-hp motor and the secondary air fan has a 700-hp motor. The two fans supply the combustion air for both combustion chambers. Separate high pressure blowers are used to supply higher pressure air for fluidizing the loop seal legs and ash coolers and air for pneumatic transport.

The plant was shut down for minor repairs and modifications at the time of our visit. One problem has been a tendency for instability of the water level in the steam drum. There is a single common steam drum which serves the boiler tubes of both combustion chambers, which may conceivably contribute to the water level instability if the boiling rate were different in the two chambers. A totally random incident occurred in the fall of 1987 in which during startup a surplus of coal accumulated in the "A" combustion chamber and then began burning rapidly causing the chamber to overheat to a temperature of about 1038°C. This caused damage to the waterwall tubes in the common partition wall between the chambers due to the large differential thermal expansion. This damage was repaired immediately thereafter and no further overheating problems have been encountered.

Visual observation of the inside of the hot cyclone separators revealed no apparent significant slag buildup. There were heavy deposits of loose, fine fly ash on the top surfaces of the convection tubes, which have a horizontal orientation. Soot blowers are not used on the superheater tube banks but on the economizer and air heater tubes only. The plant's operators have had some restrictions of solids flow or plugging in the cyclone return legs, and they have had indication of some regions of poor fluidization in the loop seal legs and are adding a number of additional fluidizing air nozzles in those regions.

The normal flue gas temperature at the baghouse is about 163°C at full load. The plant operators use teflon coated filter bags. The stack gas environmental monitoring equipment is located at ground level after a long horizontal duct run and just at the entrance of the stack.

The capital cost for the CFB boiler and turbine-generator plant addition was about $87 million. This includes all the new ancillary equipment required and a new control room with a microprocessor computer control system. The present coal price is $24-28/ton. The present operating staff is 32 persons, but the plant managers are adding 2 heavy equipment operators to the staff. The normal outage for their scheduled annual shutdown is 3 weeks. The rotary valves in the coal, limestone, and ash systems normally can operate for at least a year without having to be shut down for an overhaul.

5.3 SUMMARY OF COMBUSTION TESTS OF JORDAN OIL SHALE

The combustion tests of the Jordan oil shale were conducted in the Ahlström CFB test unit at their R&D Center at Karhula, Finland from January 11-20, 1988. The test program consisted of a series of runs in which one or more of the key operating parameters was changed for each run so that the effects on the combustion performance could be determined.

Details of the test burn results have been reported to AID by both Pyropower Corporation and by ORNL. These details are proprietary to Pyropower and interested parties will have to contact Pyropower to discuss access to such information.

The Jordanian oil shale burned very well, even at loads as low as 40 percent. A large fraction of the shale blows through the combustor as fly ash; therefore, a large portion of the ash will have to be disposed of as fine fly ash. Low SO_2 and NO_x emission levels can be achieved in the circulating fluidized bed combustor, utilizing the calcium present in the shale and requiring no sorbent or chemical additives. High carbon burnup, 98 percent or better, can be expected.

6. SHALE OIL-FIRED GENERATING PLANT DESIGN

Pyropower has prepared a preliminary design of shale oil-fired CFB boilers for nominal 20-MW and 50-MW electricity generating plants. The designs are very similar except for the differences necessitated by the difference in capacity. The principal design parameters for the two boilers are proprietary in natur- nd Pyropower would have to be contacted regarding availability. ORNL has analyzed these designs for their feasibility and has reported its findings to AID and other study participants. ORNL's analyses are also proprietary in that they necessarily convey elements of the Pyropower design which are protected by confidentiality agreements.

7. ENVIRONMENTAL CONSIDERATIONS

7.1 GENERAL ENVIRONMENTAL CONTEXT

The eastern three quarters of Jordan are either rock or sand desert. Without irrigation, this land, the *badia*, can support a shifting pastoralist economy, but cannot support sustained agricultural cultivation and settlement. The Jordanian desert is part of the great Syrian Desert which covers large portions of Iraq, Syria, Jordan, and Saudi Arabia. Being on the western periphery of this desert, the Jordanian desert tends to be slightly cooler and wetter. It is largely covered with a layer of flint and chert pebbles and sparse arid-land grasses.

To the west of the desert, the land rises to merge into a narrow strip of steppe, forest, and arable land (known as the Western Highlands) before it is interrupted by the rugged and at times spectacular escarpment of the Rift Valley. Moving southwards from the northern part of Jordan, this severe depression is marked by Lake Tiberias, the Jordan River Valley, the Dead Sea, the desertic Wadi Araba, and finally Aqaba on the Red Sea's Gulf of Aqaba. Some of the larger peaks east of the Dead Sea exceed 1500 m, but most of the land lies at elevations of 500 m to 1000 m. The banks along the Dead Sea lie at -400 m, the lowest point on land in the world.

The Sultani site is located in the eastern portion of the Karak Plateau where the western edge of the Eastern Desert lies within view of the Western Highlands. The land here is flat to rolling with some hill ridges. This land is sometimes termed the southern portion of the Mafraq Steppe region.

The Sultani site is in the south-central catchment area of Wadi Mujib, which covers an area of 4600 km^2. The upper reaches of the wadis making up the Wadi Mujib are in semi-desert areas east of the Desert Highway and east of the Hijaz Railway. Here, and for the most part around the Sultani site, rainstorms are localized and floods are comparatively few. As a result, the wadis are not deeply incised as they are farther west, lower in the drainage basin. While rainfall can be as low as 50-100 mm/y in the high, semi-desert areas of the Wadi Mujib, the western portions receive 300 mm/y. The elevation at the Sultani site is around 822 m above sea level. There is a small, low desert dam on the Wadi Sultani, just south of the Sultani site. It is usually filled in the rainy season, but dries up toward the end of the summer. Much of the flow behind the dam comes from effluent from processing phosphates at the El Abiad Mine, about 10 km south of the Sultani site.

7.1.1 Climate

Jordan's climate is commonly called Mediterranean, with rain falling mostly during the winter months. A true Mediterranean climate is to be found, however, only along the higher elevations east of the Rift Valley. The Sultani site in Central Jordan has a semi-arid Mediterranean climate. Rainfall is concentrated into a cool winter season; summers invariably have a pronounced drought. January is the coldest month and August the hottest. Temperatures range form 7°C. to 25°C.

Climatic details for Qatraneh, about 10 km north of the Sultani site and the closest source of applicable data, are presented in Table 7.1.

Table 7.1
Climatic Information for the Qatrenah Area

Element Measured \ Month:	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Year
Temperature (C°)													
Mean Monthly	9.1	9.3	12.8	16.5	19.8	22.3	23.7	24.1	22.6	18.2	13.6	8.7	16.7
Mean Daily Maximum	15.1	15.8	19.4	23.3	27.3	30.2	31.5	31.8	30.9	26.0	20.3	15.4	23.9
Mean Daily Minimum	3.1	2.8	6.2	9.6	12.2	14.5	15.9	16.2	14.3	10.5	6.9	2.0	9.5
Absolute Maximum	24.4	23.8	29.3	32.8	37.4	37.5	37.0	41.2	38.4	33.4	31.0	23.3	41.2
Absolute Minimum	-2.5	-2.0	-2.8	2.8	5.8	10.0	11.8	12.2	9.0	4.0	0.4	-4.8	-4.8
Rainfall Amount (mm)													
Mean Monthly	27.3	26.4	18.0	5.4	3.2	0.0	0.0	0.0	0.0	2.3	8.0	20.8	9.3
Mean Annual													111.4
Relative Humidity (%)													
Mean Monthly	61	58	51	51	38	39	39	46	48	50	62	64	51

Wind

Winter: Winds are mainly southwesterly and with an average speed of 5.1-7.7 m/s (10-15 knots). Occasional gale wind is from southwesterly direction. Calm wind is often experienced at night and early morning 20-30 percent of the time.

Summer: Winds are mainly west-northwesterly and with an average speed of 4.1-7.7 m/s (8-15 knots). Winds increase in the afternoon, reaching speeds of 7.7-10.2 m/s (15-20 knots). Winds during the night and early morning are generally light and variable.

Dust

The number of days with dust reducing the visibility 1 km or less is about 4 d/y. The number of days with dust reducing the visibility 5 km or less is 15 d/y.

Source: Natural Resources Authority, Amman

Wind circulation follows two patterns: the winter winds are mainly southwesterly at 25-35 km/h and the summer winds are northwesterly at speeds of 15-30 km/h. Afternoon wind speeds typically increase to 40 to 50 km/h. Abu-Ajamieh[1] reports that the Sultani area can be affected by dust storms brought on by winds blowing from the southeast. This occurs during the dry Khamasinic period (a brief, regular occurrence in the early Spring).

Rainfall (about 110 mm/v at Sultani Station) has apparently declined over the last 2000 years; this has concentrated the more "recent" nomadic pastoral activities (sheep, camels, and goats) in the more productive wadis in the western parts of the arid highlands, i.e., nearer the Sultani site. Rainfall occurs erratically, with wide annual fluctuations. This makes water resource planning difficult, because the impoundment of seasonal water flows in valleys is at the center of future water resource expansion hopes.

Snowfall occurs in December to March with mean number of days = 4 d/y. Maximum number of days with snow = 14 d/y. Maximum snow depth = 40 cm.

7.1.2 Environmental Standards

Jordan has no comprehensive environmental standards regulating industrial development such as the proposed oil shale plant. In cooperation with the International Union for the Conservation of Nature (IUCN), AID is providing the GOJ with US$150,000 in local currency and the IUCN with US$380,000 over the next two years to conduct a comprehensive analysis of the condition of the country's environmental systems and to prepare recommendations and standards that the GOJ might enact to protect environmental resources as the country undergoes further development.

In the absence of comprehensive standards to guide industrial development, the GOJ relies on the Department of Environment in the Ministry of Interior to perform monitoring and some enforcement of the more egregious affronts to the environment. Regulation is basically through negotiation, with the GOJ typically supporting the Department of Environment's decisions and actions.[2] For major development, the Department of the Environment is looking to U.S. standards and World Bank guidelines in the interim until the country adopts its own regulatory standards and procedures.

7.1.3 Wildlife and Wildlife Resources

The wetter, higher areas east of the Rift Valley offer the best opportunities for agriculture and have, therefore, been settled and/or cultivated at widely fluctuating levels of intensity for millennia (the Amman area has been continually occupied since 8000 to 7000 B.C.). Thus, not surprisingly, the landscape and attendant wildlife communities in these areas have been extensively modified. In the more arid areas, the major impacts of human habitation come from overgrazing of livestock and removal of woody vegetation for fuel. In some areas, water is trucked in for the herds of sheep and goats. This has permitted overgrazing in remote, arid areas during the summer months when the rangeland can least endure the additional stress.

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[1] Abu-Ajamieh, M., *An Assessment of the El-Lajjun Oilshale Deposit*, Natural Resources Authority, Hashemite Kingdom of Jordan, Amman, Jordan, February 1980.

[2] Tell, Sufyan A., Director of the Department of the Environment, personal communication, April 14, 1988.

Jordan has no national parks, only several wildlife reserves formally designated but with only informal protection (Arzaq Wetland and Shaumari Wildlife Reserves). Draft legislation has been prepared for the establishment of national parks, but has never been adopted by the government. A proposed Wildlife Conservation Act (first drafted in 1979, but also never enacted) would allow for roughly comparable control to be exercised over wildlife reserves as that which would be expected for national parks.

Wildlife resources near the Sultani site are similar to those of extensive stretches of land along the Desert Highway. There are no existing protected areas in conflict with the site, but one has been proposed immediately to the west.[3] There are only 12 proposed or *de facto* existing wildlife reserves in Jordan. These have been chosen to cover as wide as possible a cross section of the country's various ecosystems and indigenous biotic communities. Efforts were taken in the selection process to minimize conflict with existing land uses and to factor in ease of administration and budgetary considerations. Figure 7.1 displays the locations of these, with the proposed Abu Rukbah Wildlife Reserve identified immediately west of the Sultani site.

The purpose of the 410-km^2 Abu Rukbah Wildlife Reserve would be to protect and preserve representative areas of the Western Highlands (Karak Plateau) and the Makraq Steppe land types together with their indigenous flora and fauna. A long-term goal is the protection of range until such time that the reserve lands could be capable of sustaining the reintroduction of large animals (e.g., gazelles). The entire reserve would be fenced because of the pressures for grazing and, on the western edges, cultivation. The Royal Society for the Conservation of Nature, in conjunction with the International Union for the Conservation of Nature and the World Wildlife Fund, has ranked the priority for establishment of protection of Jordan's 11 proposed wildlife reserves.[1] The Abu Rukbah reserve is one of three in the fourth, or lowest, priority category.

No extensive floral and faunal surveys have been conducted in the Sultani area or in the proposed reserve. Data on animal occurrence and distribution, according to Clarke, are particularly deficient. Plant cover in the proposed Abu Rukbah Wildlife Reserve has been greatly reduced to almost pure stands of *Anabasis syriaca* due to overgrazing, but in the wadis, Clarke[1] reports that *Atriplex halimus* appears along with *Achillea fragrantissima*, *Peganum harmala*, and *Artemisia inculata*. He also reports an abundance of the sedgegrass *Carex pachystylis*, but it also has been highly overgrazed. Plant cover in the Sultani site is comparable, where overgrazing has caused severe damage, biological diversity is restricted primarily to the wadis, and the hillsides are almost desertic in appearance. Clarke suggests that indigenous mammalian life is restricted to hares and probably rodents. Lizards and snakes are common. Resident birds likely include Temminck's horned larks, crested larks, desert larks, and red-rumped wheatears.

One of the two access points to the proposed Abu Rukbah Wildlife Reserve would be from the Desert Highway by Wadi Sultani Station). A ranger post for the eastern portion of the reserve as well as a guard post for this eastern entry is proposed at Sultani Station.

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[3] Clarke, John E., *A Proposal for Wildlife Reserves in Jordan: Development of Wildlife Conservation in Jordan*, Royal Society for the Conservation of Nature and the International Union for the Conservation of Nature and the World Wildlife Fund (IUCN/WWF), Amman, Jordan, 9 July 1979. Also, personal communication with Mr. Maher Z. Abu Jafar, General Director, The Royal Society for the Conservation of Nature, Amman, Jordan, 18 April 1988.

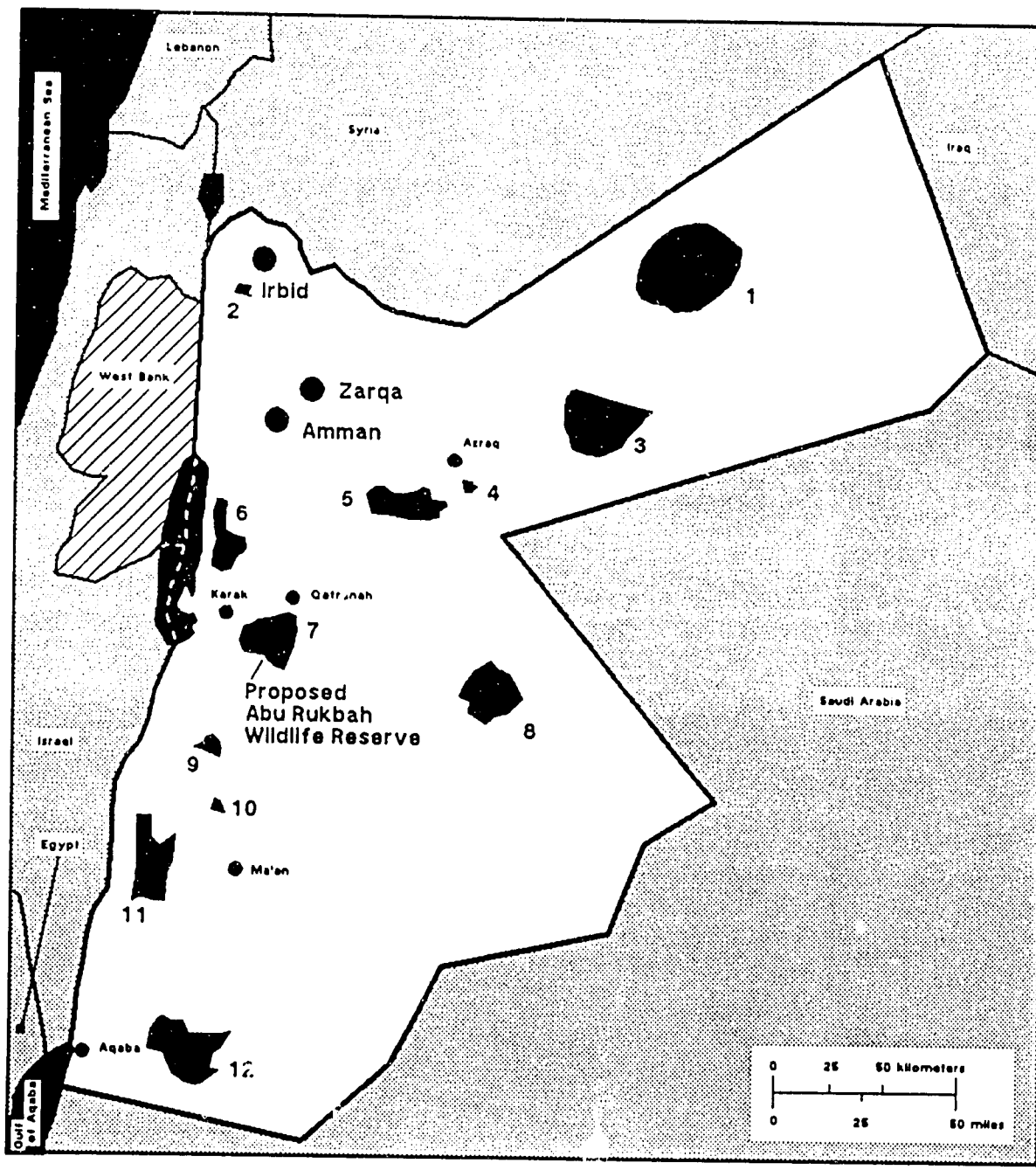

Figure 7.1
Location of Jordan's 12 proposed wildlife reserves, showing the Abu Rukbah Wildlife Reserve (highlighted) just west of the Sultani site.

7.1.4 Archaeology and Historic Sites

Parts of Jordan have been continuously occupied since around 8000 B.C. Urban concentration did not appear until around the Bronze Age (3300-1200 B.C.). Evidence of human occupation in some places dates back to 100,000 B.C. The country's archaeological resources cover major sites from the Neolithic period, the Bronze Age, the Iron Age, the Hellenistic Age, the Nabataean civilization, the Roman period, the Byzantine Empire, Early Islam, the era of the Crusades, and the Turkish occupation.

Much of Jordan's archaeological resources remain undiscovered, and if known, unexcavated in a major, scientific way. The area of the Sultani site is remote and expected to have few if any resources according to the Natural Resources Authority, which has responsibility for the lands and the mining activities there. If the oil shale project goes to a Feasibility Assessment stage, responsible authorities with expertise in the relevant areas need to be consulted about any resources at Sultani that might be in need of special protection.

7.2 MINE AND MATERIALS HANDLING SYSTEMS

The 400-MW Sultani oil shale-fueled power plant would be a large operation, with materials handling issues made even more important than in most such large operations because of the high-ash nature of the performance fuel. As mentioned in the Bechtel Group's project plan, the need for a 50-MW step is more for answering questions centered on "design issues for optimizing a 100-MW plant, in particular materials flow, rather than any need to prove the technology feasibility." Oil shale is harder than salt or coal, so mining and material handling equipment developed for these commodities are not necessarily directly applicable to oil shale.

If the proposed plant were to be built, each year mine operators would extract approximately 7.78 million tonnes of oil shale after removing 10 million bank m^3 of overburden. The design rate of the mining operation (perhaps overly conservative) is 2,000 tonnes of specification fuel per hour based on a 100 percent capacity factor of the power plant and a 72 percent efficiency factor for the mining operation.

7.2.1 The Oil Shale Resource

Jordan has long been identified as having extensive oil shale resources, possible exceeding 10 billion tons. There has been extensive core drilling by the NRA at four shale deposits in the country. Table 7.2 summarizes these oil shale resources for three of the sites, with 3 to 4 billion tons readily accessible for development. The fourth, not displayed here, is the most recent exploration effort and the most extensive reserve yet. It is located 40 to 55 km north-northeast of the Sultani site. Data on the size and quality of this reserve have not been published yet.

Table 7.2
Jordan Oil Shale Reserves

	El Lajjun	Sultani	Jurf-ed Drawish
Exploitable resources (billion tons)	1.2	0.9	2.5
Oil shale thickness (mean average in m)	29.6	31.6	68.3
Overburden thickness (mean average in m)	25.8	69.3	47.3
Shale oil content (mean average by % weight)	10.5	9.7	5.7

Source: Prefeasibility Study: Oil Shale Utilization for Power Production in the Hashemite Kingdom of Jordan, Volume I, Bechtel National, Inc., Arlington, VA, December 1988.

The Sultani site's nearly one billion tons of reserves cover an area of about 25 km^2. The Bechtel Group, Inc. has calculated that oil reserves in the northern area alone of the Sultani site appear to be sufficient to support a 400-MW plant for 30 years. With reserves in the southern area of the deposit being more than twice as large, the Sultani site could theoretically support up to 1200 MW of power generation for 30 years.

7.2.1.1 Drilling program

A total of 53 holes on approximately 1-km centers were initially drilled at the Sultani site to delineate the reserves (26 holes in 1982 and 1983 by the NRA and the BGR of the Federal Republic of Germany, and 27 holes by the NRA in 1986). An additional 28 drill holes on 150-m spacings were recently completed and used to define the reserves in the northwest section of the site, the area proposed for initial production mining. The oil content was determined in 67 of these holes (Fisher analysis on 42 boreholes), and analyses for calcium carbonate, sulfur, inorganic carbon, and organic carbon content were determined for 15 drill holes.

Based on the borehole drilling, the following geologic maps were made of the Sultani deposits: structural contour map of the upper oil shale surface, structural contour map of the lower oil shale surface, isopach map of the overburden, isopach map of the oil shale, and isoline map of the oil content percent.

7.2.1.2 Borehole Analysis

Table 7.3 summarizes the extent of the Sultani oil shale reserves, based on mineable reserve criteria that employ reserves having a greater than 5 percent oil content and a stripping ratio of overburden volume to oil shale volume of less than 3:1. The mineable reserves are in two distinct areas, one in the north and one in the south, separated by a

narrow corridor of low-grade oil shale in the central part of the deposit. The Bechtel Group, Inc. used a specific gravity of 1.8 in determining the quantity of oil shale.

Table 7.3
Sultani Oil Shale Reserves

Area	Oil Shale (million tonnes)	Oil Content (percent)	Overburden (million m^3)	Stripping Ratio (m^3:m^3)
North	320	7.44	384	2.16:1
South	658	7.61	627	1.71:1
Total	978	7.65	1,001	1.86:1

Source: Prefeasibility Study: Oil Shale Utilization for Power Production in the Hashemite Kingdom of Jordan, Volume II, Appendix 5, Bechtel National, Inc., Arlington, VA, December 1988.

Table 7.4 summarizes the mineable oil shale reserves by their oil content. The thicker oil shale beds contain a higher percentage of oil. The average organic content of the oil shale tested ranged between 8 and 11 percent by weight.

Table 7.4
Sultani Oil Shale Reserves by Oil Content
(in million tonnes)

Area	5% Oil	6% Oil	7% Oil	8% Oil	9% Oil	10% Oil	Total
North	nil	24.440	158.075	114.407	23.407	--	320.329
South	2.075	82.416	238.067	186.870	144.420	4.750	658.598
Total	2.075	106.856	396.142	301.277	167.827	4.750	978.927

Source: Prefeasibility Study: Oil Shale Utilization for Power Production in the Hashemite Kingdom of Jordan, Volume II, Appendix 5, Bechtel National, Inc., Arlington, VA, December 1988.

7.2.1.3 Oil Shale Composition and Properties

Table 7.5 summarizes the physical composition of the oil shale in terms of its usability as a fuel. The sulfur content varies between 1.6 and 4.3 percent, with most values between 2 and 3 percent.

