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A PRELIMINARY ECONOMIC FEASIBILITY STUDY FOR THE ESTABLISHMENT OF AN ENERGY-WATER COMPLEX IN THE TULAROSA BASIN

TECHNICAL COMPLETION REPORT
Project No. 3109-401
and BEF Project No. 17

New Mexico Water Resources Research Institute

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New Mexico Water Resources Research Institute
in cooperation with
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Agricultural Experiment Station, NMSU
and
Department of Chemical Engineering,
Engineering Experiment Station, NMSU
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Darrel Gertsch and William Gregory of the Los Alamos Scientific Laboratory acted in an advisory capacity in the research effort and made contributions both in advice to the study group and in data development. Although the research team is solely and totally responsible for statements and conclusions in this report, many people helped in the work.

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A PRELIMINARY ECONOMIC FEASIBILITY STUDY FOR THE ESTABLISHMENT OF AN ENERGY-WATER COMPLEX IN THE TULAROSA BASIN -- AN EXECUTIVE SUMMARY*

This study is a preliminary evaluation of the feasibility of the construction and operation of an industrial, agricultural, and recreational complex in the Tularosa basin. The proposed project involves desalting 500,000 acre-feet of saline groundwater, generating 2,000 megawatts of electricity, and recovering minerals from the reject brine.

Since the major components of the complex were assumed to be publicly financed, benefit-cost analysis was used to determine preliminary feasibility. Environmental risks associated with the energy-water project and social and political inputs were not evaluated. If portions of the complex were located on military lands in the Tularosa basin area, evaluation of the impact on the White Sands Missile Range, Holloman Air Force Base, and the McGregor Range of Fort Bliss would be needed.

The source of energy studied was nuclear power to generate steam for electricity production and desalting. Most of the electricity was to be exported outside the Tularosa basin. A small amount of the production would be required for the increased local demands created by the project.

The desalted water would be used chiefly by irrigated agriculture, with smaller amounts for municipal, industrial, and recreational needs. The water for irrigation would be blended with water from the well field to obtain water of 1,000 parts per million (ppm) dissolved solids, and then discharged to an impoundment reservoir for distribution to the irrigation system. The reservoir would also provide water-based recreation. The proposed location of the reservoir would allow gravity flow to the irrigation system, but the water would have to be pumped to the reservoir.

Minerals recovered from the desalting brine would provide additional benefits from the project. Magnesium, potash, barium, sodium chloride, and magnesium oxide were the primary minerals analyzed for recovery.

Since an energy-water complex of this size has not been built or even planned to use saline groundwater, the design and cost data for desalting sea water were used. These data, mostly from published sources, had to be scaled up or down taking into account the change in feed water (sea to groundwater supplies). Cost data were adjusted to the 1972-1974 period, and applicable technology bases were in the same time frame. The proposed complex was assumed to come on-line in the year 2000.

The study was limited by assumptions to the size of electrical generation capacity, source and type of nuclear facility, quantity of water to be desalted, and the technology of multistage flash evaporation. These assumed values may not be those best suited to a complex in the Tularosa basin. Further research is needed to evaluate this question.

*Principal contributors to this interdisciplinary research effort: Robert R. Lansford, Resource Economist, NMSU; Lynn Gelhar, Hydrologist, NMIMT; Raymond J. Supalla, Resource Economist, NMSU; Marshall Reiter, Geophysicist, NMIMT; William D. Gorman, Agricultural Economist, NMSU; D. B. Wilson, Chemical Engineer, NMSU; Stanley E. Logan, Nuclear Engineer, UNM; Richard Mead, Chemical Engineer, UNM; Allan R. Sanford, Geophysicist, NMIMT; William Schulze, Resource Economist, UNM; Shaul Ben-David, Resource Economist, UNM; Fred Roach, Resource Economist, UNM; Thomas H. Stevens, Resource Economist, NMSU; Bobby J. Creel, Resource Economist, NMSU. Other investigators contributing to the research effort: M. Iqbal Akhtar, Agricultural Economist, NMSU; James Creek, Agricultural Economist, NMSU; James A. Larson, Agricultural Economist, NMSU; Marie Matthews, Agricultural Economist, NMSU; Mark Thayer, Resource Economist, UNM.

WATER RESOURCES

Holloman Air Force Base, White Sands Missile Range, and the City of Alamogordo, the major users of water in the Tularosa basin, are developing limited amounts of available fresh water. The proposed energy-water complex would extract 500,000 acre-feet of water per year containing less than 10 g/l of dissolved solids. Quantity and quality of water were the primary considerations in the selection of a well field. The most promising site is near the eastern side of the basin. Quality of water in this well field was determined from analysis of other wells in the area. The dissolved solids concentration of the water produced from the well field would be about 5,000 parts per million. The drawdown in the well field is estimated to be about 600 feet at 30 years, and the drawdown five miles outside the field is about 12 to 15 feet. Cost estimates to build and maintain a well field to provide 500,000 acre-feet of water per year for 30 years are $98 million for well construction and collection system, $15.6 million for equipment replacement, and $440,000 per year for maintenance.

LAND RESOURCES

An energy-water complex in the Tularosa basin would require land resources for irrigation, urban development, and recreational activities. At present, 88 percent of the land is in public domain and five percent is privately owned. The public land is controlled as follows: Military services, 54 percent; Bureau of Land Management, 16 percent; Forest Service, six percent; National Park Service, four percent; Mescalero Apache Indian Reservation, seven percent; and state of New Mexico, seven percent. Land suitable for the proposed agricultural-energy project would be available.

DESALINATION

An evaluation of current water-desalting technology suggests that a multistage flash desalting plant would best suit the design of the project. Estimated costs are $300 million for construction and capital outlay, and about $13.8 million per year for pretreatment, operation, and maintenance, including a mineral recovery process.

NUCLEAR ENERGY PLANT

Among the different types of nuclear reactors considered as an energy source to produce electricity and desalted water, a steam cycle, high temperature gas reactor was selected as the most suitable. Estimated costs for the construction of such a nuclear energy plant would be about $974 million and about $119 million per year for operation and maintenance.

The seismic risk of installing a nuclear plant in the Tularosa basin was considered minor, but for precaution, the site should be on bedrock. Isolated outcrops of Permian rocks are located about six miles southwest of Tularosa and about 12 miles southwest of Alamogordo.

WATER TRANSPORTATION, STORAGE, AND RECREATION

Since not all water is used as it is produced, the water from the desalination plant would be conveyed to a storage reservoir. The distance from plant to reservoir would be about 10 miles, with an increase in elevation of about 1,000 feet. The cost of a conveyance system is estimated at $50.6 million for construction, about $34.7 million for replacements, and about $506,000 per year for maintenance.

The storage reservoir would need to hold about 250,000 acre-feet of water. Rinconada Creek, northeast of Tularosa, was selected as a suitable site for the reservoir, which would have a range of water elevations from about 5,200 feet (minimum recreational pool) to about 5,500 feet (maximum pool size).

An earthen dam across the canyon would cost about $230.8 million to construct and about $231 thousand per year to operate and maintain. The recreational potential of the reservoir was estimated by using a theoretical demand model, which projected 1,873,152 annual visitors to the proposed lake.

WATER EXPORTATION

The water plan prepared by the State Engineer Office indicates that New Mexico may face extreme shortages of water by the year 2000. Therefore, exportation of the desalted water to the Rio Grande or Pecos River was analyzed. Of three alternatives considered, two for the Rio Grande and one for the Pecos, the Elephant Butte (Rio Grande) exportation plan was selected. Costs would be about $70 million for the conveyance system, $34.7 million for replacements, and about $700 thousand per year for maintenance and operation.

IRRIGATED AGRICULTURE

Costs and returns budgets for selected agricultural enterprises were used in a linear programming model with an objective function to maximize net return subject to water, land, and capital cost constraints. The purpose of this analysis was to determine the maximum amount farmers could pay for irrigation water. This point was determined when the aggregate net return was zero for irrigated agriculture. Increasing the interest rate from five to 10 percent does not drastically affect the cropping pattern or water use but decreases the amount that the agriculture sector can pay for irrigation water from between $55 and $56 per acre-foot to $45 to $46 per acre-foot. The distribution system would cost about $26 million for construction and $206,000 per year for operation and maintenance.

MARKET POTENTIAL FOR ELECTRICITY AND MINERAL BY-PRODUCTS

A demand analysis indicates that market potential may exist for the 2,000 MW of electricity produced by the proposed Tularosa project if the product is competitively priced.

There could be a market for the mineral products to be recovered from the reject brine. The minerals considered were magnesium metal, potash, barium, sodium chloride, magnesium oxide, sodium oxide, and sodium hydroxide. The primary products are expected to be magnesium metal and potash, for which the market potential was derived by a demand equation analysis. Market potential of the other minerals was estimated from an examination of the characteristics of each industry. Estimated costs for construction and capital outlay for mineral recovery facilities are $109 million. Operation and maintenace would run about $27.3 million per year.

PRELIMINARY ECONOMIC FEASIBILITY

Three Alternative project designs at four interest levels were evaluated by benefit-cost analysis.

The first Alternative was the project itself as originally designed for production of 500,000 acre-feet of water and 2,000 megawatts (MW) of electric power from a dual plant (nuclear and desalting) and recovery of certain minerals from the reject brine. All water is to be used within the Tularosa basin by a greatly-expanded agricultural sector and increased municipal and industrial development. Electricity production, after fulfilling project power requirements, will be exported to surrounding areas in the Southwest and only enough to satisfy local needs designated for in-basin use.

The second Alternative was the production of power only. Water production would be limited to an amount sufficient to satisfy cooling requirements. All power produced would be exported to surrounding regions in the Southwest.

The third Alternative comprised equivalent water production, power generation, and mineral recovery. But all water over and above Tularosa basin needs (those that would have occurred without the project) would be exported to the Rio Grande. Only enough water to supply a "without project" local economy would be retained within the basin and all excess from the 500,000 acre-foot production would be transferred. All net power produced (excluding internal requirements) would be exported to other regions in the Southwest.

Four interest or discount rates--five, six, eight, and 10 percent--were used to check the sensitivity of the results to changes in the discount rate. The two lower interest rates (five and six percent) represent rates commonly used for water project evaluations, and the two higher rates are representative of the lower range of publicly funded projects (municipal bonds).

The capital outlay and annual operating cost for each component in the three Alternatives are presented in Table 1. For Alternative 1 (nuclear reactor, desalting, and agriculture), the total capital outlay is $1,788.7 million and the total annual operating costs are $163.7 million. For Alternative 2 (nuclear reactor only), the total capital outlay is $1,037.1 million and total annual operating costs are $119.13 million. Costs of the nuclear plant in this Alternative are higher than in Alternative 1, because the number of turbines for generating was increased to take advantage of available steam. The total capital outlay for Alternative 3 (nuclear reactor, desalting, and water export) is $1,551.3 million and total annual operating costs are $161.34 million.

Sources of benefits for Alternative 1 would be sales of power (local and export), water for in-basin use, and minerals and recreation. Benefits in Alternative 2 would be from the sale of power only. Alternative 3 would derive benefits from sales of power (local and export), water (local and export to the Rio Grande), and minerals. Estimated benefits from mineral sales are $67.702 million and from recreation, $3.746 million. The value of water is estimated at $50 per acre-foot for local municipal and industrial uses, and $90 per acre-foot for export. Total benefits from water sales vary over the life of the project due to changes in amounts used by the different sectors.

The price of power was calculated on the basis of estimated cost of a coal-fired plant. For export, the price varies from $9.44 per MW at a discount rate of five percent to $10.06 at six percent, $11.38 at eight percent, and $12.79 at 10 percent. The price to local municipal and industrial users ranges from $10.38 per MW at five percent discount to $11.07 at six percent, $12.52 at eight percent, and $14.07 at 10 percent. Total benefits from the sale of electricity also vary over the life of the project according to the number of municipal and industrial users and the power requirements for pumping water.

Results of the analysis of the above costs and benefits are reported in Table 2. For the project to be feasible, the net benefits must be greater than or equal to zero and the benefit-cost ratio must be equal to one or more. The complete energy-water complex, Alternative 1, appears to be infeasible for two primary reasons:

Table 1. Capital outlays and annual operation costs for the cost components for the benefit-cost analysis for each alternative, Tularosa basin project, New Mexico

Cost Component	Total Capital Outlay Costs (million $)	Annual Operating Costs (million $)
Alternative 1--Nuclear Reactor, Desalting, Agriculture		
Nuclear plant	974.0	119.1
Desalting plant	300.0	13.8
Well field	98.0	0.4
Water delivery (plant to reservoir)	50.6	0.5
Agricultural distribution system	26.0	0.3
Reservoir	230.8	2.3
Mineral recovery	109.3	27.3
Total	1,788.7	163.7
Alternative 2--Nuclear Reactor Only		
Nuclear Plant	1,028.0	119.10
Well field	9.1	0.03
Total	1,037.1	119.13
Alternative 3--Nuclear Reactor, Desalting, Water Export		
Nuclear plant	974.0	119.10
Desalting plant	300.0	13.80
Well-field	98.0	0.44
Mineral recovery	109.3	27.30
Water export canal	70.0	0.70
Total	1,551.3	161.34

First, desalting technology at present is capital intensive and too costly in comparison to any reasonable projections of water values to allow feasibility even when waste heat from power production is available. Feasibility would require an increase in the value of water to $221 per acre-foot for agricultural, municipal, and industrial uses at a six percent discount rate.

Second, the capital costs and power drawdowns associated with storing water for agriculture are prohibitive in relation to the potential value. In Alternative 3, the value of water exported to the Rio Grande needs to be $187 per acre-foot to achieve feasibility. This value approaches minimum system cost of $149 per acre-foot for producing desalted water, excluding transportation costs.

Projected local uses of water cannot justify production of desalted water at this cost. Desalting, even with a dual nuclear plant and mineral recovery facility, is not economically feasible with current technology on the scale proposed for the Tularosa basin. The prospect of nuclear power production using brine water for cooling (Alternative 2) may prove feasible and the possible construction of a nuclear energy park in the Tularosa basin may merit further investigation. This decision would depend chiefly on environmental risks not evaluated in this preliminary study.

Table 2. Results of the benefit-cost analysis for Alternatives 1, 2, and 3, for the Tularosa basin project, New Mexico

Discount Rate	Net Benefits	Benefit-cost Ratio
	- - - - -(millions of dollars)- - - - -	
Alternative 1--Nuclear reactor, Desalting, Agriculture		
5	-986.570	0.508
6	-1,012.340	0.505
8	-1,076.415	0.494
10	-1,137.528	0.486
Alternative 2--Nuclear reactor only		
5	57.723	1.050
6	84.421	1.072
8	110.042	1.090
10	132.317	1.105
Alternative 3--Nuclear reactor, Desalting, Water export		
5	-382.527	0.779
6	-424.824	0.758
8	-509.777	0.719
10	-578.612	0.693

Net contributions of the individual components to the overall project were also analyzed and tabulated. To facilitate analysis, the price of water was allowed to vary to the point where the project would just break-even--all costs covered. The basic configuration only considers costs associated with the nuclear plant, well field, and desalting plant (Table 3). Water would have to be priced to all users as indicated in the table at the various interest rates to just break-even.

When a mineral recovery process is added to the basic configuration, costs and benefits increase. Benefits from mineral sales lower prices of water substantially (at six percent, for example, \$149 per acre-foot as opposed to \$191 per acre-foot). The price of water to all users would change as delineated in Table 3 and all costs would be just recovered.

The third configuration combines the three components (nuclear plant, well field, and desalting plant) of the basic configuration with the storage reservoir and the plant-to-reservoir conveyance system. All costs and the benefits from recreational use of the reservoir are included. The price of water would have to be as shown in Table 3 for the project to break-even. If mineral recovery is added to this water configuration, total costs and benefits increase, therefore the break-even price of water would be somewhat lower (\$205-\$159 at the five percent interest rate).

When the exportation of water to the Rio Grande is included in the basic three-component configuration, the capital, operating, and maintenance costs are increased somewhat. The break-even prices of water without mineral recovery and with mineral recovery added are presented in Table 3. Since the price with mineral recovery is lower in all configurations, the net contribution of this component is important.

Table 3. Break-even water prices at selected interest rates for basic and enlarged project configurations

Interest Rate	Basic Configuration	Enlarged Configurations-Basic Plus				
		Mineral	Water	Mineral-Water	Export Water	Mineral-Export
(percent)	(dollars per acre-foot)					
5	183	138	205	159	217	173
6	191	149	215	173	228	187
8	212	177	240	204	254	223
10	238	212	269	247	281	256

SUMMARY OF RESULTS AND CONCLUSIONS

There is little chance under current Nuclear Regulatory Commission procedures that a nuclear plant would be licensed in the Tularosa basin because it would not be compatible with the White Sands Missile Range. The economic analysis did not consider the loss in value of canceling or modifying WSMR activities as an opportunity cost of constructing an energy-water complex.

The major findings and recommendations of this study are summarized below.

Summary Results

- DESALTING WATER IN THE TULAROSA BASIN ON THE PROPOSED SCALE OF 500,000 ACRE-FEET PER YEAR IS NOT ECONOMICALLY FEASIBLE.
- PRODUCTION OF NUCLEAR POWER WITH BRACKISH WATER FOR COOLING APPEARS MARGINALLY FEASIBLE IF CUMULATIVE ENVIRONMENTAL COSTS ARE NOT TOO SEVERE.
- LAND FOR DEVELOPMENT OF AGRICULTURE, INDUSTRY, AND MUNICIPAL NEEDS IS NOT A LIMITATION, BUT ACQUISITION OF THE MORE SUITABLE LAND IN MILITARY USE WOULD PRESENT PROBLEMS.
- ANALYSIS OF THE MARKET POTENTIAL FOR ELECTRICITY PRODUCED IN THE TULAROSA BASIN INDICATES THAT 47,000 MW(E) WILL BE NEEDED FOR THE SOUTHWEST BY 1990, BUT IF THE PRICE INCREASES BY 3.5 PERCENT PER YEAR, ADDITIONAL REQUIREMENTS WOULD BE LIMITED TO REPLACEMENT CAPACITY.
- THE FEASIBILITY OF MINERAL BY-PRODUCT SALES DEPENDS ON TRANSPORTATION COSTS TO MARKET AND POTENTIAL RECOVERY OF CERTAIN MINERALS, BUT EVEN SUBSTANTIAL SALES WOULD ONLY PARTIALLY OFFSET THE HIGH COST OF DESALTED WATER.
- THE ANALYSIS OF THE PROPOSED WELL FIELD WAS BASED ON AN OPTIMISTIC EVALUATION OF EXISTING VERY LIMITED HYDROLOGIC DATA: ACTUAL COST COULD BE SUBSTANTIALLY HIGHER AND OTHER SITES MAY PROVE TO BE MORE FAVORABLE.
- DATA ON THE GEOTHERMAL POTENTIAL OF THE TULAROSA BASIN ARE INSUFFICIENT TO EVALUATE THIS POTENTIAL SOURCE OF ENERGY FOR DESALTING WATER.

- Exportation of desalted water from the Tularosa basin is economically infeasible until the price of water increases, but appears to be a more likely alternative than local use for agriculture because of higher-valued uses in the Rio Grande or Pecos River basins.

Summary Recommendations

- An extensive program of hydrologic data collection, analysis, and modeling will be required for detailed evaluation and design of the proposed well field.
- A similar program of data collection and analysis should be considered to assess the geothermal potential of the Tularosa basin.
- The comparability of the proposed nuclear desalination complex or of an energy park with current military activities in the project area should be evaluated.
- Potential legal barriers to land acquisition should be investigated.
- Alternative desalination technologies and a nuclear energy center including dual-purpose facilities should be evaluated. High-value uses for variable quantities of desalted water may justify some dual-purpose capability.
- Alternative technologies, including solar and geothermal energy for the potential use of the saline water resources of the Tularosa basin should be explored.

A PRELIMINARY ECONOMIC FEASIBILITY STUDY FOR THE ESTABLISHMENT OF AN ENERGY-WATER COMPLEX IN THE TULAROSA BASIN*

CHAPTER I

INTRODUCTION

The purpose of this study was to determine the "preliminary feasibility" of the construction and operation of an industrial, agricultural, recreational complex based on desalting 500,000 acre-feet of saline groundwater, generating 2,000 megawatts of electricity, and recovering minerals from the saline water in the Tularosa basin of New Mexico. No assessment was made of environmental costs or risks with the construction of the energy-water complex in the Tularosa basin, hence the analysis is incomplete and therefore termed preliminary.

The Tularosa basin project is a plan for construction and operation of a nuclear powered energy-industrial-agricultural complex based on desalting groundwater in southern New Mexico. Plant components are larger than any previously incorporated into a single unit in the world. This research addresses two critically important national needs. The first is the development of energy resources in the area, and the second is to significantly augment the quantity of water in the southwest. Every state in the intermountain and southwest area except one has a net deficit of water to satisfy the projected needs to the end of the century for energy development, agriculture, municipal growth, and wildlife protection (Figure 1).

The location of the proposed Tularosa basin complex has many unique essential features for such a proposed development. The primarily favorable features are: (1) sparse population--the development would not require the re-location of very many family units; (2) a large quantity of unused saline groundwater that could be used for development of the area; (3) large areas of state and federally owned lands which facilitate the development of a large irrigation project because of the small number of owners involved; (4) a favorable climate for agricultural development; and (5) the proximity to population and agro-industrial centers of the Rio Grande and Pecos River basins.

However, there are two serious problems with the location. First, the building of a nuclear energy plant within or adjacent to White Sands Missile Range may raise safety questions. In addition, locating part of the water well field and development of some irrigated cropland within the boundaries of Holloman Air Force Base, the White Sands Missile Range, and McGregor Range of Fort Bliss may be cause for concern from a national defense point of view.

*Principal contributors to this interdisciplinary research effort: Robert R. Lansford, Resource Economist, NMSU; Lynn Gelhar, Hydrologist, NMIMT; Raymond J. Supalla, Resource Economist, NMSU; Marshall Reiter, Geophysicist, NMIMT; William D. Gorman, Agricultural Economist, NMSU; D. B. Wilson, Chemical Engineer, NMSU; Stanley E. Logan, Nuclear Engineer, UNM; Richard Mead, Chemical Engineer, UNM; Allan R. Sanford, Geophysicist, NMIMT; William Schulze, Resource Economist, UNM; Shaul Ben-David, Resource Economist, UNM; Fred Roach, Resource Economist, UNM; Thomas H. Stevens, Resource Economist, NMSU; Bobby J. Creel, Resource Economist, NMSU. Other investigators contributing to the research effort: M. Iqbal Akhtar, Agricultural Economist, NMSU; James Creek, Agricultural Economist, NMSU; James A. Larson, Agricultural Economist, NMSU; Marie Matthews, Agricultural Economist, NMSU; Mark Thayer, Resource Economist, UNM.

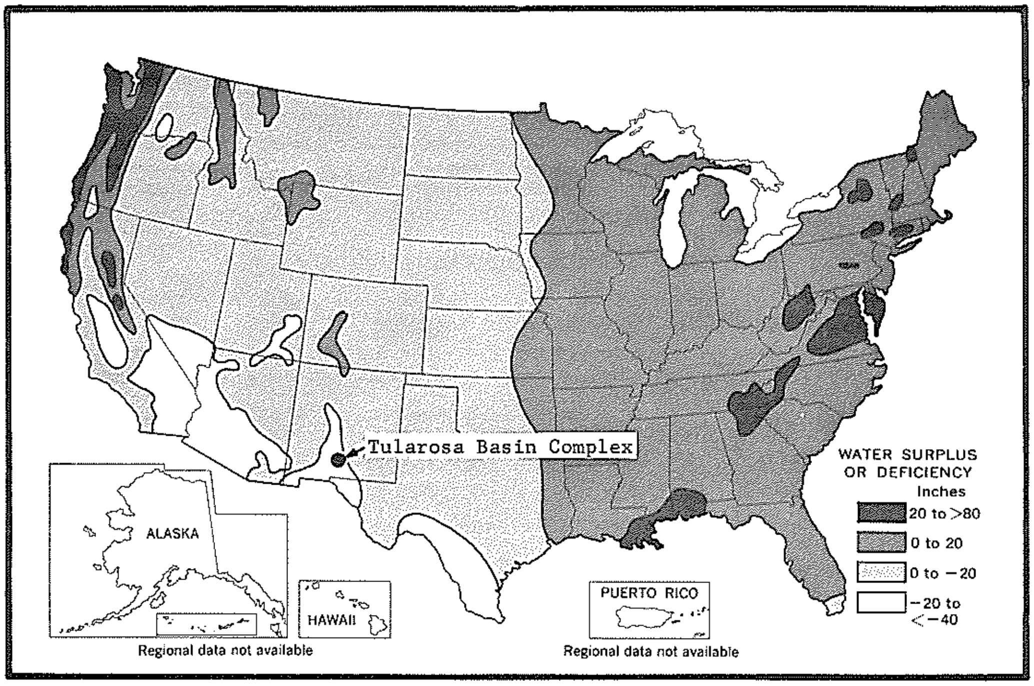

Figure 1. Areas of natural water surplus and natural water deficiency.

Source: U. S. Water Resources Council, *The Nation's Water Resources*, U. S. Government Printing Office, 1968, p. 3-2-4.

CONCEPTUAL FRAMEWORK

The original design of the research endeavor to desalt large amounts of saline groundwater, generate large amounts of electric power, and recover several million tons of valuable minerals each year was conceived by personnel at Los Alamos Scientific Laboratory (LASL) in about 1968 (Reinig, June 1973). A proposal to conduct a feasibility study, to determine the potential of such a project, was then prepared jointly by the Los Alamos Scientific Laboratory and the New Mexico Water Resources Research Institute in cooperation with New Mexico State University, University of New Mexico, and New Mexico Institute of Mining and Technology. This proposal was submitted to the United States Atomic Energy Commission and other federal agencies for possible funding about the time federal energy research was being consolidated and reorganized into the Energy Research and Development Administration.

A research project was funded by the New Mexico Board of Educational Finance (BEF) based on a portion of the above proposal. The project funded by BEF envisioned generating 2,000 megawatts of electricity, desalting one-half million acre-feet of brackish groundwater, and recovering minerals from the brine (Figure 2). The source of energy was limited to a nuclear power plant generating steam for electricity production and desalting. The electricity produced was expected to be primarily exported from New Mexico. A small quantity of electricity will be required for the increased local demands induced by the project.

The desalted water in the BEF sponsored study would be used primarily by irrigated agriculture with smaller amounts required for municipal, industrial, and recreational purposes. The water for irrigation would be obtained by blending water from the well field with desalted water at the rate of 1,000 parts per million (ppm). A reservoir would be required to store excess desalted water during some portions of the year for later use. The reservoir would provide water-based recreation in addition to impoundment. Electricity would be required to pump water from the desalting plant to the reservoir.

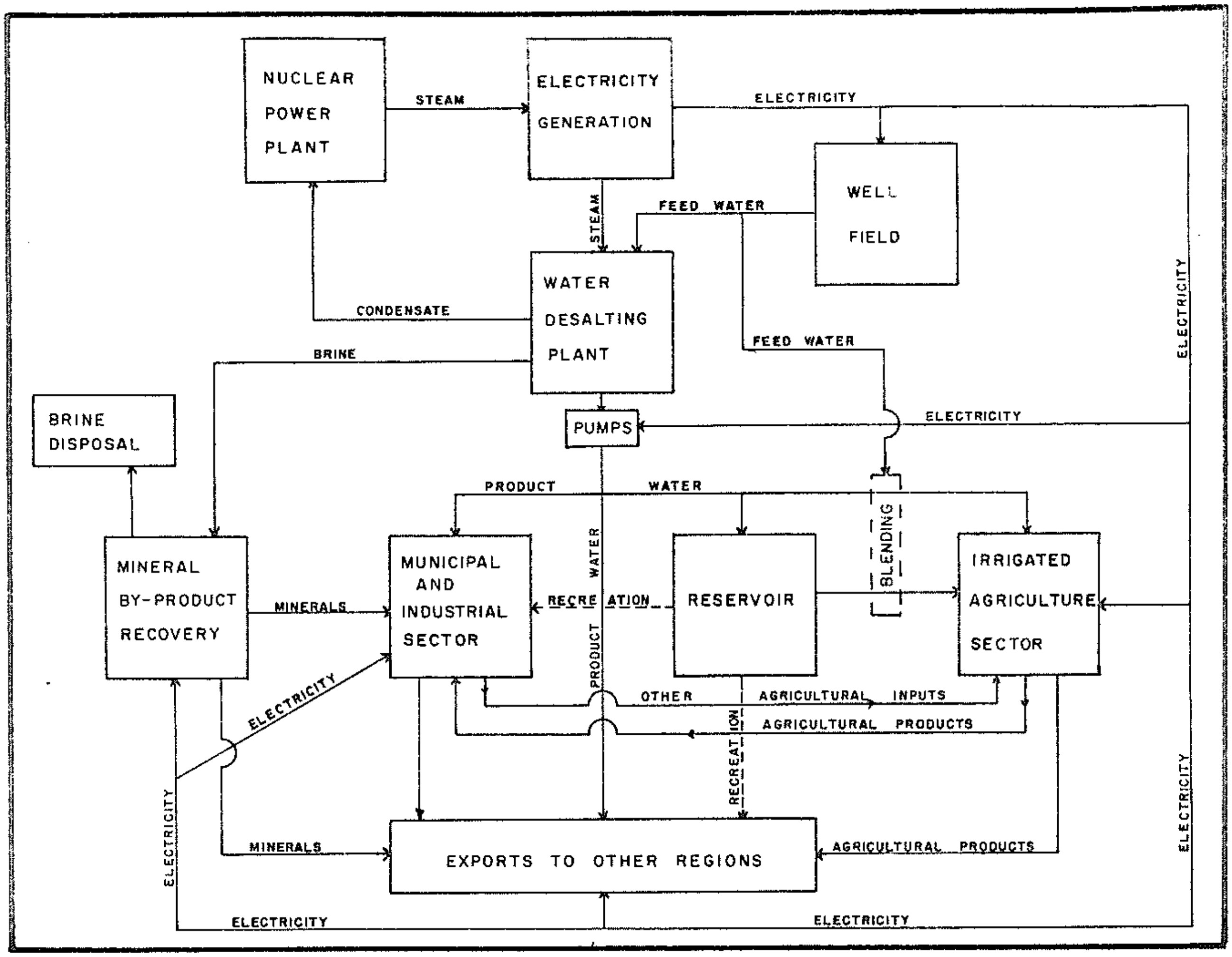

Figure 2. Schematic of proposed Tularosa basin energy-water complex.

It was expected that minerals would be recovered from the desalting brine providing additional project benefits. The primary minerals for recovery were expected to be magnesium, potash, sodium chloride, and magnesium oxide.

OBJECTIVES

The primary objective of this study was to obtain a preliminary evaluation of the economic feasibility for a proposed nuclear-desalting complex in the Tularosa basin of New Mexico producing 2,000 megawatts of electricity and desalting a half-million acre-feet of saline groundwater. To accomplish this objective, an engineering-economic benefit-cost analysis was used in the evaluation of the complex. The benefit-cost analysis requires detailed estimates of primary benefits and costs. Estimates of the following benefits and technology costs were made:

1. Benefits
   a. Electricity
   b. Water
   c. Agriculture
   d. Minerals
   e. Recreation

2. Costs and Technology
    a. Energy, nuclear
    b. Groundwater and extraction
    c. Desalting technology and cost
    d. Mineral by-product recovery, technology and cost
    e. Agricultural production
    f. Storage reservoir
    g. Water export alternatives

In addition, separate area studies were required on the land resource, ground-water resource, and the economy of the Tularosa basin in New Mexico.

METHODOLOGY

The primary analytical method utilized in this study is benefit-cost analysis. Benefit-cost analysis is a method widely utilized by the public sector to determine the economic efficiency impact of investment alternatives. Costs are defined as the value of resources in alternative uses while benefits are defined as the value of output to consumers. If benefits equal or exceed costs, the value of the output produced is equal to or greater than the value of resources invested, and the investment is efficient.

Benefit-cost analysis assumes that the relevant budget constraint consists of both the initial investment cost and annual operating expenses. Other investment criteria, such as the internal rate of return, assumes that the relevant budget constraint consists of the initial investment expenditure only (Eckstein, 1958; McKean, 1958). In the case of a typical private enterprise, investment capital is usually the constraining factor. Hence, internal rate of return analysis is the preferred criteria used to evaluate private sector investment alternatives. In the case of public projects, the total federal budget is viewed as the appropriate budget constraint (Eckstein, 1958). Thus, benefit-cost analysis is the preferred investment criteria for the evaluation of public projects. For purposes of this study, public financing of several of the major components of the Tularosa energy-water complex is assumed.

The benefit-cost analysis was used to evaluate three alternative project designs at four interest levels. The first was the project itself as originally designed: production of 500,000 acre-feet of water and 2,000 megawatts (MW) of electrical power from a dual-plant (nuclear plant coupled with desalting plant) as well as the subsequent recovery of certain minerals from the reject brine. All water production is to be utilized within the Tularosa basin by a greatly expanded agricultural sector and increased development of the municipal and industrial sectors. Electricity production (after satisfying internal project power requirements) will be primarily exported to surrounding regions in the Southwest, with only enough designated for the basin (excluding internal requirements) to satisfy local needs.

The second Alternative was the production of power <u>only</u>. Water production would be limited to an amount sufficient for satisfying cooling requirements. All power produced would be exported to surrounding regions in the Southwest.

The third Alternative was similar to the first in that water production, power generation, and mineral recovery are equivalent. However, all water over and above Tularosa basin needs (those that would have occurred without the project) is to be exported to the Rio Grande. Only enough water to supply a "without project" local economy will be maintained within the basin. All excess water remaining from the 500,000 acre-foot production is to be transferred. All net power produced (which excludes the internal requirements) is to be exported to other regions in the Southwest.

The four interest or discount rates chosen were five, six, eight, and 10 percent. The two lower interest rates (five and six percent) were chosen to represent rates commonly used for water-project evaluations, and the two higher interest rates are representative of the lower range of publicly funded projects (municipal bonds). This range of interest rates permitted analyzing the sensitivity of the results to changes in the discount rate.

Separate area studies have been developed for each of the sub-objectives. These studies provide input into the overall engineering-economic feasibility study as well as being substantive investigations of each topic.

A short research methodology section is included in each of the various study areas so the reader can keep the methodology used in that section of the report fresh in mind.

LIMITATIONS

This was primarily an engineering-economic feasibility study, therefore, environmental, sociological, anthropological, and political impacts of an energy-water complex were not considered in this study. If the preliminary assessment indicates feasibility, then the environmental, social, and political inputs of the complex should be evaluated. The impact of the energy-water complex on the White Sands Missile Range, Holloman Air Base, and McGregor Range of the Fort Bliss Military Reservation will have to be evaluated if portions of the complex are to be located on these military lands.

Because an energy-water complex of this size has not been constructed or even planned using saline groundwater, most of the available design and cost data were for desalting sea water and had to be scaled up or down to take into account the change in feed water (sea to groundwater supplies) for the desalting plant. All cost data were adjusted to the 1972-1974 time period. Applicable technology bases were in this same time frame, with the proposed complex assumed to come on-line in the year 2000.

Major limitations of this study (other than environmental, sociological, and political) are the fixed assumptions on size of electrical generation capacity, source and type of nuclear facility, quantity of water to be desalted, and the technology of multistage flash evaporation. Because of the assumptions used, the project envisioned may not be an optimal size for the Tularosa basin. Further research is needed to evaluate these questions.

ORGANIZATION OF REPORT

Chapter II presents a general description of the Tularosa basin including physical and socioeconomic factors. Chapter III is a review of the natural resources of the Tularosa basin. It covers existing water development, water quality, well quality, well-field site selection, water extraction, and cost estimates, land resources, current land ownership and use, land use feasibility, and project land use. Chapter IV covers the evaluation of desalination and electricity generation alternatives. Chapter V discusses water transportation, the reservoir characteristics and costs, and the recreation potential. Chapter VI discusses water exportation alternatives. Chapter VII discusses local municipal and industrial potential generated from the energy-water complex. Chapter VIII discusses the potential for irrigated agriculture using desalted water. Chapter IX discusses the export market potential for the electricity generated from the complex. Chapter X discusses market potential for the mineral recovery phase of the complex. Chapter XI combines date from the previous chapters into a preliminary analysis of economic feasibility under three alternatives: (1) the entire energy-water complex; (2) electrical generation without desalting; and (3) electrical generation, desalting, and exporting the desalted water to an adjacent river basin. Chapter XII presents conclusions and recommendations for further research.

CHAPTER II

BASIN DESCRIPTION

From a river basin viewpoint, the Tularosa basin is a part of the Rio Grande system; however, for purposes of this study, the Tularosa basin only includes that portion of the Tularos basin within Otero County because project primary benefits and costs will occur in the Otero County portion of the basin (Figure 3). Adjacent areas are taken into account in relevant export considerations.

The Tularosa basin is an elongated desert valley covering some 6,500 square miles of south central New Mexico. The basin is bounded on the east by the Hueco and Sacramento Mountains; on the west by the Franklin, Organ, and San Andres Mountains; on the north by a broad, high topographic divide and on the south by a subtle divide which separates it from the Hueco Bolson in Texas. Land-surface altitudes within the basin range from 3,900 feet in the alkali playa flats to over 12,000 feet in the bordering mountain peaks. The basin floor slopes gently southward and contains numerous depressions. This basin has no surface outlet; as a result, the depressions become temporary lakes during the rainy season and alkali flats during the dry season.

The following sections of this chapter are presented to give the reader a feeling for the current status of resource use and availability in the Tularosa basin.

CLIMATE

The climate in the Tularosa basin is typical of the arid to semi-arid regions of the southwestern United States. Table 1 presents a summary of climatic information for the Alamogordo, Tularosa, Cloudcroft, and Orogrande stations. Alamogordo, Tularosa, and Orogrande are typical of the central portion of the basin and Cloudcroft is typical of the bordering mountains. The mean annual precipitation in the basin ranges from 8.8 inches in the central portion of the basin at Orogrande to 25.4 inches at Cloudcroft in the bordering mountains. Precipitation on the slopes of the surrounding mountains produce intermittent stream runoff that drains toward the center of the basin, or moves as ground-water flow through the alluvial fans as interflow. The intense summer thunderstorms produce high runoff of short duration, most of which flows into the playas or alkali flats and evaporates.

Temperatures in the basin range from an average of about 61 degrees F. in the central portion of the basin to about 45 degrees F. in the bordering mountains (Table 1).

GEOLOGY

The large central part of the basin is underlain by unconsolidated bolson sediments of Quaternary age; these sediments consist of material deposited in lakes in the center of the basin and of alluvial sediments deposited around the lake sediments by streams that once fed the lakes. Lacustrine sediments in the basin consist mainly of minutely bedded silt and clay with large amounts of secondary gypsum. Because of the gypsum, groundwater in the lake sediments is high in dissolved-solids content.

The alluvium, in contrast with the lacustrine sediments, is very poorly sorted, and consists of sand, gravel, silt, and clay. It tends to be coarsest near the base of the mountains surrounding the basin and becomes finer toward the basin center.

Paleozoic, Mesozoic, and early Cenozoic (Tertiary) formations crop out in mountainous

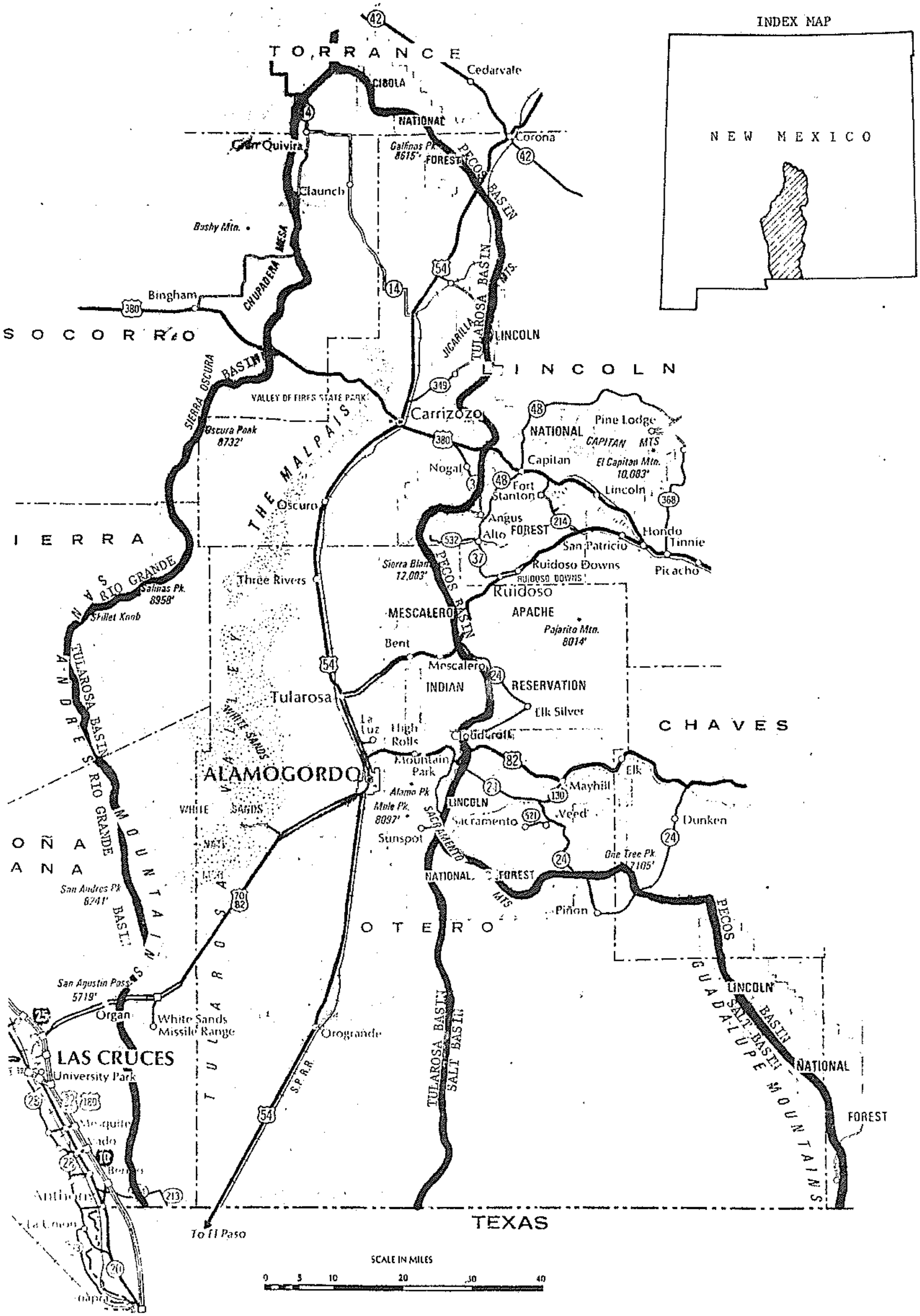

Figure 3. Map of the Tularosa basin, New Mexico

Table 1. Selected climatic data for stations within the Tularosa basin, New Mexico

	Units	Alamogordo[a]	Tularosa[a]	Orogrande[b]	Cloudcroft[b]
Elevation (above MSL)	feet	4,350	4,460	4,200	8,827
Average days above 32°F.	days	209	211	NA	NA
Average frost-free period	date	Apr. 7-Nov. 2	Apr. 4-Nov. 1	NA	NA
Mean annual precipitation	inches	9.8	10.1	8.8	25.4
Maximum mean monthly air temp.	mo-°F.	Jul.-79.7	Jul.-80.4	Jul.-81.5	Jul.-59.9
Minimum mean monthly air temp.	mo-°F.	Jan.-42.0	Jan.-43.4	Jan.-42.0	Jan.-30.0
Average annual air temp.	°F.	61.3	61.7	61.9	45.0

NA: not available

[a] New Mexico Interstate Stream Commission and New Mexico State Engineer Office, *County Profile-Otero County, Water Resources Assessment for Planning Purposes*, Santa Fe, New Mexico, 1975, pp. 12-13.