Table 7.5
Sultani Fuel Specification

Composition (% by wt.)		Low Calorific Value Fuel	Performance Fuel	High Calorific Value Fuel
Carbon (organic)		10.20	11.32	12.50
Carbon dioxide		14.14	13.87	13.37
Sulfur		2.38	2.55	2.71
Moisture		3.20	3.20	3.20
Hydrogen		1.02	1.13	1.25
Nitrogen		0.58	0.48	0.38
Oxygen (by difference)		1.18	0.65	0.34
Ash		67.30	66.80	66.25
	Totals	100.00	100.00	100.00
HHV (Btu/pound)		2000	2250	2500
Fisher Assay Oil Content (% by weight, median)		7.5	8.4	9.25
Range (% by weight, median)		6.7-8.3	7.5-9.0	8.4-9.9

Source: Pyropower Corporation, April, 1988.

7.2.2 Mining Considerations

The overburden thickness ranges between 34 m and 86 m, with a mean thickness of 69.3 m. The minimum thickness is found in the northwest part of the deposit and the maximum is in the southeast. The oil shale thickness varies between 1.5 m and 65 m, with a mean thickness of 31.6 m. The greatest thickness occurs in the southeast section of the reserves.

The mine development plans for the 20-MW and 50-MW projects are different from those of the 400-MW plant because of the much larger volumes of materials to be handled in the full-scale commercial project. The mine for either of the two smaller projects would be formed as an expansion of the existing trial pit through use of a loader and truck operation. Working benches and a system of roads and ramps would be developed in the overburden and oil shale in preparation for actual production. Three separate haul roads would be built to transport (1) overburden from the pit to an out-of-waste pile located 3 km away, east of the oil shale deposit, (2) oil shale from the pit to the process plant storage piles (3 km), and (3) spent shale ash from the power plant to the out-of-pit waste pile (4 km).

The mine for the 400-MW project would be new, also being located in the northern part of the site because of its thinner overburden along the west bank of the deposit. Complete development of this are for mining would entail the necessity of relocating an existing

railroad line (the Hijaz Railway) after about 18 or 19 years. The mine would consist of a new incline and box-cut, the development of working rock faces for electric shovels and trucks in the in-pit-system of roads and ramps. Mined shale would be fed onto a belt conveyor for transport to the surface via the incline. For the first several years of the operation, the incline would be used for transport of overburden from the pit to the out-of-pit waste pile. After sufficient mining has been completed (approximately three years) to permit room in the pit, backfilling of the pit could be started. Haulroads for the disposal of the overburden and of the spent shale would have to be built at that time.

The estimated quantities of materials to be excavated during the development stages and during normal production modes of the alternative mine projects are summarized in Table 7.6.

Table 7.6
Mine Excavation Schedule

Mine Size	Mine Development Excavation (bank m^3)	Production Schedule[a] (tonnes/y)
20-MW Plant	500,000	390,000
50-MW Plant	1,000,000	973,000
400-MW Plant	8,455,000	7,783,000

Source: Prefeasibility Study: Oil Shale Utilization for Power Production in the Hashemite Kingdom of Jordan, Volume II, Appendix 5, Bechtel National, Inc., Arlington, VA, December 1988.
[a] based on a 75 percent capacity factor

7.2.2.2 Mode of mining

Truck and shovel

Mining at the proposed Sultani oil shale plant would be by mobile mining equipment, i.e., "truck and shovel." The overburden for the mines for the 20- and 50-MW projects would be removed (after being loosened by blasting) by front-end loaders, while that of the 400-MW plant would be loaded by electric shovels. Mining of the oil shale for the two smaller mines would be by using bulldozers to rip the oil shale and scrapers to load the ripped shale for delivery to the portable crusher. In the 400-MW project, surface miners would be used to load the broken shale into trucks for delivery to trump dump hoppers. Explosives used to break up the overburden will be detonated by use of blasting delays between rows of holes and occasionally between holes in the same rows to improve fragmentation and reduce ground vibration and air blast levels. On-site, secure explosive storage will be provided for bulk blasting agents, bagged ANFO (the primary explosive), and high explosives. Construction of these would be in accordance with appropriate standards. Access to the blasting areas would be controlled prior to the time of blasting.

Dragline

The El Abiad Mine has a stripping ratio of 9.6 m^3 of overburden to 1 m^3 of phosphate ore mined. In order to reduce overburden excavation costs, in 1981 the Jordan Phosphate

Mining Company Ltd. (JPMC) procured a 30-m^3 dragline (the first large dragline in the Middle East) for its El Hasa operations (20 km south of the El Abïad Mine). An international mining contractor operated it for the first two years. Dragline production, operation, and availability proved most satisfactory, and JPMC took over the dragline operation in 1983. To reduce contract mining costs for overburden excavation, JPMC has since procured a 17-m^3 dragline for its operations at El Abïad Mine and is procuring several other small draglines for its operations elsewhere. Technical questions about Jordanian engineering and maintenance capabilities to keep such capital-intensive machinery in operation are, thus, largely moot based on JPMC's record. JPMC estimates that a dragline employed in the Sultani mine could reduce overburden excavation costs by about 50 percent.

The questions that do remain about the suitability of a dragline at the Sultani site are (1) the possibility of the incremental nature of mine and plant expansion (to match demand for power) vis-à-vis the capital intensive, one-time cost of procuring a dragline; and (2) the length of the boom necessary to allow the bucket access to the lowest-lying overburden. The relatively flat shale oil beds are highly conducive to dragline removal of overburden. Preliminary discussions with personnel[4] from the Bucyrus-Erie Company, suppliers of the 17-m^3 dragline at the El Abïad Mine, suggest that a dragline would be easily suited to operating under the physical mining demand needs and constraints of the planned Sultani operation. The main question would be the phasing of the operation.

Oil shale handling

Because of the performance specification of the fuel (2250 Btu per pound), separation of the ore must occur. In the case of the two smaller mines, oil shale would be placed in both low- and high-grade stockpiles by the scrapers according to visual inspection of grade by the equipment operator. A front-end loader would charge a portable crusher from these stockpiles. From the crushers, the ore would be transported by truck from the pit to the surface oil shale process plant stockpiles. While one stockpile would be in the process of being formed and tested, the second would be used to fuel the plant with the aid of another front-end loader. The requisite fuel is thus assured through use of selective mining, mixing at the portable crusher, and amendment from the stockpile prior to use in the plant.

For the 400-MW plant, oil shale would also be selectively mined and loaded through use of surface miners and trucks which would carry the ore to truck dump hoppers. From the hoppers, the oil shale would be moved to the surface via belt conveyor where it would enter an automatic sampler before being placed on a traveling stacker for stockpiling into two "V" slot storages. While one stockpile would be formed and tested, the second would be amended be two variable speed plow feeders for delivery to the process plant. This system

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[4] Martin F. Selfert, Manager, Drive and Power Systems, and Rami Beydoun, Electrical Engineer, Service Division. Since neither is a mining engineer, these observations will have to be confirmed by someone more familiar with the specifics of the proposed Sultani mining operation.

would assure the large volumes of uniform-quality oil shale necessary for the large operation.

7.2.2.3 Production of phosphate to reduce the mining costs

The NRA's recent core drilling to further define the oil shale reserve revealed that the Al Hasa Phosphorite Formation, which underlies the Sultani oil shale, has 3 to 12 m of phosphorite material. These deposits are unexplored in the Sultani area, but are part of the phosphate ores currently being mined in the large operations of El Abïad and El Hasa south of the Sultani area.

With a world market oversupply of phosphate rock and Jordan having ample supplies of inexpensively mined phosphates, there appears to be little incentive to mine deeper below the oil shale for what is likely low-grade phosphoritic ore. The overburden removal costs are, of course, nil, but the costs of removing overburden in the large phosphate pits mined by draglines are not that expensive a part of the overall mining and mill operations. With the 1992 (or thereabouts) closure of the El Abïad Mine and the El Hasa operation planned to be terminated in 1997 (due to their limited remaining proven economically recoverable reserves), there would be no nearby beneficiating or milling operations for any phosphate ores mined at Sultani. Extensive and expensive transportation costs would have to be incurred to pursue this option.

On April 18, 1988 in Jordan, we asked Mr. Muhammed Abu Ajamieh, the Director of Geologic Surveys and Mines in the NRA, about the potential for mining the phosphate rocks underlying the oil shale. He responded that the phosphoritic horizon is composed of very hard rocks, meaning that exploration of its extent and feasibility for mining would likely be expensive. He stressed that Jordan has many phosphate deposits that are readily mineable, there is a current glut in the international market for phosphate rock, and that there is much uncertainty associated with the mere presence of mineable ore. These uncertainties include quality issues, means and costs for beneficiation, and marketability. The fact that the phosphate reserves would be accessible without any costs to remove the overburden did not impress Mr. Abu Ajamieh. He held out little optimism or interest in NRA exploiting this potential.

Of course, what the market for phosphate rock might be by the mid-1990s when the oil shale project might first begin operation is another question. The World Bank clearly has some confidence in Jordan's potential to export phosphate on the world market at that time, given that the Bank is about to fund a $31 million loan to the JPMC for a new phosphate mine and processing plant at Shidiya, 120 km northeast of Aqaba.

Another consideration in conjunction with the El Abïad and El Hasa Phosphate Mines being scheduled to close in the 1990s is that the raw rock would have to be transported to the Shidiya site, a considerable distance. (The existing narrow-gauge Hijaz Railway, which is used to transport the production from the El Abïad and El Hasa complexes and also connects with the Sultani site, passes 25 km west of the Shidiya site. There are no current plans to make the link between the Shidiya site and this railway, although the World Bank

states[5] that "The proposed Transport III project may envisage the extension of the railway line to Shidiya, depending on the economic and financial justification of this extension." The narrow gauge line between the El Hasa and El Abiad mines suffers from the poor condition of the existing track and bed, and occasional derailments occur because of poor track maintenance. In 1986, only 48 percent of the output of these two production facilities was transported to Aqaba by rail; the rest went by contract trucking operations, whose tariffs per tonne were more attractive than the railroad's rates.)

7.3 BOILER AND POWER PLANT EMISSIONS

The main gaseous emissions of concern with operation of the proposed power plant(s) are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter. Dust, raw shale fines, and fly ash are the main components of the particulate emissions, and are discussed in Section 7.4. Dust emissions from the stacks are expected to be around 0.03 lbs/Btu heat input, within general international recommended maxima. The fly ash is the main concern regarding particulates.

A gaseous emission of increasing global concern is carbon dioxide (CO_2). The proposed project would emit more CO_2 per unit of useful heat generated than would a coal or oil plant of similar electrical power output because of the carbonate composition of the shale in the fuel. The calcium carbonate rocks would calcine to lime under the heat of the combustion process. This reaction liberates CO_2 and heat to the atmosphere as well as generating lime. This lime (CaO) in turn reacts with the SO_2 in the shale oil to form calcium sulfate, thereby limiting harmful SO_2 emissions. Pyropower has not estimated the quantities of CO_2 that would be produced by the proposed oil shale project.

Emissions from the proposed power plant (any of the proposed sizes) should be within generally accepted international standards for SO_2 without needing any downstream treatment. High combustion efficiencies from the vertical and lateral mixing inherent in the circulating fluidized bed combustion technology assure optimum carbon burnout (the test combustions in Finland showed over 98.5 percent combustion).

Shale of lower quality than the performance fuel specification may require supplemental fuel, such as petroleum coke or coal, for ignition or flame retention. Pyropower has deferred this aspect of the combustion to later studies. If such fuels are needed on a frequent basis, there, of course, would be SO_2 and NO_x emission considerations different in magnitude from the shale-alone fuel. These issues will have to be assessed in later studies.

The nature of Pyropower's circulating fluidized bed combustion technology would provide for a uniform temperature in the boiler, high heat transfer coefficients, and excellent mixing. The crushed oil shale would contact primary or fluidizing air (see Section 5) in the lower combustion chamber. Here the shale would be combusted in an oxygen-starved (reducing) environment while the calcium carbonate in the oil shale would be calcined to lime. Secondary air would be introduced at a higher level to provide the additional air

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[5] The World Bank, *Staff Appraisal Report, Hashemite Kingdom of Jordan, Shidiya Phosphate Mine Project*, Energy Division, Asia Technical Department, The World Bank, Washington, D.C., Report No. 6932-JO, restricted distribution document, December 18, 1987.

required for complete combustion. The lime component (calcium carbonate) of the shale would react with the sulfur dioxide resulting from oxidation of the sulfur in the fuel source to form calcium sulfate.

Pyropower reports that combustion and sulfur retention occur at temperatures sufficient to provide maximum calcium utilization for SO_2 removal yet low enough to minimize the formation of "thermal" NO_x (fixation of atmospheric nitrogen in the combustion air). The combustion tests in Finland demonstrated that over 90 percent of the fuel sulfur was absorbed by the inherent calcium in the oil shale. The use of staged combustion would inhibit the conversion of fuel-bound nitrogen to NO_x. High combustion efficiencies would be achieved due to the long residence time of the solids and to the well-mixed isothermal environment.

The Ahlström Laboratory's test of the Jordanian oil shale sample fuel produced typical emissions for SO_2 of below 20 ppm. This reading is equivalent to 56.8 mg/m^3, and should be viewed in reference to the World Bank's guideline (April 1984) for ambient air quality: a maximum arithmetic mean inside and outside the plant of 100 mg/m^3, the U.S. Environmental Protection Agency's maximum of 80 mg/m^3, and the World Health Organization's level at which health effects may begin to be measured of 40 to 60 mg/m^3. With the location of the proposed project, the generally excellent daily wind ventilation of the site, and with the combustion technology and fuel sources proposed, there appears little to be concerned about regarding the plant's SO_2 emissions. U.S. industrial facilities are generally required to remove about 95 percent of the SO_2 emitted. While the Pyropower boiler is intended to achieve about 90 percent SO_2 removal, this should be most adequate given the assumption (no data) that the Sultani site has low background SO_2 concentrations.

The Ahlström tests also reported NO_x emissions of 60 to 120 ppm. This corresponds to readings of 115 to 229 mg/m^3. These are stack emissions, and in the well-ventilated conditions of the Sultani site should be dispersed to NO_x concentrations easily within the World Bank guideline (November 1982) for ambient air concentration of NO_x: annual arithmetic mean of 100 mg/m^3. The U.S. National Clean Air Act and National Ambient Air Quality Standards have the same annual arithmetic mean as the World Bank guideline. Interpretation of these readings is difficult without more background data on the Sultani site and use of a dispersion model to augment these data. Candidate worst case conditions for air dispersal modeling would be several days of atmospheric stagnation, winds from the south in the Spring, or moderate wind conditions in which a stable polluted layer spreads uniformly and causes visibility reduction over a large area. The Bechtel Group reports that NO_x from the Pyropower boiler is expected to be 0.6 lbs/million Btu boiler heat input, which it says is equivalent to typical U.S. industrial plant NO_x emissions.

The environmental impacts of plant construction are expected to be normal for the type and size of facility proposed. The lack of significant seasonal rains means that construction can proceed year-round without specific stratagems needed to control for erosion and runoff beyond those undertaken in normal desert construction (flash flooding concern).

Secondary environmental effects of plant construction and operation are largely factored into the community and other workforce infrastructure design plans put forth by the Bechtel Group. Sanitary wastes in domestic and service waste streams should be kept separate and treated by using commercially available biological treatment units.

7.4 OVERBURDEN AND ASH DISPOSAL SYSTEM

Combustion of Jordanian oil shale would produce substantial volumes of overburden and ash requiring disposal. At peak, operation of the 400-MW plant would generate approximately 1000 tonnes per hour of wetted shale ash for disposal.

To provide a basis for predicting the environmental impacts of the disposed solid wastes, samples of the raw shale and ash from the test burn were shipped to Oak Ridge National Laboratory and analyzed.

7.4.1 Analyses of Shale and Ash

The material available for analysis was shipped from Finland after the test burn performed by Pyropower, Inc. The material available for analysis consisted of about 250 kg of raw shale (shipped in one 55-gal drum), about 9000 kg of bottom ash (shipped in 46 55-gal drums), and about 6000 kg of fly ash (shipped in 16 large plastic "Big Bags"). Ash was available from each of the eight test runs; most of the analyses focused on ash from test Run #1, the test run with firing conditions that most closely matched the proposed conditions for the proposed combustor in Jordan. The additional ash was set aside for later tests of its resource recovery potential.

7.4.1.1 Density

Bulk density is a physical property of ash that influences both the area that would be required for disposal of the ash and its potential for by-product utilization. Measurement of bulk density was done simply by weighing a given volume of material. No effort was made to compact the ash or shale or determine its absolute density (independent of interstitial space between particles). The bulk density of the raw shale was 1.23 g/mL, and bulk densities of fly ash and bottom ash varied from about 0.97 to 1.05 g/mL, all within 5 percent of 1.0 g/mL, the density of water. Bulk density data are presented in Table 7.7 and compared in Figure 7.2.

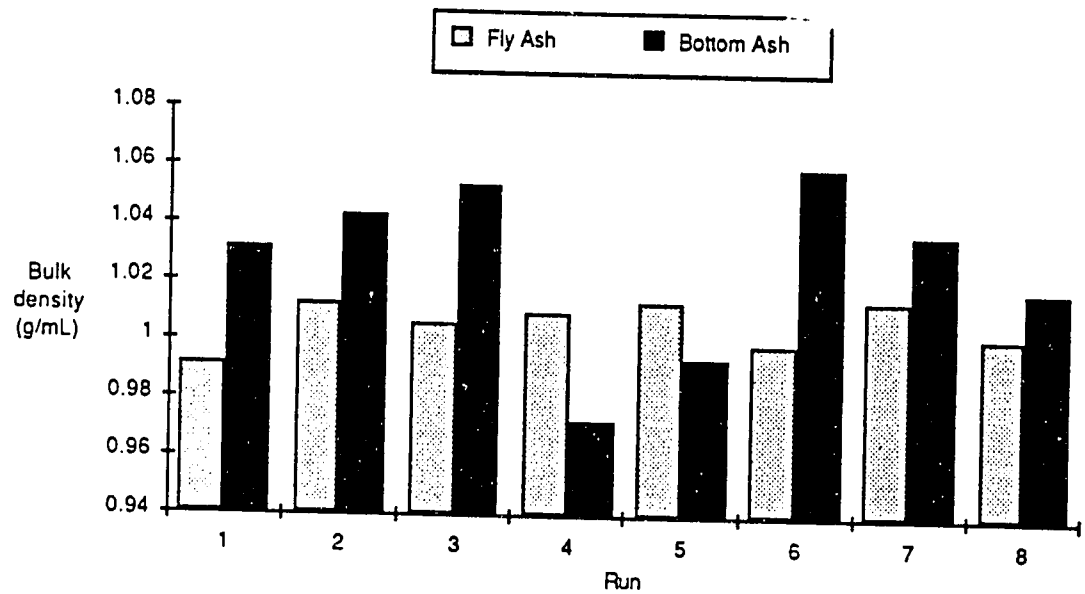


Figure 7.2
Bulk density of ash. Bulk density of raw shale was 1.23 g/mL.

Table 7.7
Bulk Density of Shale and Ash from Eight Test Runs

	Bulk Density (g/mL)	
Run	Fly Ash	Bottom Ash
1	0.9915	1.0313
2	1.0131	1.0432
3	1.0056	1.0532
4	1.0096	0.9727
5	1.0134	0.9945
6	0.9993	1.0599
7	1.0143	1.0372
8	1.0026	1.0187

Although one would expect bottom ash to have a greater density than fly ash, the smaller and more uniform particle size of fly ash (Sect. 7.4.1.2) allows fly ash to compact to a greater extent, thus producing slightly higher bulk densities in some cases (Runs #4 and #5). The variation in density of ash is much less important than the fact that the ash is at least 18 percent less dense than the crushed raw shale.

7.4.1.2 Distribution of particle size

The particle size of ash could affect by-product utilization as well as the ash's potential to generate fugitive dust from the disposal site or by-product processing facility. Distribution of particle size was determined by using the Microtrac automated particle size sampler (for fly ash) and by using sieve screens for the bottom ash and raw shale. The distributions of particle size for fly ash, bottom ash, and crushed raw shale are shown in Figures 7.3 and 7.4.

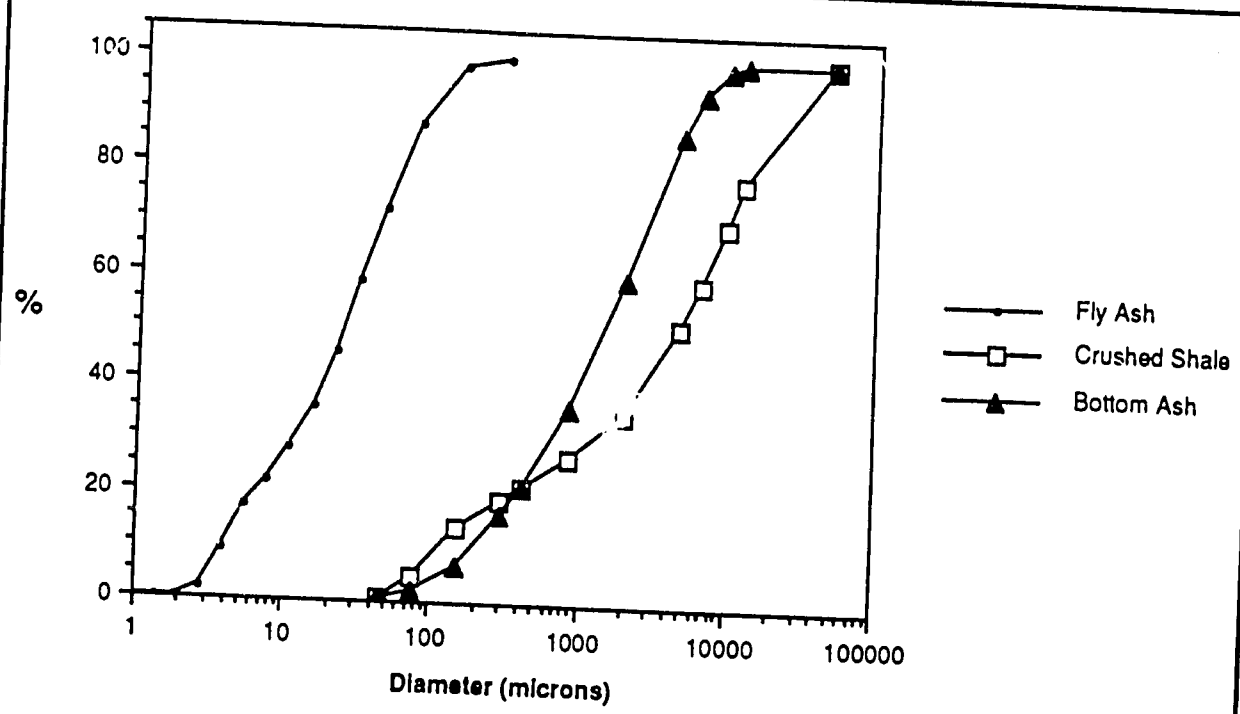
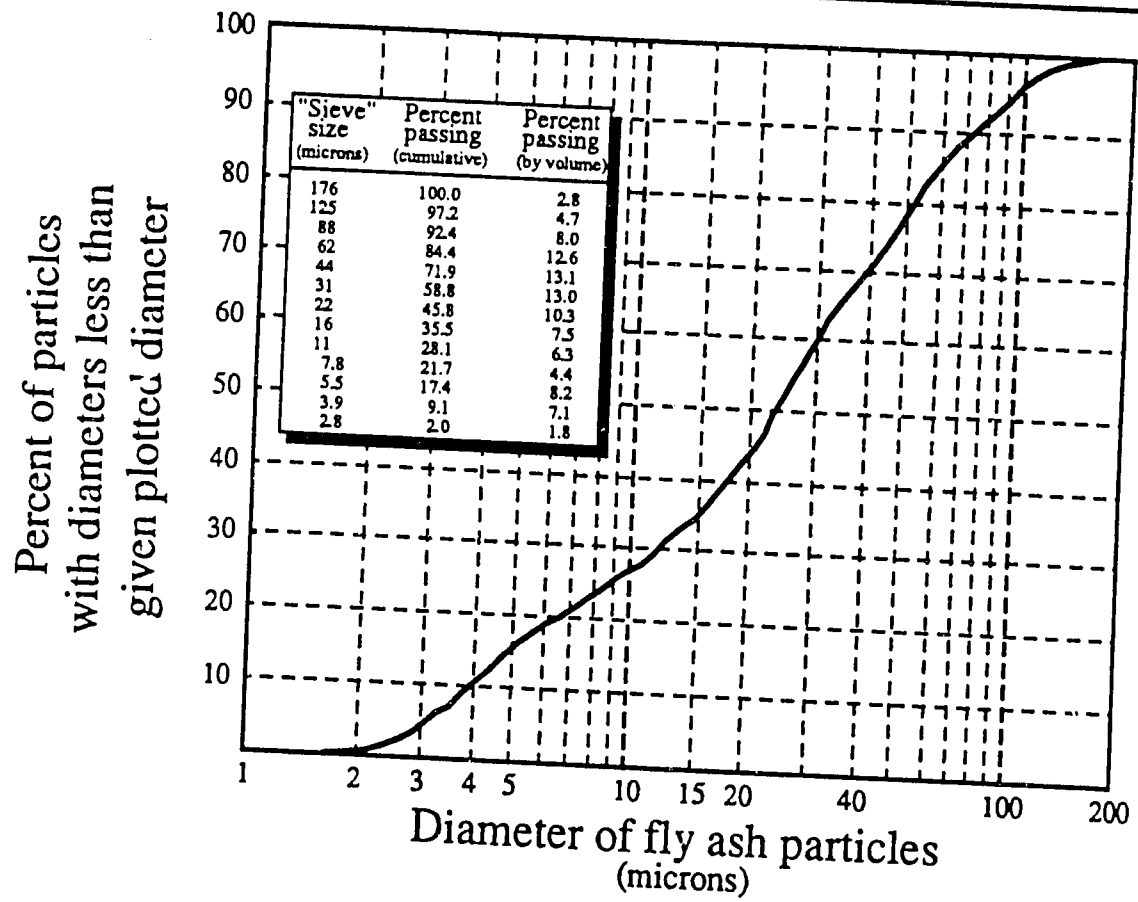


Figure 7.3
Particle size distribution of ash and crushed shale from test burn of Jordanian oil shale.
Semi-logarithmic graph indicates the per cent ash by weight that is less than the diameter shown.