[b] U. S. Department of Commerce, NOAA-EDS, *Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1941-70*, Climatography of the U. S. No. 81 (by state), National Climatic Center, Asheville, N. C., August 1973.

areas surrounding the basin and underlie the unconsolidated Quaternary bolson deposits that floor the basin. Here and there older rocks protrude upward through the bolson deposits. Usually the older rocks are much less permeable than the bolson sediments and yield much smaller quantities of water to wells. Locally, however, the rocks may be highly permeable where fractured or, as in the case of limestones, where honeycombed by solution channels. The quality of groundwater contained in bedrock aquifers is highly variable, depending on the soluble mineral content of the containing rocks.

Intrusive rocks crop out locally, forming relatively small parts of mountain masses around the basin. Among the larger intrusive masses in the area are those of Sierra Blanca and vicinity on the east side of the Tularosa basin and the Organ Mountains on the southwest side of this basin; other examples are the Jicarilla Mountains and Gallinas Peak on the northeast side of the Tularosa basin, the Jarilla Mountains in southern Tularosa basin, and the Cornudas Mountains in the Salt basin (Figure 3).

Extrusive igneous rocks constitute an important part of the Tertiary stratigraphic sequence in the Tularosa basin. Quaternary basalt flows in the northern part of the Tularosa basin also have extrusive igneous origins.

SOILS AND VEGETATION

In general, soils near mountains are light and soils in the broad valleys at some distance from the mountains (or near outcrops of clay or shale) are heavier. Caliche (secondary carbonate cement) is frequently found in soils in the area.

The major soil associations in the Tularosa basin are the Pintura-Hueco-Wink, Yesum-Holloman, Reakor-Russler, Pintura-Dona Ana-Berino, and Gypsum (Maker, Derr, & Anderson, 1972). The primary use and potential of these associations are:

Soil Association	Present Use	Irrigation Potential
Pintura-Hueco-Wink	Range and Military Reservation	Suitable
Yesum-Holloman	Range and Military Reservation	Very limited
Reakor-Russler	Irrigated farming, range, and Military Reservation	Favorable
Pintura-Dona Ana-Berino	Range and Military Reservation	Suitable for sprinkler
Gypsum	Range, Military Reservation, and National Monument	None

The Reakor-Russler soil association offers the best possibilities for expansion of irrigation in the basin and consists of approximately 270,000 acres located in narrow flat alluvial valley areas at the base of the Sacramento Mountains (Figure 4). The Pintura-Hueco-Wink soil association comprises an area of approximately 323,000 acres in the extreme southern portion of the basin and offers suitable lands for irrigation. The Pintura-Dona Ana-Berino soil association includes a large area, consisting of about 249,000 acres in the central part of the basin dominated by sandy gently rolling to duny soils. These soils have a favorable potential for sprinkler irrigation. The Yesum-Holloman soil association is located typically on a bench below the Reakor-Russler soils composed of gypsiferious and saline valley-filling sediments. This association offers very little if any potential for irrigation development.

The life zones (Bailey, 1913) in the basin range from Lower Sonoran to Canadian, or possibly Hudsonian. Playas and salt flats have little or no vegetation. Except for the playas, lower elevations are overgrown with grass or brush. At progressively higher elevations are pinion-juniper associations, a Transition zone of ponderosa pine and juniper, a spruce-fir association, and, finally, above an altitude of 11,000 feet, a possible subarctic association that includes arctic willow.

HYDROLOGY

Surface Water

Nowhere in the Tularosa basin is there a large supply of surface water. Most runoff occurs as floodflow following local rains. The Tularosa basin has perennial flow only from the flanks of Sierra Blanca in the vicinities of Alamogordo, Three Rivers, and Tularosa; sketchy streamflow records from these areas constitute the only gage records in the entire area.

Groundwater

Aquifers in the Tularosa basin may be grouped into two broad categories: bolson deposits and "bedrock." In general, the bolson deposits are unconsolidated to poorly consolidated. Alluvial sediments form the bulk of bolson deposits. Bolson alluvium is the most reliable aquifer in the Tularosa basin. Where the alluvium has adequate thickness, it is usually a reliable source of groundwater. The quality of water in the alluvium ranges from good to poor, with saline water occurring generally in areas near the zone where alluvium interfingers with the lake sediments and to areas where recharge to alluvium is from older rocks containing highly mineralized water. At the headquarters area of White Sands Missile Range in the Tularosa basin, wells that yield over 1,000 gpm have been constructed. Similar yields may be obtained elsewhere in the basin. In general, the more productive wells are in a relatively narrow zone around the

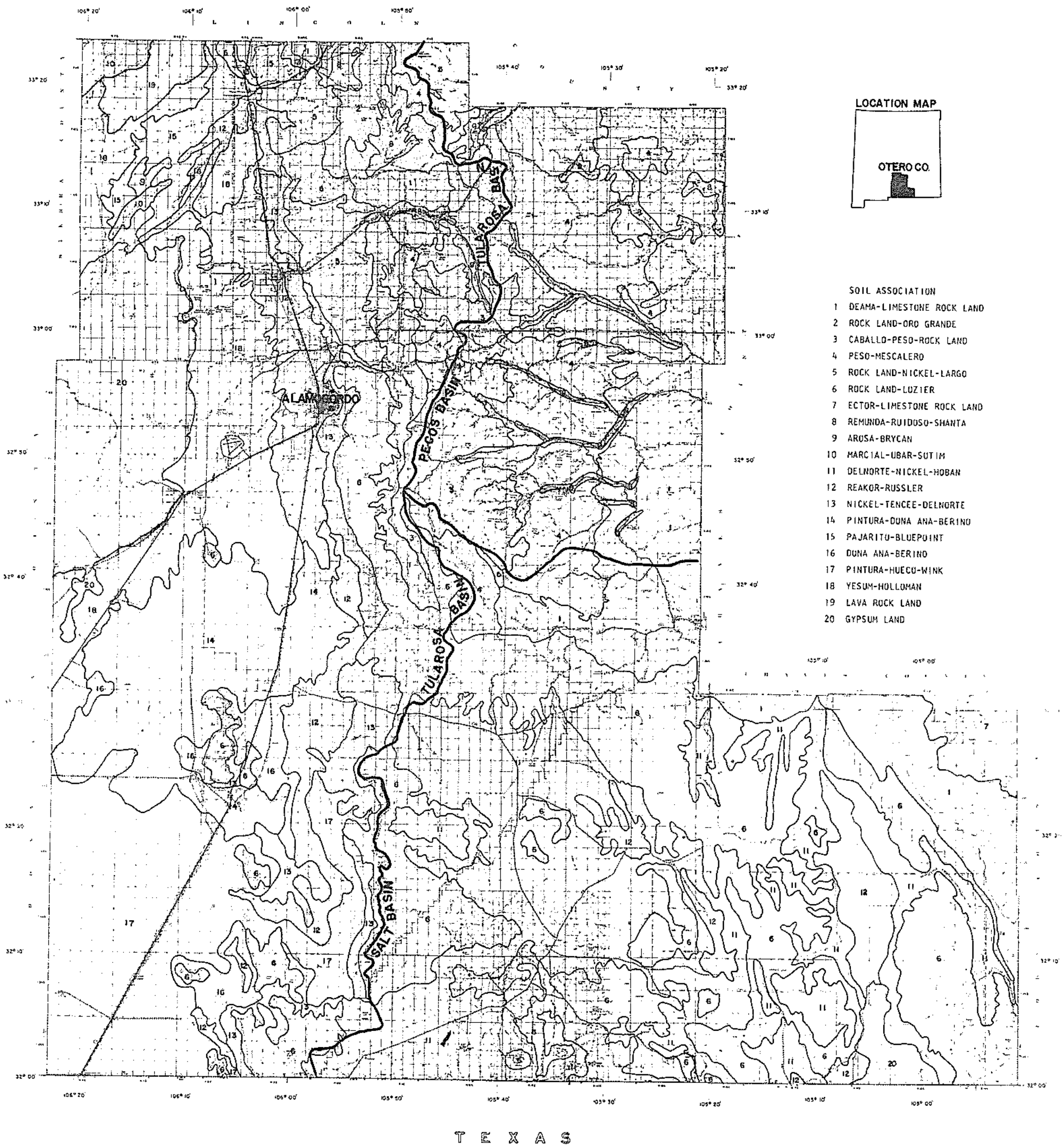

Figure 4. General soil map of Otero County, New Mexico.

sides of the basin, far enough from the outcropping bedrock to penetrate a thick section of coarse-grained alluvium, but sufficiently far from the basin center to avoid the poor-quality groundwater that is typically there.

The chemical quality of groundwater in the Central closed basins is highly variable. Quality of water in aquifers reflects types of soluble minerals in the rocks. For example, water in many of the Cretaceous and Permian formations contains large amounts of sulfate, derived from gypsum in the rocks, whereas water in the Triassic formations commonly contains more chloride than sulfate. Other strata of the bedrock formations also frequently contain water, the dissolved-solids content of which is high. Under certain conditions, usually near the outcrop areas where recharge occurs, most formations may contain groundwater that is potable owing to: (1) flushing of mineralized water from the aquifer, (2) the short length of time that the water has been in contact with soluble minerals, or (3) the fact that soluble minerals have been previously dissolved out by weathering.

Water in the bolson sediments is also highly variable in chemical quality. In general, groundwater from the central parts of the basin is highly saline. Sulfate and chloride are the most common contaminants. Sulfate commonly predominates over chloride although in most saline water both are in excess of limits set for potability. Groundwater from parts of Tularosa basin contains more than 6,000 ppm of sulfate. Almost all of the alluvial deposits in the Tularosa basin contain brines with dissolved solids content greater than 35 gallons/liter (g/l) (see Chapter III, Water Quality section).

In Tularosa basin, potable water is mostly restricted to the southwest side and to the east side in the vicinity of Alamogordo. Groundwater of good to inferior quality may be obtained northward from Alamogordo along the basin's east side. Small patches of potable water may be found elsewhere in the basin.

WATER USE

Water in the Tularosa basin comes from surface sources, underground sources, and combinations of the two. The estimated withdrawals and on-site depletions of water by sector for Otero County and the Tularosa basin within Otero County are presented in Table 2. Agriculture accounts for about 81 percent of Otero County's total withdrawals and about 79 percent of the depletions, urban water requirements account for approximately nine percent of the withdrawals and eight percent of the depletions in Otero County with military being the third largest water-using sector requiring approximately six percent of the county's withdrawals and about eight percent of the depletions. The withdrawals and depletions within the Tularosa basin are similar to those within Otero County with irrigated agriculture accounting for about 70 percent of the withdrawals and depletions, urban withdrawals 15 percent, military 11 percent, and the other sectors the remaining four percent of withdrawals.

Legal Institutions Affecting Water Use

Reflecting its paramount importance in a semi-arid state, water in New Mexico is a commodity owned by the people, and its use is closely governed by law. The institutions affecting water use range from the ancient community ditch associations to federal water importation projects involving interstate compacts, reclamation conservancy districts, etc. New Mexico has been a leader among the western states in terms of ground-water management, extensive use of interstate stream compacts, and the facility of water rights transfers. Since the Tularosa basin energy-water

Table 2. Estimated withdrawals and on-site depletions of water by sector for 1970 in Otero County and the Tularosa basin portion of Otero County, New Mexico

Item	Otero County		Tularosa Basin within Co.	
	Withdrawals	Depletions	Withdrawals	Depletions
	(1,000 acre-feet)			
Irrigation	47.3	24.2	24.9	12.6
Urban	5.3	2.7	5.3	2.7
Military - Holloman	4.0	2.4	4.0	2.4
Rural	0.5	0.3	0.4	0.2
Manufacturing	0.3	0.2	0.3	0.2
Minerals	0.1	*	0.1	*
Livestock	0.5	0.5	0.2	0.2
Fish and Wildlife	0.1	0.1	*	*
Recreation, land based	0.2	0.1	0.1	*
Total	58.3	30.5	35.3	18.3

*Less than 0.05

Source: Developed from: New Mexico Interstate Stream Commission and New Mexico State Engineer Office, *County Profile-Otero County*, *Water Resources Assessment for Planning Purposes*, Santa Fe, New Mexico, 1975.

complex conceivably could make a considerable amount of water available for export to adjoining river basins, primarily the Rio Grande and Pecos basins, a brief summary of the state's water laws and compacts and treaties concerning these adjacent basins are discussed in this section. However, should the alternatives of water export be considered, a more detailed analysis would be required into the legal, institutional, and political aspects. Additional legal research will also be required to ascertain the legal impacts on existing ground-water rights of the mining of groundwater for the Tularosa basin energy-water complex.

Water Laws

The state's water laws are based on the doctrine of prior appropriation as found in Article XVI of the Constitution with administration vested in the State Engineer. Rights perfected in surface waters before 1907 and in underground waters before the declaration of a basin by the State Engineer are not fully administrable until their priority, location, extent, etc., are adjudicated by court decree. The strict administration of surface flows according to priorities has not seen widespread application up to the present time although certain stream systems have been administered for many years. Groundwater is subject to regulation within the same general scheme of law applying to surface waters when included within an underground water basin declared by the State Engineer. About one-third of the state's area is within these declared basins, however, none of the Tularosa basin is within such declared basins.

Compacts

Utilization of water in the state is subject to provisions of eight interstate compacts entered into between New Mexico and other states. The waters of the Rio Grande system in New Mexico are subject to the Rio Grande Compact and to the Amended Costilla Creek Compact. The waters of the Pecos River system are subject to the Pecos River Compact.

The Rio Grande Compact between the states of Colorado, New Mexico, and Texas was adopted in 1939, and it apportioned the flows of the Rio Grande to the three states. Under provisions of the compact, Colorado is obligated to deliver at the Colorado-New Mexico state line a quantity of water determined from a schedule based on the annual runoff above major uses in Colorado. Likewise, New Mexico is obligated to deliver to Texas a quantity of water at Elephant Butte Dam determined from a schedule based on the annual runoff at the Otowi gaging station, located on the Rio Grande near San Ildefonso. A system of debits and credits is provided in the compact so that neither Colorado nor New Mexico is required to deliver each year the exact quantity set forth in the schedules of deliveries. For purposes of administering the compact and for delivery by New Mexico, "Texas" begins at Elephant Butte Dam. The compact covers only that portion of the Rio Grande drainage in Texas above Fort Quitman.

The Amended Costilla Creek Compact was adopted in 1963 between the states of Colorado and New Mexico. The amendments of 1963 provide minor changes in the allocations and points of delivery of water made by the Costilla Creek Compact of 1944 between the same two states. The compact allocates to the two states the natural flow of Costilla Creek and storage in Costilla Reservoir and provides a schedule for delivery of the natural flow of the stream on a daily basis during the "irrigation season." The area covered by the compact is the Costilla Creek drainage in Colorado and New Mexico.

The Pecos River Compact between the states of New Mexico and Texas was adopted in 1949. The major purposes of the compact were to provide for the equitable division and apportionment of the use of the water of the Pecos River; to promote interstate comity; to remove causes of present and future controversies, to make secure and protect present development within the states; to facilitate the construction of works for (1) the salvage of water, (2) the more efficient use of water, and (3) the protection of life and property from floods. Under provisions of the compact, New Mexico was obligated to not deplete by man's activities the flow of the Pecos River at the New Mexico-Texas state line below an amount which will give to Texas a quantity of water equivalent to that available to Texas under the 1947 condition. Water salvaged in New Mexico is apportioned 57 percent to New Mexico and 43 percent to Texas, and any water salvaged in Texas is apportioned to Texas. Unappropriated flood flows are apportioned 50 percent to each state. In the event of importation of water to the Pecos River basin from any other river basin, the state making the importation shall have the exclusive use of such imported water.

Treaties

Two international treaties between the United States of America and the United States of Mexico affect water use from the Rio Grande in New Mexico. The first treaty, executed in 1906, obligates the United States to deliver annually 60,000 acre-feet of water in the bed of the Rio Grande at the headworks of the Acequia Madre Diversion Dam located above the City of Juarez, Mexico; a provision is included that in the case of extraordinary drought or serious accident to the irrigation system (Rio Grande Project) in the United States, the amount delivered to the Mexican Canal shall be diminished in the same proportion as the water delivered to lands under the irrigation system in the United States. The second treaty, consummated in 1933, launched a cooperative effort between the two nations to relieve the towns and agricultural lands in the El Paso-Juarez Valley from flood dangers. Also, stabilization of the International Boundary was to be obtained by rectifying the channel of the Rio Grande, and flood control was to be improved by construction of Caballo Dam and a rectified channel from Caballo to El Paso.

Litigation

New Mexico Supreme Court decisions have helped shape New Mexico water law in many important ways, principally those involving the nature of ground-water rights initiated before the management of declared ground-water basins, the transferability of rights, and the necessity for interrelated administration of surface and related groundwaters.

Adjudication of Water Rights

New Mexico statutes direct the State Engineer to make hydrographic surveys and investigations of each stream system and source of water in the state, beginning with those used most for irrigation, in order to obtain records required for development of the water supply and for determination and adjudication of water rights.

Declared Underground Basins

When the State Engineer finds that the water of an underground stream channel, artesian basin, reservoir, or lake have reasonably ascertainable boundaries, and when he so proclaims, he assumes jurisdiction over the appropriation and use of such waters.

In 1956 the State Engineer declared the Rio Grande Underground Water basin which covers a large portion of the Rio Grande stream system above Elephant Butte Dam. Subsequently, several extensions to the original basin were declared, and the total declared area is about 15,876 square miles. The State Engineer has also declared the Hot Springs Underground Water basin, about 38 square miles; the Las Animas Creek Underground Water basin, about 75 square miles; and the Sandia Underground Water basin, about 73 square miles.

Also, in closed drainage basins, separate from but adjacent to the Rio Grande drainage system, the State Engineer has declared the Estancia Underground Water basin, comprising about 1,724 square miles in Torrance, Bernalillo, and Santa Fe Counties, and the Nutt-Hockett Underground Water basin, comprising about 133 square miles, in Luna, Dona Ana, and Sierra Counties.

Within the Pecos River system, the State Engineer has declared the Rio Hondo Underground Water basin, about 611 square miles in Lincoln County; the Rio Penasco Underground Water basin, about 723 square miles in Otero and Chaves Counties; the Roswell-Artesian Underground Water basin, about 4,281 square miles in Lincoln, Chaves, Otero, and Eddy Counties; the Carlsbad Underground Water basin, about 1,965 square miles in Eddy County; and the Upper Pecos Underground Water basin, about 2,708 square miles in Guadalupe and San Miguel Counties, and the Fort Sumner Underground Water basin, about 1,059 square miles in Chaves, Curry, DeBaca, and Guadalupe Counties.

FISH, WILDLIFE, AND RECREATION

Big game animals are found in the mountainous areas of the basin. Deer, turkey, and bear are present in sufficient numbers to provide good hunting. Some antelope may be found on the basin plain. Small game animals, including fur-bearers, have general distribution. There are quail and pheasant.

Water suitable for fishing is scarce in the basin. There are a few streams in some mountainous areas that offer fishing for trout. In the lower elevations, streams are intermittent and no impoundments have been constructed that might be used for fishing or other forms of water recreation.

Other types of recreational facilities likewise are scarce in the basin. A few facilities are available in the Lincoln National Forest and on the Mescalero Apache Indian Reservation bordering the basin and the White Sands National Monument. White Sands National Monument's use is restricted to day visits only. The U. S. Forest Service provides camping and picnicking sites in the Lincoln National Forest.

LAND

Within the Tularosa drainage basin in New Mexico, there are approximately 6,540 square miles or about 4.2 million acres (New Mexico Interstate Stream Commission, 1975). In the Otero County portion of the basin, there are approximately two million acres but only 0.4 percent or 7,680 acres are irrigated, located on a narrow strip on the eastern edge of the basin near Tularosa. Federal and state ownership account for about 88 percent of the total land area in the Otero County portion of the Tularosa basin.

Within the Otero County portion of the basin, the acreage controlled by military is about 54.5 percent of the total land area; land administered by Bureau of Land Management is about 15.9 percent; forest land administered by the Forest Service is about 6.2 percent of the total land area and national monuments account for about 4.3 percent. State ownership is about 7.1 percent. Private ownership is about 5.2 percent of the total land area and Indian ownership is about 6.8 percent.

SOCIO-ECONOMIC

Current Economic Structure

Once developed, the proposed Tularosa basin project would have an immediate socio-economic impact on Otero County and would induce a similar, although less intense, effect on the surrounding Counties of Chaves, Dona Ana, Eddy, Lincoln, and Sierra in New Mexico, and El Paso and Hudspeth Counties in Texas.

Alamogordo, the principal trade center for Otero County, is located 85 miles northeast of El Paso, Texas (Figure 3). The customer area for business establishments within Otero County is limited almost entirely to county residents and tourists from El Paso and the west Texas area. There is some dollar drain from Alamogordo to El Paso, although it has decreased in recent years due to the improved variety of retail stores in Alamogordo, Cloudcroft, and Tularosa.

Outside the Alamogordo area, there is very little industry in Otero County other than lumber and auto salvage. In the 1973 County Profile prepared by the New Mexico Department of Development, the Alamogordo area listed 30 industries, some of which are directly tied to the military installation (Larsen, et al., 1974).

According to the Department of Defense, Directorate for Information Operations and Control, there were 4,584 military personnel and 1,124 civilians for a total of 5,708 persons employed at Holloman AFB, as of June 30, 1974. The estimated payroll for the military personnel and the civilians employed at Holloman for FY 1974 is $61,117,000.

In the Comprehensive Plan, Part 2 for Otero County, an estimate was made of local purchases by the personnel employed at Holloman AFB through December 1973 (for FY 1974) of $10.11 million (Larsen, 1974). This estimate indicates a sharp increase from the $6.02 million spent during the same period of the previous fiscal year.

The basic socio-economic features of Otero County are discussed on an individual sector basis in the following paragraphs.

Sector Discussion of Economic Structure

Agricultural Sector. The value of crops sold during 1969 as reported in the 1969 Census of Agriculture was estimated at $1.26 million while the sale of livestock brought in another $2.39 million. Total employment in agriculture in Otero County during 1969 was 211 persons.

The principal irrigated crops grown in Otero County are alfalfa hay, upland cotton, barley, cotton, sorghum, wheat, and apples. Estimated upland cotton production in Otero County during 1972 was 1,850 bales, while production of hay, grain sorghum, and wheat was 20,000 bushels, 25,000 bushels, and 5,000 bushels, respectively.

Business and Trade Sector. The Bureau of Census has published information from the last Census of Business and Manufactures taken in 1973 and is summarized in the following sections.

Wholesale Trade. Table 3, which summarizes wholesale trade statistics for Otero County, indicates that there was 34 wholesale establishments in Otero County during 1972 with total sales of about $15.19 million. Of these 34 establishments, 28 were located in Alamogordo. The 1972 payroll for these establishments was about $992 thousand, while the number of paid employees for the week including March 12, 1972, was 174.

Twenty-seven of the 34 wholesale establishments in Otero County were merchant wholesalers while the other seven were manufacturers' sales branches and sales offices, merchandise agents, and brokers. Total sales of the 27 merchant wholesalers was about $9.35 million and about $5.84 million for the seven other operating wholesalers.

Table 3. Wholesale trade sales for Otero County and the City of Alamogordo, 1972

Item	Unit	Otero County	Alamogordo	Remainder of County
Total				
Establishments	number	34	28	6
Sales	$1,000	15,186	(D)	(D)
Inventories, end of year 1972	$1,000	890	(D)	(D)
Payroll, entire year	$1,000	992	(D)	(D)
Payroll, first quarter 1972	$1,000	229	(D)	(D)
Paid employees*	number	174	(D)	(D)
Merchant wholesalers				
Establishments	number	27	22	5
Sales	$1,000	9,349	(D)	(D)
Other operating types**				
Establishments	number	7	6	1
Sales	$1,000	5,837	(D)	(D)

*For week including March 12.

**Includes manfacturers' sales branches and sales offices, and merchandise agents and brokers.

D: Withheld to avoid disclosure.

Source: *1972 Census of Wholesale Trade, Area Statistics*: USDC Publication No. WC72-A-32 for New Mexico.

Retail Trade. As indicated in Table 4, there was 357 establishments involved in retail trade in Otero County during 1972. Total sales in retail trade of about $64.02 million was a little over four times the sales in wholesale trade in the county. Of the 357 retail establishments in the county, 285 with a total sales proceeds of about $58.54 million were located in the City of Alamogordo. The total number of retail establishments with a payroll was only 241 with sales proceeds of $60.94 million. The 1972 payroll for those establishments was about $6.80 million, and the number of paid employees for the week including March 12, 1972, was 1,664.

According to the sales proceeds, the automotive dealers group (all establishments) was the forerunner with total sales of $15.78 million, closely followed by food store establishments with $12.11 million, while the lowest contributing group of business establishments was the group of drug stores and proprietary stores with sales of $1.35 million.

Industrial Sector. Table 5 presents general information on manufacturing taken from the 1972 Census of Manufactures. There were 33 manufacturing establishments in Otero County during 1972, of which only 10 establishments had 20 employees or more. All other relevant data on manufacturing establishments in Otero County, i.e., number of employees, payroll, value added by manufacturing, etc., have been withheld to avoid disclosing figures for individual companies.

Employment Status. While 1973 total employment data were available for the non-agricultural sector of the New Mexico counties in the study, only covered private employment[1] data were available for the agricultural sector.

Table 6 summarizes the available employment data by sector. The annual average employment in all non-agricultural sectors in Otero County was 11,094 in 1973, however, there were only 22 covered employees in the agricultural sector during that year. The largest number of people were employed by the Government sector (4,071) followed by the Services and Miscellaneous sector (2,298), and the Wholesale and Retail Trade sector (1,971). The remaining sectors contributions to total employment in the county were significantly lower than those of the three sectors mentioned above.

Demographic Situation

Population Characteristics

The population data presented in this sector are taken from the 1970 Census of Population. Table 7 contains population characteristics of Otero County and the City of Alamogordo. In 1970, Otero County had a total population of 41,097. The urban population was 33,887 (82 percent of the total) with the remaining 18 percent living in rural areas. The City of Alamogordo had a population of 23,035 (56 percent of the total county population, Table 7). Forty-two percent of the total population of Otero County was under 18 years of age, 54 percent were between 18 to 64 years of age, and the remaining four percent was 65 years old or over. The median age for the whole county in 1970 was 22.4 years, and the median number of years of school completed by persons 25 years old and over was 12.4. Comparisons of population characteristics between Alamogordo and the county as a whole are negligible. The median income of Alamogordo families during 1970 was estimated at $8,640.

[1] "Covered Private Employment includes employees covered under the State Unemployment Insurance (UI) Law. Persons not covered by UI Laws include self-employed persons, unpaid family workers, workers in private households and most of the agricultural employment (regular and seasonal farm workers):" Employment Security Commission of New Mexico.

Table 4. Retail trade for Otero County and the City of Alamogordo, 1972

Item	Unit	Otero County	Alamogordo
All establishments			
Number		357	285
Sales	$1,000	64,020	58,543
Operated by unincorporated businesses*			
Sole proprietorship	number	200	151
Partnerships	number	28	20
Establishments with payroll			
Number		241	202
Sales	$1,000	60,938	56,777
Payroll, entire year	$1,000	6,795	6,285
Payroll, first quarter	$1,000	1,610	1,489
Paid employees**	number	1,664	1,528
Kind-of-business group			
Building materials, hardware, garden supply, mobile home dealers (all establishments)			
Number		12	10
Sales	$1,000	4,571	(D)
General merchandise group stores (all establishments)			
Number		13	11
Sales	$1,000	7,894	(D)
Food stores (all establishments)			
Number		44	27
Sales	$1,000	12,112	10,468
Automotive dealers (all establishments)			
Number		28	24
Sales	$1,000	15,782	15,467
Gasoline service stations (all establishments)			
Number		54	38
Sales	$1,000	4,906	3,752
Apparel and accessory stores (all establishments)			
Number		25	22
Sales	$1,000	2,491	(D)
Furniture, home furnishings, and equipment stores (all establishments)			
Number		27	27
Sales	$1,000	3,688	3,688
Eating and drinking places (all establishments)			
Number		70	54
Sales	$1,000	5,745	5,171
Drug stores and proprietary stores (all establishments)			
Number		8	7
Sales	$1,000	1,348	(D)
Miscellaneous retail stores (all establishments)			
Number		76	65
Sales	$1,000	5,483	4,294

*Includes only establishments for which legal form of organization is known.

**For week including March 12.

D: Withheld to avoid disclosure.

Source: *1972 Census of Retail Trade--Area Statistics*, USDC Publication No. RC72-A-32, New Mexico.

Table 5. General statistics of manufactures in Otero County, 1972

Item	Unit	Otero County
Establishments		
Total	number	33
With 20 employees or more	number	10
All employees		
Number	1,000	(D)
Payroll	million $	(D)
Value added by manufacture	million $	(D)
Cost of materials	million $	(D)
Value of shipments	million $	(D)
Capital expenditures, new	million $	(D)

Source: *1972 Census of Manufactures--Area Series*: USDC publication No. MC72(3)-32 for New Mexico.

D: Withheld to avoid disclosing figures for individual companies.

Table 6. Annual average sectorial employment in Otero County, 1973*

Employment Sector	Otero County
Agriculture**	22
Non-agriculture	
Manufacturing	957
Mining	(D)
Contract construction	779
Transportation and public utilities	664
Wholesale and retail trade	1,971
Finance, insurance and real estate	354
Services and miscellaneous	2,298
Government	4,071

* Subject to revision.

**Covered Private Employment--includes employees covered under the State Unemployment Insurance (UI) Law.

D: Disclosure--included in Services and Miscellaneous sector.

Source: Employment Security Commission of New Mexico--Labor Information Series (Table B), 1972-1973, and Covered Employment and Wages (Quarterly Reports, 1973).

Table 7. Population characteristics for Otero County and the City of Alamogordo

	Otero County	Alamogordo
Total population	41,079	23,035
Urban	33,887	23,035
Rural	7,210	0
Percentage distribution by age group		
Under 18	41.7	40.6
18-64 years	54.2	54.8
65 years and over	4.1	4.5
Median age	22.4	23.1
Median school year completed by persons 25 years old and over	12.4	12.4
Median income (dollars)	8,117	8,640
Percent of families with income of		
Less than poverty level	12.3	11.9
$15,000 or more	14.0	16.3

Source: *1970 Census of Population*, PC(1)-B33 and PC(1)-C33, New Mexico.

Income Distribution

Total personal income in Otero County was estimated at $155.2 million, of which $122.1 million was the result of total wage and salary disbursements (Table 8). Earnings from labor and proprietorship amounted to $136.8 million of which only $2.6 million were farm earnings. Of the $134.2 million earned from non-farm sources, $81.7 million or 61 percent were directly due to Government employment, including federal, state, and local government agencies. The high percentage of non-farm earnings originating from Government employment can be explained by the substantial military and civilian employment at Holloman AF Base located in Otero County and White Sands Missile Range localted in Otero and Dona Ana Counties.

Transportation

Otero County is served by U. S., State, and County highways (Figure 3, Table 9). Otero County is served by U. S. Route 54, which begins in El Paso, Texas, and runs in a northerly direction through Alamogordo, Carrizozo in Lincoln County, and finally intersects Interstate Route 40 and U. S. Route 60 at Santa Rosa in Guadalupe County. U. S. Route 70 connects Las Cruces to Alamogordo, Tularosa, and Mescalero and then enters Lincoln County and moves east through Roswell. U. S. Route 82 begins at Las Cruces and follows the same route as U. S. 70 until it reaches a point just north of Alamogordo, where it departs from U. S. Route 70 and goes through the Sacramento Mountains to Cloudcroft, Mayhill, and Elk, and then enters Eddy County and continues eastward through Artesia.

With regard to rail service, Otero County is served by the Southern Pacific Railroad, which originates in El Paso, Texas, and goes north alongside U. S. Route 54 through Alamogordo. Alamogordo is the only scheduled stop for rail-freight service in Otero County. No passenger service is available. The Southern Pacific Railroad, after leaving Otero County, continues in a northeasterly direction through Lincoln County.

New Mexico Transportation Company provides daily bus passenger and freight service at Alamogordo and Tularosa.

Table 8. Personal income by major sources in Otero County for 1972

Item	Otero County (millions of $)
Personal income	
Total personal income	155.2
Total wage and salary disbursements	122.1
Other income	33.1
Earnings from labor and proprietorships	
Total labor and proprietorship earnings	136.8
Farm earnings	2.6
Non-farm earnings	134.2
Earnings from government employment	
Total government earnings	81.7
Total federal earnings	72.1
Federal civilian earnings	27.4
Federal military earnings	44.7
State and local earnings	9.6

Source: Print out by Regional Economics Information System Bureau of Economic Analysis.

Table 9. Otero County highway mileage, 1969

Highways	Urban Highways Mileage	Rural Highways Mileage
Primary	11	158
Secondary	16	229
Local (City streets)	147	
County		1,376
Military		62
National Park & Monument		9
Indian Reservation		104
Total Highways	174	1,938

Source: New Mexico Interstate Stream Commission and New Mexico State Engineer Office, *County Profile-Otero County, Water Resources Assessment for Planning Purposes*, Santa Fe, New Mexico, 1975.

The county is well served with motor freight service for all commodities. The service is provided by a number of trucking companies.

Frontier Airlines provide scheduled daily flights at the Alamogordo Municipal Airport. Local charter service is also available.

SOURCES OF ENERGY

The primary sources of energy in the Tularosa basin for powering a large energy-water complex are fossil-fuels, nuclear, solar, and geothermal. Because of the limited scope of this study, the preliminary economic feasibility was based on nuclear energy as the primary energy source. A detailed discussion on nuclear energy as a source for this development is presented in Chapter IV. Within or adjacent to the Tularosa basin, there are limited coal deposits that are deemed inadequate for such a large-scale development. Solar and geothermal are in infant developmental stages with geothermal appearing to have more immediate applications to large-scale energy developments than solar energy. Therefore, a cursory examination of geothermal potential in the Tularosa basin follows.

Geothermal Energy

The Tularosa basin demonstrates certain geological and geophysical similarities with the geologic Basin and Range province, the latter being an area of regionally high geothermal potential. Chapin (1971) includes the Tularosa basin as part of the Rio Grande rift; an area--probably an extension of the Basin and Range to Socorro--having anomalously high geothermal flux along its western boundary (Reiter, et al., 1975). Summers (1965) indicates hot spring activity southwest of the Tularosa basin which may also indicate an area of anomalous geothermal activity. The graben, horst-type structure of the Tularosa basin and its surrounding mountains, along with the Tertiary intrusives within the Basin and in the bordering mountains indicates that the Tularosa basin may indeed be part of the Basin and Range province, derived by similar extensional tectonic forces. Seismic investigations (Herrin, 1969) project P_n velocities[2] under the Tularosa basin and neighboring areas as similar to those in the geologic basin and range, suggesting a relatively thin crust and relatively high regional upper mantle temperatures.

Terrestrial heat flow measurements taken in the Tularosa basin and bordering areas are compatible with the above geological information. These geothermal measurements (heat flow escaping from the earth's interior) at a dozen sites within and in proximity to the Tularosa basin are similar in magnitude (1.5 HFU - 2.3 HFU)[3] to values observed for much of the Basin and Range province. However, heat flux typically considered synonymous with geothermally potential areas (5 HFU - 10 HFU) has not yet been observed within the Tularosa basin.

Presently the acquisition of heat flux data at new sites within and near the Tularosa basin is being made so as to better estimate the regional geothermal character of the area, and possibly indicate an area of very high heat flow. In addition, measurements of crustal radioactive heat generation are being made so that the heat flux from the mantle may be estimated.

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[2] P_n is the compressional wave velocity in the upper part of the upper mantle along the moho.

[3] One HFU = 1×10^{-6} CAL/CM^2 per second.

This data will allow a better understanding of the relative contributions to the near surface heat flow, such as mantle heat flow, crustal radioactive heat generation and magmatic and tectonic heat generation in the crust. Basic data collected by Edwards (1975), Decker and Smithson (1975), indicate that geothermal anomalies observed along the Rio Grande rift are due to thermal sources such as magma bodies, hydrothermal circulation and high mantle temperatures; and not due to increased crustal radioactivity.

Figure 5 illustrates sites for which finalized or unfinalized heat flux data in southcentral New Mexico have been obtained. Figure 6 illustrates finalized data sites superimposed on a contour map of terrestrial heat flow in southcentral New Mexico. A band of high heat flux ($\geq$ 2.5 HFU), (twice normal) exists along the western portion of the Rio Grande rift. It is also quite possible that anomalously high heat flow areas exist within proximity to the Tularosa basin. For example, an area in the southwestern portion of the Tularosa basin may be characterized by heat flows of 2.0-2.5 HFU.

Considerable additional exploration will be necessary before reasonable postulations can be made of the existence, location, and extent of anomalous geothermal areas within or near the Tularosa basin. More evaluation work is necessary before a geothermal power estimate for the area can be reasonably made. Possible sites for geothermal gradient measurements should be based on geological and geophysical considerations. With the sparce data presently available, it appears that areas in proximity to the intrusives, plutons and dikes could be geothermal environments. After a geological investigation of these potential geothermal environments has been made, consideration may be given to the drilling of narrow tests for temperature measurements. It would also appear from the sparce data that potentially interesting geothermal areas may be in proximity to the areas of igneous activity in the northeastern and southwestern regions of the Tularosa basin. If experimental water wells are drilled in the Tularosa basin, they should also be used as heat flow sites. In addition to geological and terrestial heat flow studies, it would be prudent to consider the geochemistry of water well samples as a possible indicator of geothermal anomalies. Electrical soundings may also be employed to better appreciate the extent of wet geothermal systems. Although the intrusive activity may have occurred in the approximate range of 30 to 45 million years before present (MYBP), fault systems remaining relatively open may allow groundwater circulation to considerable depths, creating some geothermal waters. Relatively open fault systems may also allow younger magma to intrude to shallow depths as compared to the depth of the mantle, thus creating geothermal areas.

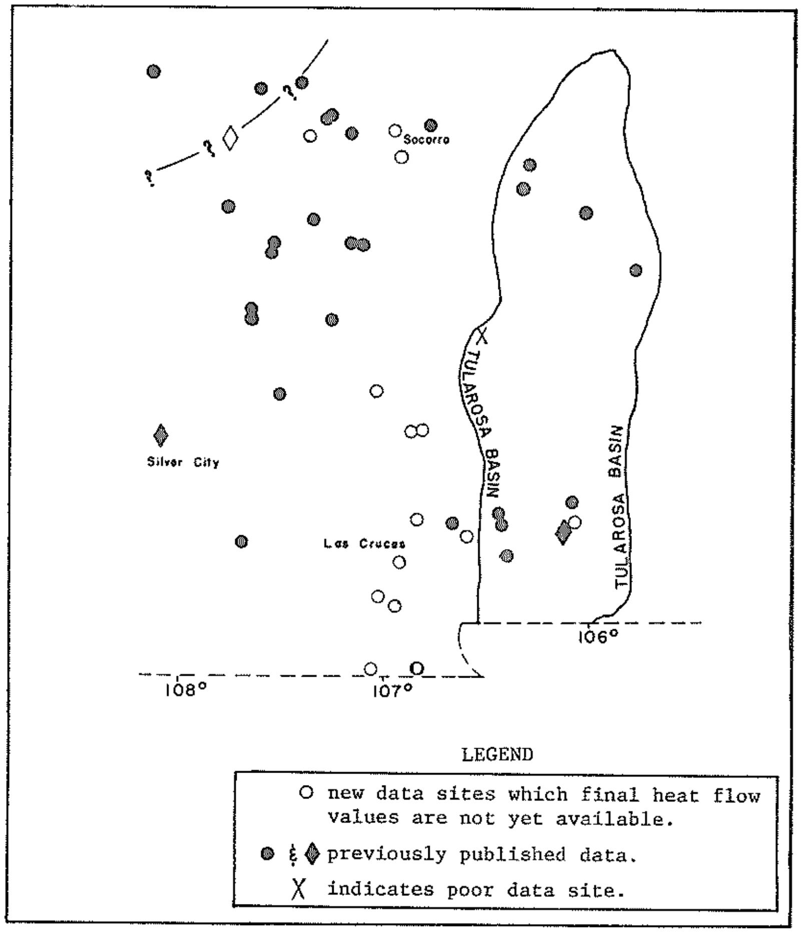


Figure 5. Heat flow sites in southcentral New Mexico.

Source: Adapted from "Terrestrial Heat Flow Along the Rio Grande Rift, New Mexico and Southern Colorado" by Marshall Reiter, C. L. Edwards, Harold Hartman and Charles Weidman, GSA Bulletin, June 1975.

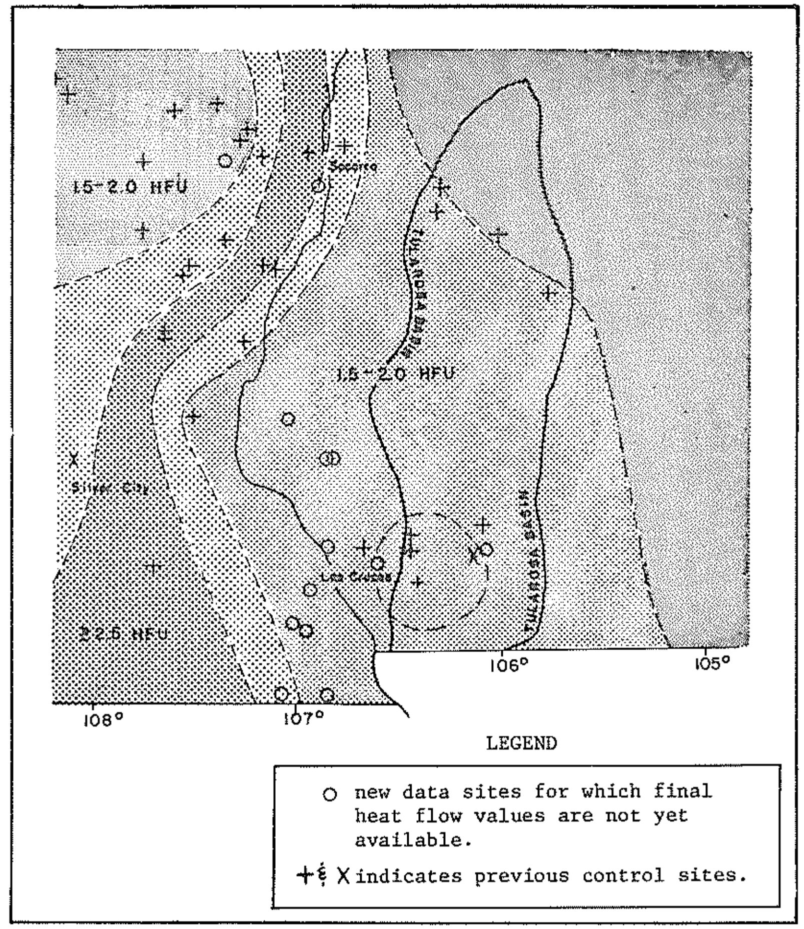


Figure 6. Heat flow contour map of southcentral New Mexico.

Source: Adapted from "Terrestrial Heat Flow along the Rio Grande Rift, New Mexico and Southern Colorado," by Marshall Reiter, C. L. Edwards, Harold Hartman and Charles Weidman, GSA Bulletin, June 1975.

CHAPTER III

NATURAL RESOURCE AVAILABILITY

WATER RESOURCES

Basin Description

The Tularosa basin is an elongated desert valley covering some 6,500 square miles of south central New Mexico. The basin topography is characterized by a north trending horst and graben structure that developed in the middle to late Cenozoic time. The basin is bounded on the east by the Hueco and Sacramento Mountains, on the west by the Franklin, Organ, and San Andres Mountains; on the north by a broad, high topographic divide and on the south by a subtle divide which separates it from the Hueco Bolson in Texas. Land-surface altitudes within the basin range from 3,900 feet in the playas to over 12,000 feet in the bordering mountain peaks. The basin floor slopes gently southward and contains numerous depressions. This basin has no surface outlet; as a result, the depressions become temporary lakes during the rainy season and alkali flats during the dry season.

The climate of the Tularosa basin is typical of the arid to semi-arid regions of the southwestern United States. Mean annual precipitation in the basin ranges from less than 10 inches in the central portion to over 25 inches in the bordering mountains. Precipitation on the slopes of the surrounding mountains produce intermittent stream runoff that drains toward the center of the basin or moves through the alluvial fans as interflow.

The Tularosa basin rock formations can be classified into two main divisions; Precambrian and Paleozoic consolidated rocks and Cenozoic unconsolidated and semi-consolidated rocks. The Cenozoic formations form the only important aquifers in the basin. Strain (1966) indicated that basin filling had begun by early Miocene time. Streams flowing from the mountains formed coarse alluvial fans near the mountain front and fined-grained alluvium in the basin center. Lacustrine deposits predominate in the center of the basin. Strain (1966) states that the formation of Lake Cabeza de Vaca resulted in deposition of a continuous sheet of lacustrine deposits that merged with floors of the Hueco and Mesilla bolsons by early Pleistocene time. By late Pleistocene time, Lake Otero, the predecessor of Lake Lucero, covered 700 square miles of the Tularosa basin (Herrick, 1904). These lacustrine deposits are composed of bentonitic claystone, siltstone and silt with layers and veins of gypsum. The ancestral Rio Grande evidently entered the Tularosa basin through the gap between the Organ and Franklin Mountains (Hawley, et al., 1969). Consequently, thick fluvial deposits predominate in the extreme southwest corner of the Tularosa basin.

Existing Water Development

The limited amount of fresh-water available in the basin is presently being developed for consumption by the chief users whom are Holloman Air Force Base, White Sands Missile Range Headquarters, and the community of Alamogordo. Well fields have been developed along the mountain front on extensive alluvial fans. Alamogordo receives its water supply from well fields at Grapevine, Alamo, La Luz, and San Andres canyons and from the Boles and Douglas well fields. This supply is supplemented by water from the Bonito Lake pipeline. Holloman Air Force Base obtains the majority of its water from the Boles and Douglas well fields; the remainder is supplied by the City of Alamogordo. White Sands Missile Range obtains its fresh water supply from alluvial deposits in the re-entrant between the Organ and San Andres Mountains and along the mountain front.

Surface water in the Tularosa basin is limited to the Rio Tularosa, located east of the community of Tularosa (Figure 7). Approximately 6,880 acre-feet of slightly saline water per year is available for irrigation from the Rio Tularosa (McLean, 1970). Numerous irrigation wells also extract slightly saline groundwater in the Tularosa area. It is estimated that 11,000 acre-feet were pumped in 1969 for irrigation (Garza and McLean, 1972).

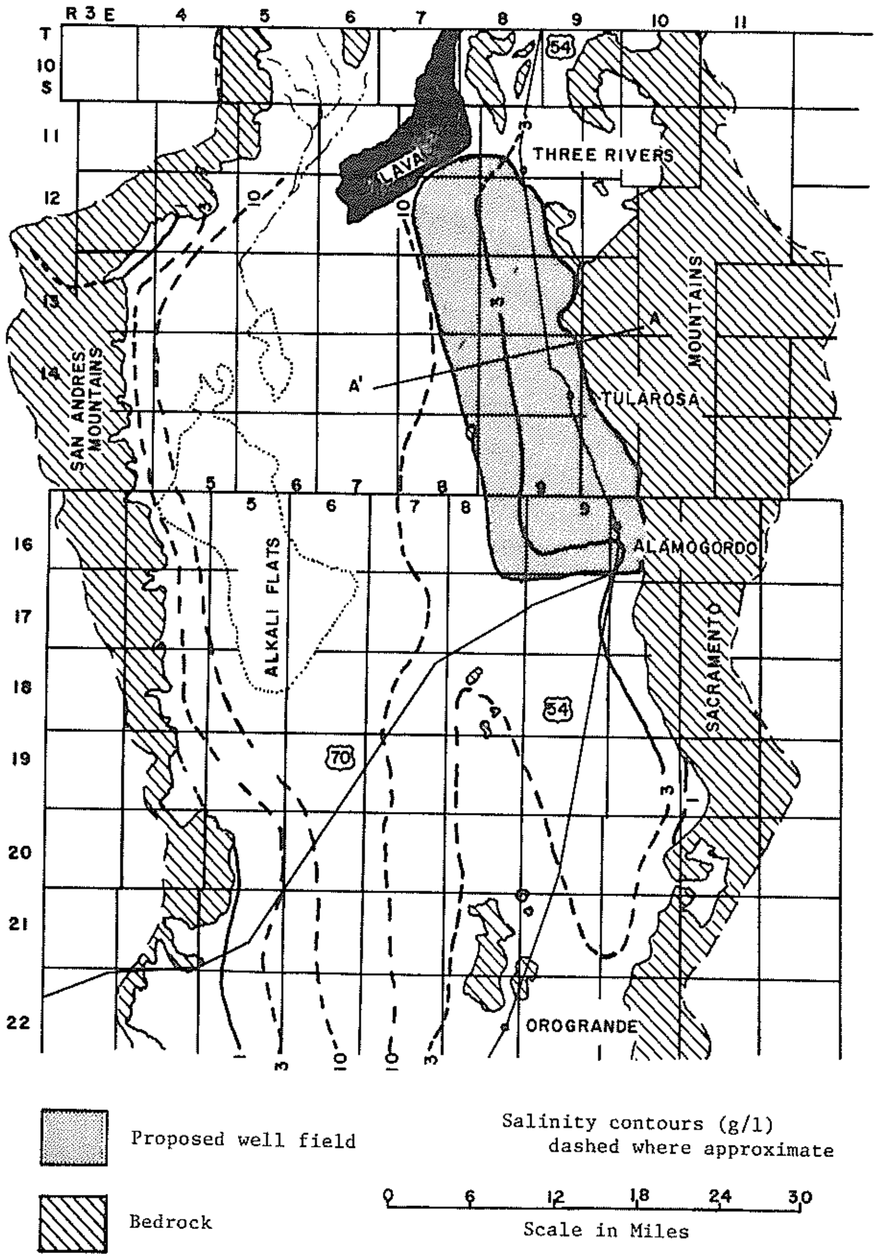


Figure 7. Tularosa basin salinity contours (g/l) of the top 1,000 feet of aquifer.

Yields from wells throughout the Tularosa basin are highly variable, reflecting the nonhomogeneity of the Cenozoic sediments. Maximum yields are derived from wells developed high on alluvial fans adjacent to mountain canyons. Well yields as high as 1,400 gpm with transmissivities of 47,000 ft^2 per day have been obtained. Wells developed lower on the alluvial fans yield 300 to 700 gpm in aquifers with transmissivities of 1,000 to 2,000 ft^2 per day.

Little or no information is available on the yields and transmissivities of wells in the central portion of the basin. Due to finer sediments and high clay content in this area, yield and transmissivities are expected to be extremely low. The specific yield (the percent volume of water that can be drained from a volume of rock by gravity) of the upper part of the alluvial fans is 12 to 15 percent. Specific yield of the lower part of the alluvial fans has been determined at eight to nine percent, and that of the deposits in the central part of the basin is estimated to be six percent or less (McLean, 1970).

The thickness of the Cenozoic deposits in the Tularosa basin has been determined by gravimetric and seismic studies. Unconsolidated alluvium has been encountered to a depth of 6,015 feet in a test hole drilled east of White Sands Missile Range Headquarters. Alluvium may be as thick as 8,000 feet at the southern end of the basin and generally thins toward the northern boundary of the basin.

Water Quality

Water in the alluvial deposits of the Tularosa basin is freshest near the mountain front and generally increases in salinity with distance from the mountain front and with depth. Stream runoff entering the alluvial fans acquire dissolved solids from the runoff area. In addition, water moving through the fan acquire more dissolved material. The concentration of minerals present in the water is dependent upon the solubility of the materials through which the water flows.

Fresh water is defined as containing less than 1,000 mg/l dissolved solids. The location of fresh-water deposits in the Tularosa basin is illustrated on Figure 7; shown is the average salinity of the upper 1,000 feet of water in the aquifer. Two important fresh-water aquifers occur near White Sands Missile Range Headquarters and south of Alamogordo. An estimated 37 million acre-feet of fresh-water bearing alluvium lies in the region between Alamogordo and a locality 10 miles south of Grapevine Canyon (McLean, 1970). Specific yield of these deposits has been determined to be eight to nine percent in the Boles well field, six miles south of Alamogordo, and estimated at 12 percent in the San Andres well fields, eight miles south of Alamogordo (McLean, 1970). Thus three to four million acre-feet of water may be present in this region.

The other large fresh-water body lies adjacent to the San Andres, Organ, and Franklin Mountains from Ash Canyon on the north, extending well into Texas on the south. This fresh-water unit is by far the largest in the basin. It is from this source that White Sands Missile Range Headquarters derives its supply. An area of over 400 square miles is underlain by fresh-water bearing alluvium extending to a maximum thickness of 1,800 feet. Knowles and Kennedy (1958) estimated that 6.2 million acre-feet of fresh water is theoretically recoverable in this portion of the Hueco Bolson in New Mexico.

Water in the 1-3 g/l salinity (dissolved solids) range is present through much of the Tularosa basin. This saline-water-unit occurs as a transitional zone between the fresh-water unit near the mountain front and the more saline water lying in the central part of the basin.

The 1-3 g/l zone varies considerably in thickness and extent (Figure 7). The largest volume of 1-3 g/l saline water occurs in the alluvial deposits adjacent to the mountain front near Tularosa. About 16,000 acre-feet of this saline water was used for irrigation in 1968 (McLean, 1970). Approximately 360 million acre-feet of basin deposits are saturated with 1-3 g/l saline water (McLean, 1970).

Information on the thickness of the 3-10 g/l saline water unit is sparse. Throughout much of the basin the thickness is less than 250 feet (Figure 7). The unusual thickness in the Alamogordo area is part of the transitional zone between the fresher water adjacent the mountain front and the more saline water in the central basin. The volume of water in the 3-10 g/l unit is probably of the same order of magnitude as that in the 1-3 g/l unit, but further testing is necessary to more accurately define this unit (McLean, 1970).

The 10-35 g/l saline-water unit predominates throughout much of the central part of the basin (Figure 7). In the northern region of the basin, this zone may be encountered at depths as shallow as 250 feet. In the southern extremities the 10-35 g/l unit is slightly deeper. The quantity of water in this zone is unknown, but may be of the same order of magnitude as that in the 1-3 g/l or 3-10 saline-water-units.

An estimated 98 percent of the alluvial deposits in the Tularosa basin contains brines with dissolved solids content greater than 35 g/l. In a test hole near White Sands Missile Range Headquarters over 4,000 feet of the 6,015 feet of deposits penetrated by the well contained brine. Brine concentration reached a maximum of 112 g/l at a depth of 3,000 feet. Brine also occurs at shallow depths beneath the dry alkali lakes so numerous in the central part of the basin.

Well-Field Site Selection

A volume of 500,000 acre-feet of water containing less than 10 g/l dissolved solid is the requirement established by the project. Design and economic considerations are based on a 30-year life expectancy.

In selecting a well-field site, an effort was made to locate an area that would satisfy the hydrologic and geologic requirements imposed by the study. Hydrologic aspects that were considered were: water quantity and quality, depth to the water table, specific yield and transmissivity values, and aquifer response to pumping. Geologic considerations included thickness and composition of the aquifer material, and subsurface impermeable rock locations.

Quantity and quality requirements were primary considerations in site selection. Because the central part of the basin contains sediments of very low permeability, there are few areas from which the required volume of saline water can be extracted. The presence of existing fresh groundwater development or unacceptable geologic conditions eliminated several potential sites. A site in the Tularosa area (Figure 7) was chosen for its overall favorable hydrologic and geologic parameters. This site has no significant fresh-water units; the salinity of the Rio Tularosa discharging from the mountains usually exceeds 1 g/l. The well-field area is underlain by a trough (Figure 8) that parallels the mountain front extending from Alamogordo north to approximately Rinconada Canyon. The trough is about 2,800 feet deep and is saturated with 1 to 3 g/l saline water but may be underlain by higher salinity waters.

Values of specific yield and transmissivities were obtained for existing wells in the Tularosa basin. Data indicate that these two parameters vary considerably within the basin and within the same geologic formation. A representative specific yield value of .10 was selected based on data from the Boles well field which was thought to approximate conditions within the selected well-field site. Data for transmissivities were sparse; therefore, the

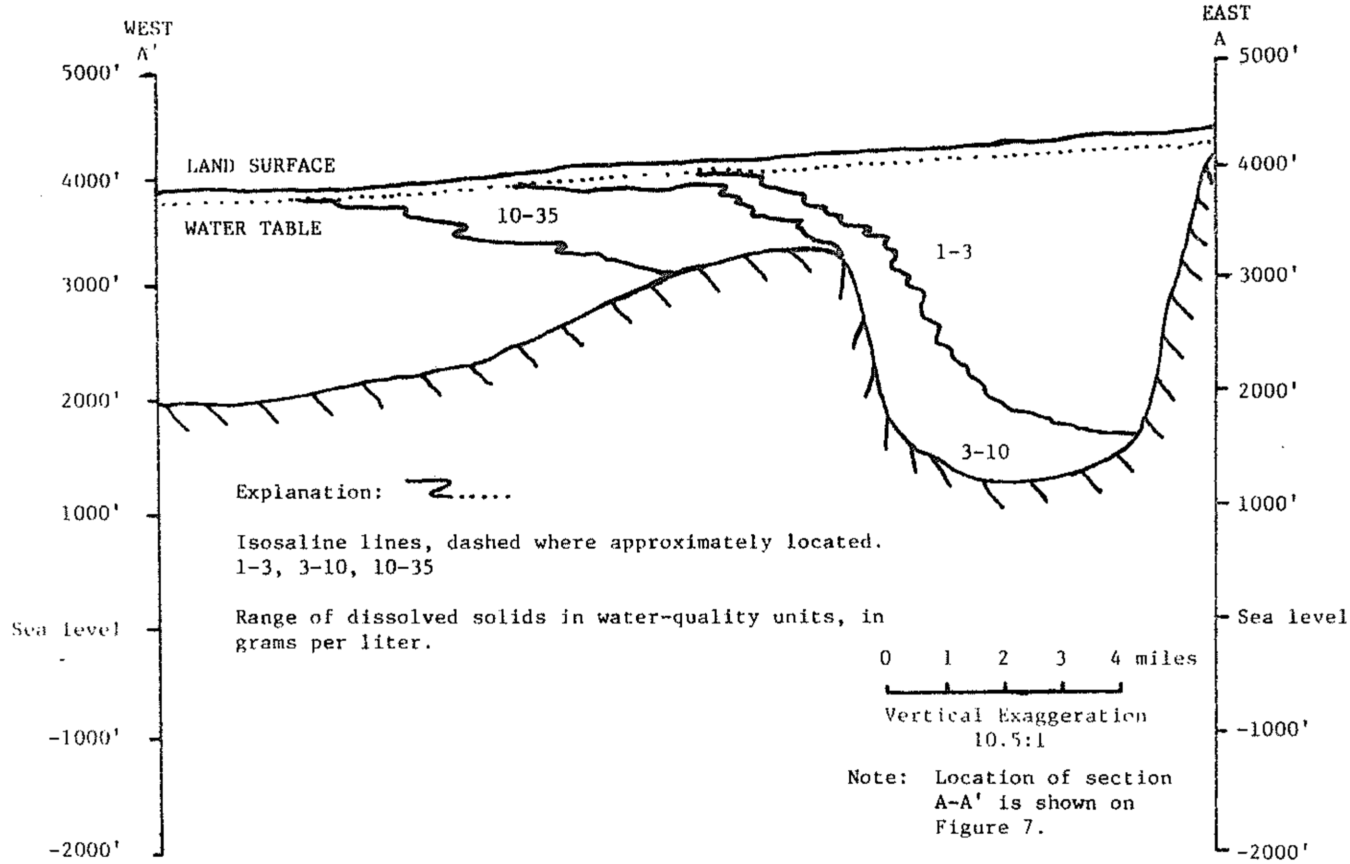


Figure 8. Diagrammatic section A-A' near Rio Tularosa showing water-quality units.

selection of a representative transmissivity value was made after discussions with J. S. McLean of the U. S. Geological Survey in Albuquerque. From his studies of the Tularosa basin (Garza and McLean, 1972), transmissivity values ranged from 5,000 ft^2/day high on the alluvial fans to less than 250 ft^2/day near the toe of the fans. For this study an average value of 1,500 ft^2/day was used.

The proposed well field covers approximately 400 square miles of the northeastern corner of the Tularosa basin (Figure 7). Depth to the water table averages 200 feet. Chemical composition of the groundwater varies with locale; an average chemical analysis for wells located in specific townships is presented in Table 10. The wells available for sampling are usually located in areas of better water quality; thus the recommended design quality of the feedwater is higher than the average (see Table 10).

Water Extraction and Cost Estimates

The number of wells required to extract 500,000 acre-feet of water per year is dependent upon the discharge capacity per well. The groundwater recharge in this area is estimated on the order of 5,000 acre-feet/year (Garza and McLean, 1972). Thus, the well field analysis was based entirely on groundwater mining. Discharge capacities for wells already existing

Table 10. Summary of water quality for the Tularosa basin well field based on 100 wells, 1970

Item	Township 13S	Township 14S	Township 15S	Township 16S	Average for Field	Recommended Design Quality*
Number of wells	10	20	15	55	-	-
	------milligrams per liter------					
Total dissolved solids (TDS)	3671	3132	2750	2972	3131	5000
Calcium (Ca)	402	441	329	310	371	592
Magnesium (Mg)	161	162	137	138	149	238
Sodium & Potassium (Na & K)	211	320	316	433	320	511
Chloride (Cl)	597	295	423	644	489	781
Sulfate ($SO_4^=$)	2104	1709	1140	1088	1510	2411
Bicarbonate (HCO_3^-)	170	187	230	228	203	324
Silica (SiO_2)	26	18	-	54	32	52

Source: McLean J. S., "Saline Groundwater Resources of the Tularosa Basin," *Office of Saline Water*, Report No. 561, 1970.

*Note that the above recommended values show some minor differences from the values shown in Table 18. Additional wells were included in the above data. Such differences are not considered to be significant.

in the area indicated that a discharge of 1,000 gpm (gallons per minute) is probably feasible if properly designed. Well discharge of 1,000 gpm would require 400 wells to extract the 500,000 acre-feet of water. This assumes that the well field will produce the 500,000 acre-feet by operating only the part of the year corresponding to a stream factor of 85 percent as assumed for the dual purpose nuclear energy plant (desalting and generation of electricity). An auxillary 35 wells were included in this number for control purposes and to offset expected maintenance shutdown periods.

Well spacing was designed so as to minimize well interference. A grid pattern was superimposed on the well-field site to facilitate the development of economic and drawdown models. The equidistant grid model allows each well to be considered as a separate closed system from which expected drawdown values can be calculated.

The well drawdown calculations were developed using the solution for a well in a closed square (Miller-Dyes-Hutchinson, 1950) and the procedure outlined by Kumar (1973). The Jacob correction (Jacob, 1963) was applied, with a specific yield correction to account for aquifer dewatering. Calculated drawdown values were plotted with respect to time (Figure 9).

Drawdown effects, external to the well field, were estimated based on the analysis developed by Hantush (1967). A constant transmissivity of 1,500 ft^2/day was used in these calculations. Figure 10 shows the calculated drawdown for two locations five miles outside the designated well field with respect to time. It is seen that the external drawdown is quite small in comparison with the average drawdown in the well field (600 ft. at 30 years). These results indicate that

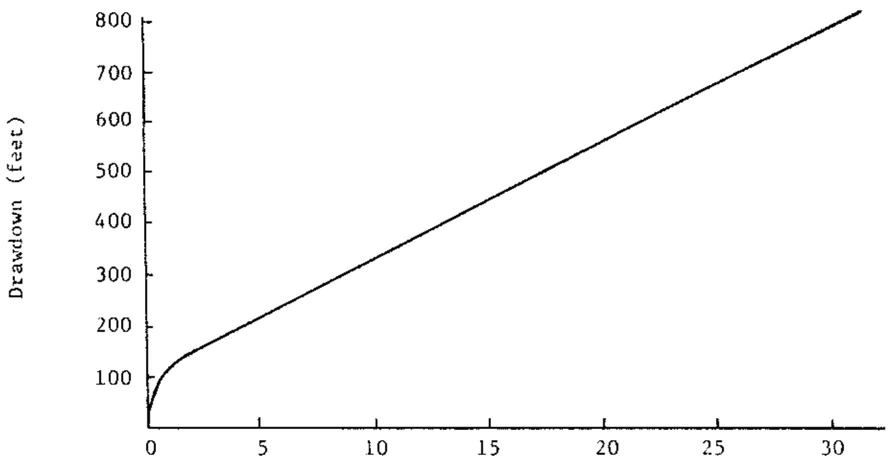


Figure 9. Well drawdown, Tularosa well field.

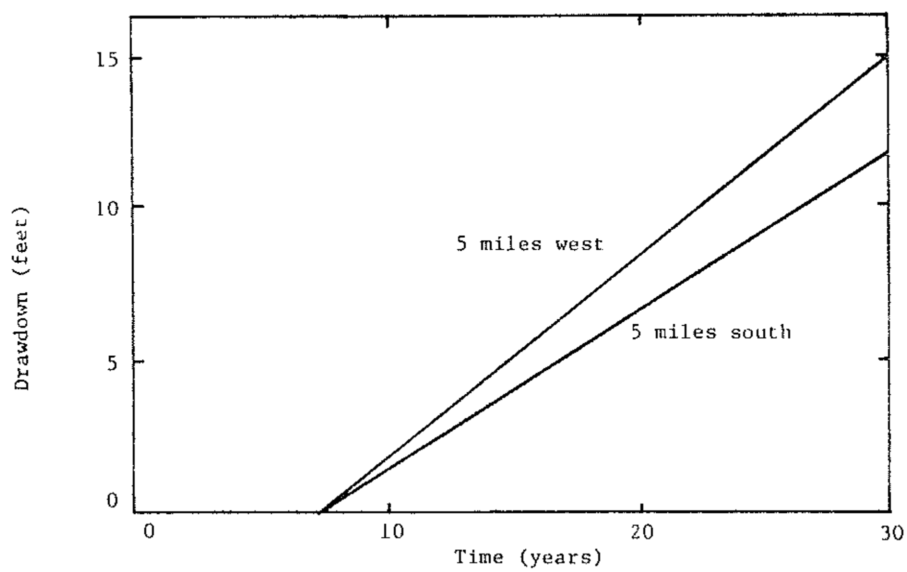


Figure 10. Estimated drawdown outside well field.

most of the water will be obtained by dewatering the well-field area with only a small portion being derived from areas external to the field. Thus, average water quality in the well-field area should be representative of the quality of the water produced from the wells. These estimates of external drawdown are preliminary; complicated transmissivity distributions and geologic conditions could alter the behavior.

Total well depth determination for construction evaluation was based on a 20 foot average water table drop per year for 30 years. Selection of this average drop was based on available well-field area and required production rate. The total well depth includes the depth to the water table, screen length, and localized coning effects. A well depth of 1,100 feet was required. A 1,000 gpm well requires a well diameter of 14 inches (Lehr and Campbell, 1973). A 100-foot section of well screen was necessary based on calculations from Lehr and Campbell (1973).

The sedimentary and stratigraphic conditions may necessitate a differentiated gravel pack around each well and a highly developed well.

The wells, designed for maximum yield of 1,000 gpm, utilize 24-inch diameter boreholes penetrating 1,100 feet of the aquifer. Well construction costs for feedwater production wells were based on Gibbs and Sanderson (1969) collection cost data for deep sandstone wells in northern Illinois. By regression analysis, they developed the following cost-depth relationship:

$$C_w = 0.029d^{1.87} \qquad (1)$$

Where C_w is well construction cost in 1966 dollars and d is well depth in feet. Equation 1 was adjusted to 1972 prices by applying Engineering News--Record Cost Indexes for 1966 and 1972. Construction cost for wells then becomes:

$$C_w = 0.0497d^{1.87} \qquad (2)$$

Estimated construction costs for the 400 wells is listed in Table 11.

The material and labor costs of the following were included in equation 1 and 2 cost estimates:

1. Setting up and removing the drilling equipment.
2. Drilling the well.
3. Installing casings and lines including construction casings.
4. Grouting and sealing the annular spaces between the casings and between casings and the boreholes.
5. Installing well screens and fittings.
6. Gravel packing and placing material.
7. Developing the well.
8. Conducting one eight-hour pumping test.

Cost estimates of pumping equipment for production wells were based on data compiled by Gibbs and Sanderson (1969). These data represent the direct expenditure involved in furnishing a basic vertical turbine pumping system capable of delivering 1,000 gpm. Included with the pumps are risers, cables, and motors. Not included in this estimate is the cost of installation of pumps, control systems, and well houses. Gibbs and Sanderson developed the following

Table 11. Summary of costs for the Tularosa well field to produce 500,000 acre-feet of water per year based on 1972 dollars.

Cost Items	Cost thousands of dollars
Initial Capital Costs	
Well construction (400 wells including pumps, motors, electrical distribution lines, and controls	$24,000
Collection system (excluding canal)	45,000
Total	$69,000
Replacement Costs (at 15 years)	
Pumps, motors, and controls	$12,500
Maintenance Costs (per year)	350

equation for vertical turbine pump cost:

$$P.C. = 7.309Q^{0.453}H^{0.642} \qquad (3)$$

Where P.C. is pump cost in 1966 dollars, Q is the desired yield in gpm, and H is the total head against which the water must be lifted in feet.

Pumping equipment costs were derived for the first 15-year interval when lift values would be less than 500 feet, and the second 15-year period when lift values would exceed 500 feet. Replacement of pumping equipment, controls, valves, and hardware will be necessary during the expected life of the project. This cost has been computed and listed in Table 11.

Additional pumping equipment and controls are needed that were not included in the pump cost. Therefore, the estimated prices for magnetic starters, motorized control valves, and central control system equipment have been added (Table 11).

It was estimated that one percent per annum of the total capital costs would be ample to provide for maintenance of the wells. Maintenance of the pipeline is taken as the standard .25 percent per annum of capital cost of the pipeline (Table 11).

Feedwater collection system (connecting pipe) costs were calculated from data developed by the Office of Saline Water (U. S. Geological Survey, 1972). Costs are given on a per-mile basis depending upon pipe diameter.

Several collection system models were considered. The selected model consisted of 13, 10-mile long main trunklines, traversing the width of the well field. To each trunkline, 10 lateral pipelines were connected each of which was two miles in length (Figure 11). The cost of the connecting pipe was selected from charts for pipe large enough to carry the full capacity of water for the designed system (see Table 11). A proposed canal will carry water from the main trunklines to the desalination plant. The construction cost for the canal has not been included in the collection system cost.

Electrical distribution lines design for the well field was modeled after the pipeline network. An estimated 450 miles of lines were needed at a cost of $3,000 per mile (Table 11).

Electrical energy needs per well per annum were derived from the following equation (Lehr and Campbell, 1973).

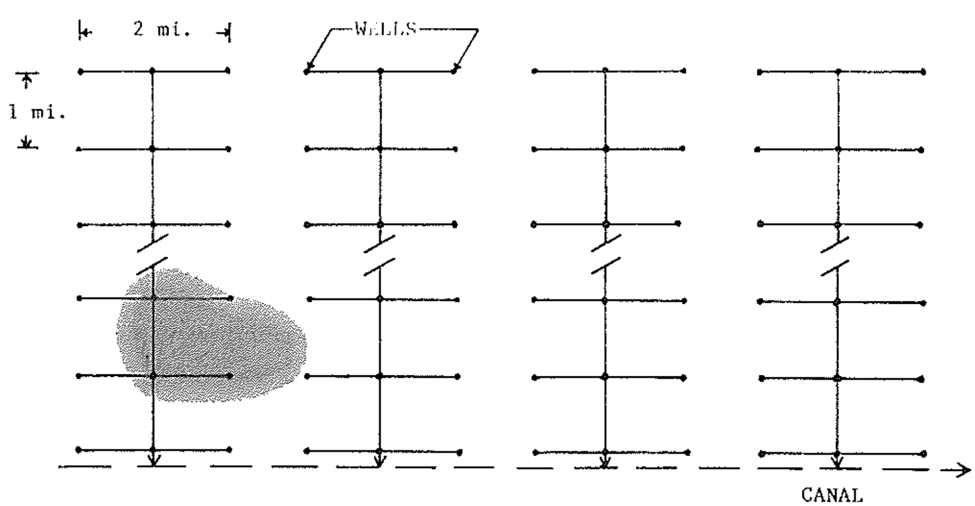


Figure 11. Proposed feedwater collection system.

$$\text{Kw-hr/yr} = \frac{\text{GPM} * \text{H} * .748 * 8760}{3960 * \text{OPE} * \text{ME}} \qquad (4)$$

Where GPM is well yield in gallons per minute, H is the heat against which water must be lifted in feet, OPE is the overall pump efficiency, and ME is motor efficiency. Values of .53 for overall pump efficiency and 0.9 for motor efficiency were obtained from charts developed by Lehr and Campbell (1973). Calculated values of electrical requirements for the well field were plotted against time (Figure 12). The graph illustrates the expected electrical consumption as the lift increases.

Recommendations - Hydrology

The hydrologic estimates developed herein are based on limited field information. These predictions are reasonable but do represent a somewhat optimistic estimate of the feasibility of developing saline groundwater in the Tularosa basin. The scale of this water development (500,000 acre-feet/year) was dictated by initial project assumptions; the result is a very intensive ground-water mining scheme. More modest scales of development should also be considered in any future studies. A prerequisite to further evaluation of the water resources is a detailed field study of favorable areas such as the proposed Tularosa well field.

This study should include surface geophysical exploration to determine the extent and configuration of the unconsolidated material, drilling, and geophysical logging of several test holes for land subsidence estimation, extensive water quality sampling for chemical analysis (including trace elements), and several well pumping tests. These observations will yield information on the aquifer properties (specific yield and transmissivity), the water quality distribution, and design conditions for production wells.

In order to predict changes in water quality and the distribution of drawdown, a detailed three-dimensional numerical model should be developed to simulate the aquifer behavior. The current distribution of salinity represents a condition of dynamic equilibrium between the fresh water inflow from the mountains and the density excess of the saline waters in the basin. As a major well field is developed, this equilibrium condition will be upset and a new distri-

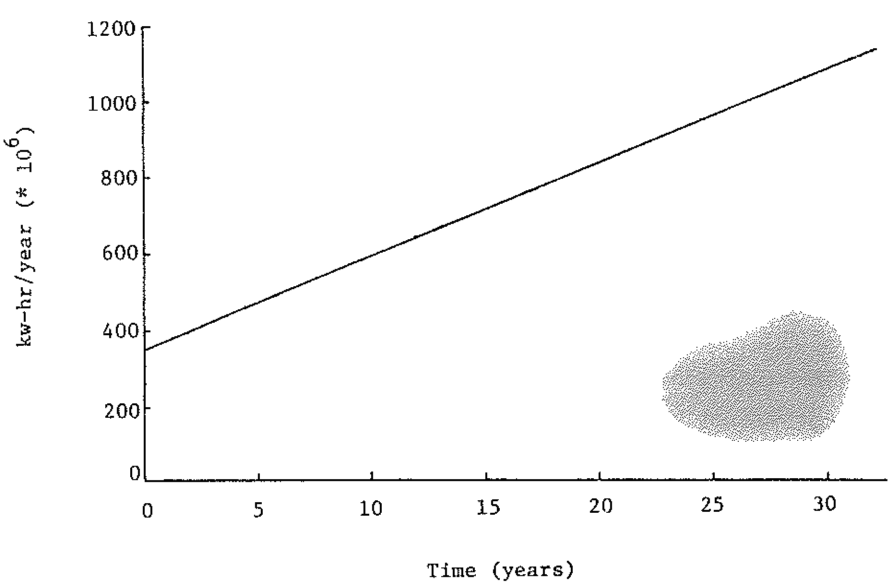


Figure 12. Energy requirements for pumping, Tularosa well field.

bution of salinity will develop. The model will predict this transition and will allow the design of pumping schemes to control the quality of the water produced from the well field. The long-term effects after the pumping of the well field has been discontinued should be considered in this modeling. The results of the field study recommended above would be required as input data for the model study.

In addition to the proposed Tularosa well field, another area with favorable hydrologic conditions was identified but not evaluated because of the limited scope of this study. This area is in the southwestern corner of the basin along the east side of the Organ and Franklin Mountains from the White Sands Missile Range Headquarters south to the Texas border. There appears to be large volumes of fresh and slightly saline water in this area that may be amenable to extraction.

LAND RESOURCES

This section considers the availability of Otero County land resources for the irrigation, urban development, and recreation activities associated with water desalination. The analysis includes: a description of current land use and land ownership, an evaluation of physical and institutional constraints associated with changing land use patterns, and a projection of future land use if the project is developed.

Current Land Ownership

Land in Otero County is distributed among four major types of ownership: Federal, Indian Reservation, Private, and State. Federal ownership is further divided into four subcategories: Military, Bureau of Land Management (BLM), Forest Service, and the White Sands National Monument. Military land, the largest category, comprises 31 percent of the total land area of Otero County; BLM land, 22 percent; Forest Service land, 13 percent; and the National Monument, two percent (Table 12). The Mescalero Apache Indians have jurisdiction over 460,255 acres, or 10.8 percent of the county total. Private and State land each comprise 10.6 percent of the total county acreage.

Slightly less than one-half of the Otero County land area falls within the Tularosa basin (Table 12). Of the land within the basin, over 54 percent is owned by the military, 16 percent by BLM, six percent by the Forest Service, four percent is a National Monument, seven percent belongs to the Mescalero Apaches, seven percent is state land and only five percent is privately owned.

Locations of these lands were derived from several BLM maps and are shown in Figure 13. It can be seen that Military, Indian Reservation and forest areas take up massive areas of space, while most Private, BLM, and State lands are scattered within the remaining areas.

Current Land Use

Land in Otero County is currently used for six major purposes: military use, forest production, national monuments, urban development, rangeland grazing, and irrigated agriculture (Table 13). Military uses include the White Sands Missile Range, used for testing missiles; and the Fort Bliss Military Reservation, used by the army for training purposes. Approximately 35 percent of Otero County lands are used by the military. Rangeland grazing is the next largest use, taking up about 32 percent of the land. Forest uses, which include timber, woodland grazing

Table 12. Land ownership in Otero County, New Mexico, 1975*

Land Ownership	Otero County	Tularosa Basin Within the County
	- - - - - - -acres- - - - - - -	
Federal	2,886,626	1,676,411
Military	(1,312,011)	(1,129,758)
Bureau of Land Management	(941,526)	(329,170)
Forest Service	(544,129)	(128,523)
National Monument	(88,960)	(88,960)
Mescalero Apache Indian	460,255	140,917
Private	451,531	107,520
State	449,908	146,560
Total	4,248,320	2,071,408

*BLM and Forest Service acreages from Stucky, H. R. and Donald C. Henderson, *Grazing Capacities and Selected Factors Affecting Public Land Use*, New Mexico State University Agricultural Experiment Station, Research Report 158, Las Cruces, New Mexico, 1969.

BIA, Private, State and Total Federal land ownership from Larson, Kenneth W., and Associates, *Land Use Study and Thoroughfare Plan*, (Comprehensive Plan, Part 2), Albuquerque, New Mexico, 1974.

Military and National Monument acreages estimated from BLM land ownership maps.

Table 13. Land use in Otero County, New Mexico, 1975*

Land Use	Otero County	Tularosa Basin Within the County
	- - - - - - -acres- - - - - - -	
Military	1,467,531	1,250,078
Rangeland Grazing	1,332,915	417,564
Forest Uses	1,324,384	293,046
National Monument	88,960	88,960
Urban Uses	17,920	14,080
Irrigated Agriculture	16,610	7,680
Total	4,248,320	2,071,408

*Military, National Monument, and Urban acreages estimated from 1974 land use map prepared by Kenneth W. Larson and Associates of Albuquerque.

Rangeland Grazing and Forest acreages estimated from 1969 land use map prepared by the State Engineer and the Interstate Stream Commission of New Mexico.

Irrigated Agriculture acreage estimated from both of the above maps.

and recreation, account for 31 percent of the land. The White Sands National Monument covers 2.1 percent of the land. The eastern part is open to the public for recreation, the western part is used for missile testing. Residential, commercial, and industrial uses make up the urban areas, which contain 0.4 percent of the lands. The major urban centers in the county are Alamogordo, Tularosa, and Cloudcroft. Irrigated agriculture covers 16,610 acres, which amounts to 0.4 percent of the total land in Otero County.

The situation is considerably different if one considers only that part of the county which is within the Tularosa basin. Over 60 percent is used for military purposes, while only 20 percent is used for rangeland grazing and 14 percent for forest uses. Also, there are only 7,680 acres of irrigated agriculture within the basin as opposed to 16,610 acres for the entire county.

Many areas of land have more than one use, but the major uses are mapped in Figure 14.

Land Use Feasibility

Development of a water desalination complex in the Tularosa basin will require a substantial amount of land for irrigation, urban development and recreation. Nearly 150,000 acres of irrigable land will be needed in order to utilize available water. Urban land requirements could increase by as much as 50 percent in the Alamogordo and Tularosa vicinity, and there will be a strong demand for using lands in the vicinity of the reservoir for recreation. The suitability of Otero County lands for these purposes depends on three types of constraints: location, current use, and soils.

Location Constraints

The most important factor is the need to locate water-using activities near the source of water (well field and reservoir) in order to keep water delivery costs at a minimum. The proposed well field is located in a rather narrow strip from Alamogordo north, and the most likely reservoir site is located to the northeast of the well field (Figure 14). Considering water transfer costs only, irrigation should occur in the same general vicinity.

The value of proximity to jobs and reservoir means that most urban development will probably occur around Alamogordo and Tularosa.

Soils Constraint

Soil type is an important constraint in identifying irrigable lands but is of little signifigance with reference to land suitability for urban development and recreation.

Assuming that some combination of sprinkler and flood irrigation is used, soil maps indicate that Otero County has over 300,000 acres of land that is potentially irrigable (Maker, et al., 1972). This acreage is located almost entirely in the western one-third of Otero County. Nearly half of the irrigable acreage is located in a contiguous area that lies from 10 to 25 miles south of Holloman Air Base. The remaining acreage lies primarily in a narrow strip that runs through Alamogordo and Tularosa to the county border.

Current Use Constraints

Current land use often limits what can be done with the land in the future. Current use constraints in Otero County include: (1) land used for urban purposes cannot be economically changed to other uses such as agriculture; (2) national monument lands cannot be easily allocated to other uses, given current national policy; (3) national forest lands cannot be easily allocated to other uses, given existing forest management policies; and (4) military lands are difficult to shift to other uses, because of the limited supply of land suitable for military use. In the case of the water desalination project, national forest lands are located where little impact is likely; national monument lands are easily avoided; and there is very little urban land use in Otero County. The military land use constraint, however, is of significant importance.