"Sieve" size (microns)	Percent passing (cumulative)	Percent passing (by volume)
176	100.0	2.8
125	97.2	4.7
88	92.4	8.0
62	84.4	12.6
44	71.9	13.1
31	58.8	13.0
22	45.8	10.3
16	35.5	7.5
11	28.1	6.3
7.8	21.7	4.4
5.5	17.4	8.2
3.9	9.1	7.1
2.8	2.0	1.8

Figure 7.4
Particle size distribution of fly ash from test burn #1 of Jordanian oil shale
Semi-logarithmic graph indicates the per cent fly ash by weight that is less than the diameter shown. Ten percent of the fly ash (by weight) was less than 4.07 μ in diameter; 50 percent was less than 24.90 μ in diameter; 90 percent was less than 80.05 μ in diameter; and 100 percent was less than 176 μ in diameter.

The lower size limits for dust particles are in the transition zone to larger gas molecules (about 1μ or less) and as such are likely to be exhaled as readily as they are inhaled, depending on particle shape and specific gravity. The upper limit for particulate size is around 500 μ, or at about the size where gravity will rapidly remove a particle from the air such that is poses no hazard to respiration.

7.4.1.3 Proximate and ultimate analyses

Proximate, ultimate, and elemental analyses were performed on crushed raw shale and fly ash and bottom ash from Run #1. Table 7.8 presents the results from these tests.

Table 7.8
Results of Proximate, Ultimate, and Elemental Analyses

	Crushed shale	Fly ash	Bottom ash
Proximate analysis			
Moisture (%)	1.64	0.16	0.25
Volatile matter (%)	35.2	3.37	5.12
Fixed carbon (%)	<1.0	<1.0	<1.0
Ash (%)	67.03	98.71	96.31
Ultimate analysis			
Carbon (%)	18.0	<1.0	<1.0
Hydrogen (%)	1.52	<1.0	<1.0
Nitrogen (%)	<1.0	<1.0	<1.0
Sulfur (%)	3.01	4.94	3.49
Oxygen (%)	26.4	28.7	28.9
Btu/lb (dry wt)	2564	a	a
kJ/kg	5963	a	a
Elements, (ppm[b])			
Ag	<4	4	5
Al	11000	17000	9380
As	<60	<60	<60
B	24	31	20
Ba	80	128	320
Be	0.6	1.1	0.5
Cd	182	156	153
Co	4	5	3
Cr	451	535	342
Cu	136	162	122
Fe	6160	9080	4950
Ga	<40	<40	<40
K	3700	5300	3200
Li	29.5	32.5	29.6
Mg	5470	5550	3960
Mn	38.7	56.9	51.9
Mo	244	275	177
Na	2820	3790	2550
Nb	40	43	39
Ni	240	295	183
P	18000	20000	16000
Pb	<20	<20	<20
Sc	3.6	5	3.1
Sr	994	1110	917
V	438	541	341
Y	23.1	28.7	20.8
Zn	1630	1730	1210
Zr	25	31	21

[a] did not fire

[b] as-received basis, analyses performed by ICP (Inductively Coupled Plasma?)

7.4.1.4 Carbon and sulfur analyses

Data on total carbon and sulfur content of the shale and ash are presented in Table 7.9.

Table 7.9
Concentration of Carbon and Sulfur in Raw Shale and Ash from Run # 1

Constituent	Oil Shale	Fly Ash	Bottom Ash
Sulfur (%)	3.73	6.04	3.02
Total carbon (%)			
Replicate 1	14.0	0.46	1.00
Replicate 2	17.2	0.47	1.04
Replicate 3	18.2	NA[1]	1.75
Average	16.5	0.5	1.3

[1] not available

7.4.1.5 Leaching characteristics of ash and shale

To determine the potential for contamination of groundwater, the extraction procedure for toxicity (EP-Tox) was performed. This test is routinely used to determine if waste materials are classified as "hazardous" under the U.S. Resource Conservation and Recovery Act (RCRA) because of the toxicity of the leachate generated from the waste. To perform the EP-Tox, the ash or shale was ground using a mortar and pestle so that all particles would pass a 9.5 mm sieve. The ground material is placed in a flask of distilled water and placed on a shaker. The contents of the flask are filtered to remove the solids, and the liquid elutriate is analyzed to determine what constituents of the waste have dissolved in the water. The elutriate for the ash and shale were analyzed for trace elements and semi-volatile organic compounds. A waste is considered hazardous because of its toxicity if the concentration of any constituent in the elutriate exceeds the Drinking Water Standard (set by the U.S. EPA) by a factor of 100. Data from the EP-Tox are presented in Table 7.10.

7.4.2 Potential Water Quality Impacts

Water quality impacts from the disposal of ash and overburden could involve the leaching of soluble trace elements into groundwater and introduction of fugitive particulate matter into ephemeral watercourses or reservoirs. The extent to which these potential impacts would be expected to occur is discussed below.

The results of the EP-Tox leaching test (Sect 7.4.1.5 and Table 7.10) indicate that the fly ash from combustion of the Jordanian oil shale has a greater potential for leaching soluble trace elements than does the bottom ash or raw shale. The concentrations of chromium and selenium in the leachate from fly ash were about 10 times greater than levels that leached from bottom ash. The tendency of fly ash to leach trace elements is thought to be associated with the small particle size of fly ash and also possibly the greater solubility of trace elements that have undergone more extreme heating, complete separation from the organic matrix of the fuel, and subsequent adsorption onto the surface of fly ash particles. In an exception to the pattern of fly ash having the greatest tendency to leach trace elements, the raw shale produced almost 100 times the concentration of cadmium leached from fly ash or bottom ash. Because semivolatile organic compounds were not found in the ash leachate, no contamination of groundwater by organic compounds would be expected from ash disposal.

Table 7.10
Concentration of Constituents in Leachate from EP-Tox Test on Raw Shale and Ash from Run # 1

Constituent	Oil Shale	Fly Ash	Bottom Ash	Drinking Water Standard
Trace Elements (mg/L)				
Arsenic	0.11	0.15	0.13	0.05
Barium	0.049	0.15	0.12	1.0
Cadmium	0.18	<0.002	<0.002	0.01
Chromium	0.017	2.0	0.31	0.05
Lead	<0.05	<0.05	<0.05	0.05
Mercury	<0.0001	<0.0001	0.0001	0.002
Selenium	0.22	0.69	0.06	0.01
Silver	<0.006	<0.006	<0.006	0.05
Semi-volatile Organics				
	65 compounds[a]	BDL[b]	BDL[b]	BDL[b]

[a] 65 compounds include phenol, bis(2-chloroethyl)ether, 2-chlorphenol, 1,3-dichlorobenzene, 1,4-dichlorobenzene, benzyl alcohol, 1,2-dichlorobenzene, 2-methylphenol, bis(2-chloroisopropyl)ether, 4-methylphenol, n-nitroso-di-n-propylamine, hexachloroethane, nitrobenzene, isophorone, 2-nitrophenol, 2.4-dimethylphenol, benzoic acid, bis(2-chloroethoxy-methane, 2,4-dichlorophenol, 1,2,5-trichlorobenzene, naphthalene, 4-chloroaniline, hexachlorobutadiene, 4-chloro-3-methylphenol, 2-methylnaphthalene, hexachlorocyclopentadiene, 2,4,6, trichlorophenol, 2,4,5-trichlorophenol, 2-chloronaphthalene, 2-nitroanailine, dimethylphthalate, acenaphthylene, 2,6-dinitrotoluene, 3-nitroaniline, acenaphthene, 2,4-dinitrophenol, 4-nitrophenol, dibenzofuran, 2,4-dinotrotoluene, diethylphthalate, 4-chlorophenyl-phenylether, fluorine, 4-nitroaniline, 4,6-dinitro-2-methylphenol, n-nitrosodiphenylamine, 4-bromophenyl-phenylether, hexachlorobenzne, pentachlorophenol, phenanthrene, anthracene, di-n-butylphthalate, flouranthene, pyrene, butylbenzylphthalate, 3,3'-dichlorobenzidine, benzo(a)anthracene, chrysene, bis(2-ethylhexyl)phthalate, di-n-octylphthalate, benzo(b)flouranthene, benzo(k)flouranthene, benzo(a)pyrene, indeno(1,2,3,-c,d)pyrene, dibenz(a,h)anthracene, benzo(g,h,i)perylene

[b] below detection limits, either 0.001 or 0.006 mg/L

Ash disposal from the proposed facility appears to pose some risk of groundwater contamination. After the first 3 years of mine development, ash would be disposed of by placement in the pit from which the oil shale had been removed. This pit is expected to be up to 91 m deep (69 m of overburden and 32 m of shale). Because the A2-B7 aquifer (Sect. 7.5) can be found at depths of 80 to 95 m in the Sultani area, ash placed in the bottom of the mine pit could be below the water table and subject to leaching by groundwater. Ash placed above the water table would also be subject to leaching by precipitation, although such leaching would be expected to be less extreme because of the very limited precipitation. Based on the results of the EP-Tox leaching test, leaching of fly ash could result in concentrations of chromium, selenium, and perhaps arsenic that exceed the U. S. drinking water standards. Some dilution of these elevated levels could be expected as groundwater migrated away from the disposal site. Nonetheless, disposal of ash below or near the water table could degrade groundwater quality locally to the extent that water might become unsuitable for use as a potable water supply. A possible mitigation would be

to place overburden or bottom ash in the bottom of the mine pit, while placing fly ash, with its greater tendency to leach trace elements, nearer to the surface.

The reactability of the spent shale with any constituents of the overburden is unknown.

7.4.3 Potential Air Quality Impacts

Transport and disposal of ash may result in the release of fugitive particulate matter. Operating plans call for ash from the combustion unit to be wetted (to a 20 percent water content by weight, using boiler blow-down and other plant waste water streams) and trucked to the site of disposal or by-product utilization. The wetting is to minimize the generation of dust during transportation to the mine and disposal. Haul roads and pit roads are to be sprayed with water on a periodic basis to suppress dust generation. The ash is to be layered with overburden in the disposal plan in order to minimize wind erosion and to reduce the potential for leaching. The Bechtel Group's plans call for the ash to be disposed of in a surface landfill for the first three years of operation until the mining pit was sufficiently developed to accept waste ash.

The particle size distribution for fly ash, bottom ash, and crushed shale (Figures 7.3 and 7.4) indicates that fly ash would have the greatest potential to generate fugitive particulate emissions. Particles less than 45 microns (μ) in diameter constituted less than 1 percent by weight of both the bottom ash and the crushed shale, but about 75 percent of the fly ash. Smaller particles are much more likely than larger particles to generate fugitive dust because they can be suspended by wind. About 25 percent of the fly ash consists of particles less than 10μ in diameter, and are considered to pose a greater risk to human health than larger particles because of the hazards of inhaling and retaining small particles.

The rate of fugitive emissions from fly ash would depend on the moisture content of the fly ash, wind velocity at the surface, the roughness of the surface, and the presence of obstacles such as rocks or vegetation. At present, insufficient information regarding ash handling and disposal is available to estimate actual emission rates. The quantities of fly ash expected to be produced by the combustion process relative to bottom ash are in the ratio of 60 to 70 percent fly ash to 30 to 40 percent bottom ash (by weight).

Additional considerations of these issues can be found in Section 7.4.6.

7.4.4 Potential Land Use Impacts

The Bechtel Group estimates that the waste from the mine supporting the 400-MW project would be in excess of 25 million bank m^3 and that the spent shale equivalent would be more than 6 million bank m^3.

Shale consumption by four 100-MW units is estimated to be 22,680 tonnes/d, or 7.78 million tonnes/y, based on operating 350 days/y (a higher production figure than necessary to support a 400-MW plant operating at a 75 percent capacity factor). This production rate would also produce 6.127 million tonnes/y of wetted ash. Given the shale's specific gravity of 1.8 g/cc (in place), the average 69 m thickness of the overburden, average 32 m thickness of the oil shale seam, a 95 percent shale recovery rate, and a 20 percent excess overburden removal rate for the tiering needed in the pit wall, it is calculated that 0.17 km^2/yr would be disturbed for mining operations. It is assumed that

the overburden has the same specific gravity as the shale and that its volume expands by 40 percent (the Bechtel Group's plans assume a 30 percent expansion factor) upon removal; if overburden is piled to a depth of 10 m, the area required for overburden disposal during the first three years of operation is estimated to be 4.0 km^2. Approximately 7.4 million bank m^3 of overburden is to be excavated and hauled to the out-of-pit waste pile.

Ash production by the proposed facility is estimated to be 5.3 million tonnes/y, based on the 67 percent ash content of the shale. The test burn indicated that fly ash and bottom ash would be produced in a ratio of 53:47. Based on the bulk densities measured for fly ash and bottom ash from Test Run #1 (Table 7.4.1), annual production of ash would be 2.8 million m^3/yr of fly ash and 2.5 million m^3/yr of bottom ash. During the first three years of operation, ash disposal would be in a surface landfill, the out-of-pit waste pile; if ash were piled to a depth of 10 m, 1.6 km^2 of land would be required.

7.4.5 Overburden Handling

7.4.5.1 Out-of-Pit Surface waste disposal and land reclamation

Relevant World Bank guidelines for land reclamation include:

> Surface mine reclamation shall be performed in such a manner that the lands are returned to conditions capable of supporting prior land uses or uses that are equal to or better than prior land use. ... Highwalls and spoil piles must be eliminated and the approximate original contour restored. All surface areas must be stabilized and protected in order to control slides, erosion, subsidence, and accompanying water pollution. Water impoundments, retention facilities, dams, or settling ponds shall be adequate for intended land use. These facilities cannot produce significant adverse effects to adjacent water resources. Operators must use best practicable commercially available technology to minimize, control, or prevent disturbances to surface or underground water quality, quantity, or flow. Mining wastes and rubbish must be properly disposed of so as to minimize, control, or prevent water pollution. ... It is important that land reclamation be started as soon as possible and at least three years after the opening of the mine. The Bank Mission should receive concrete and detailed proposals on the reclamation program and on the means necessary to achieve it.[6]

The Bechtel Group's plans call for employing reclamation procedures that would "minimize adverse impacts during mining and [that would] restore all affected lands to their pre-mining land use." While the emphasis is appropriately on controlling wind and water erosion, more than land stabilization is required by the World Bank. The Bank calls for elimination of all high walls and spoils piles. The Bechtel Group's plans do not at this conceptual, prefeasibility stage contain details about whether the excavation pit would be completely backfilled upon completion of the mining operation or whether the mining area would be permanently fenced to keep people forever away from the pit's highwall. They also do not address the issue of whether or not the pit's highwalls would be graded to a lower, more stable slope. There have been deaths of Jordanian youths due to suffocation under shifting spoils piles from abandoned phosphate mines and from drownings in abandoned phosphate pits. While the Bechtel Group's plans call for revegetation, they do not at this cursory analytical stage call for any test plots to determine which species would do best and what fertilization/irrigation regimes (if any) would work best on the reclaimed lands.

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[6] The World Bank, *Environmental Guidelines* (also called *Environmental Industrial Waste Control Guidelines*), Office of Environmental Affairs, The World Bank, Washington, D.C., 1984.

The land's prior use was overgrazed open pasture. The Bechtel plans do not have details about what procedures would be employed to prevent overgrazing while new vegetation is being established.

The ash alone is an undesirable plant growth medium because of its small particle size (texture), which encourages erosion, compaction, and cementation (in as few as 3 days after being moistened) which causes poor root penetration and low permeability. The ash has a high alkalinity and high quantities of dissolved salts, including elements that may be toxic to plant growth or at a minimum that may inhibit water and nutrient uptake. The Bechtel Group's plans call for revegetation using the original topsoil; this is appropriate and probably essential. The vegetative cover will "take" most quickly and persist longer with topsoil than it would with overburden or ash materials. The reclaimed areas should be fenced and protected by other proper maintenance and monitoring activities to ensure stability.

In general, the Bechtel Group's plans at this stage of analysis call for appropriate consideration to reclamation needs. The open pit at the end of the mining operation would be the chief reclamation concern. The out-of-pit waste disposal pile would be engineered for stability and its surfaces revegetated. No mention is made of the aesthetic compatibility of the final form of the pile with the surrounding landforms. In a site as highly visible as this (along the Desert Highway), this issue needs consideration. No mention is made of the engineering precautions taken for assuring stability of all disturbed areas in the event of major flash floods. Little mention is made of the need to integrate the final landforms into existing surface water drainage patterns. This, too, could be important in a flash flood.

7.4.5.2 Erosion and sedimentation control

Consistent with the World Bank's guidelines, the Bechtel Group's plans call for water ditches to be dug on the surface around the excavation pit area and the waste disposal area to prevent indigenous surface and groundwaters from being contaminated with rainwater runoff from the disturbed areas and to prevent these waters from entering the disturbed areas. Sedimentation ponds are to be constructed to collect water from disturbed areas in order to achieve zero discharge. After these ponds are built, the topsoil in the pit area, haul roads, and waste disposal areas would be removed and stored for use in later land reclamation. Water runoff from within the pit would be collected in a sump and would be used for wetting the haul roads.

The Bechtel Group does not identify what it would do with extensive water runoff that may be collected in the excavation pit, as with that from a flash flood or extensive and unusual seasonal rains. Nor do the plans identify how seepage from intercepting the water table in the excavation pit would be remedied or what effect such seepage could have on total plant operations.

7.4.6 Dust Control

Jordan's air quality outside of the major cities is quite good, benefiting from consistent daily winds, little persistent cloud cover, a variable topography that promotes daily air movement, and a warm, sunny climate. Overnight air inversions are occasionally observed in the valleys and uplands, but are generally broken up by daily wind patterns within 6 to 8 hours. The Bechtel Group's plans call for establishment of baseline studies of site-specific air quality to monitor and model fugitive dust (and other) emissions. Such information and

models would help develop necessary mitigation practices to assure the protection of the local air quality and worker and local residents' health.

World Bank guidelines for dust concentration levels consider two contexts: one for the workplace and one for the environment beyond the plant boundaries. Dust concentration levels for inside the plant/mine complex are threshold limit values (TLV) for workers exposed eight hours a day, and 40 h/week. The plant/mine complex should be designed and operated to provide actual dust levels well below the TLV.

World Bank environmentally acceptable levels of dust emissions vis-à-vis background dust levels are: annual geometric mean less than 70 mg/m^3 above local background level and maximum 24 hourly concentration less than 5 x annual geometric mean of local background dust level. The U.S. National Clean Air Act and the National Ambient Air Quality Standards call for a maximum annual arithmetic mean of 75 mg/m^3 and a maximum of 260 mg/m^3 in any 24-h period. At this point there are no background dust data for the Sultani site.

Health Effects

The five main factors which influence the interaction between dust and the human body are:

(1) physical characteristics (size, shape, hardness);
(2) chemical composition;
(3) concentration in the atmosphere;
(4) duration of exposure; and
(5) individual susceptibility.

The size of the dust particles that may be encountered due to the processes of the plant are described in Section 7.4.1.2. Shape and hardness are unknown at the current level of this prefeasibility study. The chemical composition is described in Section 7.4.1.3. Individual susceptibilities among the workforce are unknown. The duration of exposure is, in part, a normal 40-h work week, but also dependent on local meteorological and topographic conditions.

Dust deposited in the lungs may cause pneumoconiosis, which can be disabling or not, depending on whether or not the dust is physiologically active and on individual susceptibility. Generally, the disabling forms of pneumoconiosis are caused by crystalline silica or quartz (SiO_2). Based on the test burn results, there is very little silicon in the Sultani ash.

According to the U.S. Bureau of Mines, dust of these particle sizes have these retention rates in human lungs:

Table 7.11
Dust Retention in Human Lungs

Particle Diameter (micrometers, μ)	Approximate Retention in Human Lungs (%)
6-10	20
5	25
4	42
3	50
2	70
1	70
0.5	50

Source: U.S. Bureau of Mines, *Sampling and Evaluating Respirable Coal Mine Dust: A Training Manual*, U.S. Bureau of Mines Information Circular No. 8503, February, 1971.

For consideration of health effects, total dust is much less important than respirable dust. In this regard, for the Sultani fly ash samples tested, about 10 percent of the ash were below 4 μ in diameter and a total of 26.5 percent were below 10 μ. One half of the fly ash sampled were below 24.90 μ. Thus, from the perspective of particle size alone, the fly ash represents a potential health hazard.

Dosage received by humans is the product of dust concentration and exposure time. To further define both of these values for the Sultani site, it is necessary to know more of those conditions that might cause dust particles to become airborne and how long might one expect those conditions to exist on an annual basis. This procedure can be generalized in a six-step process that includes more than just site meteorology and particle size distributions.[7]

(1) Determine Particle Size Distribution. From Section 7.4.1.2, it is known that the fly ash ranges in size from 2 μ to 176 μ in diameter.

(2) Estimate Threshold Friction Velocity. A threshold friction velocity (U_f), the wind speed at ground level necessary to initiate the airborne suspension of particulates needs to be determined. Its value depends on particle size distribution, the presence or absence of surface crusting, soil or substrate water concentration, and the presence or absence of nonerodible elements such as vegetation or stones.

(3) Determine the Roughness Height of the site terrain. The roughness height (Z_o) is a measure of the size and spacing of surface irregularities, such as trees or buildings, that obstruct wind flow. This parameter is used to convert the threshold friction velocity at ground level to wind speed at a typical weather station height of 7 m.

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[7] Leu, David J. and Paul W. Hadley, "The California Site Mitigation Decision Tree Process: Solving the 'How Clean Should Clean Be' Dilemma," in *Hazardous Waste Site Management: Water Quality Issues*, National Academy Press, Washington, D.C., 1988, pp.67-97.