Part of the proposed well field and much of the irrigable land falls within the boundary of White Sands Missile Range (WSMR). This means that one must consider the possible implications of using military land for a well field and/or irrigated agriculture. Testing missiles requires large areas of open space to avoid the threat of property damage or loss of life. According to WSMR officials, any development along the eastern edge of the missile range would significantly impose upon their current operations. The more people and property there exists in the vicinity of the missile range the more difficult it is to insure a safe missile test.

Other military lands potentially affected by the project include Holloman Air Base and the McGregor Range portion of Fort Bliss Military Reservation. Holloman Air Base is potentially affected by possible developments along major runway approaches, leading to increased risk to property and life. The northern portion of the McGregor Range lies in an area that contains irrigable land. If part of the McGregor Range was diverted to irrigated agriculture, less land would be available for training exercises, but other parts of the Range would remain usable.

The following section considers the location, soils, and current use constraints discussed above in determining the lands most suitable for project operations.

Projected Land Use

Construction of the water desalination complex would mean a need for about 150,000 acres of irrigated agriculture and a significant increase in urban lands. The sites believed most suitable for these purposes are shown on Figures 13 and 14 in red.

Future urban land use is projected by assuming that Alamogordo and Tularosa will increase in size by approximately 50 percent and Cloudcroft by 25 percent. Most of their growth is expected to occur along major roads leading to the well field and plant site.

The irrigated agriculture was projected by identifying about 150,000 acres with suitable soils that was located near the well field and reservoir, but off military lands as much as possible. The total irrigated acreage shown in Figure 14 includes about 150,000 acres, plus a 20 percent loss factor for irrigated lands located within the well field and a five percent loss factor for lands located elsewhere (Table 14). The loss factor is included to account for roads, canals, wells, and other encumbrances.

These projected changes in land use mean that there will be significantly less rangeland grazing and military use of land. Military acreage is reduced by 33 thousand acres, and rangeland grazing by 127 thousand acres. All of the reductions in military acreage is from the most northern part of the McGregor Range where loss of land is expected to impinge least on current military operations. No irrigation or urban development is projected to occur on WSMR, but part of the well field would be located on the Range and the intensification of activity in the near vicinity would increase the risks associated with missile testing.

Table 14. Projected land use in Otero County, New Mexico*

Land Use	Otero County	Tularosa Basin Within the County
	------- -acres- --------	
Military	1,434,251	1,216,798
Forest Uses	1,324,384	293,046
Rangeland Grazing	1,206,107	290,756
Irrigated Agriculture	175,418	166,488
National Monument	88,960	88,960
Urban Uses	19,200	15,360
Total	4,248,320	2,071,408

*Estimated from Figure 14.

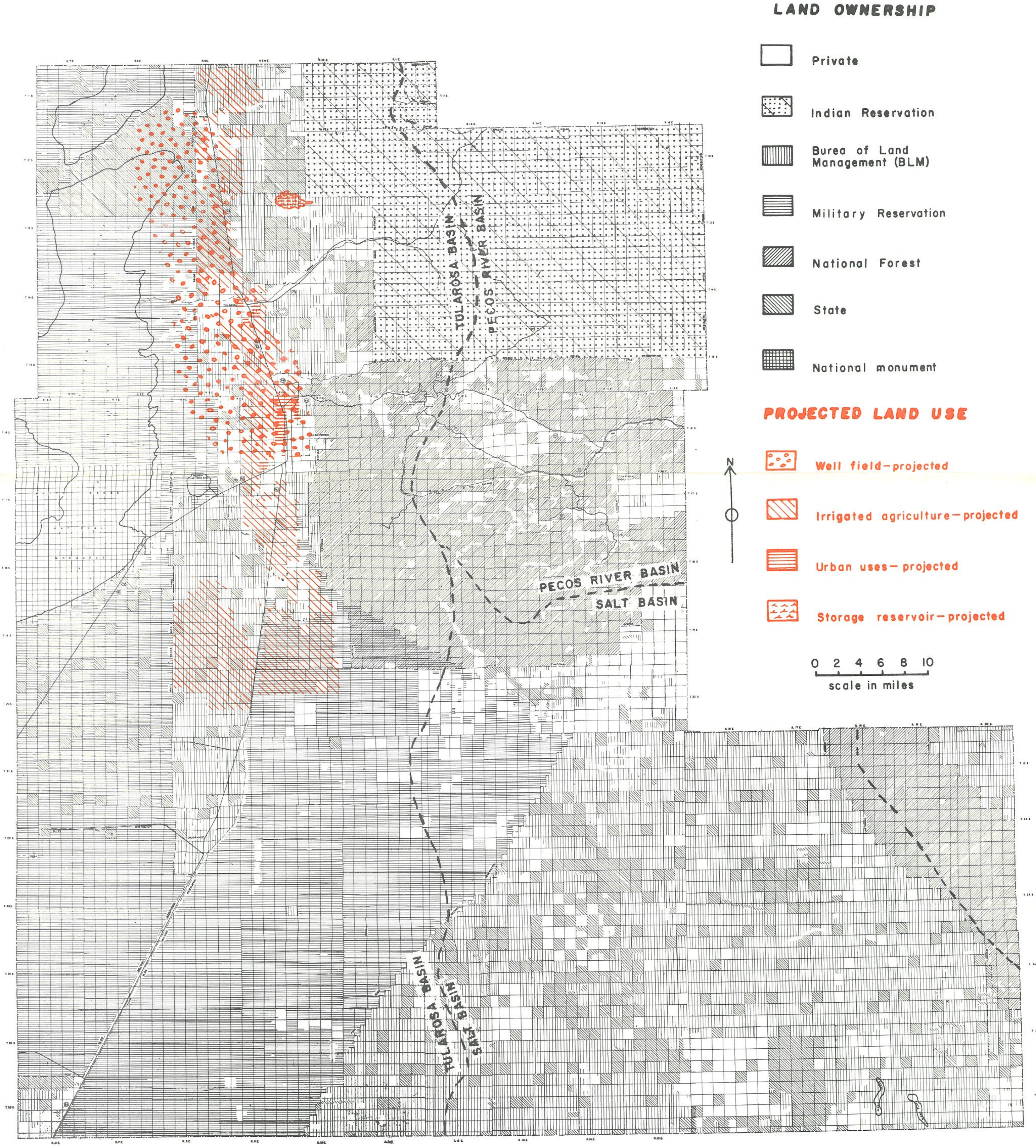


Figure 13. Current land ownership and projected land use map of Otero County, New Mexico, 1975

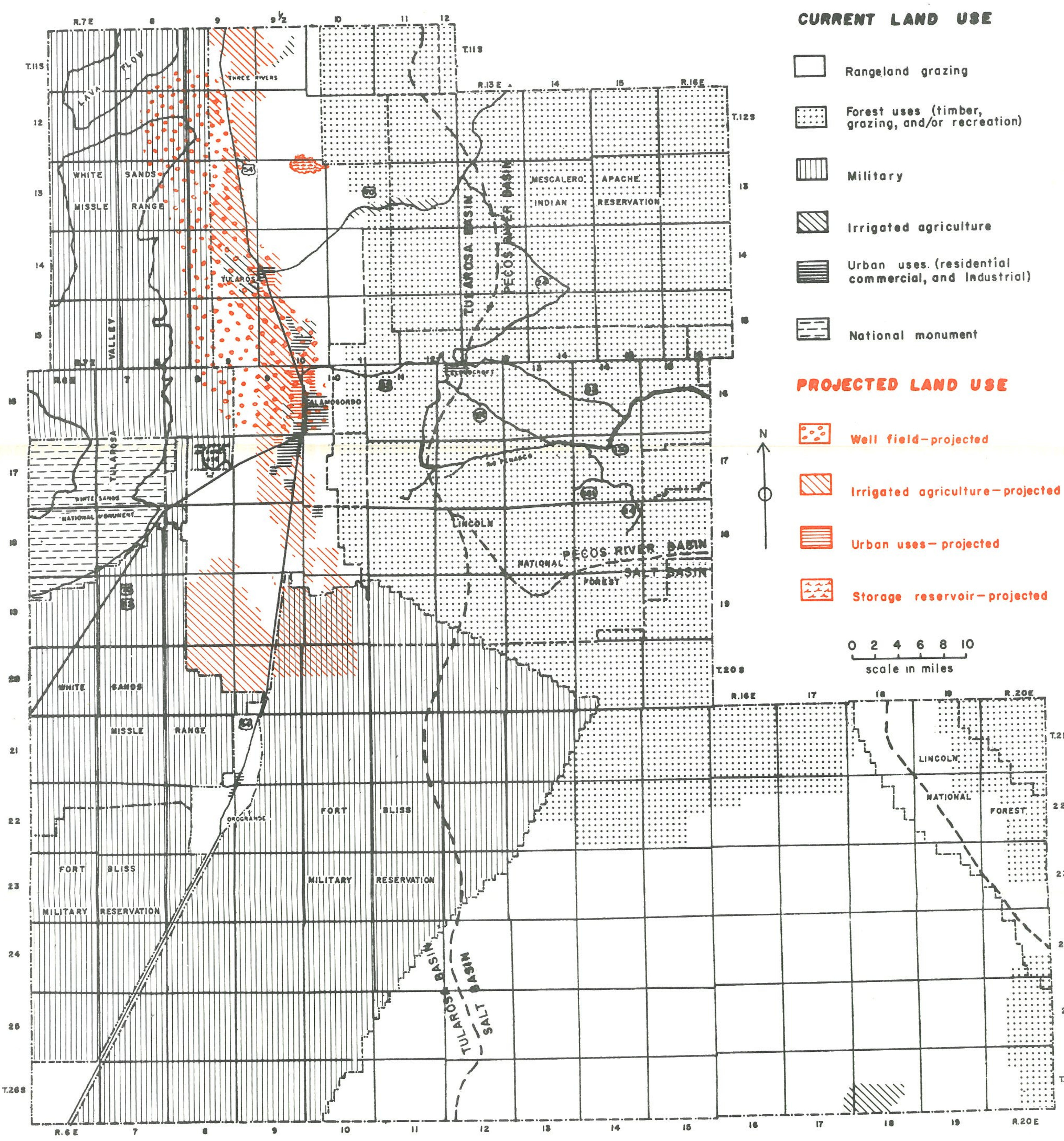


Figure 14. Current land use and projected land use map of Otero County, New Mexico, 1975

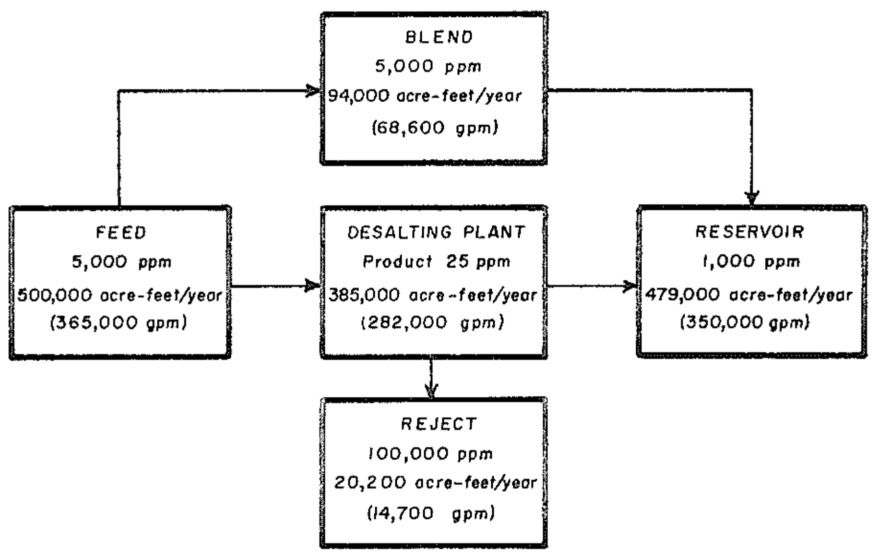
CHAPTER IV

EVALUATION OF DESALINATION AND ELECTRICITY GENERATION ALTERNATIVES

DESALINATION ALTERNATIVES

Water Supply Summary

This portion of the report considers only water which will be processed for desalting, blending, or mineral recovery. Figure 15 is a simple schematic of the water flow associated with the desalting plant. Included is the stream balance and the major assumptions made in developing the balance. Solute composition in parts per million by weight is shown in Table 15. It is assumed in the material balance that all materials have equal solubility and no solutes are separated within the desalting plant. As will be discussed under pretreatment, there may be selective removal of solutes to facilitate operation of an actual desalting plant.



Assumptions

1. No conveyance losses from well field to plant or plant to reservoir.
2. Feed storage at desalination plant two-day supply in open pond, neglect evaporation loss (add 6,500 acre-feet to reservoir evaporation).
3. Desalination product 25 ppm; assumes some mist entrainment.
4. Density of feed brine 8.35 lbs/gallon; neglect density change in estimating gpm. Reconsider when analyzing reject to mineral recovery.
5. Stream factor at desalting plant set by nuclear power plant availability is 85 percent.

Figure 15. Desalting plant flow schematic, Tularosa basin energy-water complex, New Mexico

Table 15. Solute composition, Tularosa basin, New Mexico

Component	Actual Analysis[a] (ppm)	Mass Fraction	Desalting Plant: Feed Water (5,000 ppm basis)	Desalting Plant: Product Water (25 ppm basis)	Desalting Plant: Reject (10^5 ppm basis)
Calcium	389	.1285	643	3.2	12,850
Magnesium	135	.0446	223	1.1	4,460
Sodium + Potassium	294	.0972	486	2.4	9,720
Chloride	532	.1758	879	4.4	17,580
Sulfate	1439	.4755	2378	11.9	47,550
Bicarbonate	203	.0671	335	1.7	6,710
Silicon Dioxide	32	.0106	53	.3	1,060
Nitrate	2.2	.000727	3.6	.02	72
Total	3026.2		5000.	25.	100,002

[a]Source: Gelhar, L., Private Communication, March, 1975.

In addition to this summary of the water supply, there are five other major sub-sectors contained in this desalination section. First, the pretreatment of feed water is discussed at length. Included here are estimates of probable costs to be expected in the process of reducing or breaking-up scale. Three potential processes are examined in the next section. They include multistage flash evaporation (MSF), reverse osmosis (RO), and electrodialysis (ED). From the MSF process, desalting plant costs are developed in the next section with supporting material. These costs are based upon two recent proposals and adjusted upward to account for the scale increase necessary for the proposed Tularosa basin energy-desalination complex. The treatment of reject brine is addressed next, including cost estimates furnished for converting brine to a solid. This conversion is believed necessary before minerals could be economically recovered or stored. Mineral recovery is discussed in the last section under three separate categories: solid removal during pretreatment, brine processing for salts, and trace metal recovery.

Feed Water Pretreatment

In desalination processes, pretreatment is practiced for scale control, corrosion prevention, and in multistage flash units; deaeration is also included. A major difference, the source of feed water, exists between the proposed Tularosa basin dual purpose (power-desalination) project and those reported in the literature. For the majority of the systems operating and of the systems for which there have been conceptual design studies, the feed is sea water. Table 16 gives a comparison between the Tularosa basin feed and sea water. While the total concentration of solute in the Tularosa basin feed is much less than the solute concentration of sea water, there are higher concentrations of scale forming components, e.g. calcium, carbonate, comparable concentration of sulfate, and, in addition, silica.

Two types of scale can form in brine evaporators, the alkaline scales (calcium carbonate and magnesium hydroxide), and calcium sulfate scale. At the present time, calcium sulfate scale is avoided by limiting the brine concentration and the evaporator operating temperature, and if these restrictions could be relaxed, more efficient evaporators would be built. (In a dual purpose power-desalination facility, the evaporator temperature is governed by the efficiency desired in the power plant, and in this study, has been fixed at 250° F.) Alkaline scale control

Table 16. Comparison of Tularosa feed with sea water

	Tularosa Feed[a]	Sea Water[b]
	ppm (by weight)	ppm (by weight)
Calcium	643	430
Magnesium	223	1,330
Sodium	486	10,890
Potassium	c	400
Chloride	879	19,680
Sulfate	2,378	2,740
Bicarbonate	335	80[d]
Silicon Dioxide	53	-
Nitrate	3.6	-
Bromide	-	70
Total	5,000	35,620

[a]Source: Gelhar, L., private communication, March 1975.

[b]Source: Kobe, K. A., *Inorganic Process Industries*, MacMillan Co., New York 1948, p. 14.

[c]Included in Sodium.

[d]As carbonate.

methods are in use, but periodic descaling is still required. To reduce the frequency of this operation, generous fouling allowances must be made in design, with significant increases in the evaporator capital cost. For a multistage flash evaporator the heat transfer area constitutes about 30 percent of the total cost, and the design allowance for fouling may be as high as 20-25 percent, corresponding to approximately six percent of the evaporator capital cost (Elliot, 1969).

Before describing the nature of scale formation and its control, it is worthwhile defining two terms used in the field. The name scale is normally used to describe a hard, adherent, normally crystalline deposit which is difficult to remove mechanically. Under certain conditions, a soft, amorphous material may be deposited or suspended in the brine, and this is termed sludge. Sludge, if deposited, can be equally as objectionable as scale but is generally more easily removed. The major components of scale are calcium carbonate, magnesium hydroxide, and calcium sulfate; the proportions depending upon the operating conditions. Identification of the compounds present in sludges is difficult, but the same cations are present, often with organic material and phosphates derived from the additives (corrosion inhibitors). In both cases, sodium chloride, silica or silicates, and copper and iron salts are found, but are generally considered as trapped impurities.

Scale deposits by a process of crystallization from a super-saturated solution. The alkaline scales are formed by reaction of the bicarbonate ions:

$$2HCO_3 \rightarrow CO_3^{=} + CO_2 + H_2O \qquad (1)$$

$$CO_3^{=} + H_2O \rightarrow CO_2 + 2OH^- \qquad (2)$$

At temperatures below 185° F. deposition of calcium carbonate by reaction (1) predominates. At temperatures above 185° F. increasing proportions of magnesium hydroxide have been reported, due to reaction (2).

Calcium sulfate can exist in three crystalline forms, gypsum ($CaSO_4 \cdot 2H_2O$), hemihydrate ($CaSO_4 \cdot 1/2\ H_2O$) and anhydrite ($CaSO_4$). The stable form at temperatures above about 100° F., is anhydrite, but crystallization from sea water evaporators does not occur spontaneously, and the solubility limit of the metastable hemihydrate generally applies in sea water evaporators. The conditions normally applied to flash evaporators (brine concentration factor of two and top temperature of 200-250° F.), are below the solubility limit of all forms.

The scale constituents all have solubilities which decrease with increasing temperature, so that supersaturation is most likely to occur, and be greatest, in the boundary layer at the heat transfer surface. For the alkaline scales a solution at or close to supersaturation is produced by decomposition of the bicarbonate ion in the flash chambers.

At present calcium sulfate scale formation in sea water evaporation is avoided by limiting the top temperature and the concentration in the recirculating brine. Further discussion, in regard to the Tularosa basin feed water, is delayed for the moment.

Two methods of alkaline scale control are used extensively in practice additive treatment and pH adjustment. Table 17 lists examples. The most commonly used method of scale control utilizes the addition of a small amount of treatment compound to inhibit nucleation of scale and to disperse any solids in suspension so that they are readily removed in the blowdown (Grace, et al., 1962; and Badger, et al., 1959). The material commonly used for alkaline scale control in sea water evaporates is sold under a brand name (Hagevap) and consists of a mixture of a sodium polyphosphate, lignin sulphonic acid derivatives, and an antifoaming agent. Polyphosphates have the property of inhibiting the deposition of $CaCO_3$ from supersaturated solutions when added one-to-two ppm quantities and have been used since about 1936 for controlling scale in recirculating water systems. The lignin derivatives are anionic surface active agents which should help to disperse scale particles, and the polyethylene glycol derivatives are used to suppress foaming. Polyphosphate based additives are limited to temperatures below 195° F. The uncertainty in the optimum conditions for polyphosphate treatment results in extra cost due to downtime for cleaning, and capital cost to provide additional heat transfer surface. Apart from the temperature limitations, polyphosphates are not effective in preventing calcium sulfate or magnesium hydroxide precipitation.

The simplest method of alkaline scale control is the addition of acid to react with the bicarbonate ion:

$$HCO_3^- + H^+ \rightarrow CO_2 + H_2O \qquad (3)$$

An addition of 80 percent of stoichiometric sulfuric acid is normally used and a degassing tower is provided for carbon dioxide removal before the evaporator. Careful control of acid addition is required to prevent corrosion, and neutralization of excess acid has been proposed. However, this too requires careful control, and is expensive in terms of the chemical requirements.

Acid dosing is extremely effective and costs about the same as Hagevap treatment in areas where acid is freely available. It is not subject to the temperature limit of 190° to 200° F. which applies to Hagevap, and can be used to the limit of calcium sulfate scale formation. Thus in areas where acid is comparatively cheap, advantage can be taken of the cost reduction due to increased top temperature.

Although there are many further systems suggested for scale and corrosion control, only one will be considered, and this is to remove the cations from the system prior to the evaporator. This alternative will be discussed under mineral recovery.

Acid addition is selected as the method of pretreatment for the Tularosa basin feed. Large quantities of sulfuric acid are currently available (200 mile radius) from SO_2 pollution control

Table 17. Scale, foam, and corrosion control

Plant Number	Maximum Brine Temp. (°F)	Feed Water Salinity (ppm)	Scale Control	Scale Removal	Foam Control	Corrosion Control
1	210	35,000	Sulfuric Acid	--	Dow "C"	Nil
12	182	33,000	Hagevap	Hydrochloric Acid	a	Nil
14	221	sea	Nil	Acid	--	Nioprine
15	190	35,000	Hagevap or Calgon	Toprogge	Hagan Cl	Cath. Protec.
18	195	36,000	Hagevap	--	a	Nil
20-22	195	35,000	Hagevap	Sulfuric Acid	a	Epoxy
24	243	20,000	Sulfuric Acid	--	--	Movel & Rubber
25-26	190	sea	Hagevap or Calgon	Acid	a	Rubber
27	198	--	Hagevap	H400	a	Nil
30	190	20,000	Calgon	Hydrochloric Acid	Al 14	Rubber
32	133	37,000	Aqua-Chem ACI	--	--	Nil
33-34	200	21,000	Hagevap	--	a	Cath. Protec.
35	225	38,000	Sulfuric Acid	--	Nil	Nil
37	170	--	Hagevap	--	a	Non-Ferrous
38-40	160	42,000	Hagevap	Hydrochloric Acid	a	Cath. Protec. and Epoxy
41	190	39,000	Hagevap	Hydrochloric Acid	a	Cath. Protec. and CR Paint
42	180	42,000	Hagevap	--	a	Chlorinated Rubber Paint
43	192	42,000	Hagevap	--	a	Chlorinated Rubber Paint
44-47	144	45,000	Hagevap	Acid	a	Chlorinated Rubber Paint
48-49	192	45,000	Hagevap	Acid	a	Chlorinated Rubber Paint

[a]Included in scale control material.

Source: Badger, W. L. and Associates, Inc., "Critical Review of Literature on Formation and and Prevention of Scale," PB-161-399, July 1959.

Grace, W. R. and Company, "Removal of Scale-Forming Compounds from Sea Water," PB-181-406, September 1962.

systems on metallurgical operations and electrical power generation. Although lower temperature operation would favor both electrical power production and calcium sulfate scale prevention, evaporator efficiency would be seriously reduced, significantly increasing the cost of desalinated water.

Although the process of reverse osmosis and electrodialysis are not major considerations for desalination in the Tularosa basin project, a brief consideration of pretreatment requirements will be given.

As is true for evaporation, the realities of calcium carbonate solubility apply to membrane processes. Extensive experiment data show quite clearly the effect of acidification in reducing alkalinity (and subsequent alkaline scale) (Mintz, 1970; and Channabasappa, 1970). As a result of this data and because of cellulose acetate's greater chemical stability in the pH range of five to six, acidification to this level for reverse osmosis is commonly accepted practice. Many of the organic acids and negatively charged colloids that foul membranes, are precipitated in an acidic medium and solubilized in an alkaline one. It has been common practice to acidify only the concentrate stream and then only after filtration. The converse is true, i.e., a dilute alkali is effective in cleaning fouled membranes.

The problems of iron slime formation and silica deposition on membrane surfaces have occurred in localized situations. In these cases, the periodic disassembly of equipment for membrane cleaning has been considered more acceptable than rigorous pretreatment. This is partially justified by the problem of membrane fouling associated with organic compounds because it is difficult to identify and remove organic solutes from naturally occurring brines. Ion exchange has been used for iron removal.

There are two factors which make the costs of adequate pretreatment more acceptable. The first is the need for high water recovery, and the second is the increased public consciousness of water quality and the resulting need to better treat all waters intended for beneficial use. Table 18 presents cost data on pretreatment for several different brine systems and serves as the basis for the estimates to be used in this study.

Table 18. Raw water analysis in parts per million (ppm) and pretreatment costs for different brines

	Sample Brines			
Constituent	#1	#2	#3	#4
Calcium	216	394	119	348
Magnesium	79	259	72	215
Sodium	92	915	914	1,330
Potassium	0	23	16	0
Bicarbonate	356	480	475	140
Chloride	20	2,140	132	441
Sulfate	715	650	1,940	3,730
Nitrate	0	0	7	37
TDS	1,478	4,861	3,685	6,311
Total Hardness	866	2,050	594	1,755
M. O. Alkalinity	292	393	388	115
Carbon Dioxide	36	49	20	63
Iron	2	7	2	0.02
Manganese	1	4	1	0
Silica	20	32	20	58
pH	7.2	7.2	7.6	6.5
Temperature ^{o}F	48	80	58	80
Cost c/1000 gallons for 50 mgd*	9.6	7.0	18.3	19.8

*Mgd: Million gallons daily

Source: Mintz, M.S., "Pretreatment Systems for Membrane Processes," Paper presented at Symposium on Reverse Osmosis, Roswell, NM, Nov. 4-5, 1970.

Assuming that the multistage flash evaporation is the processing method chosen for the proposed Tularosa basin energy-desalination project, minimum acidizing would be three to four cents/1,000 gallons. This is equivalent to $9.80 to $13.00/acre-foot.

Desalination Process Description

Three processing methods are considered for desalination: (1) multistage flash evaporation (MSF); (2) reverse osmosis (RO); and (3) electrodialysis (ED). Both RO and ED use electrical energy as the primary energy mode whereas multistage flash uses steam. It was determined that in the proposed Tularosa basin dual purpose operation that the electrical power generators would be base loaded and this would be entered into the region's electrical utility grid. For this reason RO and ED were eliminated as potential desalination methods for the project. However, these two processes will be described briefly following discussion of the MSF process; for under a different basis, they may be viable alternatives for desalting Tularosa basin water.

Multistage Flash Evaporation (MSF)

The majority of operating units for desalting sea water are multistage, multi-effect, flash evaporators (International Atomic Energy Agency, 1968; McCabe and Smith, 1967; NcDermott, 1971). While there are a large number of patented variations on the actual physical design and mechanical operation of this type of equipment, the basic operation of a single stage is shown in Figure 16. Heated sea water (brine or brackish water) is released into a closed vessel which is maintained at a lower pressure than the vapor. The vapor, upon contacting the tubes (containing the incoming sea water), is condensed to form desalted water.

The multistage equipment is as shown in Figure 17. A sequence of single stages in series is arranged. Sea water is circulated through the different stages and acts as the condenser for vapors produced in each stage. The pressure is lower in each succeeding stage and more of the sea water evaporates. This sequence of equipment would constitute a single effect. If the unit were then coupled in series to another or several similar sets of stages in series, the unit would be a multistage, multi-effect evaporator. The technolgical basis was set at 1974 levels. Under this basis, multistage, multi-effect evaporation is the method to be used. Under an advanced technology, long-tube vertical evaporation would probably be used. Summaries of these processes obtained from the report of the joint United States-Mexico-International Atomic Energy Agency study follows (IAEA, 1968).

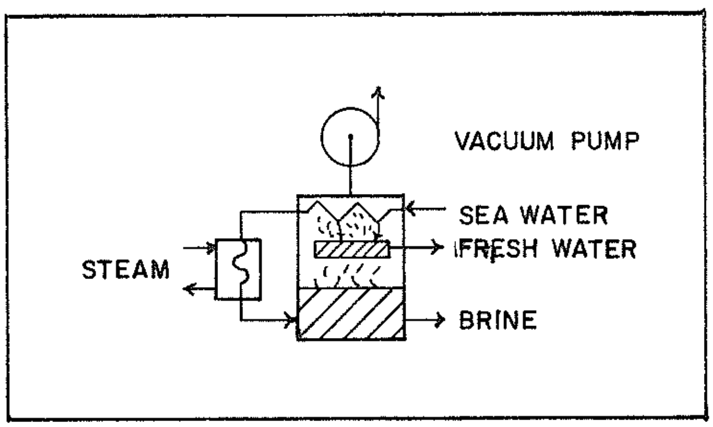


Figure 16. Single stage flash flow schematic.

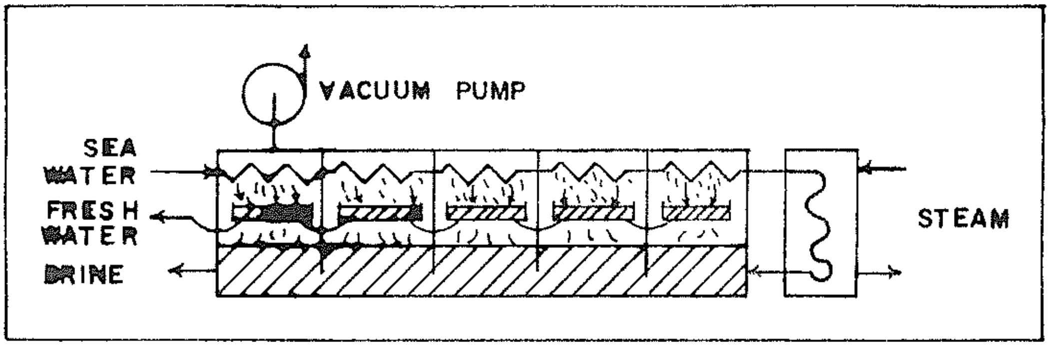


Figure 17. Multistage flash flow schematic.

In the absence of operating plants of the 250-million-gallon-per-day size, certain assumptions were made in relationship to desalting plant operating temperatures, materials of construction, heat-transfer rates, methods of scale control, and construction techniques. In all cases, these assumptions were based on obtaining minimum product water costs compatible with a planned 30-year plant component life. A maximum operating temperature in the desalting plant was assumed to be 250° F. This temperature level is compatible with sulfuric acid scale-control methods and with present-day materials operating characteristics. The main evaporator structures are constructed of steel for that portion of the plant operating above 200° F. and of reinforced concrete and steel for the low-temperature end. Exterior concrete walls, roof, and floor are lined on the inside with steelplate, which forms a part of the reinforcement and also seals the building to ensure vacuum and pressure integrity. The plant flows are divided into two desalting trains of 250 mgd each. Each train is housed in a structure increasing in width from 360 feet at the high-temperature end of the plant to 420 feet at the low-temperature end. The flash stage design incorporates two flashing brine levels and a product water tray. The condenser tubing is 0.035 inch wall, 90:10 copper-nickel alloy, and sufficient condenser tubing is installed in the plant to allow for tube plugging caused by failures. Tubes of up to 250 feet in length are used in the plant and a tube life of 30 years is anticipated.

The control of scaling in the condenser tubing is based on the use of the sulfuric acid treatment which has been successfully demonstrated and is used in a large number of present-day plants. With this type of feed treatment, a brine concentration of 2:1, i.e., to 70,000 ppm, can be tolerated. The Tularosa basin analysis was based on a concentration to 100,000 ppm. This was done based on a much lower magnesium content in the feed and a required production of 492 mgd compared to the design capacity of 500 mgd. However, by only taking the project brine to 70,000 ppm, product water would be decreased to 381,600 acre-feet/year (385,800 with 100,000 ppm). To keep the water that is being transferred to the reservoir at 1,000 ppm, 93,025 acre-feet per year of raw brine water is needed (94,000 when reject is 100,000 ppm), thereby reducing desalted water plus blend available by around 5,000 acre-feet every year. For purposes of this initial analysis, 100,000 ppm reject will be carried forward with the assumption that the acid treatment process is altered to such a degree that 100,000 ppm will be tolerable.

Table 19 presents the basic design parameters for the multistage flash plant (International Atomic Energy Agency, 1968). The plant is designed for a performance ratio of 12.8 (pounds of water evaporated per 1,000 BTU used). Each 250 mgd evaporator train is broken into 10 module streams, each delivering 25 mgd.

Table 19. Summary of MSF plant parameters*

Item	Parameter
Plant dimensions	
Evaporator, 250 mgd train, ft.	567 L x 420 W x 24 H
Water plant site dimensions, 1-bgd, ft	920 L x 1920 W
Performance ratio, lb product/1,000 BTU	12.8
Brine temperature range, °F	250 to 102
Concentration ratio	Approximately 20
Shell construction	Concrete and steel
Number of trains and product of each	2 at 250 mgd each
Module streams/train.	10
Number of flashing brine levels	2
Power requirements, MW	152
Number of stages of heat recovery	48
Number of stages of heat reject	2
Steam requirements, BTU/hr.	13.4×10^9
Deaerator design	
Number of spray stages	2
Water flow, lb/hr/ft²	20,000
Steam required, lb/100/lb feed	0.0033
Makeup water flow per train, lb/hr	172.25×10^6
Brine tray design	
Maximum flow lb/hr ft or width	1,000,000
Number per train	2
Width, top tray, ft.	27.33 (high temperature) 31.33 (low temperature)
Width, bottom tray, ft	36 (high temperature) 42 (low temperature)
Stage design	
Stage length recovery.	8 to 13 feet
Stage length reject.	42, 28 feet
Submergence loss, °F	0.8 to 2.4
Pumps and drives (all pumps are vertical dry-pit-type centrifugal pumps)	
Brine recycle	
Number of pumps.	8
Flow per pump, gpm	330,000
Pump head, ft.	160
Type of drive.	Synchronous motor
Brake hp	17,000
Deaerator feed	
Number of pumps.	4
Flow per pump, gpm	167,000
Pump head, ft.	25
Type of drive.	Synchronous motor
Brake of hp.	1,500
Product Water	
Number of pumps.	4
Flow per pump, gpm	86,000
Pump head, ft.	120
Pump speed, rpm.	450
Type of drive.	Synchronous motor
Brake hp	3,500
Blowdown	
Number of pumps.	4
Flow per pump, gpm	86,000
Pump head, ft.	42
Type of drive.	Synchronous water
Brake hp	1,250

	Evaporator recovery	Evaporator reject	Brine heater
Tube material	90:10 CuNi	90:10 CuNi	90:10
Velocity, ft/sec.	4.5	5	4.5
OD and wall, inches	0.75 x 0.035	0.75 x 0.049	0.75 x 0.035
Tube life, year	30	30	30
Overall U, BTU/ft-ft².	591	461	660
Fouling factor.	0.0005	0.0007	0.0005
Surface area, $ft^2 \times 10^6$	98.3	6.1	4.2
Tube length, ft	250,225	70	21
No. of tubes.	1,055,000	446,000	1,060,000
No. of tube bundles/stream.	4	2	4
Brine temp., in-out, °F			239.9 to 250
Steam temp. leaving turbine, °F			260
Steam flow, BTU/hr.			13.4×10^8

*Source: Clawson, M. and H.H. Landsberg, "Desalting Seawater-Achievements and Prospects," Gordon and Breach Science Publishers, New York, 1972.

Reverse Osmosis (RO)

Figure 18 presents a simplified schematic for a reverse osmosis cell. This process, the osmosis of ions, uses semi-permeable membranes allowing fresh water only to permeate the membrane and thus separate the brackish water into a fresh water and a concentrated brine. The driving force for the separation is chemical in origin and except for the pumping required to overcome the osmotic pressure no other power is required for the separation. RO is limited to efficient operation for limited feed concentrations (less than 5,000 ppm). Modular design readily lends itself to large installations currently producing greater than one mgd.

Electrodialysis (ED)

Figure 19 presents a simplified schematic of an electrodialysis unit. An electric field separates the anions to the right and the cations to the left. Permeable membranes allow ions to pass through in one direction only: permeable anion membranes (A) allow anions to pass through from left to right whereas permeable cation membranes (C) allow cations to pass through from right to left. Fresh water is formed in alternate cells.

Advanced Desalting Techniques

In the evaporator technology which could be considered applicable to a plant built in 2000, it would be assumed that the vertical-tube evaporator (VTE) process would have reached a level of development such that it could be applied to very large desalting plants. The VTE process has certain inherent advantages over the multistage flash (MSF) process based on 1974 technology. These are:

1. Higher theoretical thermodynamic efficiency which makes greater temperature-driving forces available.

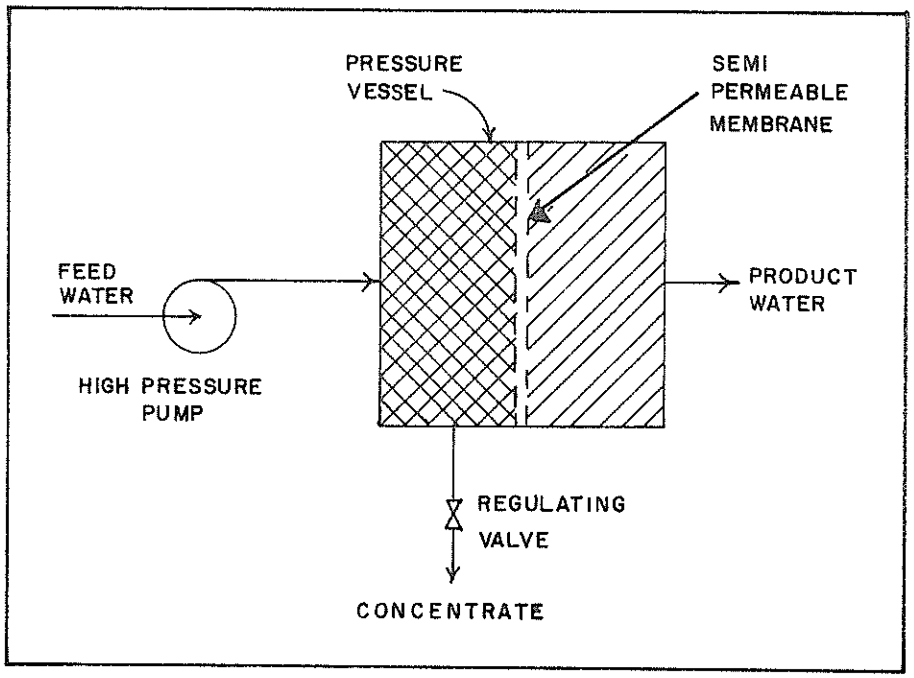


Figure 18. Reverse osmosis cell, flow schematic

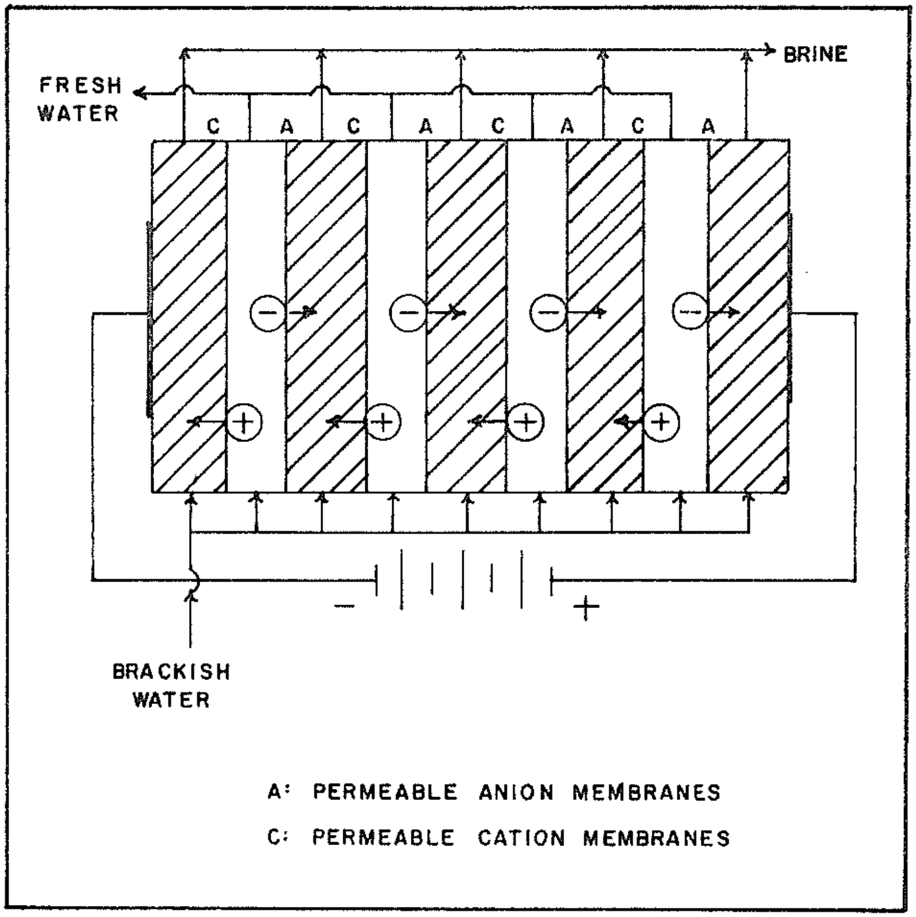


Figure 19. Electrodialysis cell, flow schematic.

2. Possibility of high-flux heat-transfer systems using evaporator tubes with new geometries.
3. Decreased pumping power and higher blowdown concentrations.

In addition to the choice of the VTE process for advanced plant application, certain assumptions can be made relative to operating conditions and capital and operating costs. At present, plans are underway to improve plant economics by extending the top operating temperature of distillation plants to 350° F. The possibility of going to this temperature rests on the suitability of water pretreatment systems so as to prevent scale formation. Three processes, the lime-magnesium carbonate process, the ion exchange process, and the carbon dioxide suppression (calcium sulfate seed process) may allow raising the temperatures to between 300° and 350° F. The present method of sulfuric acid pretreatment is not amenable to prevent scale at these temperatures.