(4) Determine the Threshold Wind Velocity. The threshold wind velocity (U_t) is the wind speed, as measured at a wind sensor station generally 7 m above the ground, that is necessary to initiate soil erosion (in this case, lifting of the dust). The threshold wind velocity is determined from the threshold friction velocity, U_t, according to this equation[8]:

$$U_t = U_f(13.1\text{-}2.5 \ln Z_o)$$

where

U_t = Threshold Wind Velocity at 7m (m/s),
U_f = Threshold Friction Velocity (m/s), and
Z_o = Roughness Height (cm).

(5) Estimate the Respirable Particulate Emission Rate

Cowherd *et al.* developed this equation to estimate the annual average emission rate of respirable particulate matter from erodible surfaces:

$$E_{10} = 0.036(1\text{-}V)(U/U_t)^3[F(X)],$$

where

E_{10} = Emission rate for total respirable particulate matter (PM10)(g/m2-h),

V = Fraction of exposed dispersal area that is vegetated (for bare soil, $V = 0$),

U = Mean annual wind speed (m/s), and

$[F(X)] = 0.18(8x^3 + 12x)/e^{x2}$, where $x = 0.886(U_t/U)$.

(6) Project downwind particulate concentrations. From the above equations, one can derive a conservative annual estimate of the total dust concentration at the site boundary in $\mu g/m^3$. This assumes a uniform distribution of dust particles on the ground across the site.

Assuming the fly ash to be inert or only a "nuisance dust," World Bank threshold limit values for an 8-h workday are 5 mg/m^3 for respirable dust (as defined by the British Medical Research Council criteria, and as sampled by a device producing equivalent results) and 15mg/m^3 for total dust. According to EPA guidelines, adverse human health effects begin when ambient levels of dust exceed 80 $\mu g/m^3$. Current guidelines call for 75 $\mu g/m^3$ as the annual geometric mean for a project background limit and 260 $\mu g/m^3$ as the maximum allowable 24-h concentration, no more than once per year. The World Bank has used these as inputs to its own guidelines, but is hesitant to be more stringent beyond these because variations due to the physical or chemical characteristics of dusts, climates,

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8 Developed by Cowherd, C.M. *et al.*, *Rapid Assessment of Exposure to Particulate Emissions from Surface Contamination Sites*, Kansas City, Mo., Midwest Research Institute, 1984.

locations, and other factors make universal guidelines somewhat difficult to meaningfully implement.

Stack Emissions:

When background levels of dust are high, dust emissions from the stacks should not be greater than 100 mg/m^3.

Ambient Levels:

Annual geometric mean	100 μg/m^3
Maximum 24-h concentration	500 μg/m^3

The main air pollutant from the proposed project will be fugitive dust. Pyropower and the Bechtel Group's use of cyclones in the combustion process should help minimize ash dispersal there. The Bechtel Group calls for the use of dust collectors at the oil shale process crushing plant, in both the storage and processing areas. Single cyclones remove about 90 percent of the larger particles, but less than 50 percent of those smaller than about 10 μ. Their removal efficiencies could be increased by using second-stage cleaning in scrubbers, filters, or precipitators. This issue should be investigated in later design stages in order to protect worker health and the general environment.

Open-pit mining will, of course, generate considerable dust. Because of the deep nature of the pit, however, much dust from excavation will be contained below ground level, in the pit and away from prevailing winds. The extensive use of trucks will necessitate regular water spraying on roads to suppress fugitive dust. Dust emissions at the crusher should be controllable by dry cyclones. Water spraying is about 80 percent effective for particles larger than 5 μ, so this technique should be effective at the Sultani project.

7.4.7 Resource Recovery

The use of the waste ash for cement manufacture or as an amendment to other construction materials has not been studied in depth at this time. In a feasibility assessment, this can be examined through (1) market studies in Jordan and (2) engineering and durability studies with the ash sent to Oak Ridge National Laboratory from the test burn. Preliminary assessment of a market for the vast quantities of ash suggest that there is now no demand for the extra ash in Jordan or in nearby international markets. This situation could change by the mid-1990s or later.

7.4.8 Conclusions

- There has been extensive work undertaken in the U.S. public and private sectors to determine the degree of pollution control that will have to be used by oil shale facilities to protect air quality. Because no large-scale facilities exist to date and because the proposed project employs an innovative technology, there have been no opportunities to verify the predictions arising from recent work or to make informed projections for new fuels in new locations with new technologies. Dispersion conditions in Jordan are different than in the Western U.S. Air modeling methods are not fully adequate even in the U.S., and background data for Jordan for the Sultani area are non-existent. Therefore it is not possible to predict with confidence what impacts oil shale mining and

CFBC technology would have on air quality at various levels of shale oil production.

- Studies of occupational diseases among oil shale miners in the U.S. have been limited because relatively few people have worked in such mining operations and for relatively few years. The Soviet experience in Estonian mines suggests that workers should be monitored for evidence of pulmonary fibrosis. Although conditions there are not translatable to Jordan, the incidence of respiratory diseases in other industries indicates that exposure to the shale dusts and ashes at the Sultani project could be hazardous. Worker controls through breathing masks are likely to be difficult to enforce. The appropriate precautions would be to make every effort to limit and suppress dust and ash particles and to put in place a long-term program to monitor miners' and plant workers' lungs and general health. Such a health monitoring program should include periodic examinations and systematic record keeping. Worker training programs, including an intensive training program for new workers and refresher courses for all workers throughout their careers are essential.

- The land reclamation program proposed for the Sultani project is generally reasonable and responsible. Highwalls in the excavation pit need to be eliminated before abandoning the mine site. More studies of revegetation strategies should be undertaken than are suggested in the current report.

- Consideration of using the fly ash as an amendment to cement, asphalt, or other construction materials both as a profitable venture and as a means to decrease the quantities of material to dispose is premature at this stage of the analysis given the current market glut for such materials (both domestic and export), the uncertain future market, and the existing and future capacity in Jordan for producing cement. It is impossible to plan for the use of the ash at this time. Under any foreseeable positive market and product-suitability combinations, it is unlikely that any significant reduction in ash wastes could be achieved through this proposed use of the ash.

- Erosion and sedimentation controls, both short- and long-term, during mining and waste disposal appear adequate. Flash flood events need to be considered in the engineering of sedimentation ponds, ditches, and other erosion control structures.

- There is ample surface area available at the Sultani site for permanent storage of mine and plant wastes. Because of the available space, safe and aesthetically pleasing slopes and heights for the out-of-pit disposal pile should be easily achieved through appropriate and sensitive engineering practices.

- Exhaust gases from the plant's boilers would likely be within limits to control emissions and ambient concentrations of SO_2 and NO_x.

- The dust particles from the ash or from the raw oil shale fines appear to be low in silica content (except when cherty materials would be run through the boilers), therefore minimizing the threat of silicosis to plant and mine workers.

- According to laboratory analyses of the leachate from the ash from the test burn, ash disposal from the proposed facility appears to pose some risk of groundwater contamination. Concentrations of chromium, selenium, and possibly arsenic could exceed U.S. drinking water standards. Appropriate monitoring and backfilling precautions would have to be taken (see Section 7.5).

7.5 WATER AVAILABILITY AND QUALITY

The availability and quality of Jordan's water resources are the major environmental concerns in the country. Water resources in Jordan are becoming increasingly scarce and increasingly expensive to exploit. North Jordan has at least 95 percent of the country's population (the Amman area itself creates 70 percent of the country's water demand), but has only 55 percent of its surface area. Groundwater and surface water supplies in the north are extensive, but insufficient to meet all demands for irrigated agriculture, domestic needs, and industrial applications. Groundwater resources in the extreme southeast are also extensive, but remote from demand centers.

Irrigated agriculture presently accounts for 76 percent of water consumed in Jordan. With population growing at 3.8 percent per year (and expected to slow to only 3.2 percent by 2010) and rising incomes (per capita GDP = U.S.$1,560 in 1987), demands for municipal and industrial water will only increase.

The World Bank believes that nearly as much land is under irrigation as can be accommodated in a sustained manner. Increases in agricultural production will have to come from efficiency improvements in water use and from new technologies rather than from expanded irrigated acreage. Therefore, water requirements for irrigation in the year 2015 are expected to be only 6 to 15 percent higher than 1986 levels. Municipal water requirements, on the other hand, are expected to triple over the next 30 years. Projections for municipal and industrial (M&I) consumption in future years are consistent with other arid countries.

The projected strong increases in demand for municipal water come not just from population growth. Improved levels of service, such as the number of private residence connections, are expected to increase in urban areas from 85 percent in 1985 to 100 percent in 1990, and in rural areas from 17 percent in 1985 to 40 percent in 1990 and 65 percent in 2005. The World Bank reports that Jordan's estimated overall municipal per capita water requirements (135 L/c/d) in 2015 would be well below present levels in industrialized countries (250-400 L/c/d) and reflect the high cost of water in its arid environment. Table 7.12 shows projected municipal water demand for the country as a whole and for the urban areas relevant to the current study.

M&I water consumption as a proportion of total water consumption is expected to increase from 24 percent in 1985 to 30 percent in 2005 and 45 percent in 2015.[9] All demand for water is expected to exceed sustainable supply by about 2010. Meeting these competing demands will require serious negotiations with those needing water for irrigation.

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[9] The World Bank, *Jordan Water Resources Sector Study*, The World Bank, Infrastructure Operations Division, Country Department III, Europe, Middle East and North Africa Regional Office, Report No. 7099-JO, June 27, 1988 (restricted use document).

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According to the World Bank, the Government of Jordan will have to consider either (1) using water stored behind the yet-to-be-built Wahdeh Dam entirely for M&I use and reducing total water availability in the Jordan Valley to about 310 Mm3/y, or (2) overpumping from the Disi reservoir (not a sustainable or acceptable long-term strategy), or (3) developing new water sources (e.g., demineralization, importation, etc.). These options are discussed below.

Table 7.12
Municipal Water Demand Projections
(selected governorates)

	1985		1990		2005		2015	
Governorate	Population (000)	Mm^3	Population (000)	Mm^3	Population (000)	Mm^3	Population (000)	Mm^3
Amman/Zarqa	1504	67	1896	96	3379	177	4631	243
Karak	116	3	132	4	199	7	274	9
(North Jordan)	(2444)	(102)	(2945)	(134)	(4969)	(237)	(6809)	(326)
Total Jordan	2694	116	3246	151	5438	267	7451	366

Source: Adapted from: The World Bank, *Jordan Water Resources Sector Study*, Infrastructure Operations Division, Country Department III, Europe, Middle East and North Africa Regional Office, Washington, D.C., Report No. 7099-JO, restricted distribution document, June 27, 1988.

7.5.1 Water Availability

There is great interdependence among surface and groundwater resources and agriculture, municipal, and industrial demands for Jordan's limited water. Allocation decisions have to take into account this interdependence and the sometimes deficient information on groundwater resources and hydraulic behavior.

7.5.1.1 Surface water resources and use in Jordan

The Yarmouk and Zarqa rivers are the main surface water resources in Jordan. Most surface water consumption (World Bank estimates the total for 1986 to be 336 Mm^3) is for irrigation: 102 Mm^3/y for upland irrigation and 229 Mm^3/y for irrigation demand in the Jordan Valley. The World Bank believes that the main potential (and last remaining investment options) for effectively increasing the use of surface water resources in Jordan lies in the construction of new water storage facilities on the Yarmouk River, the Jordan Valley, and on rift-side wadis. Projects currently under study (the Wahdeh Dam, Karameh Dam, and Side Wadis) is estimated at 300 Mm^3.

Around 1000 springs (*ain*) have been identified, with water quantity and quality measurements made on 900 of these. Total volume of spring water in Jordan is 233 Mm^3/y.

7.5.1.2 Groundwater resources and use in Jordan

The oldest and deepest Jordanian aquifer is in the Disi stratigraphic group, consisting of sandstones and quartzites. This huge, largely fossil-water aquifer is believed to underlie much of the eastern part of Jordan and much of the Arabian peninsula as well. It outcrops only in the southern part of the country, far from demand centers. Its great depth and high salinity make it an unattractive water source in the northern part of the country.

The next higher aquifer is also extensive across much of Jordan and belongs to the Kurnub system of sandstones. It outcrops in the western part of the country along the eastern banks of the rift-side wadis which drain to the Dead Sea, the Jordan Valley, and the Wadi Araba. Its springs have water that is highly mineralized and warm. The Disi and Kurnub aquifers function much as one hydraulic system. Recharge from higher aquifers through leaking of aquitards and faults is minimal compared to the size of the fossil water storage of the whole system.

The Amman Wadi Sir (from the A7 - B2 group) aquifer is the largest and most important water-bearing hydraulic system in Jordan. Its carbonate rocks (chert-limestone, sandy limestone, and limestone) form the upper layer of the Western Uplands and are the source rocks for the Sultani oil shale. This aquifer has the highest recharge rate in the country. In its eastern portions,it is overlain by thick aquitards. Salinity tends to increase from east to west, relative to distance from the recharge areas.

These hydraulic systems, their uses, and their flows will be discussed in more detail below. In Table 7.13, one can readily see the current importance of and reliance that Jordan places on the Amman Wadi Sir aquifer. Table 7.14 displays the most recent record (1986) of productive uses of the country's groundwater resources.

About one-fourth of the country's irrigation water is pumped from groundwater reserves. Overdraft – mining – of these reserves has occurred more and more frequently, with private wells for irrigation or industrial purposes exacerbating the situation. The Amman area is withdrawing its groundwaters at a rate about 50 percent above the recharge rate. Groundwater resources with a high rate of recharge are generally of good quality, while groundwater from the deeper aquifers where recharge rates are low, are generally unsuitable for use due to high salinity.

7.5.1.3 Groundwater resources of the Wadi Mujib

The Wadi Mujib watershed covers an area of 6,596 km^2, spreading from just south of Amman (the Queen Alia International Airport is well within the basin's boundary) to over 115 km to the southeast. It represents nearly 7 percent of Jordan's land area (see Figure 7.5). The northern half of the watershed is administered by the governate of Amman and the southern half is administered by the governate of Karak. The population of the watershed is about 80,000 (1985), or 12 people/km^2, and is projected to grow to about 110,000 by 2005.

The Wadi Mujib basin consists of two main wadis, the Wala (also known as the Heidan) in the north and the Mujib in the south. These two join to form the Wadi Mujib immediately upstream from the wadi's Dead Sea estuary. Numerous tributaries feed these two wadis from gentle slopes on the flat uplands, draining into steep-sloped gorges at the lower elevations. The entire basin is bisected by the Siwaqa fault. At the confluence of the two

major wadis, the base discharge from the basin's two main aquifers amounts to 35 Mm^3/y of water at 1,100 ppm salinity. The Wadi Wala contributes about 23 Mm^3/y at 750 ppm, while the Wadi Mujib contributes about 12 Mm^3/y at 1,800 ppm.

Table 7.13
1986 Groundwater Production
(Mm^3)

Aquifer	Municipal and Industrial Use	Irrigation Use
B4-Rijam	14.7	7.4
A7 - B2 (Amman Wadi Sir)	108.8	147.1
A4 (Hummar)	18.2	1
Kurnub	1.1	3.6
Disi	8.6	14.5
Miscellaneous	3.9	4.3
1986 Total	155.3	177.9

Sources: (1) Chene, J.M., *Jordan Water Resources Sector Study*, Chapter 2: The Water Resource Base, draft report, The World Bank (Washington, D.C.) and Sogreah Consulting Engineers (Grenoble, France), October 1987.

(2) The World Bank, *Jordan Water Resources Sector Study*, Infrastructure Operations Division, Country Department III, Europe, Middle East and North Africa Regional Office, Washington, D.C., Report No. 7099-JO, restricted distribution document, June 27, 1988.

Table 7.14
1986 Groundwater Consumption
(Mm^3)

Use	Quantity
Drinking water supply	132.6
Industry	18.8
Agriculture	173.6
1986 Total	325.0[a]

Source: Chene, J.M., *Jordan Water Resources Sector Study*, Chapter 2: The Water Resource Base, draft report, The World Bank (Washington, D.C.) and Sogreah Consulting Engineers (Grenoble, France), October 1987.

[a] total differs slightly from total in Table 7.13 because of that table's inclusion of miscellaneous aquifers' production.

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The groundwater potential of the watershed is relatively rich because of the favorable hydrogeology. The two main aquifers feeding the Wadi Mujib discharge are the Kurnub (or K aquifer – see discussion, below), a deep aquifer with mineral content of up to 2,500 ppm, and the Amman Wadi Sir (termed the A7 - B2 or the B2 - A7, each part of the Balqa/Ajjlun or B/A layer), the main aquifer with the higher-quality water (550 ppm), evidenced by the 155 private wells and 68 GOJ-owned wells tapping its depths. Using salt balance as an indicator of source, one can estimate that about 90 percent of the Wadi Wala base flow comes from the Amman Wadi Sir aquifer and only about 40 percent of the Wadi Mujib's base flow from this shallower aquifer. Table 7.15 summarizes the current uses of the groundwater resources of the Wadi Mujib.

The most important groundwater resources in the southern, and upper reaches of the basin are found in a band located near the Desert Highway to the south of Siwaqa. There are three existing well fields here (Siwaqa, Qatraneh, and Sultani) and two proposed new well fields (Siwaqa-Qatraneh and Sultani). In 1986 the existing fields were overpumped, underscoring the need to improve aquifer recharge and the need to protect the aquifer for the proposed new well fields.

The Water Authority of Jordan has stated that the proposed oil shale plant at Sultani may withdraw 2.0 Mm^3/y of water, and the Bechtel Group has designed the plant and mining operations to work within this constraint. At least 5 Mm^3/y are available from the shallower aquifer (the A7 - B2), according to studies performed in conjunction with the El Lajjun retorting plant. The proposed termination of operations at the El Abiad Mine site in 1992 may liberate up to 2.8 Mm^3/y of water rights. If these could be transferred to the NRA for its use in the Sultani oil shale operations, most questions regarding groundwater availability would be moot.

7.5.1.4 Surface Water resources of the Wadi Mujib

Tributaries of the main wadis are dry except for short periods after rainfall. Constant base flow is seen only on the lowest downstream reaches of the Mujib River, below the King's Highway bridges. Some irrigated farming is dependent on this flow. Base flow is a constant 1.1 m^3, or 35 Mm^3/y. During the rainy season, flows increase to 29 Mm^3 from the Wadi Wala and 36 Mm^3 from the Wadi Mujib, totalling 65 Mm^3. These seasonal high flows are unused.

The upper Wadi Mujib, or the Wadi Mujib proper, has tributaries of the Mujib River and two existing retention dams. These are desert dams, used mainly to retain seasonal rain waters to allow for aquifer recharge. The Qatraneh retention dam is on the tributary Wadi Hafira and permits 1.8 Mm^3/y recharge in the rainy season, of which 1.4 Mm^3/y is pumped from new wells in the dry season. The other retention reservoir is the Sultani dam near the proposed oil shale plant. Its reservoir has been almost entirely silted in by processing residues from the El Abiad Phosphate Mine located just south of the dam. Japanese hydrologists estimate that 0.9 Mm^3 of wastes and sediment will have to be dredged from behind this dam to restore

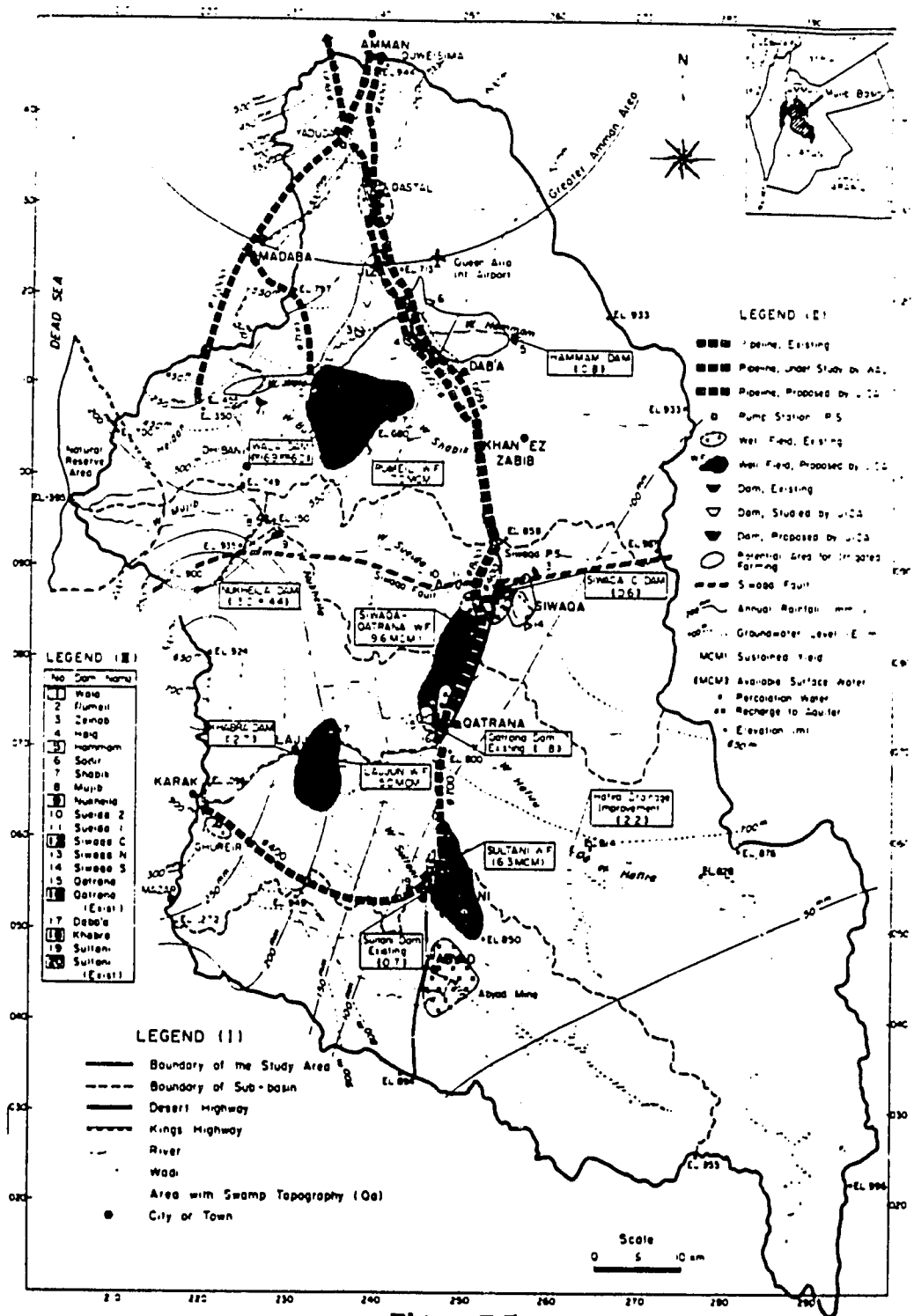

Figure 7.5
The Mujib Watershed

Source: Japan International Cooperation Agency, *Hydrological and Water Use Study of the Mujib Watershed*, final report, summary, The Hashemite Kingdom of Jordan, Ministry of Planning in association with the Water Authority of Jordan, No. 103, July 1987.

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Table 7.15
Wadi Mujib Basin: Current Groundwater Exploitation
(Mm^3/y)

	WAJ (1986)[a]	JICA (1987 study)[b]
Municipal	18.3	16.4 (15 to Amman) (1.4 to Karak)
Industrial	9.6 (with Hasa Mine plus El Abiad Mine)	2.8 (El Abiad Mine)
Irrigation	31 (plus Wadi Wala springs[c])	14 (plus Wadi Wala springs)
Total groundwater use	58.9	33.2

Source: Chene, J.M., *Jordan Water Resources Sector Study*, Chapter 2: The Water Resource Base, draft report, The World Bank (Washington, D.C.) and Sogreah Consulting Engineers (Grenoble, France), October 1987.

[a] Water Authority of Jordan, *Rainfall Data in Jordan (1980-1985)*, Hashemite Kingdom of Jordan, Amman, Jordan, 1986.