It should be noted that the VTE process uses MSF for brine preheating. This incorporation of the MSF concept with VTE tends to improve system thermal efficiencies and enhance water delivery rate.

In relation to the structural considerations for an advanced VTE plant, a reinforced concrete and steel structure would be used for those plant stages operating below 250° F. Above this temperature, an all-steel structure would be employed.

Improved heat-transfer surfaces typified by double-fluted vertical tubes would be used in the VTE portion of the plant and spirally grooved tubes for the MSF portion. Heat transfer coefficients up to approximately 1,500 BTU/hr-ft^2 °F. are assumed for VTE and about 1,150 BTU/hr-ft^2 °F. for MSF portion.

A comprehensive review of materials to be used in heat exchange sections of the advanced plant shows the following:

1. Depending upon the pretreatment selected, aluminum could possibly be a practical evaporator material. Aluminum tubes would reduce heat exchanger costs to about 40 percent of 90:10 copper-nickel (based on 1968 data).
2. Titanium tubes having very thin gauges could be incorporated in evaporators. Depending on the production quantities and the minimum wall thickness used, it may be that titanium could show definite promise for reducing evaporator costs.
3. Development of ferous-based tubing having corrosion-resistant cladding or coatings is possible. This would be especially true if a lime-magnesium carbonate scale control method is used.

Advanced plant design considerations include water only alternatives. Figure 20 illustrates the effect of decreasing the ratio of power-to-water output. As temperature is increased above the assumed 300° F. maximum temperature, evaporator efficiency improves while the cost of water remains fairly constant. A plant operating at 325° F. would have a performance ratio of 15.5 pounds of water produced per 1,000 BTU of steam used compared with 13.6 pounds per 1,000 BTU of steam used for the 300° F. plant. For this increased temperature condition, using only back-pressure steam from a fast breeder reactor, the net electrical power would be reduced 25 percent (compared to 250° F. desalting plant operation). Additional water could be produced by increasing the evaporator temperature further if that were feasible, or by bypassing prime steam from the nuclear system to the evaporator. This type of desalting process would evolve into a water-only plant if mainly prime steam were supplied to heat the evaporators, the only power generation being for station pumping. The economics projected by Figure 20 indicate that the cost of water from a water-only plant would be about 12 percent greater than that from an optimized dual-purpose plant because the higher cost of prime steam relative to that of exhaust steam (does not include nuclear reactor). It should be emphasized that this modest cost penalty reflects the advantages to be gained both from the low-cost heat produced by advanced breeder reactors and the high efficiency to be achieved with advanced evaporators. Near-term, water-only plants lack these advantages and the water from them would be more expensive than that from near-term dual-purpose plants.

Desalting Plant Costs

Estimates of desalination capital costs from various sources are summarized in Table 20. Capital costs, in dollars-per-gallon daily of productive capacity, are shown for each unit of the dual-purpose plant. The following additional points refer to the development of the data in Table 20 (Clawson and Lansberg, 1972; MacAvoy and Wells, 1972):

1. The energy plant portion of the costs for dual-purpose plants producing water and electricity have been derived by using the available energy method or an approximation to this method based on estimated potential electrical output.
2. No adjustment has been made to compensate for different dates of source estimates. Since there has been a general price inflation over the period, estimates prepared earlier will on this account have lower dollar costs than more recent estimates.
3. Capital costs vary as a function of interest rate so that for purposes of comparison capital costs based on fixed charge rates of around five or six percent have been used.

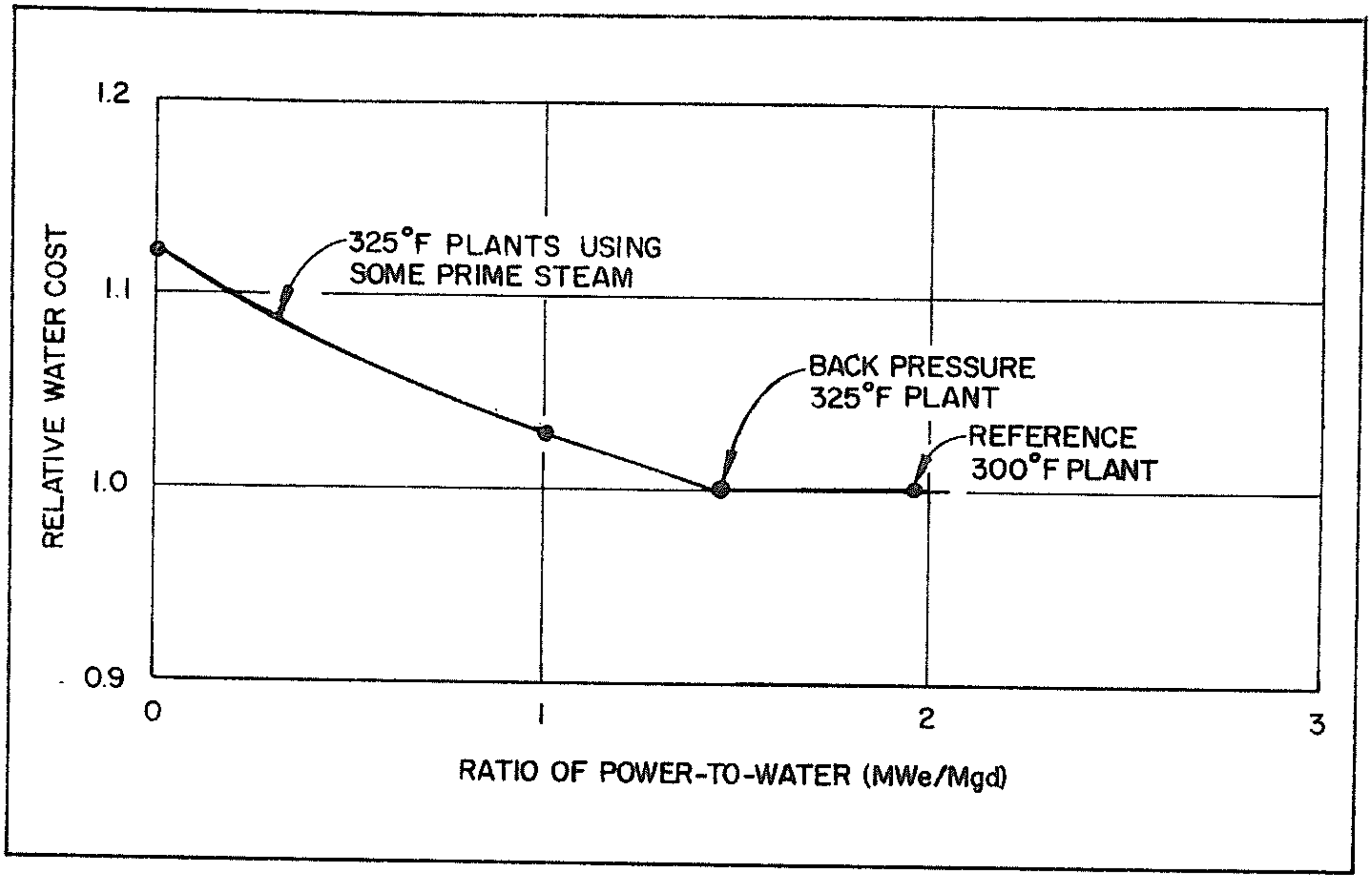


Figure 20. Relative water cost from large complexes producing power and water.

4. Land costs and product water conveyance costs have not usually been included because these two items are highly dependent upon the particular site involved.
5. In allocating capital costs between electricity and water, efforts were made to reduce the water capital costs at the expense of electric-power capital costs.

From Table 20 a number of observations can be made concerning the various total capital costs.

1. The most "realistic" of these estimates for large-scale plants based on the current MSF technology are the revised Kaiser Engineers study for the Israel plant and revised Bechtel study for the metropolitan water district (MWD) plant (see the second and third entries in Table 20). Both estimates, especially the revised MWD estimate, are more realistic than many of the others because contractual agreements for actual construction based on them were being considered.
2. In relationship to an actual bid by Westinghouse on a Keys West plant with a 2.62 mgd capacity and capital cost of $1.32 per gallon daily of capacity, it is interesting that essentially no decline in total unit capital costs occur in the Kaiser and MWD estimates, which are much larger plants.
3. The MSF alternative in the IAEA USA-Mexico Study and, to a greater degree, the Oak Ridge National Laboratory (ORNL) MSF water plant costs appear too low to be reconciled with the revised MWD costs.

Table 20. Summary of desalination capital cost estimates from various sources

Report	JIDDA, Saudi Arabia dual purpose plant	Revised study, dual purpose plant for Israel			Metropolitan water district plant (Rev.)		Desalting study for northern New Jersey and New York City						OSW Report No. 214: 250 MGD VTE-MSF	OSW Report No. 391: 250 MGD VTE-MSF
Report prepared by	Dept. of Int.	Kaiser Engineers			Bechtel		Ralph M. Parson Co.						Oak Ridge	Nat'l Lab
Plant size (mgd) water	5.0	100			150		100	150	300	100	150	300	250	250
Net power production-MW	34	298			1839		1,500						-not stated-	
Date of technology	1967	1970-1975			*		*						Mid 1970's	Late 1970's
Technical Description														
Desalination plant														
Desalination process	MSF	MSF			MSF		MSF						MSF	VTE-MSF
Module or train size (mgd)	2.5	25					50.0						50	62.5
Perf. ratio (lbs H_2O prod. per 1000 BTU)		8.43					10.36						10.0	13.1
Brine concentration ratio	1.4	2.0											2.0	2.5
Top brine temperature, °F	250	235					200 0						250	260
Power plant														
Gross power production, MW	36	351			1972		1,635	1,659	1,727	1,662	1,685	1,760		
Thermal output, Thermal MW		1,593					5,080	5,350	6,120	4,450	4,780	5,500	3,300	3,300
Heat source	Oil	BWR (or PWR)					BWR or PWR			Fossil Fuel			HWORC	HWORC
Cost Parameters														
Fixed charge rate	3.33	4.2	6.2	9.2	5.44	5.96	5.44	5.44	5.44	5.44	5.44	5.44	5.185	5.185
Index date of costs		Mid-1968			1968	1968	1965	1965	1965	1965	1965	1965	1965	1965
Water Costs														
Capital costs $ per gal. of daily cap.														
Energy plant	.336	.374	.392	.414	.239	.239	.175	.177	.169	.123	.124	.116		
Desalting plant	.912	.920	.975	1.043	.871	.871	.702	.687	.674	.672	.672	.659	.412	.361
Total	1.248	1.294	1.367	1.457	1.110	1.110	.877	.864	.843	.795	.795	.795		
Site land (or artificial island)					.087	.087								
Product water conveyance	.07	.250	.250	.250	.273	.273								
Unit steam and fuel costs ¢ per MBTU														
Fuel costs	17.5	11.5	11.5	11.5			11.5	11.5	11.5	29.0	29.0	29.0		
Exhaust steam costs													5.47	5.91
Prime steam costs													13.0	13.0
Unit water costs ¢ per 1000 gal.														
Fixed charges on energy plant	4.12	4.40	7.42	12.07	3.95	4.33	3.29	3.23	3.04	1.84	2.11	2.00		
Fuel	17.01	6.55	6.51	6.48	5.62	5.62	4.68	4.81	4.77	11.07	11.08	10.95	5.84	5.56
Energy plant O&M	1.75	1.43	1.44	1.46	.90	.90	.52	.56	.52	.35	.60	.38		
Nuclear insurance		.61	.61	.61	.38	.38	.42	.43	.40					
Fixed charges on desalting plant	0.0	12.30	19.37	30.85	14.43	15.81	11.68	11.53	11.32	11.68	11.53	11.32	6.50	5.70
Chemicals	3.04	3.10	3.10	3.10	2.39	2.39	3.05	3.07	3.06	3.05	3.07	3.06	1.38	1.38
Desalting plant O&M	13.94	3.83	3.87	3.91	2.94	2.94	3.72	3.09	2.59	3.72	3.11	2.59	2.10	2.36
Total ¢ per 1000 gal.	39.87	32.19	42.32	58.48	30.61	32.37	27.35	26.72	25.70	31.71	31.51	30.30	15.81	15.00
Site land (or artificial island)					.93	1.13								
Product water conveyance					5.27	6.09								
Other		2.47	2.58	2.77										
Electricity Costs														
Capital costs $ per KW cap														
Power plant	180	272	286	304	211	211	148	146	143	111	110	109		
Power transmission	132	17	17	17										
Total unit elect. cost mills per KWH	5.99	3.27	4.17	5.57	2.97	3.11	2.54	2.51	2.49	3.59	3.58	3.57	2.00	2.00

*Somewhat Advanced

Table 20. Continued.

Report	IAEA USA-Mexico study								Non-base load applications for nuclear dual-purpose plant design The Joint Seawater Desalting Project				U.N. desalination plant operation survey
Report prepared by	International Atomic Energy Agency Joint Team								IAEA w/ Mekorot Water Co. Ltd., Research & Desalting Division				United Nation, 1969
Plant size (mgd) water	1000								Base plant: 100		Non-base load: 44.3		2.25
Net power product. MW	1700				1867				300		435		15
Date of technology	Mid-1970's				1980's				1970-1975		1970-1975		1964
Technical Description											Plant remains physically identical to base plant; operating changes are made		
Desalination plant													
Desalination process	MSF				MSF-VTE				MSF		MSF		
Module or train size (mgd)	250				250				25		25		
Perf. ratio (lbs. H_2O prod. per 1000 BTU)	12.8				13.6				8.41				
Brine concentration ratio	2.0				2.5				2.0		2.0		
Top brine temperature, °F	250				300				232				
Power plant													
Gross power production, MW	2,160				2,330				349				
Thermal output, thermal MW	10,000				10,000				1,593				
Heat source	BWR				LMFBR				BWR				
Cost Parameters													
Fixed charge rate	3.65	5.68	7.66	9.66	3.65	5.68	7.66	9.66	6.0	9.0	6.0	9.0	
Index date of costs	1966-1967				1966-1967				1968		1968		1964
Water Costs													
Capital costs \$ per gal. of daily cap.											Additional investment= \$10.6 million		
Energy plant	.079	.085	.090	.094	.104	.111	.117	.123					
Desalting plant	.506	.536	.554	.584	.276	.299	.313	.326					
Total	.585	.621	.644	.678	.380	.410	.430	.449	2.10	2.23	2.206	2.336	4.83
Site land (or artificial island)													
Product water conveyance	.109	.115	.120	.125	.109	.115	.120	.125					
Unit steam and fuel costs ¢ per MBTU													
Fuel costs	10.9	12.1	13.1	14.1	-1.6	.2	1.7	3.1					
Exhaust steam costs	6.1	7.3	8.4	9.6	.6	2.6	4.3	6.1					
Prime steam costs	14.0	16.5	18.9	21.3	2.2	5.7	8.9	12.2					
Unit water costs ¢ per 1000 gal.													
Fixed charges on energy plant	.88	1.47	2.09	2.76	1.15	1.92	2.73	3.61					Dual invest-ment: \$6.9x10^5/year
Fuel													Fuel: \$6.38x10^5/year
Energy plant O&M	4.76	5.26	5.69	6.12	2.26	3.04	3.69	4.31			Peak/total operating time=1.00 Peak power value=200% of base power value		Dual O&M: \$5.55x10^5/year
Nuclear insurance													
Fixed charges on desalting plant	5.31	8.99	12.68	17.00	2.81	4.88	7.07	9.41					
Chemicals	5.03	5.35	5.64	5.98	3.06	3.26	3.49	3.74					
Desalting plant O&M													
Total ¢/1000 gal.	15.98	21.07	26.10	31.86	9.28	13.10	16.98	21.07	9.61 c/M^3 *	13.34 c/M^3 **	64% of base	72% of base	
Site land (or artificial island)													
Product water conveyance	.96	1.95	2.88	3.85	.96	1.90	2.83	3.81					
Other													
Electricity Costs													
Capital costs \$ per KWcap													
Power plant	89	95	101	105	98	105	111	116					
Power transmission											(Incremental peak power cost)		
Total unit elect. cost mills per KWH	1.87	2.31	2.75	3.20	1.10	1.61	2.11	2.63	4.13	5.58	6.36	9.05	

*Or 36.3 c/1000 gal.

**Or 50.4 c/1000 gal.

4. Similar conclusions hold concerning MSF energy plant capital costs. The low IAEA USA-Mexican Study MSF energy capital cost is a result of a conscious decision by that study team to ignore the rise in reactor costs since 1965.
5. In the study of the dual-purpose plant for non-base load applications (The Joint Sea Water Desalting Project) the reference system was a 1593 MWt boiling water reactor, a back-pressure turbine for the generation of 300 MWe net power and a 100 mgd desalting plant (Glueckstern, et al., 1972).

Computer programs were used to evaluate possible improvements in desalting plant effectiveness by using plant flexibility in accommodating equipment outages. Minor improvements were predicted. The economic evaluation indicates that non-base load systems may provide an economic alternative to other peak sources, especially if low fixed charge rates and high peak to total operating time ratios can be applied. In cases where additional peak power is required, and its cost from the most economic source, at specific economic conditions, is higher than that resulting from non-base loaded dual-purpose plants, considerable reductions in water cost may be obtained.

The final analysis of the "optimal" system for the Tularosa basin project dual-purpose plant would require a much more extensive analysis than has been possible under the present circumstances. Table 21 summarizes the best available estimates for the desalting costs of an MSF unit as described in Table 19. Table 22 details the method of estimation.

Actual capital outlay for the MSF plant would occur over a five-year time frame (construction phase) and amount to approximately \$300 million.[4] Annual operating costs would be on the order of \$12.5 million, which of course, excludes the electrical power requirements, but does include the pretreatment or acidification costs.

Reject Brine Treatment

The reject brine èffluent from inland desalting plants presents either a pollution problem or a source of minerals. As a potential pollution problem the brine can neither be returned to natural surface drainage systems nor reinjected economically into brine aquifers. In the Tularosa basin, it may be feasible to run the brine as is, a slurry, to a salt bed some distance from the energy-desalination complex and not pollute the well field. This option will not be discussed, however, due to lack of adequate data. The disposal method is therefore to process it into a solid for storage, insuring that there is no leaching and subsequent infiltration of solutes into groundwater. As a source of minerals, desalting plant reject brine is competing with sea water and other naturally occurring brines for the market for inorganic chemicals. The success of mineral recovery depends on location and chemical composition of the brine, and will be considered first, with mineral recovery covered in the next section.

As described in the previous section, the reject brine will have a concentration of 100,000 ppm and be produced at the rate of 20,200 acre-feet/year. The feed will have been

[4] The \$300 million estimate was derived by working backward from the \$ per gallon of daily capacity capital charges. Dollar per daily capacity charge was, in fact, based upon the project parameter of a 30-year life, plus an annual interest charge of six percent. In addition, a comparable estimate of total capital expenditures can be developed from the IAEA 1972 study. By scaling down the 1,000 mgd IAEA Mexican proposal to a 500 mgd project and adjusting the then 1968 cost, \$200 million, to 1974 prices, an estimate of slightly over \$300 million is obtained.

Table 21. Multistage flash (MSF) desalting plant costs*

Cost Item	Cost Parameters Fixed Charge Rate (Approximately) 4.0	6.0	9.0
Capital cost-desalting plant			
$ per gallon of daily capacity	1.2425	1.3126	1.3991
Unit water costs			
¢ per 1000 gallon (25 ppm)	25.375	33.36	46.099
$ per acre foot (1000 ppm)	66.48	87.39	120.77

*1974 dollar basis

Table 22. Multistage flash (MSF) unit cost calculation

	Fixed charge (percent)	Cost per gallon daily capacity (dollars)	Cost per 1000 gallons (dollars)	Index**
100 mgd (1968)*	4.2	1.294	.3219	113.7
	6.2	1.367	.4282	
	9.2	1.457	.5848	
150 mgd (1968)	5.8	1.110	.3149	113.7
250 mgd (1974)	4.0	1.2425	0.25375	174.8
	6.0	1.3126	0.3336	
	9.0	1.3991	0.46099	

Basis: Williamson exponential factor method (used for developing scale factors for increased capacity from known examples).

*See Table 20.

**See Figure 17.

pretreated with an acid (sulfuric) before proceeding to the MSF process. This analysis assumes that there has been neither scale nor sludge deposition in the evaporation phase. For the Tularosa basin project the economical process for the treatment of the brine is solar evaporation in a lined pond.

Solar ponds with a 1/32 inch nylon reinforced butyl rubber lining represent the lowest cost universally applicable disposal method for areas with over 32 inch net evaporation per year. Disposal costs vary from 29 cents per gallon of fresh water for areas having 32 inches net evaporation of 12 cents per 1,000 gallons of fresh water for areas having 80 inches net evaporation (Riley, et al., 1970; Ganiaris, et al., 1970; and Standiford, et al., 1970). (These costs assume land costs $3,000 per acre). The Tularosa basin has approximately 68 inches of net annual evaporation in the plant areas. Land costs are about $50 per acre in the non-farmed areas at this time. Table 23 summarizes the cost of reject brine disposal by solar evaporation.

Table 23. Reject brine disposal by solar evaporation: summary of pond costs

	Lining Material					
	50-Acre Pond[a]		300-Acre Pond[b]		3,600-Acre Pond[c]	
	PVC	BUTYL	PVC	BUTYL	PVC	BUTYL
	($/acre)					
Capital Cost						
Land	50	50	50	50	50	50
Dike construction	2,982	2,982	1,153	1,153	1,153	1,153
Lining & cover	8,690	14,250	8,690	14,250	8,690	14,250
Miscellaneous	1,152	1,840	449	718	449	718
Total per acre	12,874	19,122	10,342	16,171	10,342	16,171
Total	(643,700)	(956,100)	(3,102,600)	(4,851,300)	(37,231,200)	(58,215,600)
	($1,000/year)					
Annual Operating Cost						
Labor	7.5	10.5	33.0	52.0	330	520
Supplies	7.5	10.5	33.0	52.0	330	520
General & Admin	4.5	6.0	19.5	31.5	195	315
Insurance, interest and depreciation	41.0	62.4	202.6	316.8	2,431	3,802
Total	60.5	89.4	288.1	452.3	3,286	5,157

[a]Pond dimensions: length-2,090 ft., width-1,045 ft., and dike height-8.0 ft.

[b]Pond dimensions: length-5,100 ft., width-2,550 ft., and dike height-4.5 ft.

[c]Pond dimensions: length-5,100 ft., width-2,550 ft., and dike height-4.5 ft.; evaporation ponds would be built in modules with a maximum of 300 acres each.

The quantity of solid waste, e.g. mixed salts is 6.801×10^9 pounds per year using an estimated bulk density of 105 pounds per cubic foot.[5] This is equivalent to a 100-acre block piled 10 feet high. Over the 30-year life of the project this would give a 1,000-acre block 30 feet high. Storage of this material would require safeguards against ground-water contamination from leaching of these salts into rain runoff. This would be expensive unless these salts were stored in an area of the basin in which there was no groundwater which was not saturated. Transportation of the reject brine to such an area before concentrating to dryness would remove the requirement that the ponds be lined, however, the only economical means of transportation would be gravity flow in an open channel. (Depending on quantity of blowing dust the expense of a closed conduit may be justified). If the reject brine were to be handled in this manner, the site selection for the desalting plant would have to consider the elevation requirement; that is location at an elevation sufficient to allow gravity flow of the brine to disposal ponds.

[5]Pounds solid: $500{,}000 \frac{\text{acre-feet}}{\text{year}} \times 325{,}800 \frac{\text{gallons}}{\text{acre-feet}} \times 8.35 \frac{\text{pounds}}{\text{gallon}}$

$$\times\ .005 = 6.801 \times 10^9 \text{ lbs/yr}$$

(Estimated bulk density = 150 lbs/ft.^{3}) $= 4.534 \times 10^7 \text{ ft}^3$ = volume of solids

Mineral Recovery

Mineral recovery will be covered under three subcategories: (1) solid removal during pré-treatment of evaporator feed; (2) processing of brine for salts; and (3) trace metal recovery from aqueous feeds. As a source of minerals, the Tularosa basin brines may have significant potential if the necessary energy is readily available. While this study has looked only at waters in the 1-10,000 ppm range, there are brines within the basin which are saturated. More detailed analysis of these brines is required to accurately evaluate the mineral recovery potential of the basin. In addition, most of the following is developed in terms of sea water feed. The processes, however, should be applicable to the Tularosa basin feed.

Precipitation of Scale Formers from Salt Solutions

As discussed under the pretreatment section of the principal scale formers are calcium carbonate, magnesium hydroxide, and calcium sulfate. As scale they are detrimental. Potentially, they can be removed as mineral products (through chemical treatment) solving the scale problem and providing a marketable product (Diluzio, et al., 1966; Ennis, et al., 1967).

Phosphate Precipitation

A simplified flowsheet is given in Figure 21 for the removal of scale formers from sea water, with the simultaneous production of a phosphatic by-product raw material for the manufacture of fertilizer.

Phosphoric acid is added to sea water in a reactor followed by sufficient ammonia to produce a slurry of pH 8.5. The mixture of precipitated phosphates and sea water is discharged to a clarifer. After the phosphates have settled, the clear overflow is pumped to the saline water conversion plant. The phosphate slurry (underflow from the settler) is pumped to the dehydrator and maintained at 195° F. for one hour and then filtered. In practice the resulting solids would be sent to a fertilizer plant where they can be mixed with potash and other fertilizer materials and then granulated, dried, screened, and finally bagged.

The amounts of phosphoric acid and ammonia utilized stoichiometric to the magnesium and calcium concentrations in the sea water as needed for the precipitation of magnesium ammonium phosphate and dicalcium phosphate as shown in the following equations:

$$MgCl_2 + H_3PO_4 + 3NH_3 + 6H_2O \rightarrow MgNH_4PO_4 \cdot 6H_2O + 2NH_4Cl \qquad (4)$$

$$CaCl_2 + H_3PO_4 + 2NH_3 + 2H_2O \rightarrow CaHPO_4 \cdot 2H_2O + 2NH_4Cl \qquad (5)$$

In pilot tests with sea water, phosphate recovery was 77 percent but it appears 90 percent may be reasonably anticipated. However, maximum recovery of ammonia is about 28 percent, most of the remainder being present in the treated sea water as fixed ammonia. While magnesium ammonium phosphate has many desirable features as a fertilizer, e.g. low solubility, low release, rate of release can be controlled by granule size, non-leachable, will not burn plants in overdosing, and nutrients remain available over a long period of time, local production of ammonia and phosphoric acid would be required. Further, the dilute nature of the Tularosa project feed (5,000 ppm) would require exceptionally large equipment and losses would be higher. However, as a treatment method for the concentrated reject, it perhaps would be satisfactory.

Lime-Magnesium Carbonate Precipitation

The lime-magnesium carbonate process for sea water pretreatment is designed to remove calcium, eliminate bicarbonates and reduce carbonate alkalinity to some minimum level corresponding to the

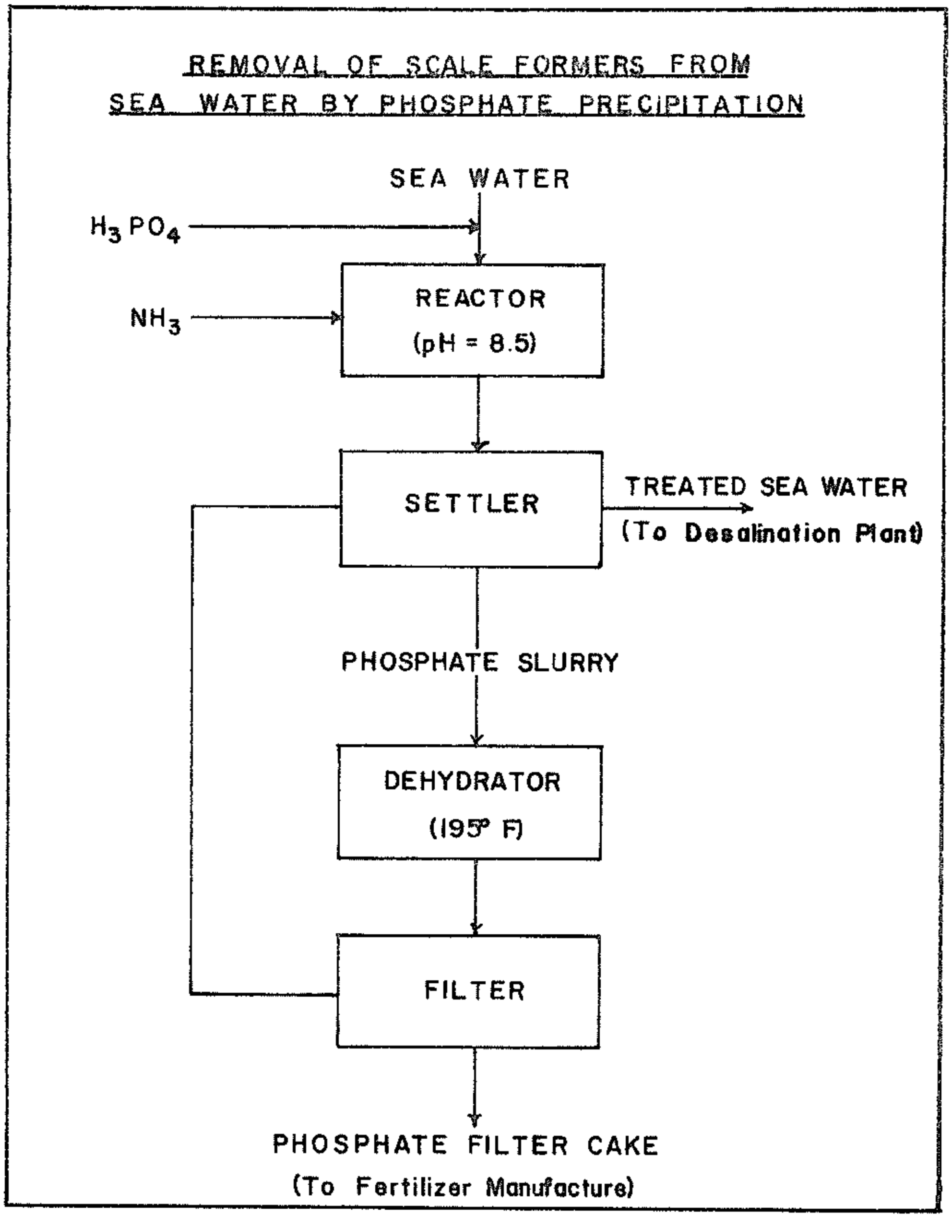


Figure 21. Flowsheet of removal of scale formers from sea water by phosphate precipitation.

amount of calcium removed. The treatment reactions proceed as follows:

Step 1 - Addition of magnesium carbonate for calcium removal (6)

$$CaCl_2 + MgCO_3 \rightarrow MgCl_2$$

Step 2 - Addition of lime for bicarbonate conversion and additional calcium removal (7)

$$Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + 2H_2O$$

Both reactions are carried out with vigorous agitation. Separation of precipitated calcium carbonate takes place in a clarifier, and a portion of the underflow solids is recycled to the raw water inlet to provide seed material for further precipitation.

This system is similar to the classical lime-soda ash process for municipal water softening, with the exception that the magnesium carbonate trihydrate ($MgCO_3 \cdot 3H_2O$) has been substituted for sodium carbonate and the order of addition is reversed. Figure 22 is a simplified flow schematic of the process. Make up lime is required and because of the large quantities of dilute feed it would not be economical for mineral recovery alone. Typical costs would be seven to ten cents/1,000 gallons.

Ammonia-Ammonium Carbonate Process

A proposed process for descaling sea water and simultaneously producing high-grade magnesia utilizes the addition of ammonia and carbon dioxide to sea water to remove calcium as calcium carbonate. Additional ammonia is then added to precipitate high-purity magnesia. After the magnesia has settled, the thickened magnesia slurry is filtered, washed, dryed, and then calcined to produce periclase (MgO). Ammonia is recovered and recycled by treating the concentrated brine from the evaporator with lime. Limestone is calcined to serve as the source of both lime and carbon dioxide.

Comparison of the ammonia-ammonium carbonate treatment with the phosphate descaling process indicates a considerable similarity between the two processes. The calcium removal step (i.e. precipitation of calcium carbonate) in the magnesia process could be retained for the phosphate

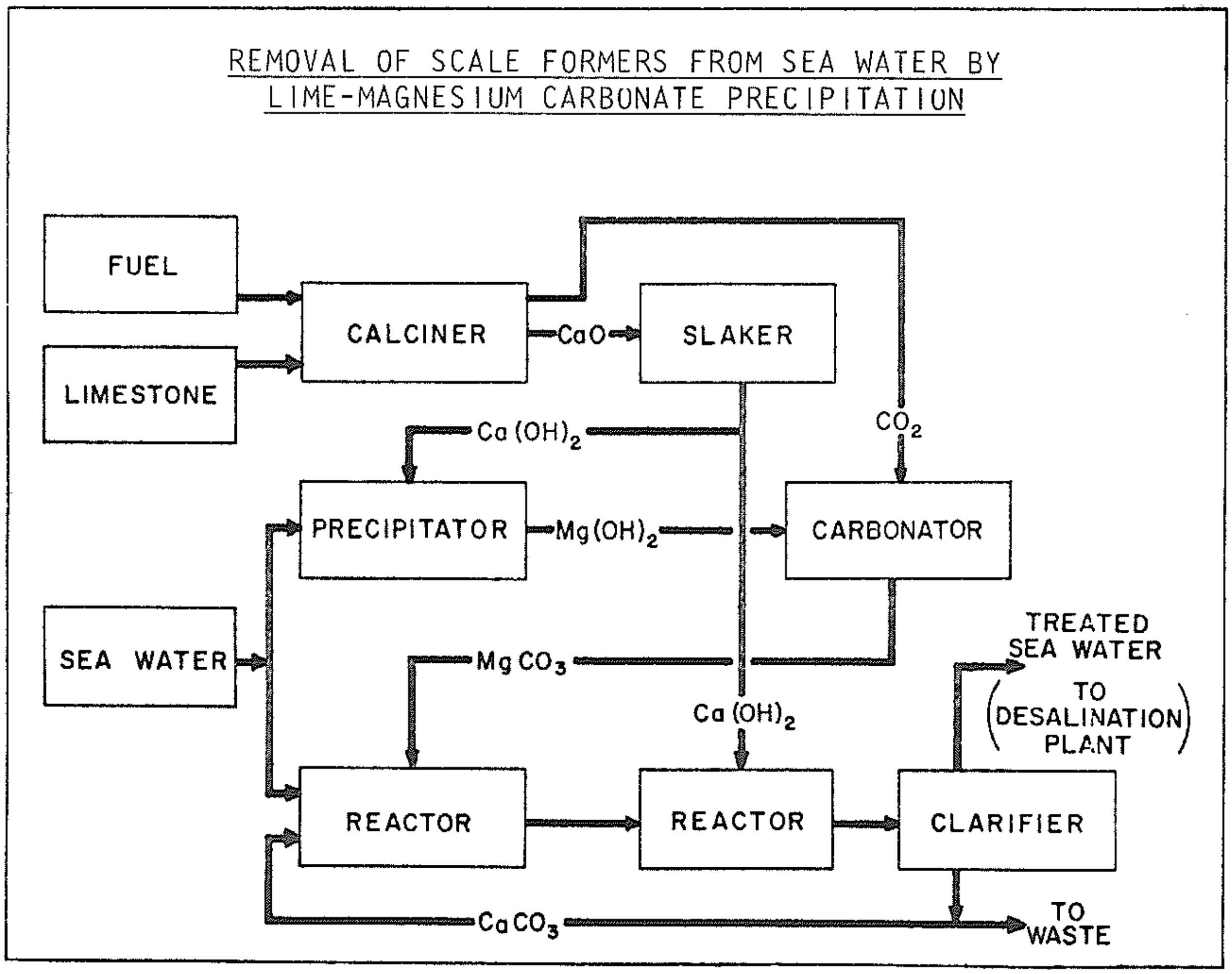


Figure 22. Flowsheet of removal of scale formers from sea water by lime-magnesium carbonate precipitation

process, thereby producing a fertilizer of slightly higher quality. The only other essential difference in the two processes is the addition of phosphoric acid required for the production of the fertilizer. It may be possible that the plant could be designed to produce both fertilizer and high purity magnesia, switching from one product to the other depending on market requirements. However, under certain market conditions, but hopefully for only short periods of time, both products may be in over supply. The plant could operate in these periods as a descaling plant to cover costs.

Lime-Soda Process

Since calcium is a more difficult scaling element to control than magnesium, much research has been done on decalcifying brine and sea water. The classical lime-soda process for the treatment of boiler water was applied to brine and sea water. In this process the water is first treated with a small amount of lime to convert the soluble calcium bicarbonate to insoluble calcium carbonate.

$$Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + 2H_2O \tag{8}$$

The water is next treated with soda ash (Na_2CO_3) to precipitate soluble calcium (present as the chloride of sulfate) as the insoluble carbonate.

$$CaCl_2 + Na_2CO_3 \rightarrow CaCO_3 + 2NaCl \tag{9}$$

$$CaSO_4 + Na_2CO_3 \rightarrow CaCO_3 + Na_2SO_4 \tag{10}$$

Approximately eight pounds of soda ash per 1,000 gallons of sea water are required to remove 90 percent of the calcium. Since the soda ash sells for about 1.5 cents/lb the raw material cost would be about 12 cents/1,000 gallons.

Desulfating with Barium Compounds

The desulfating process utilized is dependent on the handling of large volumes of barium chemicals. Barium is chemically similar to lead and, as such, is mildly poisonous in some of its forms. This condition introduces a requirement for more stringent operating procedures, and a continuous monitoring of operator health, possible build-up in effluent discharges, and a control of the plant's barium balance.

Removal of sulfates from desalting plant feed water appears technically feasible. Figure 23 is a simplified process flow schematic. The steps are:

1. Contacting brine with the barium form of cation exchange resin. This removes the sulfate ion and the carbonate ion as the barium salt, converting the resin to the sodium form.
2. Separating the desulfated brine from the resin and precipitated salts.
3. Converting the barium precipitate by roasting in a reducing atmosphere to convert the barium to a soluble form. For this purpose, the barium precipitate is compounded with carbon, such as pulverized coal.
4. Leaching the calcine to dissolve the soluble barium salts, forming barium hydrosulfide and barium hydroside. By conducting this operation in a hydrogen sulfide atmosphere, all of the barium is converted to the hydrosulfide.
5. Regenerating the sodium form of the resin with soluble barium salts.
6. Recovering by-product hydrogen sulfide and sodium bicarbonate from the solutions leaving the regeneration step.

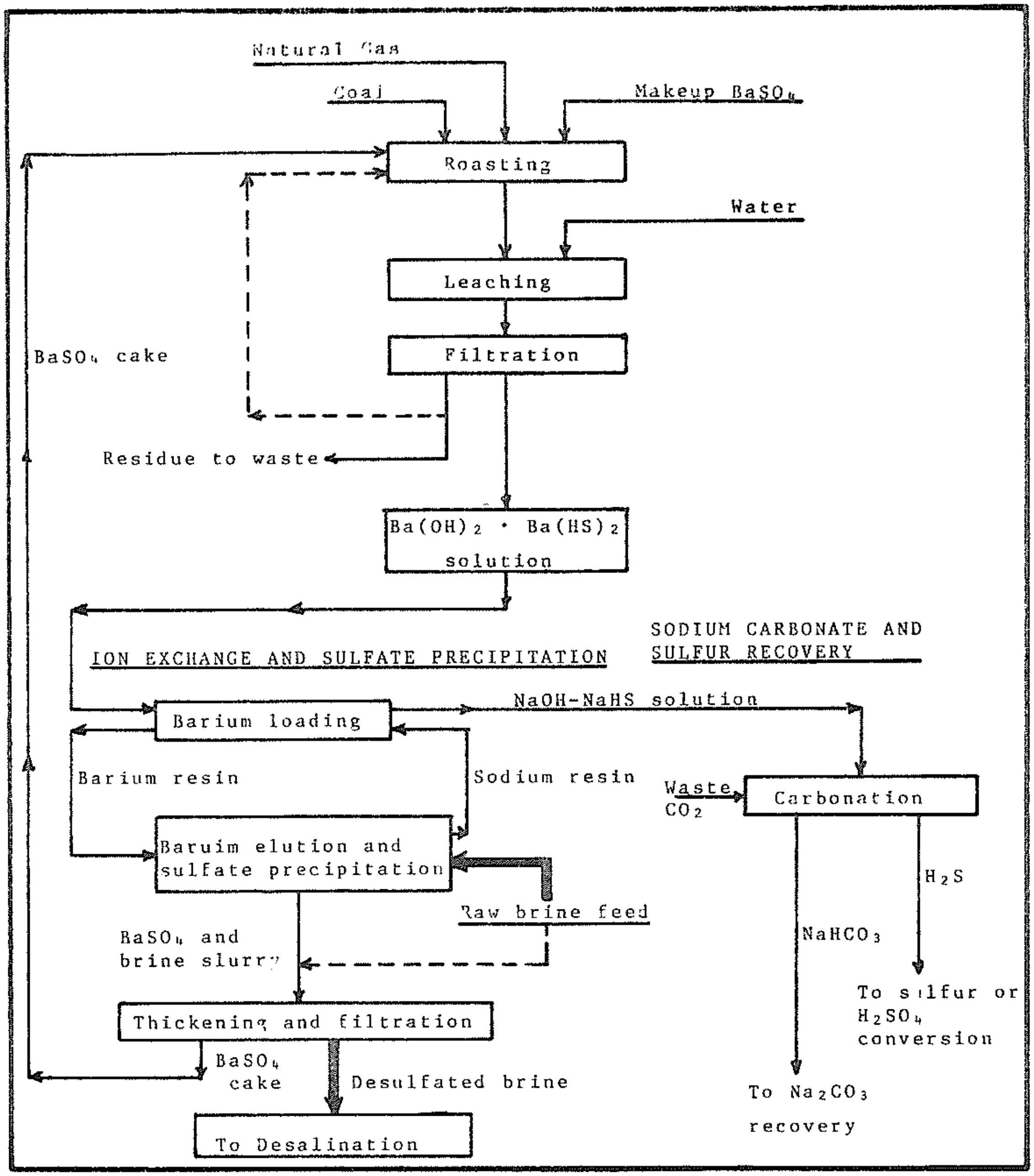


Figure 23. Flowsheet of sulfate removal process

Source: Ennis, C. E., et al., "Evaluation of Brine Desulfating Process as Applied to Desalination-Phase 1," R & D Report No. 289, U. S. Dept. of Interior, Washington, D.C., October 1967.

Processing of Brines

The processing of brine for salt is one of the oldest industrial processes (Office of Saline Water, 1970; United Nations, 1965). As an industry it has a long and continuous growth and is widely disbursed throughout the world. Sea water (35,000 ppm) and inland salt seas or underground brines (up to 300,000 ppm) are widely distributed, however, those brines that are processed are usually characterized by having only a few chemical compounds which are specifically being recovered. Very rarely are all the possible products of a given brine consumed, i.e. there will still be a residue which will have to be stored. Table 24 presents sample compositions of some of the brines that are currently being processed. To compete with these as feed stocks, the reject brine from the Tularosa basin desalting plant could require concentration. As discussed previously this could be readily accomplished by solar evaporation. As shown in Table 24, this Tularosa project reject brine compares favorably with sea water for certain chemicals. Concentration of the reject brine to 90 percent of saturation would indicate that it is a competitive source of magnesium salts with other brines currently being processed for magnesium. Calcium chloride is a second possibility but would be doubtful without new processing because of the presence of sulfate, i.e. $CaSO_4$ would be a more likely product. The presence of SiO_2 in the Tularosa basin reject brine would require extensive chemical development before an analysis of suitable processes for the other materials could be made.

Table 24. Survey of brines being processed

		Tularosa basin desalting plant reject brine	Dead Sea brine	Great Salt Lake	Michigan brines (composite)	Owens Lake Calif.	Sea Water
		(ppm by weight)					
Constituent							
Sodium		9,720	32,750	80,008	41,862	127,100	10,890
Potassium		*	7,329	7,594	8,794		400
Magnesium		4,460	40,170	4,754	8,890		1,330
Calcium		12,850	15,135	4,982	45,600		430
Cl		17,580	198,813	133,865	173,790	103,800	19,680
Br			5,946		1,867		70
Other	SO_4	47,550		26,071		27,700	2,740
	HCO_3	6,710					80
	SiO_2	1,060					
	I_2				50		
	B					3,010	
	CO_3					56,600	
Products							
			Bromine	Sodium Chloride	Bromine	Borax	
			Ca Cl_2		Ca Cl_2	Sodium Carbonate	
			Carnallite (K Salt)		Iodine		
			Lithium Salts		Mg $(OH)_2$		
			Magnesium Salts		K Cl		

*Included in sodium

Trace Metal Recovery

There is limited data available on the trace metals in the Tularosa basin brine. Table 25 is an average of 17 wells in the Alamogordo-Tularosa area. Table 26 includes a more detailed analysis of wells in this region. Shown in Table 25 are tons for each of the trace elements handled per year. The fourth column of Table 25 gives the U. S. consumption of each of these elements in 1973. None of the trace metals available from the Tularosa basin reject brine would be a major new source for U. S. consumption, with the possible exception of selenium (Kelley, et al., 1975; Cadman, et al., 1974).

Table 27 gives a summary of methods for extracting trace metals from aqueous systems.

Table 25. Average chemical analysis of 17 wells in the 1,000 to 10,000 ppm TDS range in the Alamogordo-Tularosa area

Component	Chemical analysis (ppm)	Total element per year (tons)	Apparent U.S. consumption 1973 (tons/yr)
Total dissolved solids	2,771.24		
Calcium	371.25		
Magnesium	119.24		
Sodium	382.42		
Potassium	1.85		
Chloride	767.45		
Fluoride	.44		
Sulfate	875.71		
Bicarbonate	196.07		
Silica (SIO2)	21.00		
Nitrate	4.75		
Phosphate	.01		
Total iron	.44	299.2	142,800,000
Boron	.39	265.2	1,312,000**
Manganese	.05	34.0	
Arenic	.03	20.4	
Barium	.44	299.2	1,525,000*
Cadmium	.01	6.8	6,235
Chromium	.04	27.2	1,400,000***
Copper	.02	13.6	2,350,000
Lead	.02	13.6	1,550,000
Zinc	.13	8.8	1,520,000
Nickel	.07	47.6	20,000
Silver	.04	27.2	5,843
Selenium	.01	6.8	625

*As barite
**As borate
***As ore

Table 26. Detailed analysis of selected wells in the Tularosa basin

	Alamogordo 2 Alamogordo Well # 2 133	Alamogordo 3 Alamogordo Well # 3 133	Alamogordo 4 Alamogordo Well # 4 133	Alamogordo 5 Alamogordo Well # 5 133	Alamogordo 6 Alamogordo Well # 6 133	Alamogordo 7 La Luz Canyon Spring 133	Alamogordo 8 Fresnal Canyon Spring 133	Alamogordo 9 Caballero Canyon Spring 133	Alamogordo 10 & 11 Alamo. Canyon Spring 1 N. 2 S. 133	Alamogordo 13 Bonito Lake 133
Latitude Longitude	32-58-30 105-56-30	32-58-30 105-56-30	32-54-50 105-56-50	32-54-50 105-56-50	32-56-20 105-57-00	32-59-15 105-48-15	32-57-30 104-48-15	32-53-00 105-49-30	32-51-20 105-50-00	33-27-30 105-41-45
Sodium	135.70	142.60	142.60	138.00	214.60	131.60	109.70	20.70	20.70	12.60
Potassium	1.95	1.95	1.95	1.95	4.29	1.56	1.56	4.29	4.29	0.78
Calcium	170.00	167.00	189.00	217.00	197.00	198.60	184.00	129.00	129.00	45.60
Magnesium	61.00	61.60	68.30	58.60	85.40	43.40	79.30	35.90	35.90	9.90
Iron-Total	0.25	0.25	0.25	0.25	0.25	0.25	0.95	0.25	0.25	0.25
Manganese	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Chloride	180.00	200.00	210.00	236.00	297.60	214.00	150.80	23.60	23.60	10.40
Fluoride	0.16	0.13	0.12	0.12	0.23	0.11	0.10	0.10	0.10	0.21
Nitrate	1.70	1.60	3.00	2.40	0.20	1.80	2.20	6.10	6.10	0.80
Bicarbonate	242.80	233.80	241.60	258.60	209.80	349.70	100.00	285.50	285.50	80.00
Carbonate	None	5.40	None	None	None	None	None	None	None	2.90
Sulfate	452.20	440.00	477.60	566.00	615.00	413.00	626.00	225.00	225.00	81.00
Phosphate	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.06
Total Hardness	675.00	670.00	752.50	782.50	842.50	674.50	785.00	469.50	469.50	154.50
Alkalinity	199.00	196.00	198.00	212.00	172.00	286.60	82.00	234.00	234.00	68.00
Total Dissolved Residue	1,360.00	1,337.00	1,495.00	1,625.00	1,802.50	1,302.50	1,492.50	712.50	712.50	285.00
Surfactants	0.05	0.05	0.05	0.05	0.05	0.05		0.05	0.05	
pH	7.95	8.95	8.10	8.10	7.75	8.00	8.20	7.95	7.95	8.65
Odor	None	None	None	None	None	None	None	None	None	None
Color	None	None	None	None	None	None	None	None	None	None
Turbidity	6.15	5.25	4.50	5.10	5.40	5.40	84.50	19.00	19.00	8.60
Conductance Micromhos/cm 25°C	1,653.60	1,738.40	1,881.50	1,908.00	2,279.00	1,738.40	1,722.50	890.40	890.40	339.20
Arsenic		0.040	0.040	0.040	0.040	0.010	0.010	0.010	0.010	0.040
Barium	NA	0.500	1.000	0.500	0.500	0.500	0.500	0.500	0.500	0.500
Boron	NA	0.500	0.500	0.250	0.500	0.250	0.250	0.250	0.250	0.500
Cadmium	NA	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Chromium	NA	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Copper	NA	0.025	0.040	0.025	0.050	0.025	0.025	0.025	0.025	0.025
Cyanide	NA	--	--	--	--	--	--	--	--	--
Lead	NA	0.011	0.010	0.010	0.010	0.040	0.030	0.010	0.010	0.010
Mercury	NA	--	--	--	--	--	--	--	--	--
Molybdenum	NA	--	--	--	--	--	--	--	--	--
Nickel	NA	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100	0.100
Silver	NA	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Selenium	NA	0.015	0.018	0.025	0.027	0.010	0.010	0.010	0.010	0.026
Zinc	NA	0.052	0.025	0.025	0.025	0.025	0.040	0.025	0.025	0.025
Radium 226	NA	--	--	--	--	--	--	--	--	--
Strontium	NA	--	--	--	--	--	--	--	--	--
Gross Beta	NA	--	--	--	--	--	--	--	--	--

NA: Data not available

Table 27. Summary of techniques for removing metals from aqueous systems

Method	Source	Reagents	Concentration	pH Range	Ions
Extraction	Water	Ammonium pyrrolidine, dithiocarbamate, methyl-iso butyl Ketone chloroform	Several ppb	4.5-6	Cu, Pb, Ni, Zn, Cd, Co, Mn, Mo, V
Foam separation	Industrial processes	N_2, surfactant	0.06 g/l and lower	5.5-6	Ni, Cr, Co, Sr
Autoclaving	Biological samples	Steam	ppb	--	Ti, Cr, Cu Pb, Mn, Sn
Adsorption on alumina	Radioactive rinse water	--	Up to 1x 10^3 moles/l	8.0	Sr
Aeration	Municipal & industrial water supplies	$KMnO_4$, activated carbon	0.2 mg/l	--	Mn, Fe
Manganese zeolite bed	Municipal & industrial water	$KMnO_4$, anthracite	0.2 mg/l	--	Mn, Fe
Ultraviolet radiation & magnetic field	Seawater, freshwater, industrial streams	--	--	--	All
Paper chromatographic separation	--	Mixture of chloroform, methanol, acetone, isopentanol & formic acid, TNOA-HCI	ppb	--	Cu, Pb, Cd, Bi, Hg, Mn, Co, Ni, Cu, Zn, Fe
Rotating electrodes	Process streams, seawater	--	--	--	All
Biological	a. Acid mine waters	Yeasts, sulfur, glucose	10's of mg/l	3.5	Cu
	b. Municipal & industrial water streams	Bacteria			Fe, Mn
Ion Exchange					
Chelex-100	Sea & fresh water, process waters	HCI	Varies	5-6	Cu, Pb, Cr, Ni, Zn, Co, Cd, Mn
Chitosan	Salt water	EDTA	ppb(varies)	--	Mn, Ti, Cr, Pb
Amberlite	Process liquid	Eluant	Varies	--	Cd, Co, Cu Pb, V, Zn, Ni
Titanium arsenate		$NH_4NO_3+HNO_3$	Varies	--	Pb, Cu, Cd, Sr, Zn, Mn, Ni, Co
Permutit-S1005	Seawater	Eluant	ppb	7.6 5.0(Mo,Cr) 6.0(V) 9.0(Mn)	Cd, Co, Cu, Pb, Ni, Zn, Cr
DeAcidite FF + dibromo-oxine	Seawater, cooling tower blowdown	HCI or H_2SO_4	ppb 200 ppm	--	Co, Zn, Cr,
Zeo-Karb 225	Process streams, rain water	H_2SO_4	ppb	--	Sr
Dowex	Water, process streams	Eluant	100 ppm	Varies	Ti, Sr, Mo, Cd, Cr, Cu, Zn, Pb
Precipitation					
Thioacetamide		HCI	ppb(varies)	0.75 8.0	Cd, Cu, Pb, Cr, Ti, Zn, Mo
Metal sulfides	Cooling tower blowdown	HCI	15-200 ppm	2.3	Cr, Mo, Sr, Cu, Ni, Co
Dibromo-oxine	Seawater	Acetone	ppb	8.0	Cu, Zn, Co, Mn, Pb, Cr
Potassium Ferrocyanide	Electroplating solutions	Activated carbon	--	--	Pb, Sn, Cd, Zn, Fe, Ni, Co
Dialkyldithiocarbamates	Process streams	--	70 ppm	4.2	Zn, Cu, Fe
Oxalate or sulfate	Radioactive rinse water	--	40 ppb	--	Sr
Polyelectrolytes	Process solvents	Polygalacturonic & alginic acids	mg/l	4.0-4.5	Cu, Cd, Zn, Ni, Cr
Aluminum sulfates	Industrial & municipal water	--	0.20 mg/l	6.8-7.0	Pb, Cu, Cr, Cd, Zn, Ni
Lime	Industrial & municipal water	--	0.26 mg/l	9.6	Mn & Others
Carbonates	Industrial & municipal water	CaO or NaOH	0.2 mg/l	9.5	Mn & Others
Hydroxides	a. Industrial & municipal water	$Ca(OH)_2$	100's of mg/l	9.5	Pb, Cu, Cr, Ni, Co, Mn, Zn
	b. Seawater	$Th(OH)_4$	24 mg/l	6.0	Mo
	c. Seawater	$Mg(OH)_2$	60 mg/l	--	Co
	d. Process solutions	$Mg(OH)_2 + Ca(OH)_2$	g/l	--	Sn, Pb
	e. Municipal & industrial water	NaOH	100's of mg/l	9.5	Mn & Others

Source: Cadman, T. W., and Dellinger, R. W., "Techniques for removing metals from process wastewater", *Chemical Engineering*, April 15, 1974, p. 82.

Mineral Recovery Costs

Although some of the possible mineral recovery processes have been discussed very briefly above, no real data exists from actual production plants today that is entirely applicable to this proposed project (International Atomic Energy Agency, 1972). Several different mixes or recoverable minerals could be specified, but cost estimates would be highly speculative. From the previous analysis of particle constituents and concentrations in the reject water or brine, a reasonable match was found between its potential production base and one that was developed in a R & D report from the U. S. Office of Saline Water (Office of Saline Water, 1971). Minerals included in the production mix are sodium chloride (NaCl), magnesium metal (Mg), potash (K_2SO_4), sodium sulfate (Na_2SO_4), and chlorine gas (Cl_2).

Since the costs contained in the report are in 1969 dollars, they were adjusted to the project's base year of 1974. In addition, plant scale was adjusted upward to match production potential from the 20,000 plus acre-feet of reject water by utilizing "six-tenths power law" or:

$$\text{Investment New} = \text{Investment Old} * \left(\frac{\text{Capacity New}}{\text{Capacity Old}}\right)^{0.6}$$

Investment cost was calculated at $109 million (1974 dollars) with operating costs estimated at $27.3 million. Operating costs include only labor and steam, therefore understating actual O & M costs (exclusive of power) that would be realized. Power requirements are estimated at 1.328 billion KWHR per year, which translates into an average yearly continuous flow requirement of 152 MW. In addition to the minerals recovered, approximately 10,000 acre-feet of fresh water would also be produced by this specific process (crystallizers).

Mineral production would be as follows:

$NaCl_2$	246,000 tons	Cl_2 (gas)	162,000 tons
Mg (metal)	73,600 tons		
Potash (K_2SO_4)	1,800 tons		
Na_2SO_4	235,000 tons		

DUAL-PURPOSE NUCLEAR POWER ALTERNATIVES

Introduction

This portion of the study was performed to investigate the feasibility of using nuclear reactors as an energy source that supplied both electric power and desalted water. An evaluation of the reactors currently being commercially offered as energy sources for the specific criteria of this is also included.

The question of plant availability was not considered in this study. Refueling a large reactor requires an annual shutdown of approximately four weeks. During refueling, other major maintenance projects are scheduled. Forced outages also can occur in both the power and water plants, but the use of parallel trains of equipment will increase the overall reliability. The assumption was made that the water will be drawn at a constant daily rate throughout the year and fed to the plant which operates continuously.

Methodology

The plant thermal efficiencies reported in Table 28 were used along with a simple salt balance to obtain the thermal rating of the reactor. First, the amount of water necessary

Table 28. Comparison of plant efficiencies

	LWR		HTGR	
	BWR[a]	PWR[a]	Steam[b]	Direct[c]
	-percent-			
Dual-Plant				
Gross Electrical/Thermal	21.6	21.0	28.0	36.5
Internal Electrical Consumption	12.3	12.3	10.0	10.0
Net Electrical/Thermal	18.9	18.4	25.2	32.9
Power Only				
Gross Electrical/Thermal	32.8	32.5	39.2	36.5
Internal Electrical Consumption	4.3	4.3	5.0	5.0
Net Electrical/Thermal	31.4	31.1	37.2	34.7

[a]From IAEA Study Team, 1968.

[b]From General Atomic, 1974.

[c]From Sager and Krase, 1972.

[d]Water rate for the HTGR direct cycle is a fixed linear function of performance ratio with 19 million BTU/day available per thermal megawatt.

to maximize the production of product water, subject to the study criteria, was calculated. Second, the performance ratio was used to find the corresponding energy input to the MSF plant. The efficiencies were then used to calculate the thermal rating and the saleable electric power produced by the dual-purpose portion of the plant. Enough additional capacity of power-only was added to obtain 2,000 MWe of saleable power. The cooling water for this additional capacity was assumed to be obtained from the bypass stream of well water, resulting in product water at slightly less than 1,000 ppm. The total thermal capacity required is the sum of the two components.

The corresponding power-only plant for each reactor type was defined to permit evaluation of the electrical generation sacrificed for water production. Cooling water needs were calculated, and the Nuclear Energy Center (NEC) capacity which may be supported by the water from the well field was determined.

The costs were based on cost estimates for 1,000 MWe power-only facilities. In all cases, two units of the largest size being offered today were approximately the same as the study requirement. Therefore, the cost estimates were scaled to the larger size (HTGR - 1160 MWe, LWR - 1300 MWe) and doubled. The cost reduction for the back-pressure turbine used in a dual-purpose plant was estimated by decreasing the full turbine cost by 10 percent and eliminating the cost of the cooling tower system.

The operating costs were taken from a current study of the power cost from nuclear generating plants. The costs attributable to interest, profit and debt retirement were eliminated. These costs were then adjusted on the basis of saleable power for the dual plant.

The Dual-Purpose Plant

The dual-purpose plant considered in this study will produce electric power and steam for an evaporative desalting plant. The evaporative desalting unit was selected by the project team because the technology was the most advanced of all desalting methods.

Plant Configurations

A power generating plant (shown schematically in Figure 24) is designed to extract the maximum possible thermodynamic energy from the steam (Steam, 1972). The energy not converted to electricity is discharged to cooling water as waste heat at a temperature of approximately 100° F. This low temperature energy is not suitable for use, except perhaps for agriculture or space and soil heating in cold climates. Therefore, this energy is dumped to the atmosphere by evaporating water in a cooling tower. This results in a water use ranging from 17 to 25 acre-feet of fresh water per year per megawatt of generated electricity. If brackish water is used, the water consumption of the cooling towers is higher because a larger bleed stream must be removed to prevent salt buildup.

In a dual-purpose plant (shown schematically in Figure 25), a portion of the low pressure turbine and the condenser of the usual turbine-generator set are replaced by the primary brine heater of the multistage flash (MSF) desalting plant (Hammond, 1966). The brine heater thus operates as a condenser and the rejected energy is used in the water plant. The steam is removed from the turbine at 35 psia (260° F) as in the power-only case; this obtains steam at the higher temperature required by the MSF plant, but results in a power loss. The turbine is called a back-pressure turbine because of the higher exit pressure. The water plant is rated on the basis of pounds of water produced per thousand BTU of energy supplied (performance ratio, P.R.) Existing MSF units have operated with performance ratios above 20, but most previous studies have used the 13 to 16 range to reduce the amount of pretreatment necessary for the feed water. A value of 15 is used here.

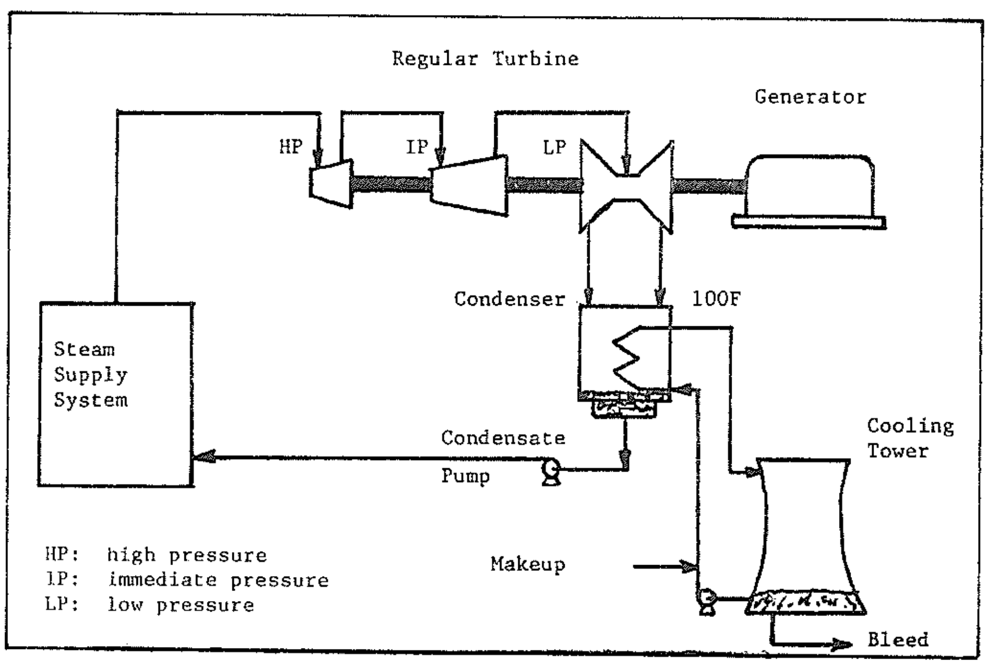


Figure 24. Electric power generation plant schematic

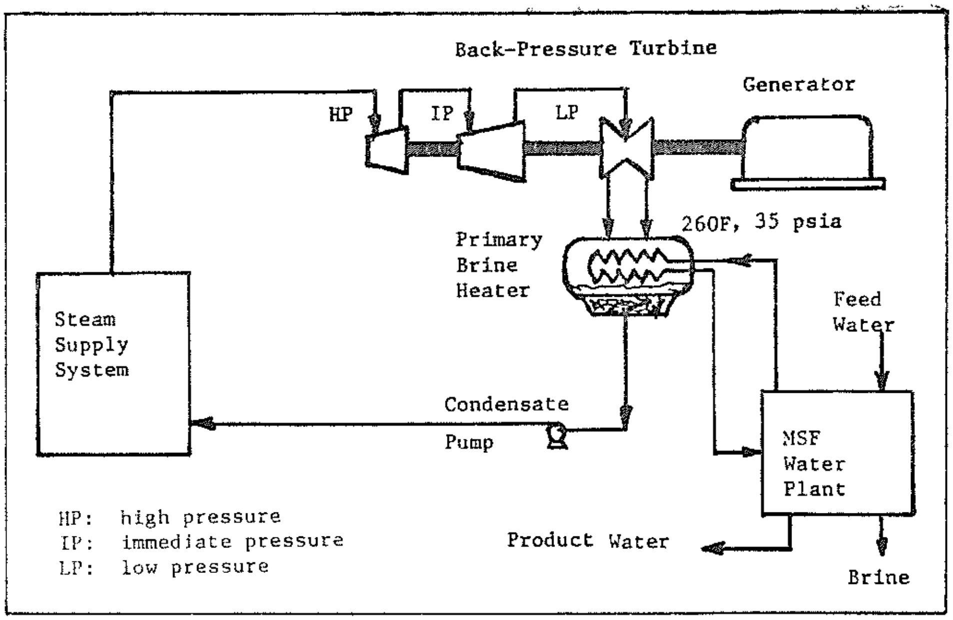


Figure 25. Dual-purpose plant schematic

Alternate Desalination Methods

Alternate desalination technologies are coupled to power plants in two ways: using a portion of the steam to drive a turbine linked to a compressor or directly, using a portion of the electrical power produced. The vapor compression process takes the low pressure water vapor from a desalter, compresses and cools it until liquid water is obtained. One freezing technique employs butane gas which is expanded to freeze the water into crystals. The gas is then separated from the ice-brine slurry and recompressed. Pumps are used to provide the pressure necessary to force pure water through a membrane in the reverse osmosis process. In the electrodialysis process, an electric potential is placed across membranes to induce separation of the dissolved ions from the water stream. All of these processes and others under study can be coupled in a dual-plant but they do not make use of the waste heat as fully as does distillation.

Nuclear Energy Sources

The energy to supply the steam to the dual plant is obtained from the fission of uranium. The types of reactors considered in this study are the light water cooled and moderated reactors (LWR) and the high temperature, gas cooled, graphite moderated reactor (HTGR). Two basic types of LWR are considered: the boiling water reactor (BWR) and the pressurized water reactor (PWR). In addition to the steam cycle HTGR, a hybrid HTGR using gas turbines and high temperature heat rejection were also investigated.

Boiling Water Reactor

The primary coolant water in a BWR boils within the reactor core. The steam generated in the reactor is dried in a steam separator and is directed as saturated steam to the turbine-generator set (U. S. Atomic Energy Commission, 1974). The boiling water reactor (BWR) is portrayed in Figure 26.

The full flow demineralizer system processes all condensate and makeup water and removes corrosion products produced in the turbine, condenser, and the shell side of the feed water heater. A second demineralizer system (the clean-up) circulates reactor water and removes

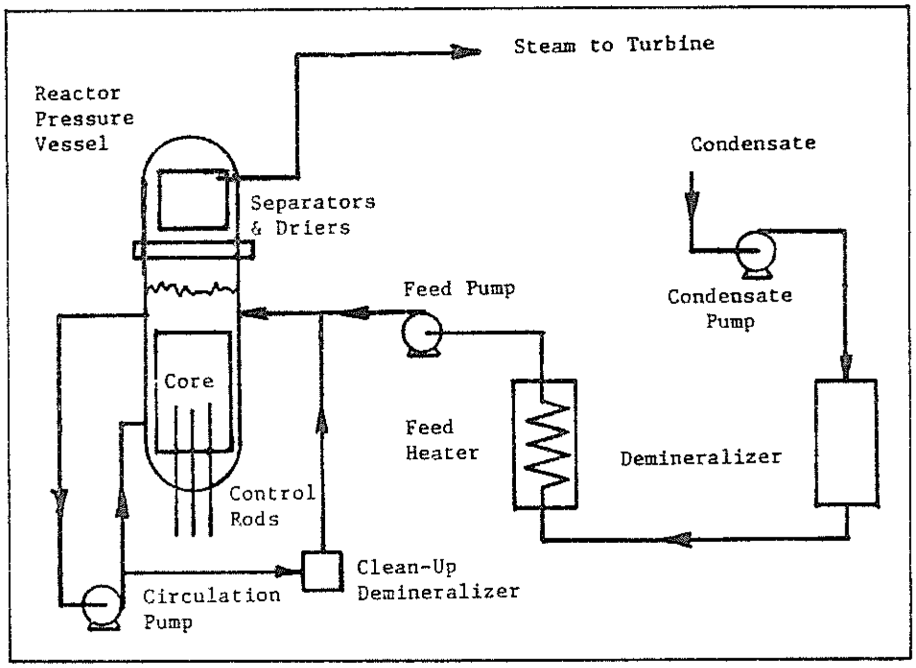


Figure 26. Boiling water reactor schematic

reactor corrosion products. Small amounts of radioactive material released to the coolant, and irradiation of corrosion products results in low-level radioactivity throughout the steam and turbine system during operation. The use of BWR in a dual-plant means that lakes in the primary brine heater could introduce radiation into the desalting plant. The consequence of leaks and the possible need for an isolating fluid loop needs further study. General Electric is the manufacturer of all BWRs in this country.

Pressurized Water Reactor

The pressurized water reactor (PWR), Figure 27, uses two loops. The primary reactor coolant loop of the PWR is kept under high pressure to maintain the water in the liquid state (Rengel, et al., 1966). The water heated in the reactor is circulated through a steam generator where the energy is transferred to the secondary loop which provides non-radioactive steam to the turbine-generator set. The PWR system is offered by Babcock and Wilcox, Combustion Engineering and Westinghouse.

Steam Cycle HTGR

Helium gas is circulated through the reactor, ducts, and steam generator by a turbine driven circulator powered by steam exiting from the high pressure section of the turbine-generator set (General Atomic Company, 1974). The steam is then reheated in the reheat zone of the steam generator and returned to the remainder of the turbine-generator set. Figure 28 shows the steam cycle HTGR. The reactor core, helium ducts, circulators and steam generators are all located inside a prestressed concrete reactor vessel (PCRV) which is field constructed, simplifying the fabrication of large reactors.

The HTGR is a second generation reactor initially using a fully enriched uranium (93 percent U-235) and thorium fuel. The thorium reacts to form fissionable U-233 (not naturally occurring) which is recovered and used in subsequent fuelings. Thus, the HTGR is a conversion reactor. The HTGR is offered by the General Atomic Company.

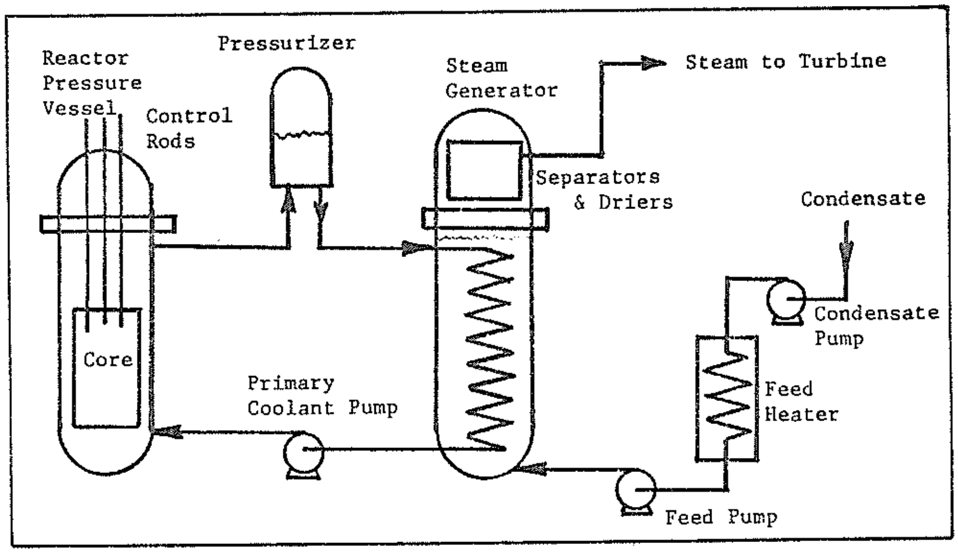


Figure 27. Pressurized water reactor schematic

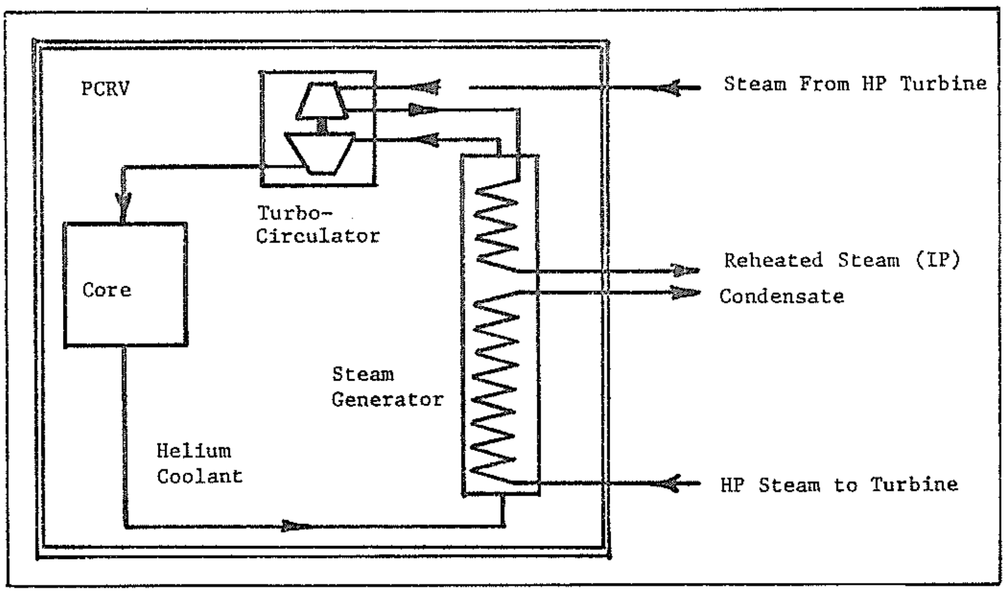


Figure 28. Steam cycle high temperature gas-cooled reactor schematic

Direct Cycle HTGR

This type of reactor is a design concept being pursued by General Atomic Company but is not yet offered commercially. The direct cycle HTGR differs from the conventional HTGR in that the circulators and steam generators are replaced by the turbomachinery and heat exchangers required for a gas turbine cycle. The outstanding advantages of such a unit are the elimination of the need for a secondary steam system (potentially lowering capital costs) and the elimination of water consumption by discharging waste heat with dry cooling towers (Sager and Krase, 1972).

Figure 29 presents a schematic diagram of the direct cycle HTGR. The helium gas leaves the core and first drives the compressor gas turbine followed by the power turbine. The gas

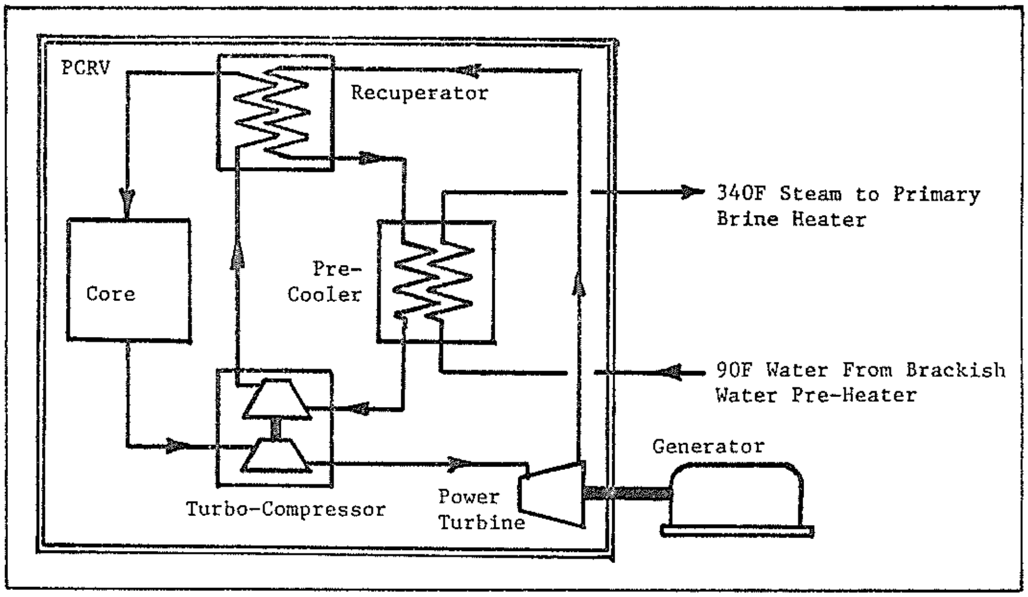


Figure 29. Direct cycle high temperature gas-cooled reactor schematic

leaving the power turbine is used in the recuperator to preheat the core coolant. The partially cooled helium passes through the precooler and the compressor before being heated in the recuperator and returned to the core. Thus only the shaft energy and high temperature waste heat (340° F) are removed from the PCRV. To obtain desalted water, the dry cooling tower must be replaced with the primary brine heater; the proposed unit allows water to be produced in addition to power with no decrease in power efficiency.

Plant Efficiencies

As previously mentioned, in a dual plant using steam cycle reactors, a portion of steam energy that would normally be used for power production is diverted to the production of water in the desalting plant. Table 28 summarizes the plant efficiencies for the four types of reactors considered in this study. These values are from previous studies of dual plants. The thermal efficiency of newer steam cycle nuclear plants for net electrical generation are approximately 1.0-1.5 percent higher than the values tabulated below.

Previous Dual-Plant Studies

Several feasibility studies for dual-purpose nuclear power and desalination systems have been conducted by public and private organizations during the last 10 years. In most cases, the engineering evaluations have been fairly well detailed, but the economic evaluations have considered only cost estimates for construction and operation of the plants. To avoid faulty conclusions, decisions should be based on a total regional economic cost-benefit analysis rather than simply water or power cost. The previous feasibility studies are listed in Table 29. The Bolsa Island project probably came closer to fruition than any of the others, but inflation during the Viet Nam War caused the utilities financing the power plant to back out. The Yuma project has reappeared because of treaty obligations concerning the salinity of the Colorado River as it enters Mexico. In fact, the Mexican study was made in order to justify desalting ocean water to provide the treaty obligations. The cost of water in these studies has reached a minimum of approximately $85/acre-foot. The articles written to project the future of the

Table 29. Dual plant feasibility studies

SITE	AGENCY	YEAR
Florida Keys	AEC	1964
Israel	U.S.D.I.	1966
New York City	AEC	1966
Athens, Greece	IAEA	1966
Northern Europe	Euratom	1968
Bolsa Island, Calif.	Combine	1965-1967
U.S. - Mexico - IAEA	Joint	1965-1968
Yuma, Arizona	U.S.B.R.	1967
Spain	Bechtel	1967
Utah	Utah	1968
Puerto Rico	U.S.D.I.-AEC	1970
Hawaii	Honolulu	1971
Diablo Canyon, Calif.	California	1972
Yuma, Arizona	Arizona	1974

dual-plant concept predict \$50/acre-foot, but most were written prior to the latest surge of inflation. Another comment about previous studies is that all the detailed cost savings are assumed to be applied to the design of the water plant so that water appears to be produced as cheaply as possible.

Applications in the Tularosa Basin

A dual plant utilizing any of the four reactor types previously described is technically feasible in the Tularosa basin. Table 30 summarizes the required thermal rating, and electrical generation and water production determined for the two LWR types. The dual-plant values meet the study criteria. Corresponding values for power generation only, for the same reactor thermal ratings, are also listed. Table 31 summarizes results for the HTGR steam cycle and direct cycle.

Dual-Plant Analysis Method

A simple salt balance was first used to determine the amount of water to be distilled for the maximum production of product water subject to the criteria of one-half million acre-feet per year pumped from a well field and specified salinities. Table 32 presents the working water balance. Next, the performance ratio (P.R. = lb of water/10^3 BTU) was applied to the flash water flow rate to find the thermal energy input required by the MSF plant. The corresponding reactor thermal capacity is

$$(\text{MSF thermal input})/(1 - \text{gross thermal eff.}),$$

where thermal efficiencies are from Table 28. The net electrical generation was then determined

Table 30. Multistage flash desalting and light water nuclear reactors

	Boiling Water Reactor		Pressurized Water Reactor	
	Dual Plant	Power Plant	Dual Plant	Power Plant
Thermal Rating, MWt	7549.3	7549.3	7632.6	7632.6
Dual Plant Thermal Fraction, %	39.3	0	38.5	0
Electric Power, MWe				
-Generated	2143.5	2476.2	2141.6	2480.6
-Internal Use	143.5	106.5	141.6	106.7
-Saleable	2000.0	2369.7	2000.0	2373.9
Water, mgd*				
-From Well Field	446.4	57.1	446.4	58.0
-Cooling Tower Use	26.3	57.1	27.3	58.0
-Disposed Brine	20.7	5.7	20.8	5.8
-MSF Product	343.0	0.0	343.0	0.0
-Saleable Product	402.0	0.0	401.1	0.0
Waste Heat to Sink, Billion BTU/Day	191.8	415.4	198.8	422.0

Note: Operation at a performance ratio of 15.0 lbs. water/1000 BTU

*Acre-feet/year - mgd x 1.12 x 10^3

Table 31. Multistage flash desalting and high temperature gas-cooled nuclear reactors

	Steam Cycle		Direct Cycle	
	Dual Plant	Power Plant	Dual Plant	Power Plant
Thermal Rating, MWt	6416.3	6416.3	10094.2	5767.8
Dual Plant Thermal Fraction, percent	50.3	0	100.0	0
Electric Power, MWe				
Generated	2152.9	2515.2	3684.4	2105.3
Internal Use	152.9	125.8	368.4	105.3
Saleable	2000.0	2389.4	3315.9	2000.0
Water, mgd*				
From Well Field	446.4	43.9	446.4	0.0
Cooling Tower Use	13.5	43.9	0.0	0.0
Disposed Brine	19.4	4.4	18.0	0.0
MSF Product	343.0	0.0	343.0	0.0
Saleable Product	414.9	0.0	428.4	0.0
Waste Heat to Sink, Billion BTU/Day	98.2	319.5	0.0	300.0

Note: Operation at a performance ratio of 15.0 lbs water/1000 BTU

*Acre-feet/year = mgd x 1.12 x 10^3

Table 32. Water balance

Water stream	Million gallons daily (mgd)	Parts per million (ppm)
Well water	446.4	5,000
Bypass stream	85.3	5,000
Desalter feed	361.1	5,000
Brine for disposal	18.0	100,000
Flash water	343.0	5
Product water	428.4	1,000

for the dual-plant portion of the facility. The balance of electrical generation required in the steam cycle systems to meet the 2,000 MWe criterion needs additional power-only capacity. The total reactor thermal rating is the sum of the two portions of the facility. The thermal fraction allocated to the dual-plant portion is listed for each reactor in Tables 30 and 31. Cooling water for the power-only capacity was assumed to be drawn from the bypass stream. This reduces the blend water added to the flash water and results in product water at slightly less than 1,000 ppm. Cooling water required to accommodate the waste heat is based upon 960 BTU/lb to 90 percent of the cooling flow with 10 percent of the flow allocated to cooling tower bleed (and combined with the MSF plant disposal brine).

The corresponding power-only plants were defined, using the reactor thermal ratings obtained for the dual-plant facilities and efficiencies from Table 28. The higher electrical generation obtained permits evaluation of the electrical capacity for water production.

The thermal capacity of the direct cycle HTGR dual plant was calculated using 18.87×10^6 BTU/d available for desalting per thermal megawatt. This value was derived from the results of a General Atomics Study (Sager and Krase, 1972) and assumes some of the waste heat is discharged via a dry cooling tower. When sufficient reactor capacity is used to meet the water production criterion, considerably more than 2,000 MWe capacity results.