[b] Japan International Cooperation Agency, Hydrological and Water Use Study of the Mujib Watershed, final report, summary, The Hashemite Kingdom of Jordan, Ministry of PLanning in association with the Water Authority of Jordan, No. 103, July 1987.

c 5 Mm3/y

its storage capacity.[10] Renewal of former storage capacity in the Sultani reservoir will permit an additional 0.6 Mm^3/y of water to be pumped from two additional wells. Such dredged material would have to be placed in a location where it would not erode back into the drainage behind the dam. Thus, besides the enormous quantities of waste materials to dispose for the proposed oil shale plant at Sultani, there appears some likelihood of spoil piles from the dredged wastes from the phosphate mine processing plant.

In its assessment of the feasibility of using desert dams for recharging aquifers, the World Bank differs from the Japanese hydrologists who also assisted the WAJ in studying the Wadi Mujib's groundwater potential. The Bank argues that direct recharge is not guaranteed, in that faulting beneath the reservoir would be required. The small size of the planned and existing reservoirs mean that sedimentation is a constant problem in terms of direct infiltration. Indeed, this can be currently seen right at the Sultani site. The World

[10] If the proposed oil shale plant needs more groundwater than WAJ is willing to commit, a negotiated dredging of these sediments through use of the heavy equipment (e.g., from the firm contracted to operate the oil shale mining operation) already near the site could be an option to liberate up to 0.6 Mm^3/y of water.

Bank argues, therefore, that large dams will need to be built, with water pumped and treated before being injected into recharge wells. The Bank has made quite preliminary identification of two larger dam sites with an expected collective yield of 21 Mm^3/y.

7.5.1.5 Competing groundwater demands in Jordan

The World Bank has identified that, in all of Jordan, additional groundwater resources of acceptable quality and economical exploitability are limited to 44 Mm^3/y, given the current understanding of the country's hydrogeological phenomena. Table 7.16 summarizes the current and projected water balance for all of Jordan, both surface and groundwater resources from 1986 to 2015. New, more expensive-to-deliver water sources will be needed as soon as 1995.

7.5.1.6 Competing groundwater demands in the Wadi Mujib

Groundwater in the Wadi Mujib is extensively used. In 1985 there were 223 existing wells in the northern part and along the Desert Highway. Private farmers growing vegetables own 155 wells and the GOJ owns 68 wells for supplying water to Amman, Karak, and many small villages within the watershed. In 1985, the Wadi Mujib's groundwater resources supplied about one-fourth of Amman's consumption.

Demands on the Wadi Mujib's groundwater resources come from proposals for more municipal and industrial water for Amman, the proposed oil shale plants at El Lajjun and Sultani, a proposed chemical/industrial complex beside the Dead Sea, and irrigation water for a 3780-ha expansion of the Southern Ghor Irrigation Project, south of the Dead Sea.

The World Bank believes that the Wadi Wala-Mujib basin is close to its maximum safe yield in terms of irrigation and M&I pumping, and that expanded pumping from the Amman Wadi Sir is inadvisable so as not to dry up springs that furnish water for local irrigation schemes. According to the Bank, additional water resources should be taken only from the lower portions of the wadi, from the base flow downstream of the Wala bridge. The Bank estimates that about 10 Mm^3/y is all that is available as the additional safe yield for the basin as a whole, and that this yield should be allocated to Amman, assuming that Karak's water needs can still be met through use of local resources. The Bank suggests strict controls over new pumping in the uplands and limitation on new irrigation in these areas. Careful study is required before liberating, at most, up to 25 Mm^3/y (salinity of 1300 ppm) for the large irrigated agriculture project or for the chemical/industrial complex.

El Lajjun

Oil shale deposits at El Lajjun (25 km to the west-northwest, see Figure 1.1) have been studied by the NRA and foreign assistance teams since 1968. In 1980 the NRA initiated a contract to conduct a technical and economic prefeasibility study for an oil shale retorting complex there. The proposed plant would have a capacity of 50,000 bbl/d. Several studies have followed this initial one as the subject plant has been investigated in more detail.

The latest engineering studies for the proposed oil shale retorting plant at El Lajjun initially stated that the plant would require 22 Mm^3/y for a period of 30 years (the lifetime of the oil shale resource under exploitation) for optimal functioning. Surface water is not available in

Table 7.16
Water Balance in Jordan, 1986-2015
(Mm^3/y)

	1986	1995	2005	2015	(2015)[e]
M&I[a] Consumption					
M&I groundwater	155	207	254	389	(351)
M&I surface water	5	38	99	147	(147)
Subtotal M&I	160	245	353	498	(498)
Upland Irrigation					
Irrigation groundwater[b]	178	152	136	136	
Irrigation surface water[c]	102	102	102	102	
Total Upland Irrigation	280	254	238	238	
Jordan Valley Irrigation[d]					
Total Jordan Valley Irrigation	238	320	338	357	(311)
Subtotal Irrigation	518	574	576	595	(549)
Grand Total Water Consumption	**678**	**819**	**929**	**1093**	**(1047)**
Water Yield					
Groundwater	333	359	390	475	
Surface water	336	424	463	463	
Return flows	9	36	76	105	
Total Water Yield	**678**	**819**	**929**	**1043**	

Source: The World Bank, *Jordan Water Resources Sector Study*, Infrastructure Operations Division, Country Department III, Europe, Middle East and North Africa Regional Office, Washington, D.C., Report No. 7099-JO, restricted distribution document, June 27, 1988.

[a] municipal and industrial water

[b] Includes 46 Mm^3/y groundwater irrigation in Jordan Valley for 1986; this is likely to decline with conversion from surface to drip irrigation; the extent of the decline has been tentatively estimated at 28 Mm^3/y. The groundwater is not included for planning purposes by WAJ. It is also assumed that groundwater extraction for irrigation from Wadi Ajib, currently overpumped, is reduced by 10 Mm^3/y.

[c] excludes irrigation in Jordan Valley

[d] refers only to area between Yarmouk and the Dead Sea

[e] By 2015, as this table shows, consumption will exceed safe yield. The World Bank sees three options for meeting this deficit: (1) to overpump from the Disi aquifer, (2) to use all the Wahdeh Dam water for M&I and reduce irrigated agriculture in the Jordan Valley, or (3) to exploit yet-unidentified sources. The figures shown here in parenthesis refer to the results that might be achieved by employing the second of these strategies.

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the immediate El Lajjun area because there are no nearby sites suitable for impounding seasonal waters. If built, the plant would need to rely entirely on groundwater resources. Based on recent findings (discussed in Section 7.5.3), it was concluded that the El Lajjun plant cannot safely withdraw 22 Mm^3/y from the shallow aquifer in the immediate surroundings (<10 km) of El Lajjun. At 5 Mm^3/y, the El Lajjun plant's 30 years of groundwater withdrawals were projected to cause these impacts after 40 years:

- maximum nodal[11] drawdown in field = 91 m
- additional drawdown at:
  - Ghuweir = none
  - Siwaqa/Qatraneh = none or marginal
  - Sultani = none
- Influence of drawdown on spring- and base flows at:
  - Ain el Lajjun = dried up
  - base flow in the upper Wadi Mujib = almost dried up
  - Ain Sarah = none

The plant's designers and hydrogeological consultants judged these withdrawal impacts on the shallow aquifer to be acceptable (although not negligible) even though a "mining" condition would be created. To meet the additional water requirements for the proposed oil shale plant, 17 Mm^3/y of water were determined to be feasible to be pumped from the deep aquifer. This water would be available in two locations: (1) at pumping depths of 400 to 500 m, but with long pipelines (approximately 30 km) to the plant; and (2) at El Lajjun itself, but with high (1000 m) pumping lifts.

If the shallow aquifer were to be entirely avoided, the deep aquifer appears to have – accurate quantitative data are lacking – ample reserves (an estimated annual throughput of approximately 57 Mm^3) to accommodate all the water needs for the El Lajjun plant, albeit at higher pumping costs. The ecological impacts of taking nearly half of the aquifer's discharge into the Dead Sea are unknown and unstudied at this point. The opportunity cost of taking future drinking water for use in processing oil shale is another unstudied consideration.

El Abiad Phosphate Mine

Plans for terminating mining in early 1992[12] would liberate 2.8 Mm^3/y.

Sultani well fields

Well fields of Sultani (Mahattat el Manzil) and Wadi El Abiad supplying farmland, the phosphate plant, and municipal water for Karak by pipeline (production in 1985 = 4.2 Mm^3; sustained yields estimated at 6.3 Mm^3/y)

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11 Nodal drawdowns represent a mean value of drawdown calculated for an area of two times 2 km^2 each. They represent the regional, or areal drawdown to which the drawdown attributable to that caused by the flow field to the individual production wells still must be added.

12 The World Bank, *Staff Appraisal report, Hashemite Kingdom of Jordan, Shidiya Phosphate Mine Project*, Energy Division, Asia Technical Department, Washington, D.C., Report No. 6932-JO, restricted report, December 18, 1987.

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WAJ plans 18 production wells here and a 11.7 km-long pipeline (500-600 mm in diameter) to connect the wells to the Sultani reservoir and a 23.1 km-long pipeline (660-700 mm in diameter) to connect with the Siwaqa reservoir.

Siwaqa-Qatraneh well field

Water pumping for the water supply of Amman (production 15.9 Mm^3/y) and for an irrigated farm at Qatraneh. The 15.9 Mm^3/y comes from 6.3 Mm^3/y from the sustained yield from the Sultani well fields and 9.6 Mm^3/y from the Siwaqa-Qatraneh well fields.

There is a WAJ proposal to connect by pipeline the Sultani well fields and the Siwaqa-Qatraneh well fields south of Siwaqa (21 production wells) to the Yadudah-Siwaqa pipeline (also proposed, and scheduled to connect to Amman) in Siwaqa. This whole proposed complex is known as the Sultani-Siwaqa Pipeline Project and is considered to be an integral part of the comprehensive plan to develop the groundwater potential of the whole Wadi Mujib basin.

Ghuweir well field

near Karak, partially supplies this area of the watershed with drinking water (1985 production = 2.0 Mm^3)

Ain Sarah

and the surrounding smaller springs that supply water for irrigation to farmers (5 to 6 Mm^3/y)

El Lajjun farmers

and other small-scale farmers in the upper Wadi Mujib (demand = 0.2 Mm^3/y)

Proposed Potash Company project on the Dead Sea using Wadi Wala-Mujib water

Water demand for this proposed (feasibility still uncertain) chemical complex planned to extract valuable minerals other than potash from Dead Sea brines is estimated to be 5 Mm^3/y in 1990, 8 Mm^3/y in 1995, and 15 Mm^3/y beginning in 2005 (the World Bank has conflicting information here: the same June 1988 source states that 20 Mm^3/y would be needed in 2005 and 40 Mm^3/y in 2015). Because of this project's location near the banks of the Dead Sea at the bottom of the Wadi Mujib drainage, advantage can be taken of residual base flow in the whole wadi.

Southern Ghor Irrigation Project

This 3780-ha expansion to the Southern Ghor Irrigation Project located south of the Dead Sea would require 40 Mm^3/y of new water sources. A proposal is to pump in groundwater extracted from groundwater resources in the Wadi Wala-Mujib. According to the World Bank, the source water development would be in the in the Wadi Mujib lower catchment basin and would include construction of a well and an intake downstream of the Wadi Mujib/Heidan confluence to abstract up to 25 Mm^3/y of water. Water resources would have to be shared with the proposed Dead Sea brines chemical/industrial processing complex.

7.5.2 Water Quality

7.5.2.1 Groundwater quality

Groundwater quality in Jordan is diminished by three major factors: recycled irrigation water, pumping of saline water from deeper aquifers, and wastewater from human settlements and industry. The aquifer (see next section) most likely to be used for the proposed Sultani plant has water that is fairly fresh, with total dissolved solids in the range of 500 to 900 ppm. The NRA provided tests on water from wells at the Sultani site and reported readings of TDS = 757 ppm and pH = 7.36. See Table 7.17 for an elemental analysis of this groundwater.

Table 7.17
Sultani Groundwater Analysis

Elemental Analysis	ppm
Ca	83
Mg	45
Na	47
K	4.3
Cl	170
SO_3	101
HCO_3	320
NO_3	2.3
TH	392

Source: NRA-supplied data to the Bechtel Group

7.5.2.2 Protection of water quality and establishment of monitoring program

Leachate from the disposed fly ash from the oil shale combustion process could be placed back in the excavation pit at such a depth as to benefit little from filtration through the replaced overburden before entering the water table. (The excavation pit will undoubtedly intersect the water table in places.[13]) Because the Sultani well field is nearby, this leachate could be diluted only slightly before being pumped to the surface and piped off to Karak or to Amman for use in municipal water systems. The U.S. RCRA leachate standards are not designed to be applicable in such circumstances. Therefore, chromium and selenium concentrations in the drinking water that may flow to these municipalities must be monitored and corrected if they exceed safe drinking water standards (see Section 7.4.2).

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[13] There is some disagreement within the GOJ about the depth of the water table at the Sultani site. Mr. Badir Herzallah of the WAJ believes that the water table is at only 60 m. Mr. Abu Azumieh and Mr. Kasim Omari of the NRA believe that it is at 120 to 180 m. This latter number contradicts the West German's study (see footnote #14) of the El Lajjun region. The West German study is more consistent with the WAJ values. The field crew digging the test burn sample stated that they had run into water in their digging at about the 70 m level.

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7.5.3 Groundwater Flow Regimes in the Wadi Mujib

The following synthesis is based on the Bundesanstalt für Geowissenschaften und Rohstoffe study[14] of the El Lajjun area's hydrogeology.

The most easily accessible groundwater resources are thought to be available in an Upper Cretaceous limestone/chertstone complex known as the A7-B2 aquifer (A = Ajjlun Group; B = Belqa Group). Carbonate rocks predominate in the system. The A7-B2 is the most important aquifer in Jordan.[6] It essentially forms the Western Highlands, outcropping in this area of relatively high rainfall and thus receiving appreciable recharge. It is up to 300 m thick and underlies most of Central Jordan east of the Rift Valley. The A7-B2 is known among local hydrologists as the "shallow aquifer." In the Sultani area, it can be found at depths of 80 to 95 m. The K + D system (K = Kurnub Group; D = Disi Group) is known as the "deep aquifer." It is much thicker (1000 m) and contains much greater volumes of water, but of a low quality. It is the lowest aquifer, and flows westward, draining exclusively into the lowest base level, the Dead Sea.

When viewed as a three-dimensional hydraulic conductivity pattern, the lithologic sequence can be divided into four groups, from deepest to surface:

1. The Kurnub and Disi formation (**K + D**, or deep aquifer) with the highest transmissitivity existing in the area
2. The **A1-A6** aquitard, a marl and claystone layer
3. The **A7-B2** (shallow aquifer) unit forming the upper aquiferous zone
4. The **B3** unit, the upper aquitard in the area, causing confined conditions where its base reaches into the hydraulic head of the A7-B2 aquifer.

This conductivity pattern basically controls the hydraulic behavior of the entire aquifer system. The A1-A6 aquitard separates the shallow and deep aquifers, but with numerous interconnected subsystems. Basically the groundwater flow in the shallow, upper aquifer is east-bound, but with interception by erosional channels that lead to the Rift Valley (and to the Dead Sea) and with downward leakage through the A1-A6 aquitard into the deep aquifer. There is a nonarticulated groundwater contour ridge approximately underneath the Desert Highway. From here the groundwater to the west flows in a westerly direction to the Wadi Mujib estuary near the Dead Sea. To the east of the highway, the groundwater tends to flow to the northeast, toward the Arzaq Oasis, and is therefore lost from the basin's base flow. The purpose of the desert dams and adjacent well fields in the Sultani, Qatraneh, and Siwaqa areas is to capture this A7 - B2 groundwater before it moves eastward to the desert and beyond feasible use. These dynamics are portrayed in Figures 7.6, 7.7,and 7.8 for the Wadi Mujib drainage and summarized in Table 7.18. By using the zones portrayed in Figure 7.8 coupled with the data from Table 7.19, one can see the relative volume of groundwater flows through the study area. Clearly, the Sultani wells are in the areas of greatest flows, and therefore are the reserves most commonly sought for M&I needs. On the other hand, mild pollution of this groundwater resource will be readily diluted in its greater flows and volumes.

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[14] Federal Institute for Geosciences and Natural Resources. *El Lajjun Oilshale Feasibility Study, Phase 1, Hydrogeology, Jordan: Possibilities of and Constraints to Groundwater Development for the Water Supply of the Envisaged Oilshale Processing Plant*, for the Central Water Authority of Jordan, Technical Cooperation Project No. 84.2092.9, Hannover, Federal Republic of Germany, Final Report, July 1987.

The Hannover group's study revealed that there are certain constraints which limit the extraction of groundwater from the easily accessible shallow aquifer. One involved some permeability details of a fault line near the El Lajjun site. Of more general implication to

Table 7.18
Results of Modeling Upper Wadi Mujib Groundwater Flows[a]
(Mm^3)

	Aquifer Recharge	Wadi Base Flow	Vertical Leakage
Recharge to the A7 - B2 Group (Amman Wadi Sir)	49		
Main Wadi Base Flow		6.6	
East groundwater outflow		1	
Spring discharges to the rift-sides:			
detected		12.3	
undetected		4	
Vertical Leakage to the Kernub and Disi (K+D) systems			25
Total	49	23.9	25

Sources: (1) The World Bank, *Jordan Water Resources Sector Study*, Infrastructure Operations Division, Country Department III, Europe, Middle East and North Africa Regional Office, Washington, D.C., Report No. 7099-JO, restricted distribution document, June 27, 1988.

(2) Federal Institute for Geosciences and Natural Resources, *El Lajjun Oilshale Feasibility Study, Phase 1, Hydrogeology, Jordan: Possibilities of and Constraints to Groundwater Development for the Water Supply of the Envisaged Oilshale Processing Plant, for the Central Water Authority of Jordan*, Technical Cooperation Project No. 84.2092.9, Hannover, Federal Republic of Germany, Final Report, July 1987.

[a] Refer to Figure 7.6

the Sultani oil shale project is the finding that the A1-A6 aquitard is more highly permeable than previously thought. As a consequence, there is higher loss of groundwater to the K + D system, the deep aquifer, than initially understood.

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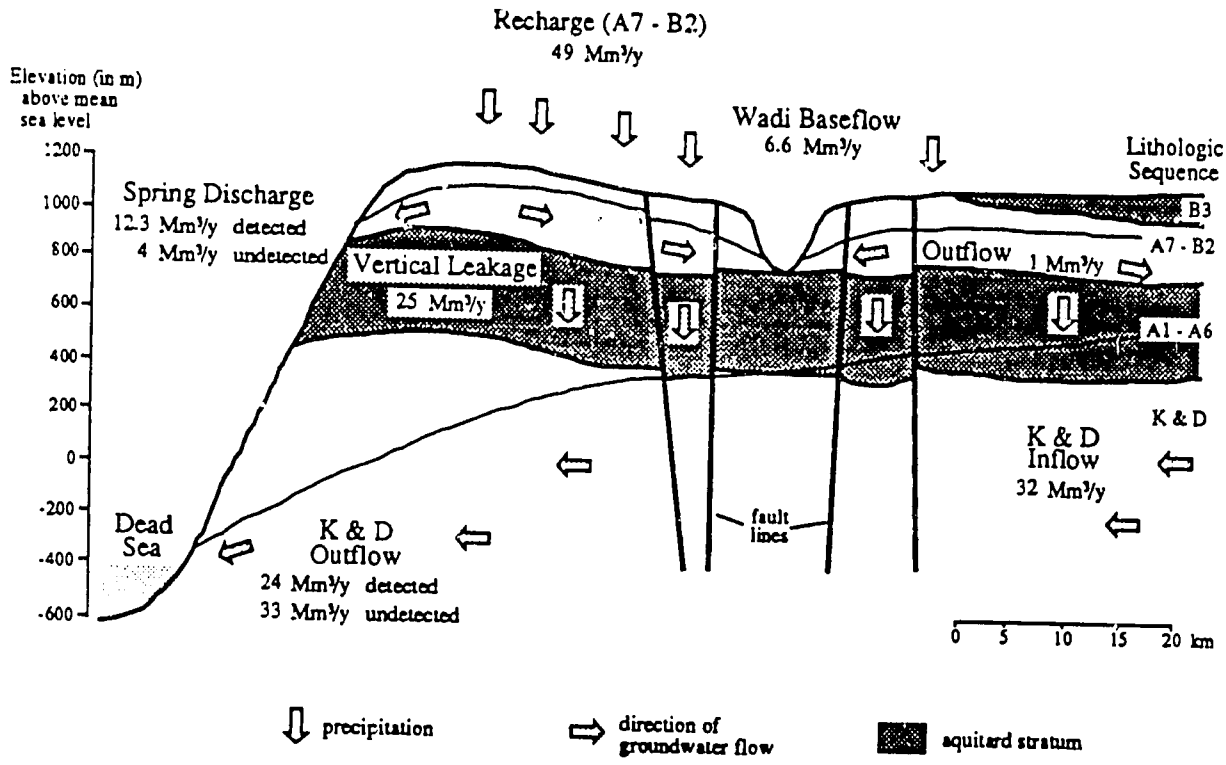

Figure 7.6
Groundwater balance for the Wadi Mujib drainage
(*Source:* Modified from Federal Institute for Geosciences and Natural Resources, *El Lajjun Oilshale Feasibility Study, Phase 1, Hydrogeology, Jordan: Possibilities of and Constraints to Groundwater Development for the Water Supply of the Envisaged Oilshale Processing Plant, for the Central Water Authority of Jordan*, Technical Cooperation Project No. 84.2092.9, Hannover, Federal Republic of Germany, Final Report, July 1987)

7.5.4 Oil Shale Plant Water Requirements

The plant water system consists of a raw water system, a treated plant makeup water system, and a plant service water system. The first measure of water conservation that the Bechtel Group's plans call for would be use of dry cooling towers to remove heat from the steam turbine exhaust. A small wet cooling tower is used to reject heat to the atmosphere from plant auxiliaries such as ash coolers.