Nuclear Energy Center

The concept of the nuclear energy center (NEC) involves grouping a number of reactors and associated fuel cycle facilities at a common site. Electrical power NEC's are assumed to have from 12,000 to 48,000 MWe of installed capacity (U. S. NRC, 1975; Rogers, 1975). If the water pumped from the well field in the Tularosa basin (446.4 MGD) is totally allocated to reactor cooling, LWR's (Table 30) with 18,000 MWe may be installed. The higher thermal efficiency of the steam cycle HTGR (Table 31) permits installation of 24,000 MWe. The direct cycle HTGR uses dry cooling towers and is not water limited. A mix of power-only and dual-purpose steam cycle reactors can be used which falls in the NEC capacity range and produces desalted water at a lower rate than in the criteria for this study.

Costs

This study compares the cost of a dual plant producing power and water dictated by the study criteria and the cost of a power-only plant of the same thermal rating. The cost of nuclear power is made up of capital costs and operating costs and each is further subdivided. No attempt is made here to predict the rise of inflation or the behavior of interest rates.

The capital costs are made up of six segments. The first is the cost of the land and preparation of the land (moving buildings, roads, and utilities) and was not considered here. The second is the cost of site preparation and all buildings. The third segment is for the reactor and auxiliaries including safety, fuel handling, instrumentation, waste disposal, and others. The turbine plant equipment comprises the fourth segment and includes turbines, condensers, cooling water treatment, and interstage heaters. The fifth segment includes the equipment necessary to placing the power in the electric distribution system. The final segment includes miscellaneous plant equipment, spare parts, and contingency capital.

The indirect capital costs include: the engineering services; the construction facilities, equipment, and services; and interest during construction. The interest charge was not included due to variable interest rates and variable duration of construction.

The production costs include three major categories: fixed, fuel, and operation and maintenance (O & M). The fixed charges, not covered in this study, are comprised of taxes, insurance, depreciation, interest, and return on investment. The fuel cycle charges include the fuel cycle itself along with waste management and transportation. The O & M charges include labor, supplies, maintenance, and liability insurance.

Table 33 presents a summary of the operating and cost data for the light water reactors based upon the PWR. Several studies (Bowers, et al., 1973; Atomic Energy Commission, 1972; and International Atomic Energy Agency, 1969) point out that the cost of a BWR and PWR are essentially equivalent.

Table 33. Summary for light water reactors

Item	Units	Dual plant	Power only
Energy			
Thermal rating	MWe	7,635	7,635
Power generated	MWe	2,140	2,480
Saleable power	MWe	2,000	2,375
Water			
Pumped from wells	A.F. per year	500,000	64,000
Consumed in process	A.F. per year	50,000	64,000
Product water	A.F. per year	450,000	0
Capital Costs			
Structures & sites	Million 1974 $	127	127
Reactor plant	Million 1974 $	195	195
Turbine plant	Million 1974 $	150	200
Electric plant	Million 1974 $	70	70
Miscellaneous	Million 1974 $	53	53
Subtotal		595	645
Professional services	Million 1974 $	94	94
Miscellaneous construction	Million 1974 $	55	55
Total		744	794
Production Cost			
Fuel, operation, & maintenance	$/Saleable MWH	9.2	7.9

Table 34 presents a summary of the operating and cost data for the steam cycle HTGR. The source of the data (General Atomic Company, 1975) did not divide up the cost internally as much as the other studies, but using some additional information (General Atomic Company, 1969 and 1970) it was possible to ratio the costs. The HTGR cost estimate seems high in comparison to the LWR estimate, but they were done in different years. An LWR estimate is included in the prime reference (General Atomic Company, 1975) and shows that the LWR has capital costs about three percent less than an HTGR but the HTGR has lower operating costs and thus a lower power production cost.

No data exist on costs for the direct cycle HTGR. This design is still in the concept stage and some components have not been tested.

Discussion and Further Study Options

The BWR and PWR types of LWR's have nearly equal performance and costs when used as dual purpose plants. The BWR has a disadvantage of possible radioactive contamination of the desalting plant from primary coolant leakage in the primary brine heater. The consequences of such leakage and a possible need for an isolation fluid loop or other mitigating control measures need further study. The PWR employs a secondary water/steam loop which avoids desalting plant contamination. The dual-purpose criteria of this study requires allocating approximately

Table 34. Summary for high temperature gas-cooled reactor (steam cycle)

Item	Units	Dual plant	Power only
Energy			
Thermal rating	MWe	6,420	6,420
Power generated	MWe	2,150	2,515
Saleable power	MWe	2,000	2,390
Water			
Pumped from wells	A.F. per year	500,000	49,000
Consumed in process	A.F. per year	35,000	49,000
Product water	A.F. per year	465,000	0
Capital Costs			
Structures & sites	Million 1975 $	160	160
Reactor plant	Million 1975 $	295	295
Turbine plant	Million 1975 $	170	220
Electric plant	Million 1975 $	78	78
Miscellaneous	Million 1975 $	57	57
Subtotal		760	810
Professional services	Million 1975 $	100	100
Miscellaneous construction	Million 1975 $	70	70
Total		930	980
Production Cost			
Fuel, operation, & maintenance	$/Saleable MWH	8.0	6.8

40 percent of the LWR thermal capacity to dual-purpose back-pressure turbine plant (Table 30) and 60 percent to conventional power-only condensing turbine plant. Further study is needed to determine the optimum mix of turbine sections, with and without condensors, to meet this capacity allocation.

The HTGR, with steam cycle, offers several advantages over the LWR. The higher thermal efficiency of the HTGR allows the project objectives to be met with a lower thermal rating and about one-half as much water for evaporation cooling. The allocation of thermal capacity equally between dual-plant and power-only plant (see Table 31) allows flexibility of designing each half of the facility as dual-purpose or power-only, or construction of two identical units, each carrying one-half of the water production and electrical generation load. The required 3,220 MWe reactor capacity is not much larger than the proposed 3,000 MWe Fulton Station HTGP. In addition, the HTGR helps to conserve uranium by utilization of thorium.

The direct cycle HTGR may prove to be the most attractive power reactor for flash desalting yet conceived. The lack of cooling water consumption means all brine pumped could be desalted. Cost information is not yet available to permit economic evaluation. The water production is accomplished completely by use of waste heat. This results in needing a larger reactor thermal capacity than for the steam cycle cases. While electrical generation is correspondingly increased, the larger plant necessarily involves a greater capital investment.

The study has shown that a dual plant utilizing nuclear energy and flash desalting is a technically feasible method for meeting the study criteria. This does not mean that it is the only feasible method or the optimum. All other desalination technologies must be studied in detail to obtain the best for the brackish water in the Tularosa basin. The dual plant could then be studied on an optimal basis.

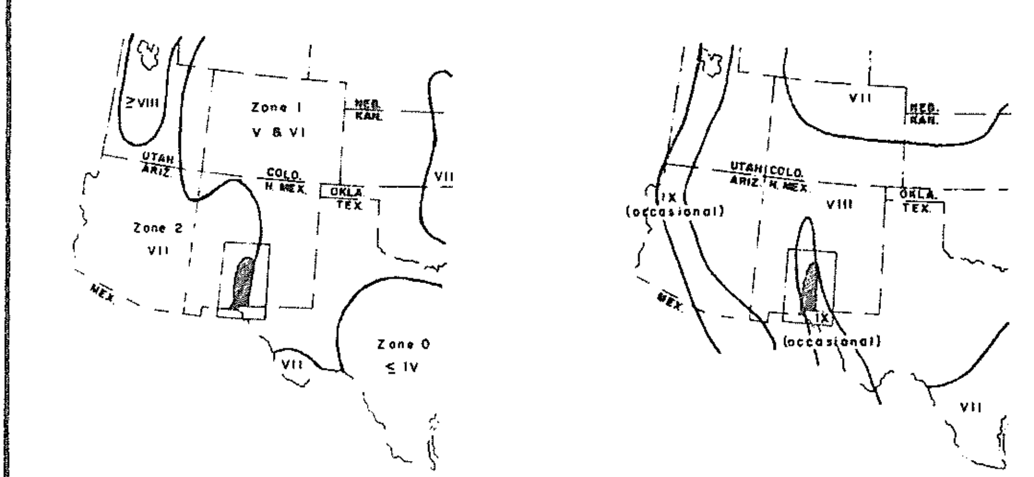
The concept of the nuclear energy center should be very carefully studied. The use of brackish water for evaporative cooling has been demonstrated, but a brine must be disposed of as in the desalting case. The proposed pumping rate of brackish water can accommodate evaporative cooling for a NEC of 18,000-24,000 MWe. It may be preferable to install some dual-purpose facilities, with a corresponding reduction of electrical capacity in order to provide for other water needs in the NEC.

SEISMICITY OF THE TULAROSA BASIN

Introduction

This section describes the seismicity of the Tularosa basin southward from the vicinity of Carrizozo to the New Mexico-Texas border. The valley, whose average width is 50 km, is bounded on the east by Sierra Blanca and the Sacramento Mountains, and on the west by Sierra Oscura and the San Andres and Organ Mountains.

The two best known seismic regionalization maps for the conterminous United States do not indicate the same degree of seismic risk for the Tularosa basin. On Algermissen's (1969) seismic risk map (Figure 30), the Tularosa basin (shaded region in Figure 30) straddles the boundary between regions having Zone 1 and Zone 2 seismicity classifications. According to the map, the maximum expected seismic intensity from local or distant shocks in such a region is VI-VII (Modified Mercalli Intensity Scale of 1931, Table 35). On an earlier seismic risk map (Figure 30), Richter (1958) places the Tularosa basin in a region that might occasionally have major damage (intensity IX on M.M. scale of 1931) from an earthquake.



a. Algermissen (1969) b. Richter (1959)

Figure 30. Seismic risk maps for southwestern U. S. (map "a" by Algermissen, 1969, and map "b" by Richter, 1959).

Richter's and Algermissen's seismic risk maps are based on essentially the same data so that differences arise principally from varying interpretations. Most of these data consist of non-instrumental reports of felt shocks. Our evaluation of the seismic risk of the Tularosa basin is based not only on the non-instrumental data, but also on a substantial amount of instrumental data not available to Richter or Algermissen. We have also attempted to incorporate in our estimate of seismicity, at least qualitatively, geologic evidence of recent crustal movements.

Data

Strong earthquakes beyond the geographical limits of the Tularosa basin could affect installations within the basin. For this reason, data have been collected over an area from 31.5°N to 34.5°N and 105.0°W to 107.5°W (see Figure 30). This area of approximately 78,000 sq. km extends at least 50 km beyond the boundaries of the Tularosa basin in all directions.

Reports of Felt Earthquakes Prior to 1962

Table 36 lists reported earthquakes within the area of study prior to 1962. Information on locations and strengths of earthquakes in this table is based on non-instrumentally determined values of earthquake intensity. Intensity values (Table 35) are assigned on the basis of reactions and observations of people during a shock and the degree of damage to structures. Given many intensity observations, the maximum intensity and limit of perceptability can be established. Both of these quantities can be related approximately to the earthquake magnitude (Richter, 1958; Slemmons, et al., 1965; Weigel, 1970).

The principal weakness of the "felt shock" data is that they are dependent to a degree on population density. In sparsely populated areas like the Tularosa basin (particularly prior to 1950) moderate shocks could have gone completely unreported, or, at best reported at low intensity levels that are not indicative of the true strengths of the earthquakes. With few exceptions, shocks listed in Table 36 are moderate and reported felt at only one location. The probability that the one location was at or very near the epicenter is small. Thus, the reported intensity is most likely an underestimate of the actual strength of the shock, and the location of the felt report is most likely to be some distance from the true epicenter.

Table 35. Modified Mercalli Intensity Scale of 1931 (Abridged)*

Scale	Description
I.	Not felt except by a very few under especially favorable circumstances. (Rossi-Forel Scale)
II.	Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing. (I to III Rossi-Forel Scale)
III.	Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motorcars may rock slightly. Vibration like passing truck. Duration estimated. (III Rossi-Forel Scale)
IV.	During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, and doors disturbed; walls make creaking sound. Sensation like heavy truck striking building. Standing motorcars rocked noticeably. (IV to V Rossi-Forel Scale)
V.	Felt by nearly everyone; many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbance of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop. (V to VI Rossi-Forel Scale)
VI.	Felt by all; many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight. (VI to VII Rossi-Forel Scale)
VII.	Everybody runs outdoors. Damage negligible in buildings of good design and construction; considerable in poorly built or badly designed structures. Some chimneys broken. Noticed by persons driving motorcars. (VIII Rossi-Forel Scale)
VIII.	Damage slight in specially designed structures; considerable in ordinary substantial buildings, with partial collapse; great in poorly built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well water. Persons driving motorcars disturbed. (VIII+ to IX Rossi-Forel Scale)
IX.	Damage considerable in specially designed structures; well designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken. (IX+ Rossi-Forel Scale)
X.	Some well built wooden structures destroyed; most masonry and frame structures with foundations; ground badly cracked. Rails bent. Landslides considerable from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks. (X Rossi-Forel Scale)
XI.	Few, if any (masonry), structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipelines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly.
XII.	Damage total. Waves seen on ground surfaces. Lines of sight and level distorted. Objects thrown upward into the air.

*From Abstracts of Earthquake Reports for the Pacific Coast and Western Mountain Region.

Table 36. Reports of felt earthquakes prior to 1962 within the region 31.5°N to 34.5°N and 105.0°W to 107.5°W.

Date Yr/Mo/Day	Time GMT	Location of Max. Reported Intensity City	Lat. N	Long. W	Maximum[1] Reported Intensity	References[2]
1868 Apr 28	?	Socorro	34.0	107.0	V	(1)
1869 ?	?	Socorro	34.0	107.0	VII	(1)
1879 ?	?	Socorro	34.0	107.0	V	(1)
1886 Jul 6	?	Socorro	34.0	107.0	V	(1)
1895 Oct 7	?		34.5	106.7	V	(1)
1895 Oct 31	12:00	Socorro	34.0	107.0	VI	(1)
1897 ?	?	Socorro	34.0	107.0	VI	(1)
1904 Jan 20	02:00	Socorro	34.0	107.0	(V)	(2)
1904 Jan 20	09:00	Socorro	34.0	107.0	(IV)	(2)
1904 Jan 30	12:30	Socorro	34.0	107.0	(V)	(2)
1904 Jan 30	14:15	Socorro	34.0	107.0	(V)	(2)
1904 Feb 22	06:00	Socorro	34.0	107.0	(IV)	(2)
1904 Mar 9	07:30	Socorro	34.0	107.0	(V)	(2)
1904 Sep 6	11:00	Socorro	34.0	107.0	(V)	(2)
1906 Jul 2	10:15	Socorro	34.0	107.0	VI	(2)
1906 Jul 12	12:10	Socorro	34.0	107.0	VII-VIII	(1),(2),(3)
1906 Jul 12	13:10	Socorro	34.0	107.0	VII	(2)
1906 Jul 16	19:00	Socorro	34.0	107.0	VIII	(1),(2),(3)
1906 Nov 15	12:20	Socorro	34.0	107.0	VIII	(1),(2),(3)
1913 Jul 18	?	Socorro	34.0	107.0	(IV)?	(1)
1919 Feb 1	04:30	Socorro	34.0	107.0	IV-V	(1)
1919 Feb 1	20:30	Socorro	34.0	107.0	V	(1)
1923 Mar 7	04:30	El Paso	31.8	106.5	V	(4),(5),(6)
1930 Oct 4	03:25	Duran	34.5	105.4	(IV)	(7)
1931 Apr 7	?	Socorro	34.0	107.0	?	(7)
1931 Oct 2	?	El Paso	31.8	106.5	(III)	(7)
1934 Jan 8	01:32	Socorro	34.0	107.0	V	(1),(7)
1934 Feb 28	?	Bernardo	34.5	106.8	IV	(7)
1934 May 8	01:15	Socorro	34.0	107.0	III	(7)
1934 May 8	04:10	Magdalena	34.2	107.5	III	(7)
1935 Jan 17	14:35	Socorro	34.0	107.0	III	(7)
1935 Jan 20	02:25	Socorro	34.0	107.0	IV	(7)
1935 Feb 21	01:25	Bernardo	34.5	106.8	VI	(1),(7)
1935 Feb 21	03:05	Bernardo	34.5	106.8	VI	(7)
1936 Aug 8	01:40	El Paso	31.8	106.5	(III)	(6),(7)
1936 Oct 15	18:00	El Paso	31.8	106.5	(III)	(7)
1937 Mar 31	22:45	El Paso	31.8	106.5	(IV)	(6),(7)
1937 Sep 30	06:16	Ft. Stanton	33.5	105.6	(V)	(7)
1941 Aug 4	07:40	Socorro	34.0	107.0	V	(7)
1942 Dec 28	04:45	Magdalena	34.2	107.5	IV	(7)
1943 Dec 27	04:00	Tularosa	33.1	106.0	IV	(8)
1947 Nov 6	16:50	Socorro	34.0	107.0	VI	(1)
1949 May 23	00:22	?	34.5	105.2	VI	(1)
1952 May 22	04:20	Dog Canyon	32.7	105.4	IV	(7),(8)
1960 Jul 22	15:49	La Joya	34.4	106.8	V	(7),(9)
1960 Jul 23	14:15	La Joya	34.4	106.8	VI	(7),(9)
1960 Jul 24	10:37	La Joya	34.4	106.8	V	(7),(9)
1960 Oct 25	19:21	Socorro	33.9	107.0	III	(7),(10)
1960 Dec 19	23:28	Socorro	33.9	106.9	IV	(7),(10)
1961 Jan 28	06:33	Socorro	34.0	107.0	IV	(7),(10)
1961 Jul 3	07:06	Socorro	34.1	107.0	VI	(7),(10)

[1] Based on Modified Mercalli Intensity Scale of 1931 (see Table 35). Intensities given in parentheses were assigned by the author.

[2] The numbers in this column are for the references listed below
(1) Coffman and von Hake (1973)
(2) Sanford (1963)
(3) Reid (1911)
(4) Woollard (1968)
(5) Bull. Seismol. Soc. Amer. (1923)
(6) Newspaper account
(7) U.S. Earthquakes
(8) Abstracts of Earthquake Reports for the Pacific Coast and Western Mountain Region
(9) Sanford and Holmes (1961)
(10) Data on file at NMIMT, Socorro, NM

The apparent epicenters of the shocks listed in Table 36 are plotted in Figure 31. With exception of one shock, December 27, 1943, all reports of felt earthquakes were outside the geographic limits of the Tularosa basin. The highest seismic activity prior to 1962 was northwest of the basin in the Rio Grande rift between Socorro and Bernardo. The only other place within the area of study reporting significant activity for this time period was El Paso.

Instrumental Locations and Magnitudes-1962 through 1972

New Mexico Institute of Mining and Technology has recently completed an instrumental study of the seismicity of New Mexico and bordering regions for the time period 1962 through 1972. A total of 172 shocks with magnitudes (M_L) ranging from 1.1 to 4.4 have been located. The 69 shocks with epicenters in or near the Tularosa basin are plotted on the map in Figure 32.

The distribution of seismic activity shown in Figure 32 is biased. More weak shocks were located near Socorro than elsewhere because of the placement of seismic stations used in the study. Station bias has been removed in Figure 33 by plotting locations for shocks whose local magnitudes equaled or exceeded 2.0. An earthquake of this magnitude or greater could be located anywhere within the region of study with the distribution of stations used.

Figure 33 indicates that the seismic activity for the period 1962 through 1972 was highest in the Rio Grande rift near Socorro. Also the rift between Las Cruces and El Paso was moderately active during this time period. Only five shocks were located directly within the Tularosa basin; three near Alamogordo, and two in the southwestern part of the basin north of El Paso.

Late Quaternary Fault Scarps

An estimate of the seismicity of a region can be obtained from the lengths, displacements, and ages of Late Pleistocene and Holocene fault movements (Sanford, et al., 1972). These studies are restricted to fault scarps that offset Quaternary geomorphic surfaces because these are the only fault displacements whose age can be even crudely estimated. Some Late Pleistocene and Holocene tectonic movements can occur along faults cutting older rocks but detection and dating of recent offsets along these faults is essentially impossible.

The principal advantage of the fault-scarp method of determining seismicity is that it incorporates a much longer span of seismic history than other techniques. However, this advantage is offset by difficulties in applying the method, in particular, obtaining accurate ages for the fault scarps.

Fault scarps cutting Quaternary geomorphic surfaces are numerous in the Tularosa basin (Talmage, 1934; Reiche, 1938, Kottlowski, 1960, Kottlowski and Foster, 1960; and Pray, 1961). The most prominent scarps are located along the eastern margin of the Franklin, Organ, and San Andres mountains. Late Quaternary movements are nearly continuous along these mountain fronts from the Texas-New Mexico border to 33.3°N latitude, a distance of about 140 km. The displacement on these scarps ranges up to 30 meters.

On the eastern side of the Tularosa basin, fault scarps occur along the base of the Sacramento Mountains. Late Quaternary faulting is essentially continuous from Tularosa (33.0°N, 106.0°W) southward for a distance of 68 km (Sanford and Toppozada, 1974).

To the west of the Tularosa basin, the Rio Grande rift has numerous fault scarps cutting Lake Quaternary geomorphic surface, particularly in the vicinity of Socorro (Sanford, et al., 1972) and Las Cruces (Kottlowski, 1960; Ruhe, 1964; Hawley and Kottlowski, 1969).

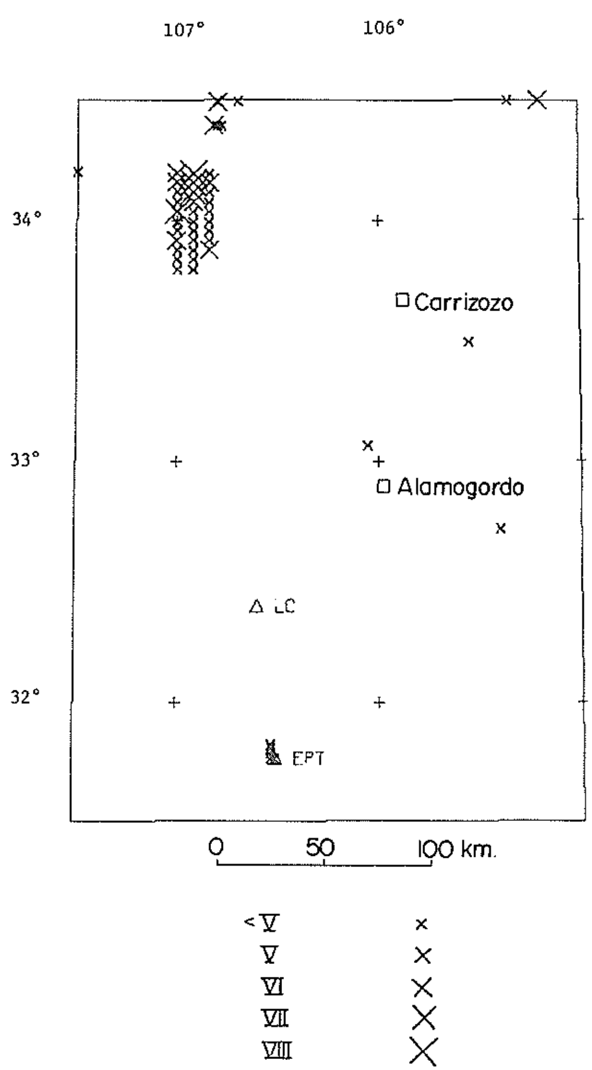


Figure 31. Apparent epicenters of felt earthquakes prior to 1962

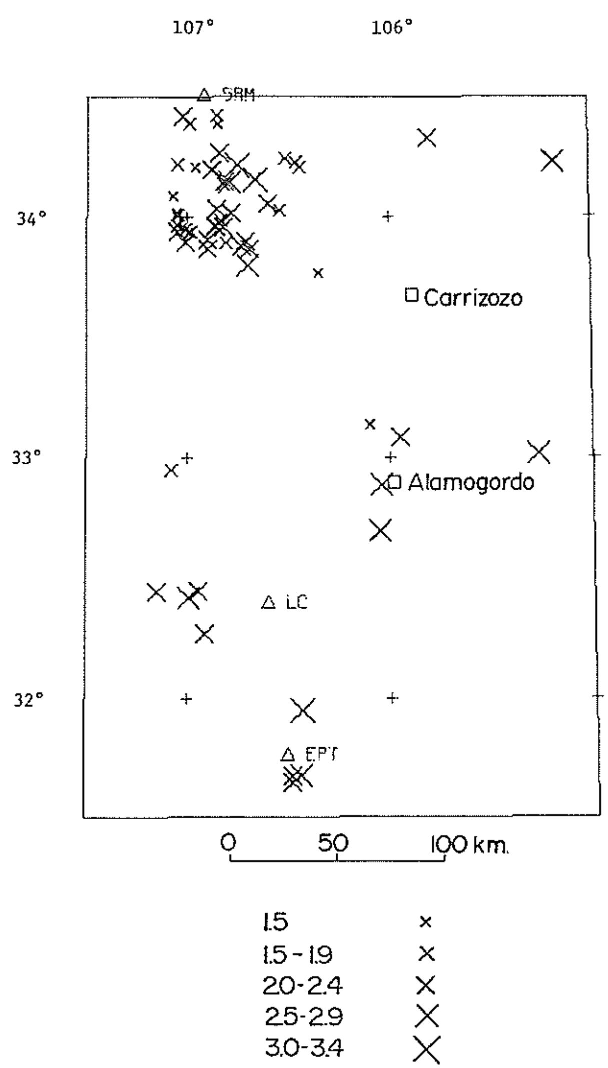


Figure 32. Epicenters of all instrumentally located earthquakes for the time period 1962 through 1972

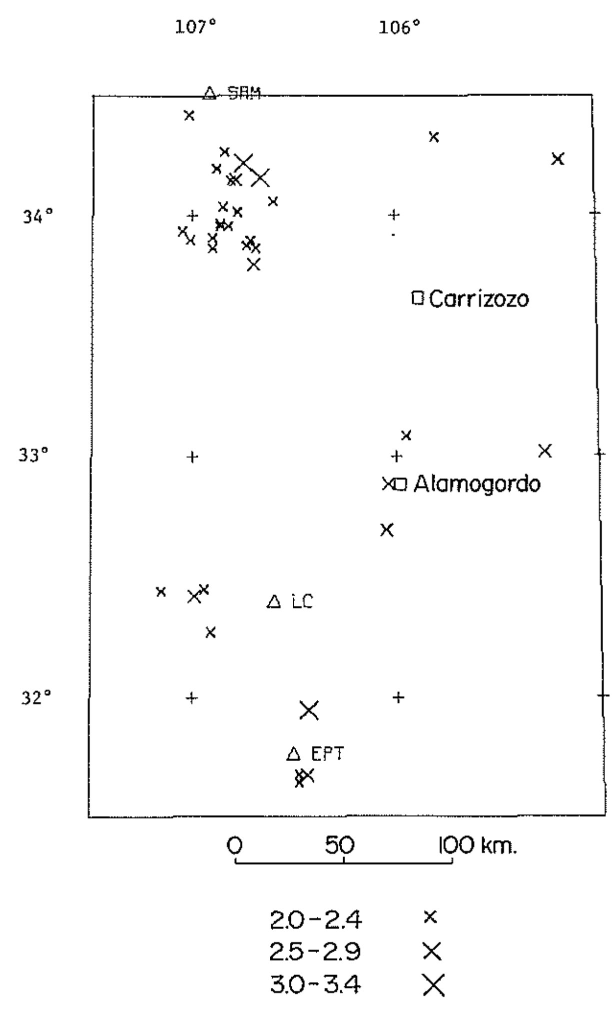


Figure 33. Epicenters of all instrumentally located earthquakes with $M_L \geq 2.0$ for the time period 1962 through 1972

Estimates of Seismic Risk

Instrumental Data

Number of earthquakes and magnitude have been found to follow the empirical relation (Richter, 1958, p. 359)

$$\log_{10}\Sigma N = a - b\ M_L, \qquad (1)$$

where ΣN is the number of shocks having magnitudes of M_L or greater, and $\underline{a}$ is the logarithm to the base 10 of the number of shocks with $M_L \geq 0$.

Listed in Table 37 are the shocks, whose magnitudes equaled or exceeded 2.0, the minimum detectable shock throughout the region of study (31.5°N to 34.5°N and 105.0°W to 107.5°W). In Figure 34, data from Table 37 are used to generate a graph of the logarithm of the cumulative number of socks (ΣN) versus local magnitude (M_L). The equation of the best straight line of the data is:

$$\log_{10}\Sigma N = 3.93 - 1.10\ M_L. \qquad (2)$$

Equation (2), which is based on 11 years of instrumental data, can be extrapolated to a 100-year period by adding $\log_{10}(100/11)$ to the coefficient $\underline{a}$ in that equation. The relation becomes:

$$\log_{10}\Sigma N = 4.89 - 1.10\ M_L \qquad (3)$$

According to equation (3), the strongest earthquake within the region during the next 100 years will have a magnitude of 4.45. An earthquake of this magnitude would do little damage unless it were to occur directly beneath an installation in the Tularosa basin. The seismic data, both reports of felt shocks (Figure 31) and instrumental locations (Figures 32 and 33), suggest that strong shocks will most likely occur west of the Tularosa basin in the Rio Grande rift. A magnitude 4.5 earthquake anywhere along the rift would have no effect on structures within the Tularosa basin.

The estimate of seismic risk obtained from the instrumental data should be accepted with caution. It is based on the extrapolation of data accumulated over a relatively short period of time. The seismic activity during this 11-year period may not be indicative of the long-term seismicity of the region. Many seismic regions of the world, for example, the Near East, experience periods of unusually high activity separated by intervals of relative quiescence (Richter, 1958, p 74).

Fault Scarps

The fault scarps located in the Tularosa basin and the Rio Grande rift indicate that major earthquakes have occurred in Late Quaternary time. The magnitudes of earthquakes producing the scarps can be determined from the empirical formula (King and Knopoff, 1968):

$$M_L = 0.45\ \log_{10}LD^2 + 2.23,$$

where L and D are the length and maximum displacement of the scarp in centimeters. Scarps with a total length of 50 km and a maximum displacement of five meters could have been formed during a single shock along the eastern margin of the San Andres Mountains. The D to L ratio assumed, 10^{-4}, is the average obtained by Iida (1965) from a compilation of fault lengths and displacements for major historical earthquakes. Using equation (6), the magnitude for the hypothetical San Andres Mountains shock is 8.30. Although the magnitude calculated can only be considered an estimate, it clearly indicates a major earthquake.

A major earthquake in a tectonic setting similar to the Tularosa basin is known to have occurred within 300 km of the basin. The shock, which occurred in 1887, produced 80 km of

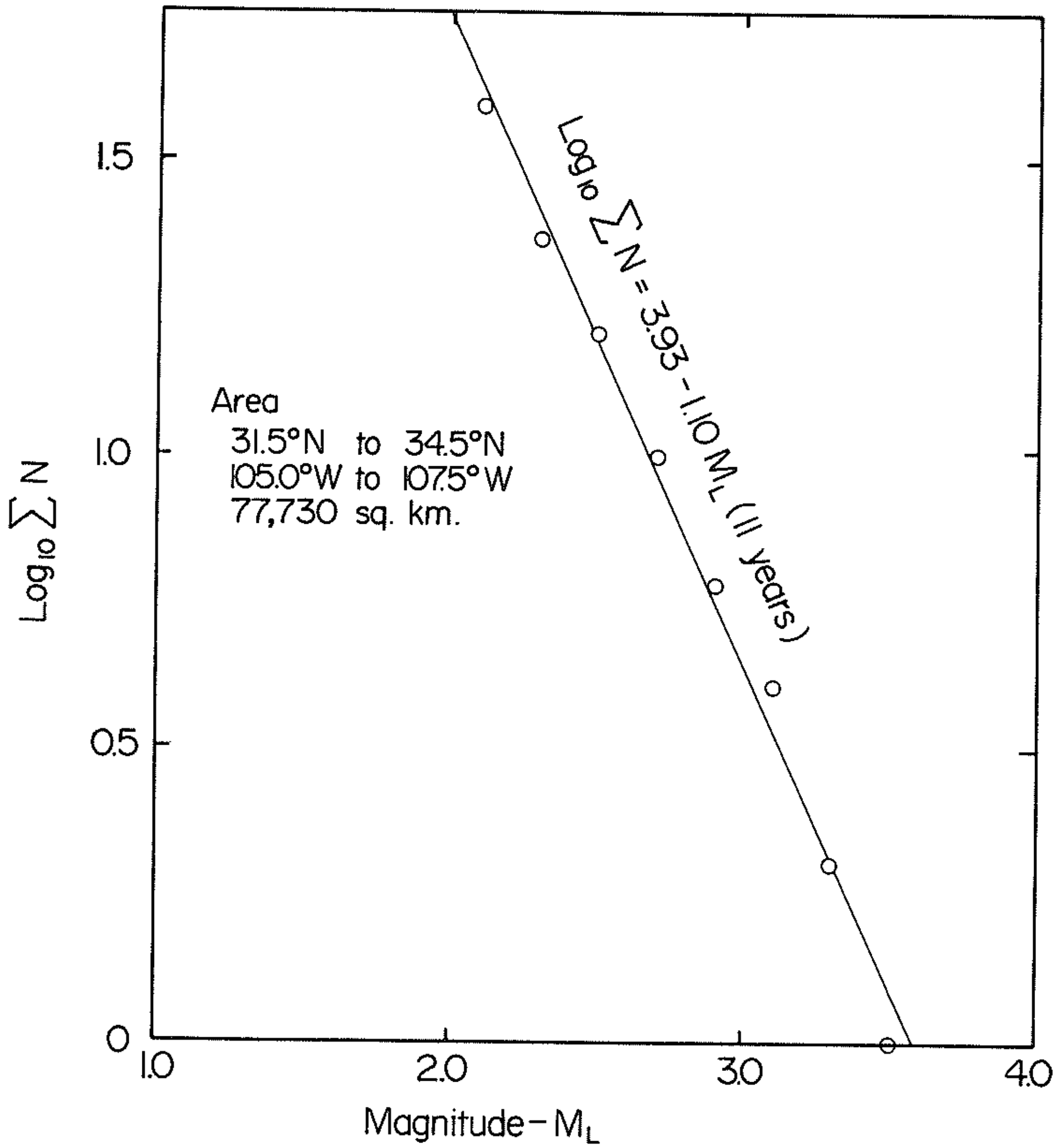


Figure 34. Logarithm of the cumulative number of earthquakes versus the local magnitude

fault scarps with a maximum displacement of about 8.5 m extending southward from the United States-Mexico border at about longitude 109°W (Aguilera, 1920).

The fault scarps in the Tularosa basin cannot be used to estimate seismic risk because their ages are not accurately known. A maximum age can be placed on the fault scarps, perhaps on the order of 400,000 years (Sanford, et al., 1972), but this is of little value because it yields a minimum estimate of seismicity. Future studies in the region should include an effort to date major movements on the scarps and thus establish recurrence intervals for major earthquakes. The intervals determined by these studies may well be very large, perhaps on the order of 250,000 years as predicted by the instrumental data. On the other hand, we have not encountered any geologic data that rules out much shorter recurrence intervals, such as 25,000 years or less.

Geographical Distribution of Seismic Risk

The number of felt shocks and instrumental epicenters within or immediately bordering the

Table 37. Instrumentally located earthquakes* from 1962 through 1972 within the region from 31.5° N to 34.5° N and 105.0° W to 107.5° W.

Date	Origin Time	Location		Local
Yr/Mo/Day	GMT	Lat. N	Long. W	Magnitude
1962 Jan 24	15:12:43.8	33.96	106.86	2.00
1962 Sep 1	16:15:07.9	34.16	106.66	3.30
1962 Dec 15	20:20:34.3	33.97	106.86	2.00
1963 Feb 22	07:02:08.1	32.42	106.99	2.81
1963 Feb 22	08:53:18.1	32.45	106.94	2.06
1963 Jul 3	19:08:00.5	33.91	106.90	2.00
1963 Aug 19	00:08:23.4	32.44	107.15	2.48
1964 Jun 19	05:28:38.8	33.09	105.95	2.00
1965 Mar 9	19:04:48.5	33.87	106.90	2.40
1965 Apr 10	07:00:55.0	33.94	107.05	2.20
1965 May 27	12:17:44.1	33.90	107.01	2.00
1965 May 27	18:50:53.9	33.98	106.73	2.18
1965 May 27	18:58:40.9	33.90	106.71	2.19
1965 May 29	13:01:08.2	33.87	106.69	2.20
1965 Jul 28	03:52:07.4	33.96	106.82	2.38
1965 Jul 28	04:38:53.4	33.80	106.70	2.77
1965 Dec 22	04:04:51.9	34.02	106.78	2.16
1965 Dec 22	03:33:29.6	34.02	106.78	2.34
1966 Oct 6	10:19:08.2	34.04	106.85	2.30
1967 Sep 29	03:52:48.0	32.27	106.91	2.38
1968 Mar 9	21:54:25.7	32.70	106.05	2.90
1968 Mar 23	11:53:38.7	32.70	106.05	2.20
1968 May 2	02:56:43.8	33.02	105.27	2.52
1968 May 15	10:13:04.8	34.27	106.84	2.03
1968 Aug 22	02:22:25.5	34.33	105.80	2.00
1969 Jan 30	05:17:38.4	34.22	106.75	3.40
1969 May 12	08:26:18.5	31.95	106.43	3.15
1969 May 12	08:49:16.3	31.95	106.43	3.00
1969 Jun 1	17:18:24.2	34.23	105.18	2.10
1969 Jun 8	11:36:01.9	34.23	105.18	2.75
1971 Jan 6	10:56:31.5	34.15	106.79	2.70
1971 Jan 27	07:56:28.3	34.06	106.60	2.46
1971 Dec 23	14:24:37.0	34.42	107.02	2.10
1972 Feb 27	09:11:48.9	34.15	106.81	2.00
1972 Feb 27	15:50:03.9	32.89	106.04	2.50
1972 May 16	22:13:44.8	34.20	106.88	2.00
1972 Dec 9	05:58:38.9	31.68	106.44	2.65
1972 Dec 10	14:37:50.2	31.68	106.48	2.40
1972 Dec 10	14:58:02.5	31.65	106.48	2.15

* All epicenters determined by New Mexico Institute of Mining and Technology, Socorro, New Mexico.

Tularosa basin are inadequate for detailed mapping of seismic risk. However, the seismic data in conjunction with the distribution of fault scarps do indicate that the highest risk will be at the base of the mountains bordering the basin, in particular, the Organ, San Andres, and Sacramento Mountains. The effects of a major earthquake anywhere along these mountain fronts would probably be great throughout the basin. The surface material for nearly all the valley floor is alluvium, a low-velocity unconsolidated rock, which accentuates ground motion created by earthquakes. Safest areas within the basin for sensitive installations, for example nuclear reactors, should be the isolated outcrops of Permian rocks within the basin, for example those located about 10 km southwest of Tularosa and about 20 km southwest of Alamogordo.

Summary

Seismic data, both instrumental and reports of felt earthquakes, suggest low seismic risk in the Tularosa basin. An extrapolation of 11 years of instrumental data indicate that the largest earthquake in a 100-year period will have a magnitude of 4.45 and most likely will have a location many tens of kilometers from the boundaries of the basin. The instrumental data also predict a very long interval, about 250,000 years, between major earthquakes.

Fault scarps along the mountains bordering the Tularosa basin are evidence that major earthquakes have occurred within the basin in Late Quaternary time. Dates of major movements on these fault scarps need to be determined in order to find out whether the long recurrence interval for major earthquakes predicted by the seismic data is correct.

CHAPTER V

WATER TRANSPORTATION, RESERVOIR CHARACTERISTICS AND RECREATION POTENTIAL

WATER TRANSPORTATION

The movement of water from the desalination plant to the storage reservoir is based upon the following two major project design criteria:

1. Distance from the desalination plant to the storage reservoir is approximately 10 miles.
2. Total static lift will be 1,000 feet, elevation of the energy-water complex of about 4,500 feet, and crest of dam at storage reservoir site approximately 5,500 feet.

In addition these assumptions were made:

1. Water will be transferred to the storage reservoir at a rate not to exceed the average production rate (product plus blend), which is 350,000 gpm or 780 cfs. In actuality, part of the product water will be transferred directly from the plant to municipal and industrial (M & I) users, therefore, the usual transfer rate will approximate one acre-foot/minute (325,829 gpm) or 726 cfs.
2. Since the largest proportion of water transferred to the reservoir site will be for agricultural uses, actual movement of the water will occur for only seven months, rather than the entire year. During the irrigation season, product water will be delivered to the agricultural distribution system. Therefore, a maximum of 60 percent of the product water, or approximately 287,000 acre-feet will be transferred (during the off-irrigation season primarily) to the reservoir. In any given year, the real transfer will probably be closer to 240,000 acre-feet.

A plant to reservoir transportation or water delivery system is specified below based upon the above criteria and primary assumptions. It must be kept in mind that the cost estimates for the specified transportation system are rather crude in nature. Engineering and hydraulic handbooks serve as the basis for these estimates.

Moving water at the rate of 726 cfs in a closed conveyance system involves measurable pressures, but not of such a magnitude as to require abnormal pipe sizes or material. Concrete pipe is the usual type found in similar systems. To ensure that the internal velocities are such that above normal damage is avoided, a 12-foot diameter pipe will be assumed.

Installation costs can vary considerably depending upon the terrain involved. For simplicity a uniformly linear gradient from the plant to the reservoir is assumed. (This will, of course, understate any derived costs). Similar projects in the Southwest have experienced excavation and installation costs of about $100 a linear foot. With the capital cost of the pipe approaching $200 a linear foot, installed cost is then $300/foot. For the 10 miles, total capital cost is estimated at $15.84 million.

With a static head of 1,000 feet to overcome, large pumps will be necessary. After examination of the literature, a centrifugal pump was selected as being potentially applicable to the delivery system. A pump capable of lifting 10^5 gpm over a 100-foot static head costs around $450,000. Because of the corrosive nature of the water being transferred, stainless steel or other suitable pump material will be needed. This will increase the cost of each required pump to around $868,500. To be capable of delivering 726 cfs or more over the 1,000-foot elevation differential will necessitate the use of 40 pumps, of which 10 are considered spares and used only for backup purposes. In addition, these 40 pumps will have to be replaced every 15 years, again because of the corrosive nature of the water.