The raw water pumps would provide pumped water to the service water system cooling tower, the boiler treated makeup water system, treated drinking water, pump seals, and other miscellaneous uses. Storage tanks for fire protection water would also be served through this system. Water for domestic use would be treated in accordance with World Health Organization standards. The service water system would provide water to the various internal plant operational needs such as condensers and other coolers. It also

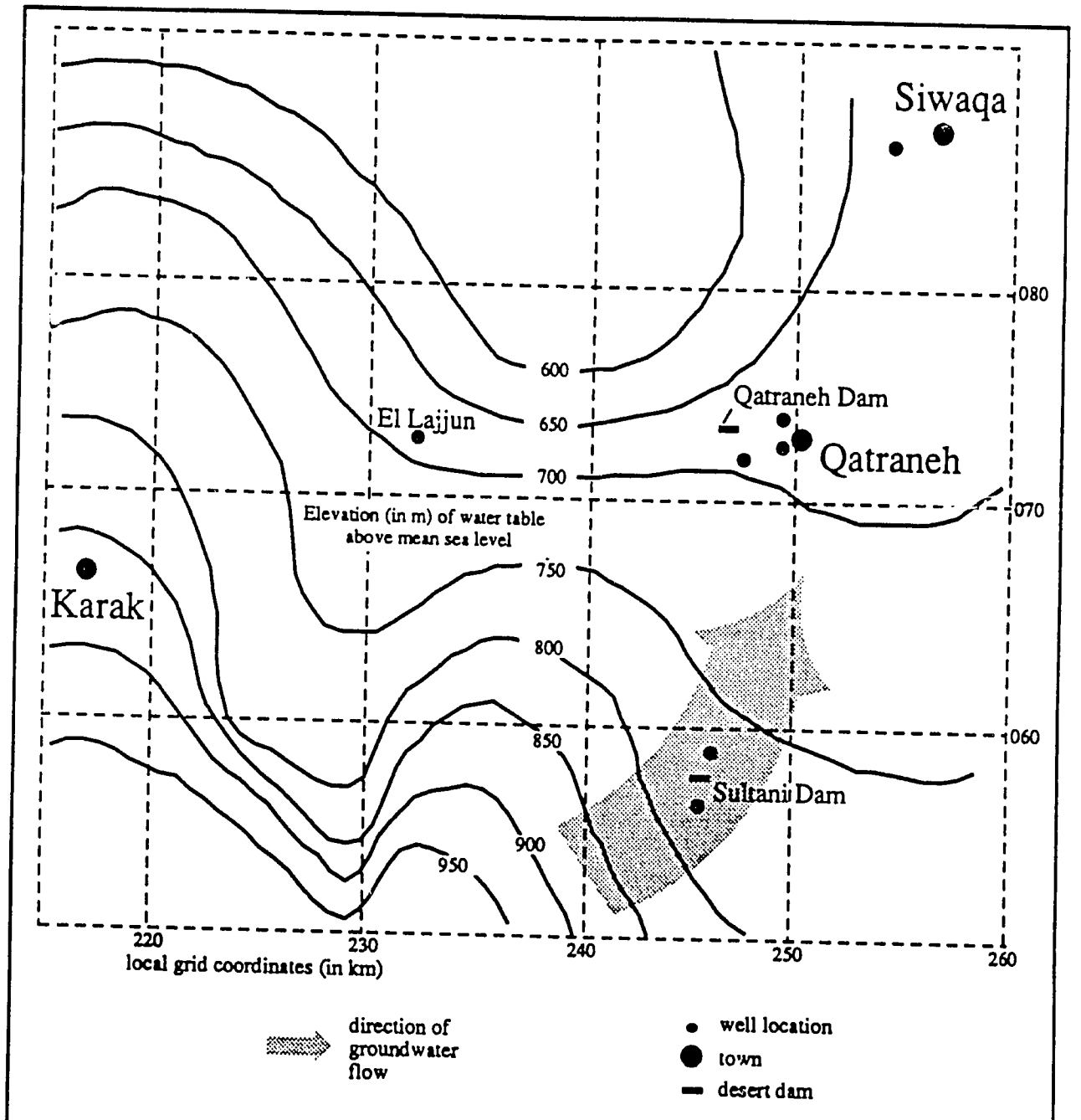

Figure 7.7
Equipotential groundwater map of the El Lajjun area, showing the Sultani site
(Source: Modified from Abu-Ajamieh, M., *An Assessment of the El-Lajjun Oilshale Deposit*, Natural Resources Authority, Hashemite Kingdom of Jordan, Amman, Jordan, February 1980)

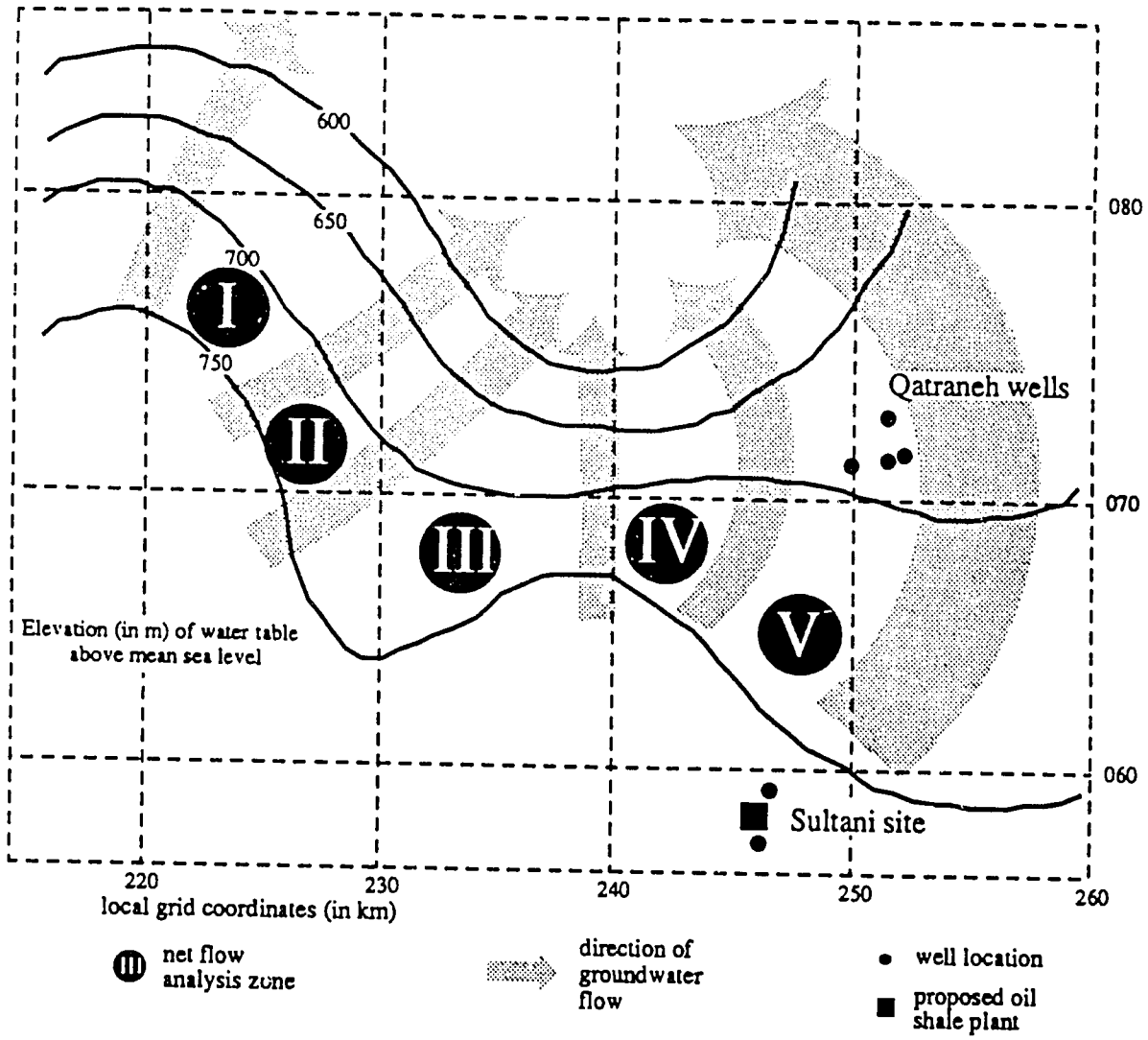

Figure 7.8
Net groundwater flow analysis of the El Lajjun area, showing the Sultani site

(*Source:* Modified from Abu-Ajamieh, M., *An Assessment of the El-Lajjun Oilshale Deposit*, Natural Resources Authority, Hashemite Kingdom of Jordan, Amman, Jordan, February 1980)

see also Table 7.19

would provide water for wetting the ash to minimize dust during ash handling. Some waste water would also be used for wetting the ash.

According to the Bechtel Group, the main liquid wastes from the plant are fuel- and ash-handling area runoff, makeup demineralizer regeneration wastes, and cooling tower blowdown. The fuel- and ash-handling area wastes are to be collected and routed to a settling pond for neutralization. Makeup demineralizer regeneration wastes are routed to a neutralization sump for pH control. Cooling tower blowdown should require no special

treatment because the circulating water pH is maintained between 8 and 9 during normal system operation.

Table 7.19
Net groundwater flow analysis of the El Lajjun area, (with the Sultani site)

Flow Zone[a]	Width (W) (m)	Transmissibility (T) ($m^3/d/m$)	Hydraulic Gradient (I)	Flow (WTI) (m^3/d)	Flow (WTI x 365) (m^3/y)
I	9,600	3.4	0.01	326.4	119,136
II	5,000	836.4	0.01	41,900.0	15,293,500
III	7,000	13.4	0.02	1,876.0	684,740
IV	7,200	(200.0) *(estimated)*	0.02	28,800.0	10,512,000
V	7,700	702.0	0.01	54,054.0	19,729,710
		Total Flow		126,956.4	46,339,086

(Source: Modified from Abu-Ajamieh, M., *An Assessment of the El-Lajjun Oilshale Deposit*, Natural Resources Authority, Hashemite Kingdom of Jordan, Amman, Jordan, February 1980)

[a] see Figure 7.8

7.5.5 Potential Impacts of Oil Shale Plant on Groundwater Quality and Supplies

No serious environmental hazards to water resources are anticipated to result from the plant and mine operations. To assure that water resources would be adequately protected, the Bechtel Group has called for environmental baseline studies to be conducted to develop protective measures for both surface and groundwater supplies. Measures to protect these water resources from contamination due to mining and waste disposal, particularly after flooding events, would also be needed. The Bechtel Group calls for further testing of the overburden to determine its chemical properties and suitability for revegetation.

7.5.6 Impact on Groundwater Quality and Quantity

It is the nature of mining activities such that there will always remain differences in the hydrologic characteristics between reclaimed areas and undisturbed areas. These differences will tend to influence the infiltration of precipitation, the surface water runoff and quality, the groundwater flows and quality, and the location and quantities of water discharged at seeps or springs. Because there exist so little site-specific data for the Sultani site, predicting the post-mining hydrogeological conditions, their seasonal variations, and their potential variation over the years, it is necessary to both gather more hydrogeological data before beginning the project and to establish a rigorous ground and surface water monitoring plan to enable the entire shale oil industry to learn as much as possible about the environmental impacts of this fuel with this technology.

Backfilled material generally has much higher hydraulic conductivity than the original undisturbed bedrock because of the increased occurrence and continuity of fractures and voids. Undisturbed shales frequently act to restrict groundwater movement. In the proposed backfilled pit, the hydrologic situation would be new and near the current water table. The fracturing and mixing of overburden materials as well as bottom and fly ash wastes would expose new (and more) rock surfaces to circulating groundwater. Minerals from these newly exposed surfaces may move into solution at enhanced rates compared with rates under the pre-mining flow paths. Thus, the chemistry of groundwater in the backfill of the overburden material alone, ignoring the ash backfill, would likely be different from that of the undisturbed overburden. Field and laboratory tests of the Green River shales of Colorado suggest that over 90 percent of the dissolved solute constituents are attributable to particles less than 0.5 mm in diameter (all the ash wastes from the proposed plant and many of the raw shale fines). These are all further reasons to have a comprehensive water monitoring system.

7.5.6.1 Environmental monitoring plan

A groundwater monitoring plan should be developed and defined as to the number and location of sampling stations, the variables to be measured, the sampling frequency and collection methods, the requisite accuracy and precision of the analytical techniques to be employed, and the quality assurance safeguards to be used. The location of the monitoring wells should be selected according to (1) the locations of potential pollutant sources, (2) the geology and hydrology of the Sultani site, (3) the probable movement and dispersion of pollutants underground, and (4) the potential for hydrologic disturbances such as dewatering wells. The wells should allow sampling from different depths, and the chemical and physical elements measured should be selected according to hydrological characteristics as well as the properties of the suspected potential pollutants. With the municipal wells for Karak located so close (<1 km) to the proposed pit, these monitoring actions are essential. Their use to advance the knowledge base of CFBC technologies with oil shale fuels further underscores the need for extensive groundwater monitoring.

7.5.7 Conclusions

- Jordan has very real water resource problems facing it.
- There are significant current and future demands placed on the limited groundwater resources in the Sultani area.
- The Sultani area, while seemingly remote, may play a secondary role in helping major municipalities meet their M&I needs as early as the late 1990s. The Sultani well fields are currently helping smaller communities such as Karak meet its M&I needs.
- There would, however, likely be adequate groundwater of sufficient quality and at reasonable pumping depths for operation of the proposed plant/mine/waste disposal complex and for meeting foreseeable future needs.
- Groundwater flow regimes in the Upper Wadi Mujib drainage suggest that leachate from the fly ash that enters the water table with inadequate filtration and dilution could cause drinking water problems with municipal users in Amman or Karak, now and increasingly possibly in the future. M&I wells for

Karak are already within one kilometer of the proposed plant site. Groundwater flow patterns take water from the Sultani area directly into wells there or northward to the Qatraneh (about 10 km away) and Siwaqa (about 20 km away) wellfields.

- Care must be taken in the fly ash waste disposal and reclamation engineering to optimize filtration of fly ash leachate through replaced overburden before it can drain into the Amman Wadi Sir groundwater.

- Monitoring wells and instrumentation or regular sampling are required to assure that water safe from chromium and/or selenium contamination is being pumped from the Sultani and Qatraneh well fields. Such monitoring and assurances should extend to the post-mining Sultani context.

8. TECHNICAL RISK ASSESSMENT

8.1 INTRODUCTION

Circulating fluidized bed technology in general has progressed to the point that there appears to be no question of its feasibility. Successful operation has been demonstrated burning a variety of solid fuels in plants of up to about 60 MW output. Larger plants, up to 110 MW, are in the initial phases of operation and, within the next 2-3 years, they should provide much evidence of the viability of larger plants.

The combustion tests of Jordanian oil shale in the Ahlström CFB test unit indicate that the shale should burn readily and yield low NO_x and SO_2 emissions in a CFB combustion system. The high volatile content of the fuel is a major contributing factor to its good combustion. The major disadvantages of the fuel are, of course, its low-heating value and high ash content. A large fraction of the shale blows through the combustor as fly ash which yields a high ash loading in the hot cyclone and convection tube banks. The primary potential problem areas are associated with the high ash content: (1) bottom ash removal from the combustor, (2) high flow rate of recycle solids through the hot cyclone and return leg, (3) fly ash deposition and erosion of the convection tube banks, and (4) erosion of superheater tubes in the combustor.

8.2 20-MW PLANT

The technical risk should be fairly low for a 20-MW demonstration plant. Eighteen plants of this size or larger have been built by Ahlström or its subsidiaries, have operated for a year or longer, and have demonstrated availabilities of 95 percent or more. The major areas of concern are the high flow rate of solids through the hot cyclone and return leg and the high fly ash loading in the flue gas which may lead to deposition and erosion in the convection tube banks. The design proposed by Pyropower should minimize the risk of deposition or erosion in the convection tube banks because the flue gas velocities will be low and steam soot blowers will be used.

While the technical risk for a 20-MW plant appears to be low, successful demonstration of this size plant may not provide adequate experience for scaling up to a 100-MW plant. It may be necessary to operate a 50-MW plant before attempting to scale up to 100 MW.

8.3 50-MW PLANT

The technical risk is moderate for a 50-MW plant. There is some operating experience with plants of this capacity firing coal or other low- to medium-ash fuel, but there is not yet any experience with high-ash fuel in plants this large. A 35-MW plant fired with anthracite culm is scheduled to begin operating this year, which should yield valuable information relative to operation with high-ash fuel.

The major areas of technical risk are associated with removal and handling of bottom ash from the combustor, high flow rate of recycle solids through the hot cyclone and return leg, fly ash deposition and erosion in the convection tube banks, and erosion of superheater tubes in the combustor. The ash flow rate for the 50-MW plant is about 10 times the ash flow rate of the Nucla plant, the largest CFB plant Pyropower has built to date.

8.4 100-MW PLANT

The technical risk is fairly high to build a 100-MW plant as the first unit. There is no plant this large operating or under construction which is designed to operate on high-ash fuel. The Nucla plant has an output of 110 MW, but it is designed for operation with coal with an ash content of about 20 to 25 percent. There have been some startup problems with the Nucla plant. One problem has been irregular flow of recycle solids in the cyclone return legs, apparently caused by restrictions or plugging from poor fluidization in the loop seals. Experience derived from the 2-year test program planned for the Nucla plant by EPRI will contribute greatly to the knowledge base for design of the larger plants. The high ash content of the Jordan oil shale will make the scale-up to a 100-MW plant for this fuel more challenging than for coal.

9. FINANCIAL/ECONOMIC ASPECTS OF THE SHALE ALTERNATIVE

This chapter addresses both financial and economic aspects of using oil shale for producing power in Jordan. Three plant sizes are considered: 20-MW and 50-MW demonstration plants, and a 400-MW commercial scale option. The 20-MW and 50-MW alternatives are considered research and development plants; the primary purpose for constructing them is to demonstrate the feasibility of the circulating fluidized bed (CFB) boiler technology and to document the operating experience using Jordan's shale. Of particular operating concern is the materials handling involved in oil shale mining, processing, and spent shale disposal. The 400-MW option is to be composed of four 100-MW units. However, it is possible to combine the demonstration features of the 50-MW option and the commercial-scale 400-MW alternative by first constructing a 50-MW plant, documenting its experience, and then constructing another 50-MW unit and 3 x 100-MW units.

The financial analysis below compares the three different oil shale options with (1) the actual financial performance of the 2 x 130-MW oil-fired units at Aqaba (Aqaba I) during the first 11 months of 1987 and (2) the estimated financial performance of 2 x 130-MW dual-fuel (coal and heavy oil) units also at Aqaba (Aqaba II) whose construction was recently delayed.[1] The financial comparison is on a cents per kWh cost basis, including fuel costs, other operation and maintenance (O&M) expenses, and capital costs.

The economic analysis consists of a series of sensitivity studies for the 20-MW, 50-MW, and 400-MW options. For each plant size, the sensitivity studies are conducted using four different assumptions on the operating characteristics of the plant: (1) capacity factor,[2] (2) average price of electricity, (3) fuel costs, and (4) capital expenditures. The approach is to examine the economic attractiveness of the shale alternatives under the most favorable set of assumptions and then perturb those assumptions to determine the economic attractiveness of each of the three plant-size options under less favorable operating assumptions. The results of the sensitivity study are an important factor in deciding whether to proceed with a more in-depth feasibility study of the oil shale-for-power alternative in Jordan.

Before proceeding, it is important to define what is meant by financial and economic analyses. Financial prices are those prices that the firm confronts in the market. They are the prices paid by market participants for inputs and the prices it receives for its output. An alternative way to express this is that a financial analysis portrays the performance of

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[1]The Aqaba II units were originally conceived to be dual-fueled, with coal being the primary fuel. However, a decision was made to use heavy fuel oil as the primary fuel because of the higher upfront capital costs associated with burning coal. A decision was made in 1987 to delay its construction. Current system planning for the Jordanian power system was discussed at greater length in Chapter 4.

[2]The economic analysis here is not being conducted in tandem with a least cost capacity expansion planning model such as WASP III. An analysis such as this is beyond the scope of this prefeasibility assessment. In the event that a feasibility study is undertaken, a capacity expansion planning model would presumably be used. A model such as WASP would estimate the actual utilization (running time) of 20, 50, and 400-MW plant options based on minimizing system cost, given assumptions about (1) the operating characteristics of all other plants in JEA's system and the shale alternatives, (2) projected fuel costs, and (3) forecasted electricity demand. In the present study, we simply assume different capacity factors for the three plant sizes in the sensitivity studies. Three capacity factors are used: 50, 60, and 75 percent.

the generating alternatives as they impact the financial records (income statement, balance sheet, and funds flow) of JEA.

In the economic analysis, a cost-benefit study of the three shale plants is conducted, taking into consideration the economic cost of the inputs used in producing power.[3] The costs are capital expenditures, fuel costs, other O&M costs, and ash disposal costs, while the benefits are revenues that JEA receives for the sale of electricity. The technique estimates the present value of net benefits from the project, using a discount rate reflecting the firm's opportunity cost of capital. Net benefits are simply the discounted value of all costs and revenues over the lifetime of the power plant. If the net present value of all revenues and expenditures equals zero (highly unlikely in real-world applications), the discount rate used in the analysis is called the *internal rate of return* (IRR). If the NPV is greater than zero using a predetermined discount rate, the IRR can be computed.

The cost-benefit technique is commonly used for project evaluation, originating from the type of analysis used by private firms in deciding on investment alternatives. When a firm engages in investment planning, it attempts to select investments that will yield the highest return for a given amount of capital expenditures. The IRR computed for the sensitivity studies is a useful number to compare various power supply options. It can be used as the basis of comparison for both the different shale plant-size alternatives and other generating options such as the 2 x 130-MW thermal units proposed for construction at Aqaba.

The sensitivity studies will be conducted at the *individual firm level*, the Jordan Electricity Authority. However, a cost-benefit analysis should consider all costs and benefits of the generation alternatives. Besides the supplier of electricity, costs and benefits of the generating alternatives to both consumers of electricity and the economy as a whole should be included in the analysis.

In Jordan's case, this is particularly important in comparing coal or heavy fuel oil generating alternatives with oil shale. Whether coal or heavy fuel oil is used, the fuel must be imported. This represents a significant foreign exchange drain which would not be the case for the shale alternative. Therefore, viewing the problem strictly from the standpoint of the firm (JEA in this case) would not include one of the most significant benefits of the shale alternative to the economy as a whole — foreign exchange savings. Another benefit of the shale option in comparison with alternatives using imported fuels which is not very easy to quantify is increased energy security. Easing reliance on imported sources of energy — especially petroleum — in a politically fragile part of the world is a substantial benefit which is very difficult to quantify in a cost-benefit analysis. Finally, there are the macroeconomic effects of using the local labor force for the shale mining operation. Employing Jordanian laborers will have a beneficial effect on national income.

Despite the caveats just presented, the sensitivity studies will be conducted at the level of JEA — the individual firm level. Besides problems with quantifying many of the costs and benefits accruing to electricity consumers and the economy as a whole, using a firm-level

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[3]Financial prices may not reflect the social opportunity cost of using the inputs in producing electricity. Many interferences in the market distort financial costs from economic costs. In the developing world, two of the primary distortions are foreign exchange controls and capital restrictions, two of the most important inputs in constructing power plants. However, in Jordan's case, these two important distortions are insignificant. Therefore, the cost-benefit analysis will be conducted using financial prices.

analysis facilitates comparison with other power generation alternatives which already have been studied. The Aqaba option, for example, has undergone intense scrutiny by the World Bank. The IRR for this option has been calculated under various input cost assumptions and can easily be compared with the results on the shale option. However, the net benefits of the shale option beyond JEA's level will be discussed in the final section of this chapter.

The results of financial and economic analyses are contingent on assumed input costs and revenue flows over the lifetime of the plant. Before proceeding to the financial and economic results, it is important to consider individual inputs and their cost for producing power using oil shale. Each of these inputs will be considered in detail below. The next section discusses capital expenditures required for each of the plant-size alternatives. Section 9.2 presents the O&M expenses for each option, including fuel cost, other O&M expenses for producing power, and the cost of disposing of the residual ash. The financial comparison and economic sensitivity results are presented and discussed in Sections 9.3 and 9.4, respectively.

9.1 CAPITAL EXPENDITURES

Figure 9.1 presents a schematic for the flow of major inputs and outputs of the integrated shale-for-power system. The data in the figure are for a 50-MW plant, operating at a 75 percent capacity factor.[4] The figure shows that 973,000 tonnes of raw shale will be mined, sent for processing (crushing), and delivered to the plant. The plant will produce 345.8 GWh of electricity each year, of which 338.4 GWh will be delivered to the transmission network and 7.4 gWh will be used in the shale processing operation. Dry ash in the amount of 657,000 tonnes will be recovered from the plant. After wetting, the ash will be 25 percent larger by weight (815,000 tonnes) and will be delivered to a holding site.

There are five broad functions involved in using oil shale for power generation in Jordan. They include:

1. mining the shale,
2. processing (or crushing) the shale,
3. producing power,
4. removing the residual ash, and, not shown in Figure 9.1,
5. housing the employees.

Each of these functions requires the expenditure of capital.[5] In the present economic analysis, there are several ways to treat the functions. The Bechtel Group treated the entire shale-for-power problem as a vertically integrated activity, presuming the operator of the power plant would be involved in both oil shale mining and processing and residual ash

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[4]The capacity factor is defined as the ratio of net generation of a power plant and the theoretically possible amount of generation. The latter is the nameplate capacity of the plant times 8,760 hours, the number of hours in a 365-day year.

[5]These five functions and associated capital expenditures subsume some other very important activities. The water supply system for the power plant is included in producing power. Environmental costs are included in both the mining and ash removal portion of the project.

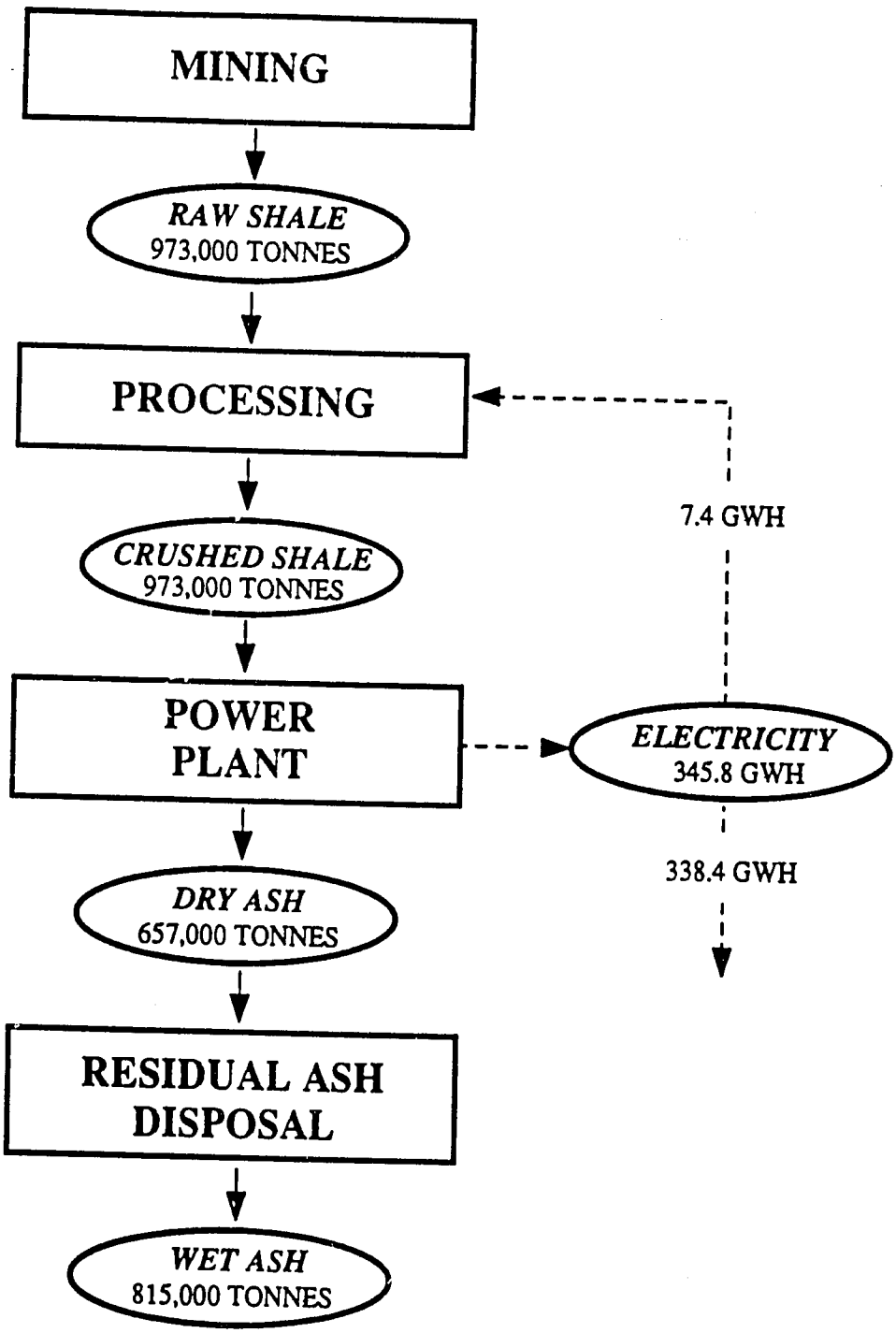

Figure 9.1
Schematic flow of major inputs and output, 50-MW plant

removal.[6] However, they separated the functions into four categories: (1) mining and processing, (2) the power block, (3) residual ash removal, and (4) community facilities or housing. For each of these categories of activity, estimated capital expenditures were provided and the unit cost of shale to the plant and the unit cost of ash removal were provided, which included the estimated O&M costs of these activities. Thus, comparisons can be made of the unit cost of oil shale delivered to the plant with other fuels, such as coal and heavy fuel oil.

In actual practice, producing power from shale in Jordan may not be an integrated activity. It is possible that the mining activity could be contracted out, providing shale to the plant and disposing of the residual ash.[7] In this case, the owner of the plant would be involved only in processing the shale and producing power.

In the ensuing economic analysis, the cost of fuel and residual ash disposal are treated as separate operating expenses for producing power. The only capital expenditures are for the plant itself. Thus, cost categories are capital expenditures on the plant itself and three categories of operating expenses:

1. power production O&M expenses, including water, labor, and the like,
2. the delivered cost of fuel (shale), and
3. ash removal.

The remaining problem is the cost of housing. The location of the proposed shale plant is in a fairly remote area approximately 100 km south of the capital, Amman. There is some likelihood that housing facilities would have to be constructed at the plant site to accommodate both indigenous labor and expatriates and their families. The cost of constructing a "town" can be significant, depending on the type of living arrangements used for the workers.

As an example, living quarters for 700 employees at Shidiya, a remote phosphate mining site approximately 300 km south of Amman, are in the design stage. The total cost of the project is estimated to be 2 million JD (approximately $6 million). The area encompasses approximately 17,800 square meters with construction costs estimated to be 90 JD per square meter, excluding the cost of infrastructure (roads, water, and electricity). The cost of the infrastructure is estimated to be another 200,000 JD ($600,000). The Shidiya site will accommodate only bachelors. It provides "bunkhouses" for four people, consisting of a kitchen, bath, and two bedrooms, two men to a room. Besides the living quarters for the workers and the infrastructure, a restaurant, a social club, a shopping area, health clinic and a guest house are included in the total cost of 2 million JD.

In contrast to the Shidiya project, the cost of construction for the town built near the El Hasa mining site from 1983-1987 was considerably more expensive. Total cost was estimated at 173 JD per square meter, even though it is located much closer to Amman

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[6]The term integrated is used here technically wherein an enterprise manufactures a commodity and all inputs used in the commodity's production.

[7]Several bids from Jordanian concerns have already been received by the Natural Resources Authority of Jordan for mining the shale. However, it is questionable whether the bids are realistic. It does not seem that the mining interests properly understood the nature of the task. For example, residual ash disposal, internalizing the environmental costs, does not seem to have been included in the bids.

and, in comparison with the Shidiya site, is considerably more accessible to the Desert Highway, running north-south through Jordan. The reason for the difference in construction cost is that the El Hasa site was constructed for families and, therefore, is much more elaborate. A total of 500 houses were constructed for 3,000 persons, based on an average of 6 persons per household. Although the El Hasa site included the same type of social facilities built at Shidiya (restaurant, shopping area, and the like), they were much more elaborate and expansive. The El Hasa site included schools for 420 students and a sports center, including a soccer field, two swimming pools, tennis courts, and a playground.

The phosphate mining company constructing these towns does not recoup its cost of construction from the inhabitants. The rent for a family living at the El Hasa site is 3.5 JD (approximately $10.50) per month. Rather, the housing is provided as a perquisite to attract skilled labor to these remote areas. The company recoups the cost of construction by depreciating the "town" using a straight-line method, 5 percent per year over a 20-year period.[8] Thus, housing is treated as any other capital expenditure in determining the cost of the plant.

A complicating factor in determining the cost of housing for workers at the proposed oil shale-fueled power plant is that production at the El Hasa phosphate mining site is scheduled to be phased out during the next several years, with operations completely terminated in the mid- to late-1990s. This scheduled termination date is well in advance of the anticipated completion of the power plant. Because of the close proximity of the El Hasa town site to the oil shale-fueled power plant (approximately 30 km), it is possible that mining and power personnel could use at least a portion of the existing town site presently occupied by the El Hasa personnel, thereby mitigating the housing cost for the proposed shale plant(s). However, the expected number of employees for the integrated power production operation is significant. For the 20-MW plant, 185 people are expected to be employed, 75 of whom will be used in the mining/processing operation. For the 50- and 400-MW plants, the numbers are 324 (163 in mining/processing) and 1,046 (396), respectively.

Another complicating factor is that some workers could live in Karak or Qatraneh and commute to the mine by company bus, as is currently the case at the El Abiad mine.

In the sensitivity analysis below, we include the cost of housing as a direct cost of producing power at the Sultani site. Thus, the capital expenditures include the capital expense for providing housing for the workers, recognizing that a portion of the workers may be miners who are not part of the ownership of the plant. Table 9.1 provides the estimated cost of housing for the three plant sizes under consideration, along with their estimated capital costs, the Allowance for Funds Used During Construction, and the cost per kW of the three plants, including and excluding the cost of housing.

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[8]While in Jordan, there seemed to be a bit of a tax controversy using this method. It seems that the phosphate company was involved in a "litigation" or discussion with the government over the deduction of the depreciation for tax purposes.

In the economic analysis that follows, the imputed capital charges are excluded from the analysis because they do not represent a cash flow item.[9] Thus, the cost of the three plant sizes, including housing, which will be used in the economic analysis range from $70.4 million for the 20 MW plant to $111.4 and $641.2 million for the 50 MW and 400 MW options, respectively. On a dollars per kW basis, the 20 MW plant is nearly double the amount for the 400 MW option when the cost of housing is included.

Table 9.1
Capital Expenditures
20-, 50-, and 400- MW Options
($ 10^3)

Category	20 MW	50 MW	400 MW
Power Plant	67,700	112,200	760,500
Housing	10,000	15,000	45,000
AFUDC[a]	(7,300)	(15,800)	(164,300)
Total	70,400	111,400	641,200
Cost/kW (without housing)	3,385	2,244	1,901
Cost/kW (with housing)	3,885	2,544	2,014

Source: Computed from Bechtel National, Inc., *Prefeasibility Study, Oil Shale Utilization for Power Production in the Hashemite Kingdom of Jordan*, December 1988, Draft.

[a] Allowance for Funds Used During Construction.

9.2 OPERATION AND MAINTENANCE EXPENSES

Given the conceptualization of the plant site presented in the previous section, there are three categories of O&M expenses which enter into the sensitivity study: (1) the unit cost of oil shale, (2) the unit cost of disposing of the residual ash from the power plant, and (3) other O&M expenses, including wages and salaries, water, and the like. Each of the three categories will be discussed below.

[9]AFUDC or Interest During Construction (IDC) is an accounting construct which allows a firm to recoup the capital charges of investment projects with long construction lead times. The amount is reflected as income on the profit and loss statement offset by a corresponding charge to the cost of the plant. The amount is recouped through depreciation charges over the lifetime of the plant. In the economic analysis, we are working strictly on a cash basis and, therefore, the amounts for AFUDC are not considered in the construction expenditures for the plant.

9.2.1 Cost of Shale

Table 9.2 summarizes the mining and processing capital and operating costs for the 20-, 50-, and 400-MW options, assuming the plants operate at a 75 percent capacity factor. The information presented in the table summarizes the Bechtel Group's analysis for the three size alternatives. The capital cost represents the out-of-pocket expenditures for constructing the mining and processing facilities, excluding the imputed amount of AFUDC. Those figures are provided in the second category of data in the table. The amount of AFUDC is smaller for the 50/50 D/E option because the cost of capital is only capitalized for the amount of debt – not the equity portion. The unit cost of providing shale to the plant is less under the 80/20 D/E option because of the lower assumed cost of debt capital.

Table 9.2
Mining and Processing Costs
20-, 50-, 400-MW Options

Category	20 MW	50 MW	400 MW
Capital Cost[a] (10^3 U.S. $)	25,335	31,923	162,816
AFUDC (10^3 U.S.$)			
50/50 D/E[b]	2,534	3,192	24,423
80/20 D/E	4,054	5,108	39,075
Operating Costs (10^3 U.S. $)			
50/50 D/E	6,827	13,118	56,606
80/20 D/E	5,582	11,556	48,945
Unit Cost (U.S. $/tonne)			
50/50 D/E	17.50	13.48	7.76
80/20 D/E	14.31	11.88	6.84
Amount[c] (10^3 tonnes)	390	973	7,783

Source: Computed from Bechtel National, Inc., *Prefeasibility Study, Oil Shale Utilization for Power Production in the Hashemite Kingdom of Jordan*, December 1988, Draft.

[a] Excludes AFUDC.

[b] Debt-to-equity ratio.

[c] Assumes a 75 percent capacity factor.

The table shows that there are significant economies in oil shale mining and processing. Under the 80/20, D/E option, the unit cost is only $6.84/tonne for the 400-MW option in comparison to $14.31/tonne for the 20- MW option. A similar result emerges for the 50/50

D/E option. The Bechtel Group study's design analysis was for the mining/processing operation to provide enough fuel for the plant operating at 100 percent capacity.

9.2.2 Residual Ash Disposal

Table 9.3 provides the same information for residual ash disposal costs as that provided for mining and processing costs in Table 9.2. Here, the unit cost for disposing of the residual shale declines for the 50-MW case in comparison with the 20-MW case, but increases for the 400-MW case because of the amount of residual ash required for disposal.

Table 9.3
Residual Ash Disposal Costs
20-, 50-, 400-MW Options

Category	20 MW	50 MW	400 MW
Capital Cost[a] (10^3 U.S.$)	1,541	2,205	8,068
AFUDC (10^3 U.S.$)			
50/50 D/E[b]	77	110	404
80/20 D/E	123	176	646
Operating Costs (10^3 U.S. $)			
50/50 D/E	394	823	6,378
80/20 D/E	316	710	5,987
Unit Cost (U.S. $/tonne)			
50/50 D/E	1.20	1.01	1.04
80/20 D/E	0.97	0.87	0.98
Amount[c] (10^3 tonnes)	327	815	6,127

Source: Computed from Bechtel National, Inc., *Prefeasibility Study, Oil Shale Utilization for Power Production in the Hashemite Kingdom of Jordan*, December 1988, Draft.

[a] Excludes AFUDC.

[b] Debt-to-equity ratio.

[c] Assumes a 75% capacity factor.

9.2.3 Other O&M Expenses

Table 9.4 presents other O&M expenses for the three plant sizes and three capacity factors. In its analysis, the Bechtel Group divided other O&M expenses into fixed and variable portions, but computed these expenses for the 75 percent capacity factor case only. To obtain the variable amounts for the 50 and 60 percent cases, O&M expenses were changed

to reflect different amounts of input. The fixed portion of other O&M expenses was not changed for the 50 percent and 60 percent cases.

Table 9.4
Other O&M Expenses
Unit Cost
By Plant Size and Capacity Factor
(¢/kWh)

Size	50%	60%	75%
20 MW	2.15	1.83	1.50
50 MW	1.34	1.15	0.96
400 MW	0.87	0.76	0.65

The table shows significant economies by increasing plant size. For the 75 percent capacity factor case, other O&M expenses were more than double on a cents per kilowatt-hour of generation basis for the 20-MW in comparison with the 400-MW plant. The 20-MW plant was more than 50 percent larger in comparison with the 50-MW for the 75 percent capacity factor case. Similar results were obtained for the other capacity factors.

9.3 FINANCIAL ASPECTS OF THE SHALE ALTERNATIVE

There are a number of competing alternatives for power generation in Jordan. Here, a financial comparison is made of several of the alternatives. First, we consider the actual operation of the 2 x 130-MW base-load thermal units at Aqaba (referred to as Aqaba I) during 1987. Second, 20-MW, 50-MW, and 400-MW oil shale alternatives are considered. Finally, the 2 x 130-MW deferred base-load units at Aqaba (known as Aqaba II) will be compared using coal as the alternative fuel.

Table 9.5 presents a summary of the comparison, providing capital cost/kW, total capital costs, fuel requirements, fuel costs, and the financial analysis on a ¢/kWh basis. The results are based on an assumed cost of capital of 15 percent for the shale alternatives and 9 percent for the two Aqaba plants[10]. The assumed capacity factor is 75 percent. For Aqaba I, the fuel and O&M costs are actual figures for an 11-month period in 1987, using a 3:1, dollar:dinar exchange rate. The Aqaba II data are based on a World Bank study. The capital costs are derived from the World Bank study and the $53 unit fuel cost is the c.i.f. price of quotations made to the Jordanian government for coal imports.

[10]The difference in the cost of capital for the Aqaba plants and the shale alternatives is attributable to the assumed capital structure for the plants. The Aqaba I and II plants are financed using debt exclusively. It is assumed that the shale alternatives will be financed partly by equity, which has associated with it a higher return than debt financing available to JEA and the Jordanian government.

Table 9.5
Financial Comparison of Generating Plant Alternatives

Category	Aqaba 1	Shale	Shale	Shale	Aqaba 2
Capacity (MW)	260	20	50	400	260
Cost ($/kW)	931	3885	2544	2014	950
Capital Cost (10^6)	242	78	127	806	247
Generation @75% (GWh)	1708	131	328	2628	1708
Fuel Needs (10^3 tonnes/y)	Actual	390	973	7783	964
Fuel Cost ($/tonne)	Actual	14.31	11.88	6.84	53.00
Comparative Cost (¢/kWh)					
Fuel	2.61	4.25	3.52	2.03	2.99
O&M	0.98	1.50	0.96	0.65	0.90
Capital	1.28[a]	8.87[b]	5.81[b]	4.60[b]	1.30[a]
Total	4.87	14.62	10.29	7.28	5.19

[a] Assumes capital cost of 9 percent per annum.

[b] Assumes capital cost of 15 percent per annum.

The results show that, from a financial standpoint, the existing 2 x 130-MW units at Aqaba I are the least costly on a cents per kWh basis, with the proposed coal plant at Aqaba II the second best financial cost option. The 400-MW shale option is more than 2¢/kWh more costly to run than the proposed plant at Aqaba.

In a capital budgeting problem, simple financial costs do not provide a true basis of comparison of competing alternatives. Financial costs are merely indicative. An economic analysis of the alternatives is required. We turn to this analysis in the next section.

9.4 ECONOMIC ANALYSIS OF THE SHALE ALTERNATIVE

9.4.1 Sensitivity Analysis at JEA's Level

Four variables will be perturbed in the sensitivity analysis:

1. *Average revenue of JEA's sales.* In 1987, the average revenue accruing to JEA for all of its sales was 20.7 fils per kWh of electricity sold, which translates into 6.0¢/kWh, assuming a 3 U.S. dollar per Jordanian Dinar exchange rate.[11] A tariff change was not made in 1988.[12] Therefore, in the sensitivity studies

[11] There are 1,000 fils in each Jordanian Dinar.

[12] As discussed in Chapter 3, a tariff study was conducted in early 1988, but tariffs were not changed based on this study. The last tariff change was in June 1986.

which follow, the base revenue is assumed to be the same as in 1987.[13] To show what effect a tariff increase would have on the economics of the proposed plant(s), average revenues were increased 25 percent to 7.5¢/kWh and 50 percent to 9.0¢/kWh in the sensitivity studies.

2. *Capacity Factor.* The Bechtel Group's analysis used a 75 percent annual capacity factor, assuming that the proposed oil shale plant would be a base-load unit. To see what effect lower annual running rates would have on the economics of the plant(s) — due either to maintenance and materials handling problems, or insufficient power needs — the IRR for 50 and 60 percent running rates were computed in addition to the 75 percent case.

3. *Debt/Equity Ratio.* The Bechtel Group's analysis assumed two different debt/equity ratios for the mining/processing function and the ash disposal function: 50/50 and 80/20. The latter results in a lower average unit cost because of the assumption that the cost of debt is less than that of equity. These input costs were summarized in Tables 9.2 and 9.3, respectively. Sensitivity analyses were conducted using both of these input assumptions.

4. *Capital Expenditures.* In their estimate of capital expenditures for the 20-, 50-, and 400-MW options, the Bechtel Group provided one estimate of capital expenditures. These estimates for the three plant sizes will be considered the base capital expenditure scenarios in this study (noted Base). To include uncertainty in the analysis, two other groups of scenarios were considered.[14] Relying on a commonly used practice, the capital expenditures in the Base scenario were changed by ±25 percent [noted Base(0.75) and Base(1.25)] in the first group. In the second group of scenarios, the base case capital expenditures were increased by 50 percent [Base(1.50)] and 100 percent [Base(2.00)] to reflect uncertainties in both the Jordanian exchange rate and the cost of constructing the plant in a foreign environment. This will be discussed more fully below.[15] The time stream of capital expenditures was obtained from the Bechtel Group's study. For the 20- and 50-MW options, the expenditures were made over a 31-month period. For the 400-MW option, it was over a 48-month period with each of the 100-MW units beginning construction six months after the previous one started.

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[13]Using 1987 data may overstate the amount. Recently, electricity prices were lowered for some customer classes as part of an austerity program announced by King Hussein on November 6, 1988. See *Wall Street Journal* and *New York Times*, November 7, 1988.

[14]The effects of uncertainty can also be included by increasing the discount rate. We choose here to change the amount of capital expenditures.

[15]As is the case with all of the scenarios, the purpose for including these two other capital expenditure scenarios in the study is not to speculate on the likelihood of their occurrence. Probabilities are not assigned to any of the input costs or revenues accruing to JEA under any of the scenarios. Rather, the sensitivity study merely bounds the results, considering (1) what probabilistically can occur (such as lower running rates and higher capital expenditures) and (2) what must occur to improve the economic attractiveness of the shale alternative (such as higher running rates and increased average revenues). It is left to individual readers to speculate on the likelihood of each scenario.

The discount rate in all of the analyses is 9 percent per annum, reflecting the opportunity cost of capital to JEA. The O&M expenses per kWh of generation under the three different capacity factors for the three plant sizes were provided in Table 9.4 above. In the Bechtel Group's study, the amount of oil shale needed, spent ash to be disposed of, and net electricity generation for the three plant sizes at a 75 percent capacity factor were provided. These amounts are also needed for the 60 and 50 percent scenarios. That information is provided in Table 9.6.

Table 9.6
Physical Quantities
Alternative Scenarios
(by plant size and capacity factor)

Size/Capacity Factor	Oil Shale (10^3 tonnes)	Spent Ash (10^3 tonnes)	Generation (GWh)
20 MW			
50 percent	260.0	218.0	89.8
60 percent	312.0	261.6	107.7
75 percent	390.0	327.0	134.7
50 MW			
50 percent	648.7	543.3	225.6
60 percent	778.4	652.0	270.7
75 percent	973.0	815.0	338.4
400 MW			
50 percent	5,188.7	4,084.7	1,752.0
60 percent	6,226.4	4,901.6	2,102.4
75 percent	7,783.0	6,127.0	2,628.0

Source: Computed from Bechtel National, Inc., *Prefeasibility Study, Oil Shale Utilization for Power Production in the Hashemite Kingdom of Jordan*, December 1988, Draft.

9.4.1.1. Base case capital expenditure scenario

The results for the base case capital expenditure scenario are presented in Table 9.7. Entries with a "." reflect a scenario with an internal rate of return less than zero. The table shows that the 20-MW option is not economically attractive. This plant size has a return greater than zero under only the most favorable conditions: a high capacity factor, low input costs (an 80/20 debt/equity ratio for both mining and processing costs and ash disposal), and a very favorable average revenue amount (9.0¢/kWh, a 50 percent increase over the amount realized by JEA in 1987).

Under JEA's current tariff structure (6.0¢/kWh), the 50-MW alternative is not economically attractive, either. None of the input scenarios resulted in an IRR greater than zero assuming this tariff structure for the 50-MW option. The IRR for the 400-MW plant under the current tariff structure approaches or exceeds JEA's opportunity cost of capital (9 percent) assuming a 75 percent capacity factor (8.56 and 9.77 percent under the 50/50 and 80/20 debt/equity scenarios, respectively). Assumed lower annual running rates result in significantly lower returns, dropping to 3.24 percent under the most unfavorable assumed conditions.

Table 9.7
Sensitivity Results
Alternative Scenarios, Base Capital Expenditures
20-, 50-, and 400-MW Plant Options

Capacity Factor[a] (%)	Average Price[b] (¢/kWh)	Debt/ Equity[c] (%)	Internal Rate of Return[d] 20 MW	50 MW	400 MW
75	9.0	50/50	.	9.33	19.04
75	7.5	50/50	.	4.30	14.16
75	6.0	50/50	.	.	8.56
75	9.0	80/20	1.75	10.80	19.97
75	7.5	80/20	.	6.15	15.18
75	6.0	80/20	.	.	9.77
60	9.0	50/50	.	6.28	14.80
60	7.5	50/50	.	1.55	10.55
60	6.0	50/50	.	.	5.55
60	9.0	80/20	.	7.62	15.61
60	7.5	80/20	.	3.32	11.46
60	6.0	80/20	.	.	6.66
50	9.0	50/50	.	3.93	11.72
50	7.5	50/50	.	.	7.89
50	6.0	50/50	.	.	3.24
50	9.0	80/20	.	5.21	12.45
50	7.5	80/20	.	1.09	8.72
50	6.0	80/20	.	.	4.30

[a] The capacity factor is the ratio of total net generation from a plant to the theoretical maximum amount that the plant can generate in a year. The latter is calculated as the product of nameplate capacity and the number of hours in a year (8,760 in a 365-day year).

[b] Average price is total revenues realized divided by total sales.

[c] Debt/equity is the assumed capitalization for mining and processing and residual ash disposal operations. They were discussed at length in Section 9.2.

[d] A "." signifies that the return is less than zero.

The returns for the 50-MW option do not exceed JEA's opportunity cost of capital even if a 25 percent increase in tariffs is assumed (from 6.0¢/kWh to 7.5¢/kWh). Only under the most favorable revenue and running rate assumptions do the 50-MW returns exceed 9 percent. Assuming the same 25 percent increase in tariff levels to 7.5¢/kWh, the simulated returns for the 400-MW option exceed 9 percent under both 75 percent and 60 percent capacity factors. They even approach that level under an assumed 50 percent running rate.

To summarize the base capital expenditure scenario, returns for the 400-MW option exceed JEA's opportunity cost of capital in 11 of the 18 scenarios and approach it in two others. The 50-MW option exceeds JEA's 9 percent opportunity cost of capital under the two most favorable sets of assumptions: high running rates and high average revenue per kWh of electricity sold. Under the pricing schedule that existed in 1987 (an average revenue of 6.0¢/kWh), the IRR for the 50-MW option never exceeds zero.

9.4.1.2. ±25 Percent capital expenditure scenarios

Tables 9.8 and 9.9 present sensitivity results for the Base(0.75) and Base(1.25) capital expenditure scenarios, respectively, reflecting a 25 percent decrease and increase in the base case scenario. The 20-MW plant is not an economically attractive option even if the capital expenditures are reduced by 25 percent (Table 9.8). Internal rates of return are greater than zero in only three cases, but do not approach JEA's opportunity cost of capital.

As was the case with the base scenario, the 50-MW alternative is not an economically attractive option under JEA's current tariff level (6.0¢/kWh) assuming a 25 percent reduction in capital expenditures (Table 9.8). The IRR is greater than zero in only one case under this tariff level. Assuming a 25 percent increase in the tariff level in the Base(0.75) scenario (Table 9.8), the return for the 50-MW option exceeds 9 percent only under the most favorable situation: 75 percent capacity factor and 80/20 debt/equity ratio for the mining/processing and ash disposal functions. The 50-MW option is economically unattractive in all scenarios where capital expenditures were increased by 25 percent [Base(1.25) in Table 9.9]. The only case in which JEA's opportunity cost of capital is approached (8.24 percent in Table 9.9) is the one which assumes a 50 percent increase in the average tariff level from what currently exists (6.0 to 9.0¢/kWh), a 75 percent capacity factor, and a 80/20 debt/equity ratio for the mining/processing and ash removal functions.

The results for the 400-MW simulations under the Base(0.75) scenario (Table 9.8) show that returns approach or exceed 9 percent under all scenarios with the exception of the 6.0¢/kWh and 50 percent capacity factor assumptions. However, increasing capital expenditures by 25 percent from the base case [Base(1.25) scenario in Table 9.9] results in returns less than 9 percent under all cases in which average revenues are assumed to be 6.0¢/kWh. Increasing average revenues by 25 percent to 7.5¢/kWh results in returns approaching or exceeding 9 percent in the 60 and 75 percent running rate scenarios.

9.4.1.3. Higher capital expenditure scenarios

Estimates of capital expenditures for power plants are notoriously uncertain. In the present case, two factors are especially important. First, the plant will be built in a developing country. Second, the foreign exchange costs are uncertain. Most recently, the Jordanian Dinar has been depreciating in international exchange markets, increasing the cost of importing materials for constructing power plants. On December 31, 1987, the

Jordanian Dinar was worth $3.04. The exchange rate stayed fairly stable during the first third of 1988, equalling $2.95 at the end of April 1988. However, since then it has steadily declined to the point where on December 15, 1988 it was $2.13.[16] The figures for capital expenditures in this study are based on a mid-1988 exchange value of $3.00 per Jordanian Dinar.

Table 9.8
Sensitivity Results
Alternative Scenarios, Base(0.75) Capital Expenditures
20-, 50-, and 400-MW Plant Options

Capacity Factor[a] (%)	Average Price[b] (¢/kWh)	Debt/ Equity[c] (%)	Internal Rate of Return[d] 20 MW	50 MW	400 MW
75	9.0	50/50	0.42	12.89	24.63
75	7.5	50/50	.	7.04	18.68
75	6.0	50/50	.	.	11.97
75	9.0	80/20	4.15	14.63	25.77
75	7.5	80/20	.	9.16	19.92
75	6.0	80/20	.	1.98	13.41
60	9.0	50/50	.	9.31	19.46
60	7.5	50/50	.	3.92	14.35
60	6.0	50/50	.	.	8.46
60	9.0	80/20	0.81	10.88	20.44
60	7.5	80/20	.	5.92	15.43
60	6.0	80/20	.	.	9.75
50	9.0	50/50	.	6.62	15.74
50	7.5	50/50	.	1.43	11.18
50	6.0	50/50	.	.	5.79
50	9.0	80/20	.	8.08	16.62
50	7.5	80/20	.	3.40	12.17
50	6.0	80/20	.	.	7.01

[a] The capacity factor is the ratio of total net generation from a plant to the theoretical maximum amount that the plant can generate in a year. The latter is calculated as the product of nameplate capacity and the number of hours in a year (8,760 in a 365-day year).

[b] Average price is total revenues realized divided by total sales.

[c] Debt/equity is the assumed capitalization for mining and processing and residual ash disposal operations. They were discussed at length in Section 9.2.

[d] A "." signifies that the return is less than zero.

[16] The latter amount is from *The Wall Street Journal*, December 16, 1988. Earlier exchange rates are from International Monetary Fund, *International Financial Statistics*, XL(9), September 1988.

Table 9.9
Sensitivity Results
Alternative Scenarios, Base(1.25) Capital Expenditures
20-, 50-, and 400-MW Plant Options

Capacity Factor[a] (%)	Average Price[b] (¢/kWh)	Debt/ Equity[c] (%)	Internal Rate of Return[d] 20 MW	50 MW	400 MW
75	9.0	50/50	.	6.94	15.41
75	7.5	50/50	.	2.41	11.18
75	6.0	50/50	.	.	6.26
75	9.0	80/20	0.07	8.24	16.20
75	7.5	80/20	.	4.08	12.07
75	6.0	80/20	.	.	7.33
60	9.0	50/50	.	4.20	11.74
60	7.5	50/50	.	.	8.03
60	6.0	50/50	.	.	3.57
60	9.0	80/20	.	5.41	12.44
60	7.5	80/20	.	1.51	8.82
60	6.0	80/20	.	.	4.57
50	9.0	50/50	.	2.07	9.05
50	7.5	50/50	.	.	5.66
50	6.0	50/50	.	.	1.46
50	9.0	80/20	.	3.23	9.69
50	7.5	80/20	.	.	6.40
50	6.0	80/20	.	.	2.43

[a] The capacity factor is the ratio of total net generation from a plant to the theoretical maximum amount that the plant can generate in a year. The latter is calculated as the product of nameplate capacity and the number of hours in a year (8,760 in a 365-day year).

[b] Average price is total revenues realized divided by total sales.

[c] Debt/equity is the assumed capitalization for mining and processing and residual ash disposal operations. They were discussed at length in Section 9.2.

[d] A "." signifies that the return is less than zero.

To provide for exchange rate uncertainty and other contingencies associated with constructing power plants in Jordan, two other scenarios were examined, assuming that the capital expenditures provided in the Bechtel Group's study were 50 percent higher (the Base(1.50) scenario) and were higher by a factor of two (the Base(2.00) scenario). All of the other input assumptions used in the base case scenario (Table 9.7) are the same. The results of the two high capital expenditure scenarios are presented in Tables 9.10 and 9.11.

As would be expected from the results of the other three scenarios, the 20-MW option is not economically attractive under the two high capital expenditure scenarios (Tables 10 and 11). For the 50-MW option in the Base(1.50) scenario, the IRR does not exceed JEA's

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opportunity cost of capital (9 percent) in any of the sensitivity runs. The results for the 400-MW option are a little more favorable. Assuming a 75 percent annual running rate, the IRR does not exceed JEA's cost of capital under the tariff structure in existence in 1987 (6¢/kWh). However, by increasing the tariff level by 25 percent to 7.5¢/kWh and 50 percent to 9.0¢/kWh under the 75 percent capacity factor case, the IRR exceeds 9 percent assuming both 50/50 and 80/20 debt/equity ratios for the mining and residual ash disposal operations. Assuming lower capacity factors for the 400-MW option, the results deteriorate. The IRR exceeds 9 percent only under the 60 percent running rate scenario when the average tariff level is assumed to be 9¢/kWh.

Table 9.10
Sensitivity Results
Alternative Scenarios, Base(1.50) Capital Expenditures
20-, 50-, and 400-MW Plant Options

Capacity Factor[a] (%)	Average Price[b] (¢/kWh)	Debt/ Equity[c] (%)	Internal Rate of Return[d] 20 MW	50 MW	400 MW
75	9.0	50/50	.	5.17	12.81
75	7.5	50/50	.	0.98	9.03
75	6.0	50/50	.	.	4.56
75	9.0	80/20	.	6.36	13.52
75	7.5	80/20	.	2.54	9.83
75	6.0	80/20	.	.	5.54
60	9.0	50/50	.	2.65	9.53
60	7.5	50/50	.	.	6.18
60	6.0	50/50	.	.	2.08
60	9.0	80/20	.	3.76	10.16
60	7.5	80/20	.	0.14	6.90
60	6.0	80/20	.	.	3.00
50	9.0	50/50	.	0.67	7.11
50	7.5	50/50	.	.	4.01
50	6.0	50/50	.	.	0.12
50	9.0	80/20	.	1.75	7.69
50	7.5	80/20	.	.	4.69
50	6.0	80/20	.	.	1.02

[a] The capacity factor is the ratio of total net generation from a plant to the theoretical maximum amount that the plant can generate in a year. The latter is calculated as the product of nameplate capacity and the number of hours in a year (8,760 in a 365-day year).

[b] Average price is total revenues realized divided by total sales.

[c] Debt/equity is the assumed capitalization for mining and processing and residual ash disposal operations. They were discussed at length in Section 9.2.

[d] A "." signifies that the return is less than zero.

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Table 9.11
Sensitivity Results
Alternate Scenarios, Base(2.00) Capital Expenditures
20, 50, and 400 MW Plant Options

Capacity Factor[a] (%)	Average Price[b] (¢/kWh)	Debt/ Equity[c] (%)	Internal Rate of Return[d] 20 MW	50 MW	400 MW
75	9.0	50/50	.	2.66	9.26
75	7.5	50/50	.	.	6.05
75	6.0	50/50	.	.	2.15
75	9.0	80/20	.	3.71	9.86
75	7.5	80/20	.	0.31	6.73
75	6.0	80/20	.	.	3.02
60	9.0	50/50	.	0.41	6.48
60	7.5	50/50	.	.	3.57
60	6.0	50/50	.	.	.
60	9.0	80/20	.	1.41	7.02
60	7.5	80/20	.	.	4.20
60	6.0	80/20	.	.	0.77
50	9.0	50/50	.	.	4.39
50	7.5	50/50	.	.	1.67
50	6.0	50/50	.	.	.
50	9.0	80/20	.	.	4.89
50	7.5	80/20	.	.	2.27
50	6.0	80/20	.	.	.

[a] The capacity factor is the ratio of total net generation from a plant to the theoretical maximum amount that the plant can generate in a year. The latter is calculated as the product of nameplate capacity and the number of hours in a year (8,760 in a 365-day year).

[b] Average price is total revenues realized divided by total sales.

[c] Debt/equity is the assumed capitalization for mining and processing and residual ash disposal operations. They were discussed at length in Section 9.2.

[d] A "." signifies that the return is less than zero.

The results for the Base(2.00) scenario are presented in Table 9.11. The IRR for the 400-MW option exceeds JEA's opportunity cost of capital (9 percent) in the two most favorable scenarios: a 75 percent capacity factor with an average revenue of 9.0¢/kWh. The only cases in which the IRR for the 400-MW option exceeds zero under the tariff structure in existence in 1987 (6¢/kWh) are the ones assuming a 75 percent capacity factor. The 50-MW option is not economically attractive under any of the input assumptions.

9.4.1.4 A closer look at the 50-MW option

Table 9.12 summarizes the results of Tables 9.7 through 9.11 for the 50-MW option. Several comments are in order. First, the 50-MW option is not economically attractive

Table 9.12
Summary of Sensitivity Results
50-MW Plant
(percentages)[a]

Capital Expenditures, Capacity Factor	Average Revenue, Debt/Equity Ratio					
	6.0¢/kWh		7.5¢/kWh		9.0¢/kWh	
	50%	80%	50%	80%	50%	80%
Base(0.75) Scenario						
50 percent	.	.	1.43	3.40	6.62	8.08
60 percent	.	.	3.92	5.92	9.31	10.88
75 percent	.	1.98	7.04	9.16	12.89	14.63
Base Scenario						
50 percent	.	.	.	1.09	3.93	5.21
60 percent	.	.	1.55	3.32	6.28	7.62
75 percent	.	.	4.30	6.15	9.33	10.80
Base(1.25) Scenario						
50 percent	.	.	.	.	2.07	3.23
60 percent	.	.	.	1.51	4.20	5.41
75 percent	.	.	2.41	4.08	6.94	8.24
Base(1.50) Scenario						
50 percent	.	.	.	.	0.67	1.75
60 percent	.	.	.	0.14	2.65	3.76
75 percent	.	.	0.98	2.54	5.17	6.36
Base(2.00) Scenario						
50 percent	.	.	.	.	.	.
60 percent	.	.	.	.	0.41	1.41
75 percent	.	.	.	0.31	2.66	3.71

[a] A "." signifies that the return is less than zero.

under the current tariff structure of JEA under all scenarios. An average revenue of 6.0¢/kWh is not enough to generate an IRR greater than zero under any of the scenarios except one. Second, increasing average revenues by 25 percent to 7.5¢/kWh results in a return greater than 9 percent in only one case in which capital expenditures are 25 percent

less than the base case, the running rate is high, and the mining/processing and ash disposal operations are assumed to be capitalized on a 80/20 debt/equity basis. Third, increasing average revenue by 50 percent to 9¢/kWh leads to significantly better results. Under this case, the returns are greater than zero for all cases assuming 60 and 75 percent running rates and are greater than 9 percent in cases in which capital expenditures are assumed to be relatively low [Base(0.75) and Base scenarios]. However, the table suggests that even under this most optimistic assumption on the level of tariffs, the economic results are very sensitive to the amount of assumed capital expenditures. And, the recent reduction in electricity tariffs in Jordan as part of an economic austerity program does not portend well for increases in electricity tariffs, at least in the near future.

9.4.2 Beyond JEA's Level

The sensitivity study conducted in this report was taken at the individual firm level, that of JEA. There are three important extra-firm benefits — benefits that accrue to the economy or society as a whole — that must also be considered when evaluating the oil shale for power option. One of the most important is the foreign exchange savings resulting from using indigenous oil shale in comparison to importing petroleum or coal. Imported petroleum has been a significant drain on foreign exchange since the international petroleum shocks in the 1970s. Second, mining and processing the oil shale and disposing of the residual ash in comparison with importing coal and/or petroleum will have a significant net impact on employment in the country. The expected number of employees for the integrated operation is significant. For the 20-MW plant, 185 people are expected to be employed, 75 of whom will be used in the mining/processing operation. For the 50- and 400-MW plants, the numbers are 324 (163 in mining/processing) and 1,046 (396), respectively. Finally, there is an energy security benefit to Jordan in terms of using domestic energy in comparison with importing petroleum. The premium that the country places on this difficult-to-quantify, extra-firm benefit — and the foreign exchange and employment benefits — may determine if the plant will be built in the case of it appearing to be economically unattractive from the standpoint of the electricity authority.

APPENDICES

APPENDIX A: FEASIBILITY OF DRAGLINES

A.1 INTRODUCTION

The Bechtel Group mentions that they considered use of a dragline to reduce overburden removal costs. The April site visit by the study team included visitation to the El Abiad Mine to observe, among other objectives, a dragline in operation there and discuss its applicability to the proposed Sultani mining operation. The Bechtel Group concluded in there study that a dragline operation was not appropriate for the Sultani operation – without elaboration or reasons given. ORNL investigated further the potential for dragline(s) operation at Sultani as an alternative to using trucks and shovels for overburden removal. As expressed in Chapter 7, pp. 7-10,11, an official of the JPMC estimated that overburden removal costs could be halved through use of a dragline. Bucyrus-Erie representatives, the vendors supplying the JPMC draglines, also stressed a closer look at the option, based on what they knew of the Sultani plans and their knowledge of the experiences with draglines at the El Hasa and El Abiad mines. The following constitutes this closer examination of the feasibility of using draglines.[1]

A.2 FINDINGS ON THE FEASIBILITY OF DRAGLINES

There are two major factors which dominate any consideration of dragline feasibility at the Sultani mining operation: (1) the immediate and great capital investment required if a single large walking dragline were to be used and (2) the great depth of the box cut that would necessitate removing a large percentage of the material by use of trucks and front-end loaders to the out-of-pit storage area, resulting in additional costs.

If we assume a 50-MW plant as the initial unit, later phased with another 50-MW unit and then three successive additions of 100 MW each until a total of 400 MW of capacity is reached, several scenarios for dragline use can be assessed. The original 50-MW plant would be supplied with fuel made accessible by removing overburden with a loader and truck operation, as suggested by the Bechtel Group. Assuming a 900-shifts-per-year work schedule (as per Bechtel), the economic life of the major units (loaders, dozers, trucks, and scrapers) would require replacement of the entire fleet in approximately 4 1/2 to 5 1/2 years after start-up. During this period, the initial development and box cut would have been completed and an ongoing pit well established. According to the Bechtel Group, approximately $39 million of new capital investment would be needed at that time to replace the older equipment and to purchase new shovels and trucks required for the increased rates of production as the 100-MW units come on stream. Thus, an opportunity would exist at that time to consider phasing in draglines as an alternative to continuing to meet an increased production schedule with truck and shovel technology. The capital investment for the shovel-truck operation would not be exceeded and the objection to opening of the box cut with draglines would be surmounted.

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[1] The analysis described here was conducted by Dr. Samuel Shaw, III, P.E., Golden, Colorado and is based on his report to ORNL, December 198[illegible]

A.2.1 Multiple Small Draglines

The chief remaining question would be the applicability of draglines to the existing restraints of depth and type of overburden, production requirements, dimensions of the pit required for the mining equipment, etc. One way of addressing these questions is the use of two or more smaller draglines. The high capital investment of a single large dragline of sufficient capacity to handle removal of all the overburden would be avoided, smaller draglines would allow a better phasing of the required capital investment as production requirements increased, and production capability could be adjusted as the stripping ratio varied over the life of the mine.

Acquisition of a 31- to 34-m^3 capacity dragline to work in tandem with a smaller crawler-mounted dragline of about 18-m^3 bucket capacity would have a total capital investment (including all costs of transportation, erection, electrics, and buckets) of approximately $16.2 million for the larger machine and $6.5 million for the smaller – a total of $22.5 million.

Prior to the period when the deepest overburden is encountered – about 10 to 12 years into mine operation – a second small dragline could be purchased. This machine could be dedicated to pulling back spoils from the other two machines so that maximum pit depth of about 60 m could be accommodated.[2]

Another possible combination would be to purchase a 50-m^3 walking dragline and team it with the 18-m^3 crawler dragline. The capital investment would be approximately $25.25 million for the larger machine and $6.5 million for the smaller one. With this combination, the second small unit would not be required in those areas having the higher stripping ratios.

A.2.2 Effect of Multiple Small Draglines on Annual Operating Costs

Annual operating costs were computed for each multiple dragline combination and an estimation was made of the change in operating costs of the stripping equipment and various support units that would be replaced by the dragline operation. Similarly an estimate was made of the changed manpower requirements (approximately 88 hourly personnel) and the resultant change in labor costs. Relevant data came from the appropriate tables in the Bechtel Group report.

The respective yearly operating costs of the dragline operations versus those of the shovel and truck operation are displayed in Table A.1.

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[2] There is a relatively small area where the depth of the overburden is 65 m. It is possible, in consideration of the limited extent of this area, that the prestripping of 5 to 10 m might be contracted to local mining companies with machinery scaled to the task.

Table A.1
Annual Operating Costs Compared:
Multiple Draglines vs. Truck and Shovel Technology

Costs	Truck and Shovel ($ million)	One 31- to 34-m^3 Dragline, Two 18-m^3 Draglines ($ million)	One 50-m^3 Dragline, One 18-m^3 Dragline ($ million)
Direct Costs			
Various trucks, shovels, etc.	5.791		
P&H 2355 Dragline		2.080	1.040
P&H 752 Dragline		2.314	
P&H 757 Dragline			3.599
Additional Labor	0.510		
Totals	6.301	4.394	4.639
Difference		-1.907	-1.662
(percent)		-30.3	-26.4
Depreciation	3.405	1.460	1.822
Difference		-1.583	-1.945
(percent)		-46.5	-57.1

A.2.2 Effect of Multiple Small Draglines on Operational Logistics and Safety

Although the use of draglines would result in lowered costs of stripping, other aspects do not appear as favorable. Because of the Sultani site's significant overburden thickness and the great depth of the lower layers of the oil shale deposit, the stability of any spoils piles produced by the draglines must be assured. Depending on the amount and the location of groundwater inflows likely to be encountered in some of the deeper mining, there could be a marked effect on the stability of the spoils. Consideration must be given to the possible effects on the stability of the high spoils banks if the lower portions are saturated, especially at the toes of such spoils piles.

Another significant constraint to dragline use is the 80-m width of the pit as contemplated in the Bechtel Group's design for the truck and shovel operation. The maximum practical

width possible with use of draglines would be more nearly only 30 m. This would greatly reduce the area for maneuvering equipment in the pit bottom, especially that required for the CAT-785 trucks. It is also probable that this width would be insufficient for the effective use of the two continuous miners planned by the Bechtel Group's mining scheme. Probably of equal concern, the reduction in width increases the potential danger from even small slides from either the highwall or the spoil bank. Not long into the development of the mining operation, the pits will increase to significant lengths. This will require the spoil banks to remain stable for comparatively long periods of time so as not to jeopardize the integrity of the main haul road located in the pit bottom.

A.3 CONCLUSIONS

- It would be possible to strip the overburden using multiple draglines with 28- to 34-percent rehandle.
- Use of draglines would reduce unit costs of stripping overburden
- Because of the unusual height of spoil banks and highwalls, presence of groundwater affecting the stability of the spoil banks, plus severe limits on the width of the pit attainable, the safety requirements for equipment and personnel appear to make the use of draglines impractical.
- In addition to the reasons of safety, the great length of the pits will require spoil banks to be stable for comparatively long periods of time to preserve haul roads in the bottom of the pit, and this may not be possible under the conditions noted.
- Consideration should be given to a possible combination of a dragline and a truck and shovel operation. If a truck and shovel operation were used for prestripping, it may be possible to solve the problems of high spoil banks, spoil instability, and narrow pit width and still use the more cost-effective dragline for handling a large proportion of the overburden.

Study of a dragline alternative indicates that although more cost-effective than the shovel-truck concept, their use in moving 100 percent of the overburden is impractical because of safety and operating constraints. It is recommended that additional study be given to the possible design of a mining system incorporating both concepts, utilizing the inherent cost-effectiveness of draglines to the greatest extent possible.