Power requirements to move this water over the 10-mile distance (1,000 static head) are enormous. Actual power requirements were estimated as 110 MW per year. This specific power requirement will be necessary only about 50 to 60 percent of the time (in keeping with one of the major assumptions of only a portion of the water being transferred to the storage reservoir), or an average yearly requirement of about 60 MW. In any given year this represents between six and seven percent of the net power produced by the nuclear reactors in the complex.

To summarize, the following will serve as gross estimates for the transportation of water delivery system from the desalination plant to the storage reservoir.

1. Ten miles of concrete pipe of 12-foot diameter at $300 an installed foot--$15,840,000.
2. Forty centrifugal pumps rated at 10^5 gpm over a 100-foot static head at $868,500 each--$34,740,000.
3. Forty pumps needed at the end of 15 years for replacement purposes at $868,500 each--$34,740,000.
4. Power requirement of 110 MW for between six and seven months of the year, about 60 MW on a yearly average.

RESERVOIR CHARACTERISTICS AND RECREATION POTENTIAL

Reservoir Characteristics

The proposed Tularosa basin storage reservoir allows for the possibility of extensive water-based recreational consumption and its corollary, monetary benefits from the recreation activities. The purpose of this section or portion of the study is to, initially, describe the proposed site and the operating characteristics of the reservoir and, secondly, to employ an estimated per capita demand equation to predict future recreational visitation benefits. The descriptive component includes a description of construction, a schedule of capital expenditures involved in construction, as well as a graphic description of the proposed reservoir and dam. The demand equation utilized to project future use is developed within the study and is described in full detail herein.

Description of Reservoir Site

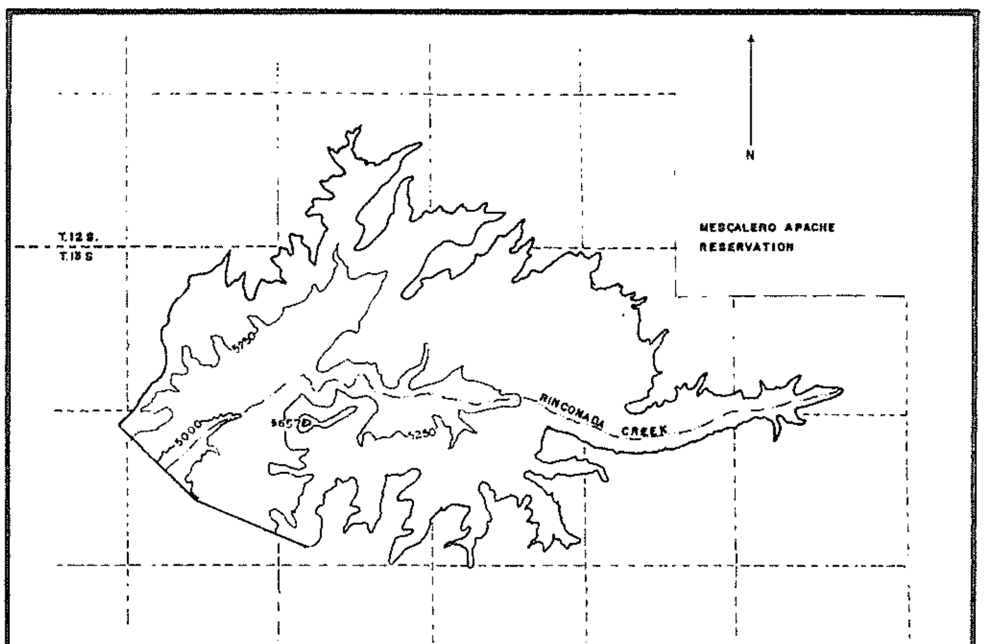
Within the designated project area, and within reasonable transportation distance, there exists many narrow and small box canyons in the Sacramento Mountain Range. The vast majority of such canyons do not approach the necessary storage capacity. However, there are several canyons with the potential to handle relatively large quantities of water.

Of these, the site along Riconada Creek appears to be most feasible. This is based on two considerations. One, it has storage capacity far in excess of most others (particularly La Luz and Dry Canyon which were initially thought to be similar to Riconada Creek). Second, actual elevation at the base of the reservoir would be significantly lower than most others examined. Based upon on-site inspection and examination of various topographical maps, the Riconada Creek site was found to be capable of handling around 300,000 acre-feet, more than the 250,000 acre-foot requirement. On the other hand, all remaining sites initially considered were found to be extremely questionable as to their ability to actually store this magnitude of water. Of course, a very detailed engineering study would have to be conducted before any final selection was made. A permit from the State Engineer would be required since the dam would be located on a natural water course and would impound surface waters. It should also be noted that the dam must be designed to pass or store the runoff resulting from the probable maximum precipitation in addition to planned storage.

After construction of the dam, water would rise rather slowly at first, but once the narrow valley immediately behind the dam had filled, would rise more quickly, rapidly backing up several of the smaller canyons, as well as the major Riconada Creek bed. Because the terrain is very steep in places, average water depth would be considerable in these areas, while in other portions where the terrain is more gradual, water level would be much lower. However, due to the rugged terrain surrounding almost the entire reservoir site, shoreline access would be limited primarily to the water side, or in some cases four-wheel drive vehicles approaching from land.

Figure 35 is a sketch of the absolute maximum pool size at 5,500 feet elevation above sea level containing over 250,000 acre-feet of water and proposed recreational minimum pool at approximately 5,200 feet elevation above sea level with about 15,000 acre-feet of water. As can be seen, there is a tremendous difference between the various pools. All shoreline except the rather long finger at the rear of maximum reservoir pool is rather steep and extremely rugged as mentioned above. Water elevation would range from 5,200 feet when only the recreational minimum pool was present (toward the end of irrigation season) to 5,400 feet plus at maximum probable storage immediately preceeding start of irrigation season.

The reservoir would be located approximately four miles from a major highway (U. S. Highway 54). Reservoir and dam would be partially visible from most of the highway, thereby increasing potential recreation use.



Note: Minimum pool size is between 5,000 and 5,250 feet above sea level.

Figure 35. Sketch of reservoir at maximum and minmum pool sizes, Tularosa basin energy-water project.

Runoff in Rinconada Creek varies tremendously from year to year depending upon snow pack on the Sierra Blanca portion of the Sacramento Range and spring and summer rain storms within the mountains. Evaporation from the recreational minimum pool could possibly be compensated by the capture of spring runoff and floodwaters.

Storage Requirements

Water production from the desalination plant will be approximately 480,000 acre-feet (product plus blend water) per year. The distribution of said supply will be among agricultural, municipal, and industrial users.

Traditionally, the municipal and industrial sectors have utilized water as it is being produced. It is probable that within the Tularosa basin potential M & I users would be capable of consuming their needs on a continuing basis directly from the desalination plant itself, thus eliminating large storage requirements (of course, the usual steel reservoirs and municipal treatment facilities may be necessary).

Agricultural demand of water, however, is concentrated into an irrigation season, usually about six months in New Mexico. Because of this concentrated demand and the magnitude of required quantities, a large storage reservoir will be necessary to satisfy agricultural water delivery needs.

Storage requirements were calculated as follows. On-farm water deliveries have been estimated to be about 395,000 acre-feet over the irrigation season. Again assuming that the irrigation season is six months, and that water production from the desalination plant will be continuous over the year (except for the usual maintenance), over half of the agricultural water requirements will have to be stored during the non-irrigation season. In addition, some water must be stored even during the season because actual irrigation practices require release of water only during specific time intervals. However, storage during the non-irrigation months will constitute the maximum necessary agricultural need for normal on-farm deliveries.

From the above, approximately 200,000 acre-feet must then be available from a reservoir prior to start of irrigation. Added to this will be the necessary contingency margin for potential breakdowns in either the desalination plant, nuclear reactor, or water conveyance system from the energy-water complex to storage reservoir. Specification of this contingency margin can vary, but for purposes of this initial study will equal 25 percent of the average monthly on-farm delivery requirements, 400,000 acre-feet divided by six months times 25 percent is approximately 17,000 acre-feet. (Any major shutdown of the nuclear reactor, and necessarily the desalination plant, would require such a contingency quantity that several reservoirs would have to be constructed--definitely cost prohibitive).

Even with concrete lined conveyance channels for the agricultural distribution system some water loss will occur; here primarily evaporation as opposed to seepages and non-agricultural plant use along unlined channels. From several other major distribution systems in the Southwest, a reasonable estimate of such losses has been one-half of one percent (.5 percent) of the diverted water, or 2,000 acre-feet. Evaporation will also transpire from the reservoir pool itself. Even though the largest amount of exposed surface area will be during months of relatively low pan evaporation, actual evaporation quantities will be significant. Agricultural water will be minimal toward the end of irrigation season, although the maintained recreational pool will still be present. During these months, pan evaporation is at its highest.

Total cumulative pan evaporation for the months of September through May is around 60 inches. Average exposed surface acreage will depend on the reservoir pool present at the conclusion of irrigation season, desalination delivery schedules, and runoff from the mountains. By examination of the fluctuating pools, 2,000 surface acres would seem to be a reasonable estimate of probable maximum size during a normal year. Therefore, average exposed acreage can be assumed to equal half that amount, 1,000 acres. Pan evaporation, 60 inches or five feet, multiplied by the average exposed surface area, 1,000 acres, gives us a gross but applicable estimate of reservoir evaporation of 5,000 acre-feet.

Storage capacity is now the sum of those previous estimates: on-farm deliveries of 200,000 acre-feet; 25 percent of an average monthly delivery or 17,000 acre-feet; 0.5 percent of the total delivery, or 2,000 acre-feet; and reservoir evaporation loss, 5,000 acre-feet. A total of around 225,000 acre-feet is the estimate for maximum agricultural storage capacity at the reservoir.

Because of the natural drainage and runoff from the winter snow pack or spring/summer mountain rains, capacity of the reservoir will have to be increased over and above the estimated maximum agricultural requirement to accommodate this excess water. A flood safety margin of at least 25,000 acre-feet will be needed, with a strong possibility of much more once a comprehensive study has been conducted to estimate the expected timing and quantity of runoffs. (As a bonus, most of the captured flood waters will be available for beneficial use).

With this bare minimum flood margin of 25,000 acre-feet which includes the minimum recreational pool added to the agricultural requirements, necessary reservoir capacity is now estimated to be a minimum of a quarter million acre-feet (250,000), a rather substantial amount in the Southwest.

Dam Construction

With minimum storage requirements of 250,000 acre-feet, and extremely mountainous terrain at the reservoir site, dam size will be large. Elevation at proposed dam site is approximately 5,000 feet. Maximum pool size permitted (minimum storage requirements plus a flood margin) will put the water elevation at about 5,500 feet. Therefore, height of the dam will be a minimum of 500 feet from base to spillway.

The width of the canyon almost rules out a concrete structure (even with a narrow canyon mouth, costs would probably be prohibitive). An earthen-filled structure then is used as the basis for estimating costs. Many of the dams in the Southwest are earthen-filled, thereby increasing availability of comparative structures.

Of course, any dam will be site specific, that is, design characteristics (from which costs are estimated) are highly dependent on terrain, bed rock depth, etc. of the site. For purposes of these initial and rather gross cost estimates, a general structure was designed based upon elevation and width distances at the proposed site, bed rock availability very near the surface along the entire length of the dam, and standard structural characteristics of earthen-filled dams for similar areas.

Actual dam length will be approximately a mile and a quarter (6,600 feet) with the height at center 500 feet. Figure 36 is a schematic of the proposed structure. This was based upon examination of topographic maps, and then making the simplifying assumption that dam shape would be linear.

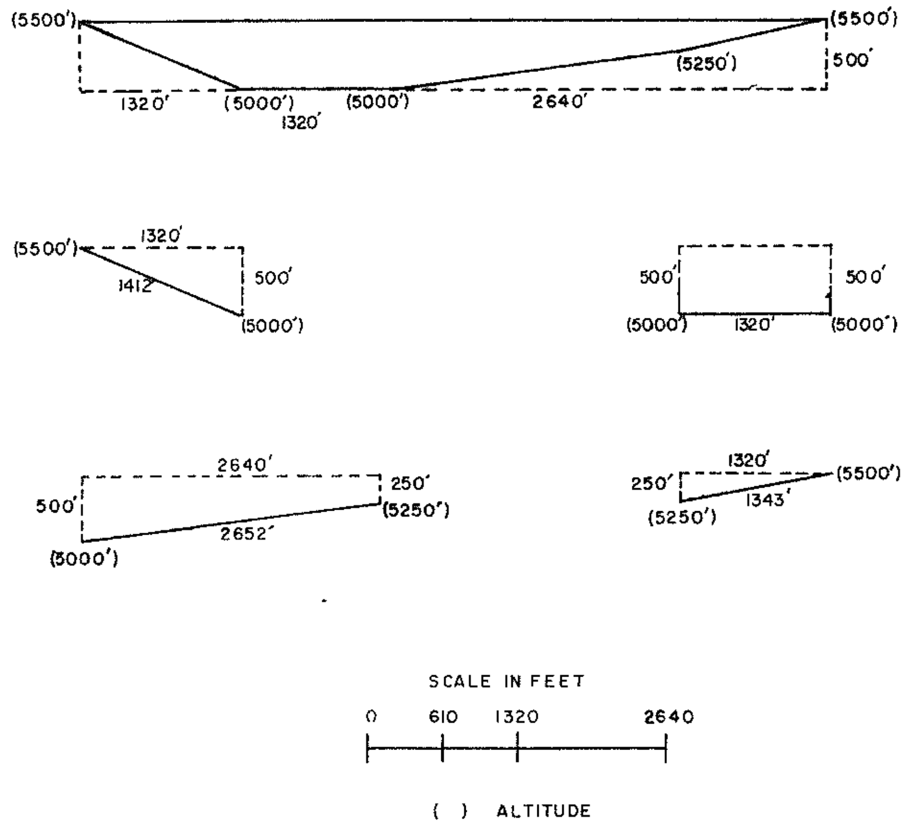


Figure 36. Schematic of proposed dam structure.

<u>Cost Estimate</u>

1. Earthen-Filled Dam
   Average depth of 250 feet
   Length of 1320 feet
   \$1.85 a cubic yard   6,000 cy/ln foot 79.2×10^5 yd^3
   ≅\$14.7 x 10^6
2. Average depth of 500 ft
   Length of 1320 feet
   \$1.85 a cubic yard   32,000 cy/ln foot 42.2×10^7 yd^3
   ≅\$78.1 x 10^6
3. Average depth of 375 feet
   Length of 2640 feet
   \$1.85 a cubic yard   15,000 cy/ln foot 39.6×10^6 yd^3
   ≅\$73.3 x 10^6
4. Average depth of 125 feet
   Length of 1320 feet
   \$1.85 a cubic yard   11,500 cy/ln foot 19.8×10^5 yd^3
   ≅\$3.7 x 10^6
   Spillway
      Maximum flow 3,000 cfs
      Head of 400 ft
      ≅\$5.4 x 10^6

Outlet works

Maximum flow	1,500 cfs
Maximum head	400 ft

≐$9.4 x 10^6

Total estimated cost (below) is in 1974 dollars, and represents a gross figure based upon the before-mentioned design. It includes excavation and other costs as a percentage of earth-fill costs.

Earthen-Dam	\$169.8 x 10^6
Spillway	\$ 5.4 x 10^6
Outlet works	\$ 9.4 x 10^6
Subtotal	\$184.6 x 10^6
25 percent for site excavation/preparation	\$ 46.2 x 10^6
Total	\$230.8 x 10^6

Maintenance of a minimum reservoir pool would probably add very little to the capital cost because of any implied design changes. These will be ignored in the initial estimate.

Construction Schedule

Construction of such a structure will take approximately eight years. With start-up and finishing stages being rather small in comparison to the middle years in terms of costs, the following cost distribution schedule has been developed using similar earthen-filled structures in the Southwest as a comparative basis.

1st year	6%	\$13.8 x 10^6
2nd year	12%	\$27.2 x 10^6
3rd year	18%	\$41.5 x 10^6
4th year	18%	\$41.5 x 10^6
5th year	15%	\$34.7 x 10^6
6th year	15%	\$34.7 x 10^6
7th year	10%	\$23.1 x 10^6
8th year	6%	\$13.8 x 10^6

Relationship of Other Major Components

The reservoir and dam will be located about 10 miles from the actual Tularosa basin energy-water complex. By usual automobile transportation, the realistic distance will be increased to around 16 miles. Mean elevation of the desalination plant is 4,500 feet with base of dam being 5,000 feet giving a static lift of 500 feet to base. Dam crest is at 5,500 feet elevation, making total necessary static lift 1,000 feet for the product water.

The production well field will be located west and southwest of the reservoir at distances ranging from five to 12 miles. It may be possible to directly transport the blend or brackish water from the well field to the reservoir site, thus saving significantly on the total transportation costs in terms of pipe needed and energy to deliver the water. However, a much more detailed analysis would be needed and the original assumption of product plus blend water being considered as one and transported to the reservoir will be maintained.

Agricultural users will be located west and southwest of the reservoir site at elevations around 4,500 feet. Thus, gravity flow will be utilized to deliver water to the farm site via the main canal from the dam to the laterals just above most of the farms.

As with agricultural users, potential municipal and industrial users of desalinated product water would be located west and southwest of the dam and reservoir. However, as mentioned earlier, most M & I users will take delivery of product water from the desalination plant itself, thus saving on the cost of transporting the water over the 10-mile system up a vertical climb of around 1,000 feet. If large manufacturing facilities were to develop in that area that required substantial amounts of water, it would still probably be cheaper to build their own storage facilities near the plant site (most likely around the 4,500 foot elevation as is the case for much of the valley or basin floor) as opposed to paying the power bill to move the desired amount to the reservoir for storage.

Operating Characteristics of Reservoir

Since the reservoir's primary purpose is to store product water from the desalination plant for agricultural use, a continuous flux will be noticeable. Because the irrigation season is approximately six months, water will be flowing into the reservoir half the year, and flowing out the other half.

Beginning in October, outlet works will be closed for six or seven months to allow the build-up of over 200,000 acre-feet of water. From this time until the start of irrigation (most likely April), water will flow from the desalination plant to the reservoir at a fairly continuous rate of 726 cfs (acre-foot a minute). When the irrigation season begins, most of the water from the plant will flow directly into the agricultural distribution system. The 200,000 acre-feet plus in the reservoir will be released in selected amounts at various time intervals during the period April through September. Except for the recreational pool maintained during the irrigation season, the reservoir could probably be viewed as a bathtub, filling and draining once over a year.

During the first several years, more water would be stored than released to build up the minimum recreational pool and to offset seepage to bank storage until a static equilibrium was reached. After that time, however, inflows would about equal outflows over a given year. (This ignores evaporation loss which would have to be compensated for by additional inflows and flood/runoff capture which would be released as supplemental water). Maximum pool size (approximately 250,000 acre-feet) of the reservoir will result in about 26 miles of shoreline and 2,500 acres of surface area. As the reservoir empties to supply irrigation needs this will, of course, decrease tremendously. The minimum recreational pool will contain approximately 15,000 acre-feet, with surface area of 100 acres and shoreline of only three to four miles. Of course, with the necessary large fluctuations, actual available surface acreage and shoreline will be significantly greater during the majority of any year with an average surface area of between 1,000 and 4,000 acres during the period of highest recreational use.

Recreation Potential

Recreation Demand

The model of demand for water-based recreation incorporates a recent major theoretical advance in demand theory. Lancaster (1966) has developed a model which has achieved both wide acceptance and empirical success. This model restructures demand theory to incorporate characteristics of consumption activities which yield utility to consumers. Commodities are then consumed jointly with the activities. Clearly, recreation can best be defined as an activity within this framework. Thus, the common unit in recreation studies, the visitor day, has a natural place as an activity within Lancaster's framework. The theoretical demand model to be used in this study can be described with the following notation:

$\vec{z}$ = the vector of characteristics which yield utility to consumers derived from recreation activities;

$\vec{r}$ = a vector of recreation activities (boating, fishing, water skiing, etc.) in visitor days;

$\vec{x}$ = the vector of commodities jointly consumed with recreation activities;

$\vec{q}$ = a vector of quality parameters associated with the particular recreation site (congestion, surface area, temperature, etc.);

d = a scalar measuring distance of a particular user or group of users from the recreation site;

$\vec{p}$ = cost of transportation per unit distance d; and

Y = income of a consumer or average income of a group of consumers depending on the formulation of the model.

It is assumed that consumers maximize a utility function,

$$U(\vec{z};\ Y - \vec{p}\vec{x} - \hat{p}d),$$

which is determined by the characteristics of the particular overall recreation experience, $\vec{z}$, and income remaining after subtracting the total cost of the recreation experience, $Y - \vec{p}\vec{x} - \hat{p}d$. This utility function is subject to two constraints. First, characteristics of the recreation experience, $\vec{z}$, are assumed to be a vector function of the quality parameters of the recreation site, $\vec{q}$, and of the recreation activities undertaken, $\vec{r}$, as well as the distance to the site, d:

$$\vec{z} = \vec{G}(\vec{q};\ \vec{r};\ d).$$

The second constraint relates levels of consumption of recreation associated commodities, $\vec{x}$, to levels of recreation activities, $\vec{r}$, through a matrix, B:

$$\vec{x} = B\vec{r}$$

where consumers are assumed to optimize this problem, the implicit function theorem allows us to determine the level of recreation activities as a function of quality parameters, prices, income, and distance:

$$\vec{r} = \vec{F}\ (\vec{q};\ \vec{p};\ \hat{p};\ Y;\ d).$$

This methodology incorporates both the Hotelling-Clawson approach (Clawson, 1959) which uses travel cost as the determinant of recreation demand for a specific site and recent attempts to include quality parameters such as surface area and angler success (Stevens, 1966) to explain recreation demand over multiple sites. Thus, there already exists considerable empirical evidence supporting this type of methodology.

Within the context of the above theoretical justification, a per capita recreation demand relationship that contains not only the traditional economic determinants (income, travel cost) and the environmental quality variables, but also embodies the latest attempts to specify recreation demand, a gravity index measuring nearby water based recreation alternatives (Grubb and Goodwin, 1968) and a measure of congestion (as an implicit price of the use of the reservoir), was estimated. The equation used is of the form:

1)
$$\begin{aligned} VD_{it}/N_{ikt} = {} & b_0 + b_1R_{it} + b_2A_i + b_3JT_i + \\ & b_4(JT_i)^2 + b_5JU_i + b_6(JU_i)^2 + b_7C_{it-1} + \\ & b_8(C_{it})^2 + b_9G_i + b_{10}t + b_{11}D_{it} + b_{12}Y_{it} \end{aligned}$$

where:

i = Lake

t = Time: 1960 = 0 for lakes in the statistical sample

k = County

VD_{it} = Visitor days at lake i during time t

N_{kt} = Population in county k during time t (millions)

Y_{kt} = Per capita income in county k, time t

R_{it} = Annual rainfall in millimeters

A_i = Surface area in acres

JT_i = Maximum average daily January temperature in centigrade

JU_i = Maximum average daily July temperature in centigrade

C_{it-1} = VD_{t-1}/A_i Measure of congestion in visitor days per acre per year

D_{ik}* = Distance from lake i to center of county k

A_{ij} = Total surface area of alternative lakes around lake in concentric circle j; j 25 miles in width

D_j* = Distance from lake to the center of concentric circle j. D_j = 12.5; 37.5,..., 137.5.

G_i = $\sum_{j=1}^{6} A_{ij}/(D_j)^2$ = Proximity index (gravity index) to 150 miles.

D_{it}* = $(\sum_{k=1}^{M_i} D_{ik}N_{ikt})/\sum_{k=1}^{M_i} N_{ikt}$ = Travel distance index weighted by population to 200 miles (ten thousands)

Y_{it} = $(\sum_{k=1}^{M_k} N_{ikt}Y_{ikt})/\Sigma N_{ikt}$ = Per capita income within 200 miles of lake i (thousands)

To enable estimation of the above equation, pooled cross-sectional and time-series data were generated from 38 reservoirs and their immediate surrounding areas. The sample was scattered throughout the 48 continuous states and consisted of 255 observations. The data base included annual number of visitor days, average temperatures, annual precipitation and surface area at lake i. The surface areas of alternative reservoirs within 150 miles of lake i, in addition to population and per capita income by county were also utilized. Yearly growth rates for both population and per capita income, by state, were used to update the data base. From this foundation the travel distance index, proximity index, and the congestion measure were derived.

Sources of Data

The source of information concerning population and per capita income was the U. S. Department of the Commerce Social and Economic Statistics Administration, Bureau of the Census. Climatic data were obtained from the *Climatological Data National Summary, 1962-1972*, prepared by the National Oceanic and Atmospheric Administration, Department of the Commerce. Information concerning the 38 reservoirs investigated in this study was acquired from the Corps of Engineers, Department of the Army, while surface area figures for alternative recreation sites were obtained from Aeronautical and Operational Navigation Charts, published by the Aeronautical Chart and information

*Map scale 1:7,500,000

Center, U. S. Air Force. References other than those listed above, which were used in the processes of data collection are listed in the bibliography.

In order to achieve the desired result of fitting the collected data to the formulation discussed above, a single equation model (linear in its coefficients) was estimated using the least squares technique. The major hypotheses were that rainfall would be negatively related to the dependent variable, visitor days, while income and surface area would be positively related to visitation. Furthermore, the total cost index viewed as an implicit price by the user, and the gravity index, defined as a measure of alternative water based recreation to lake i were hypothesized to be inversely related to per capita use at lake i. The non-linear terms, congestion and the temperature variables, were expected to be positively related to visitation in some regions, while being negatively related in others. This type of behavior displayed between dependent and independent variables would yield a functional relationship which would include an optimal level of congestion and of temperature, as determined by the lake user. Therefore congestion, when positively related, would be viewed as a benefit by the recreationist and, when negatively related, would be viewed as another implicit price one must pay for the use of recreational facilities.

Results--The Demand Equation

The equation giving the best fit for per capita recreation use is of the following form:

$$\begin{aligned} 2)\quad VD_{it}/N_{ikt} = {} & -1419571 - \underset{(-3.867)}{152.3}\, R_{it} + \underset{(17.19)}{14.48}\, A_i + \\ & \underset{(1.201)}{10740}\, JT_i - \underset{(-1.260)}{655.1}\,(JT_i)^2 + \underset{(2.359)}{174600}\, JU_i - \\ & \underset{(-2.556)}{3151}\,(JU_i)^2 + \underset{(4.109)}{590.2}\, C_{it-1} - \underset{(-4.096)}{44590}\,(C_{it-1})^2 - \\ & \underset{(-2.031)}{103100}\, G_i + \underset{(6.690)}{46380}\, t - \underset{(-4.793)}{135200000}\, D_{it} - \underset{(-7.289)}{285500}\, Y_{it} \end{aligned}$$

Note: t statistics are included in parentheses below each estimated coefficient.

Interpretation

The basic hypotheses that rainfall, the total cost index, and the proximity index would be negatively related to the dependent variable, are satisfied at the one percent level of significance. But more interesting results come from further inspection of the equation. First of all, of major importance is the fact that income is negatively related to visitation. The implication that recreation is an inferior commodity is contrary to existing economic theory. One explanation for this phenomenon is that those lakes in a higher per capita income area are relatively close to urban centers while lakes associated with lower per capita income are a significant distance from the major metropolitan areas. The negative relationship between per capita income and visitation implies that lakes near urban centers are used less often, on a per capita basis, possibly because of the people's desire to get away.

Further analysis of the equation reveals that the squared terms (January temperature, July temperature, congestion) are all negatively related, while the corresponding linear terms of these variables are all positively related to visitation. The suggestion is that there is a most desirable level for temperature and congestion. Before reaching the optimum level there is a positive relationship between increases in congestion (or temperature) and increases in the number of user days. Subsequent to scaling the peak, however, a negative relationship sets in. With this concept in mind, it was possible to maximize the three relevant functions, and to determine the optimal magnitude of January temperature, July temperature, and congestion. The level of congestion that would maximize visitor days (all else held constant) would be 661.8 visitor days per surface acre, per year, while the most favorable temperatures would be 8.2 degrees centigrade (47.7 degrees F.) in January and 27.7 degrees centigrade (82 degrees F.) in July (Figures 37, 38, 39). Other inferences from the estimated equation were that the larger the lake, the more visitation (positive relationship between surface area and visitor days) and that the trend indicator which incorporates changes in tastes, etc. was related positively to the dependent variable. The latter result indicates that throughout the sixties and early seventies, the relevant years for the sample, there was a strong bias toward increasing per capita recreation demand.

Application of the Model

The recreation demand function developed above can now be used to achieve the previously stated objective of this portion of the study: to estimate annual visitation to the proposed Tularosa basin reservoir. This was achieved in a four-step process: data collection, utilization of the econometric equation for forecasting purposes, interpretation of the resulting prediction, and application of the congressional per-day dollar allotment to standardize the benefits ($) derived.

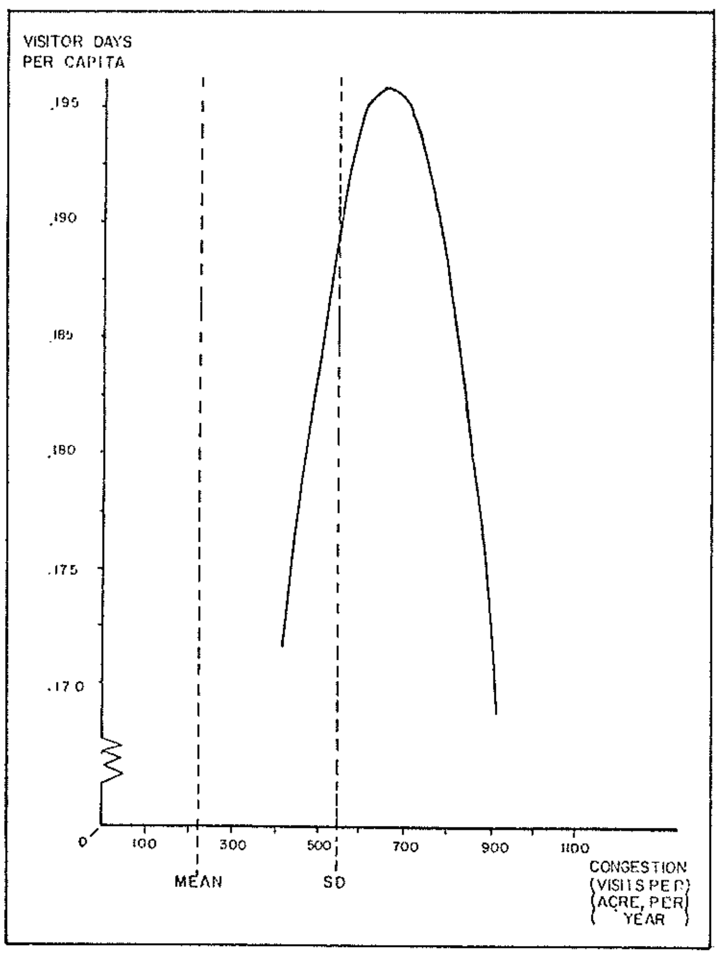


Figure 37. Visitor days per capita versus the level of congestion (visits per acre per year).

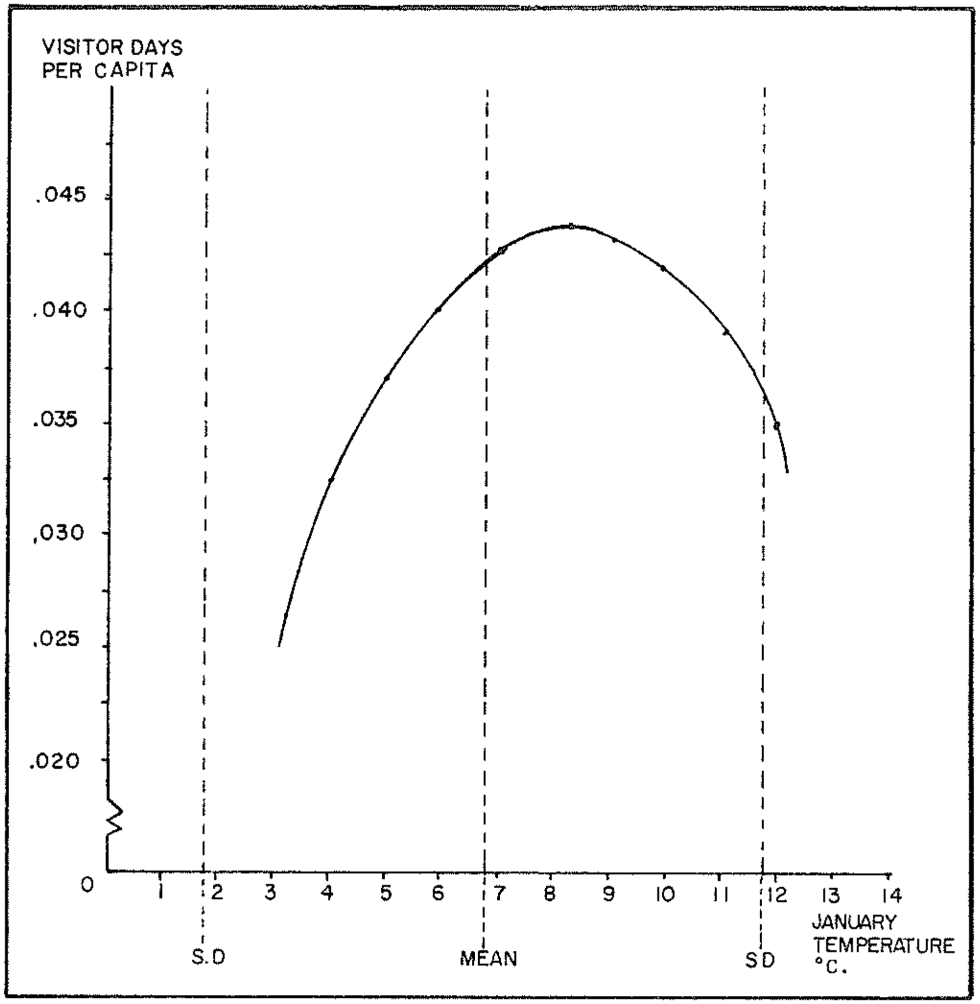


Figure 38. Visitor days per capita versus January temperature.

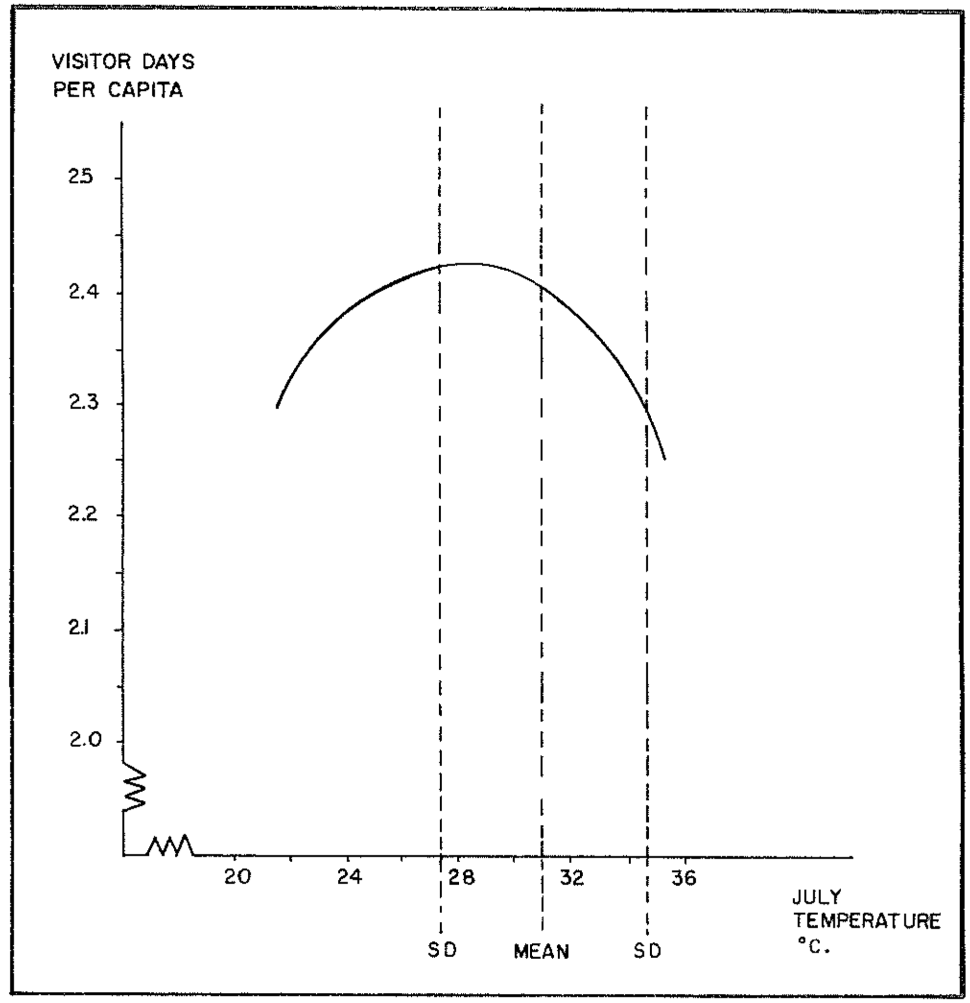


Figure 39. Visitor days per capita versus July temperature.

Data Collection

Data pertinent to the Tularosa basin area were obtained from the list of sources delineated above and is stated in the identical units of measure as the former information. Population, income, and the appropriate indices which are derivations of this information are projected for the year 2000, using an annual growth rate which is the average for the states of New Mexico and Texas. The area of concern (0 to 200 miles from the reservoir) is expected to possess an aggregate population of about 1,725,800 which serves to generate a travel distance index value of .00249, and a total regional income of $19,484,630,000. A population of 94,000 (this figure is inflated for the inflow of population due to construction, etc. as well as for annual growth) is predicted to reside in Otero County, the immediate environment of the proposed lake. Assuming that the environmental parameters will remain stable from the present until the year 2000, annual precipitation is expected to be 305 mm while the maximum average daily January and July temperature should take the values of 5.1 degrees (C) and 25 degrees (C), respectively. The gravity index was calculated to be .01506, an exceptionally small value, due mainly to the fact that there is no alternative water-based recreation within 50 miles of the proposed Tularosa reservoir. With the information above, an expected average surface area of 1,200 acres for the proposed lake, and a simplifying assumption that $VD_{t-1} = VD_t$, the level of congestion of 1,561 visitors per acre, per year, is achieved where the final variable, time, was truncated at 1980 in order to approximate a trend curve that shows a marked increase in recreation demand (1960-1980) followed by a leveling off period as society reaches some equilibrium level of recreation demand consistent with decreased expectations.

Recreation Visitation Forecast, Interpretation

The estimated econometric demand equation and the data pertaining to the proposed Tularosa basin reservoir yields as a prediction of recreation usage 1,873,152 visitor days in the year 2000, or 4.276 visitor days per surface acre, per day. This is far in excess of the optimal 1.8 visitors per acre per day.

On initial inspection, 1,873,152 annual visitor days seems a large number for a lake in southern New Mexico that occupies a surface area of 1,200 acres (by comparison, Elephant Butte Lake is roughly 30 times as large and had only 1.47 million visitor days in 1973). Upon further investigation, however, the proposed Tularosa impoundment is found to possess many favorable characteristics that seemingly enable it to attract visitors in excess of what was originally anticipated. First of all, the environmental parameters dictate large usage. The maximum average daily July temperature of 25 degrees (C) is extremely close to the most desirable 27.7 degree mark. This combined with the relatively low annual precipitation (12.04 inches) makes the Tularosa reservoir environmentally attractive. Other favorable factors are the large immediate population (a projected 94,000 in Otero County), all within a few miles of the reservoir, and the very low gravity index measure (.01506) which translates into a lack of water-based recreational alternatives. One final element that gives the lake under consideration a comparative advantage is that it is located a significant distance from the large urban areas and thus subscribes to the definition of a low-income area reservoir. The negative relationship between income and visitation in our estimated equation may mean that as people attempt to get away, the Tularosa basin reservoir will be one place that is sought out.

Total Net Benefits

Congress has permitted up to two dollars a day in net benefits directly attributable to water-based recreation. Implementation of the extreme figure, in conjunction with the estimation of 1,873,152 annual visitors to the proposed lake site, allows for the fulfillment of the final objective of this study: an estimation of annual total net benefits equal to $3,746,300.

CHAPTER VI

WATER EXPORTATION

The idea of importing water into New Mexico is not new. Nor is the idea of shifting this scare resource within the state. However, new internal supplies of the quantity produced from the Tularosa basin energy-water complex adds a new dimension to possible intra-state water transfers in the form of exportation from the complex to adjoining river basins. This section will concern itself with discussion of potential demand for this water in the Rio Grande and Pecos River basins, delivery of water from the energy-water complex to these river basins, and feasibility of such transfers.

POTENTIAL DEMAND

Data prepared for the State Water Plan[6] indicates that by the year 2000 New Mexico will need an additional one million acre-feet of water (depletion) to meet its projected demand. Of course, this assumes a population growth rate commensurate with the OBERS-72 estimate, no substantial increase in irrigated agriculture, and no retirement of any existing irrigation acreage and its associated water rights. By 2020, this shortage will have increased to over 1.3 million acre-feet.

A fifth of the above shortages will occur in the Rio Grande basin, while another tenth is projected to be in the Pecos River basin. With a large proportion of the state's growth programmed for these two river basin systems, their percentage of the total shortage will increase through time. Extrapolating from the 2020 estimate to the year 2030, projected demand will exceed available supply by over a half million acre-feet in the Rio Grande, and around 150,000 acre-feet in the Pecos. By 2030 the probable shortage would even exceed the availability from the Tularosa basin energy-water complex (as presently designed).

As seen above, potential demand in the two adjoining river basins is projected to be such as to warrant serious consideration of developing further the exportation of Tularosa basin water to other portions of the state.

DELIVERY SYSTEM

Any schema for transporting water out of the Tularosa basin to either the Rio Grande or Pecos will involve a rather large conveyance system to carry the necessary quantities the required distance. Although the energy-water complex and well field are located within the Tularosa basin--a closed central basin and technically part of the Rio Grande basin drainge system (Figure 40), they are physically closer to natural drainge conveyance channels located in the Pecos drainage system. Dividing the two drainge systems are the Sacramento Mountains which are situated just east of the complex and well field. Figure 40 presents the drainge systems, transportation alternatives, and their relationships to the proposed project.

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[6]Data prepared by New Mexico State Engineer Office.

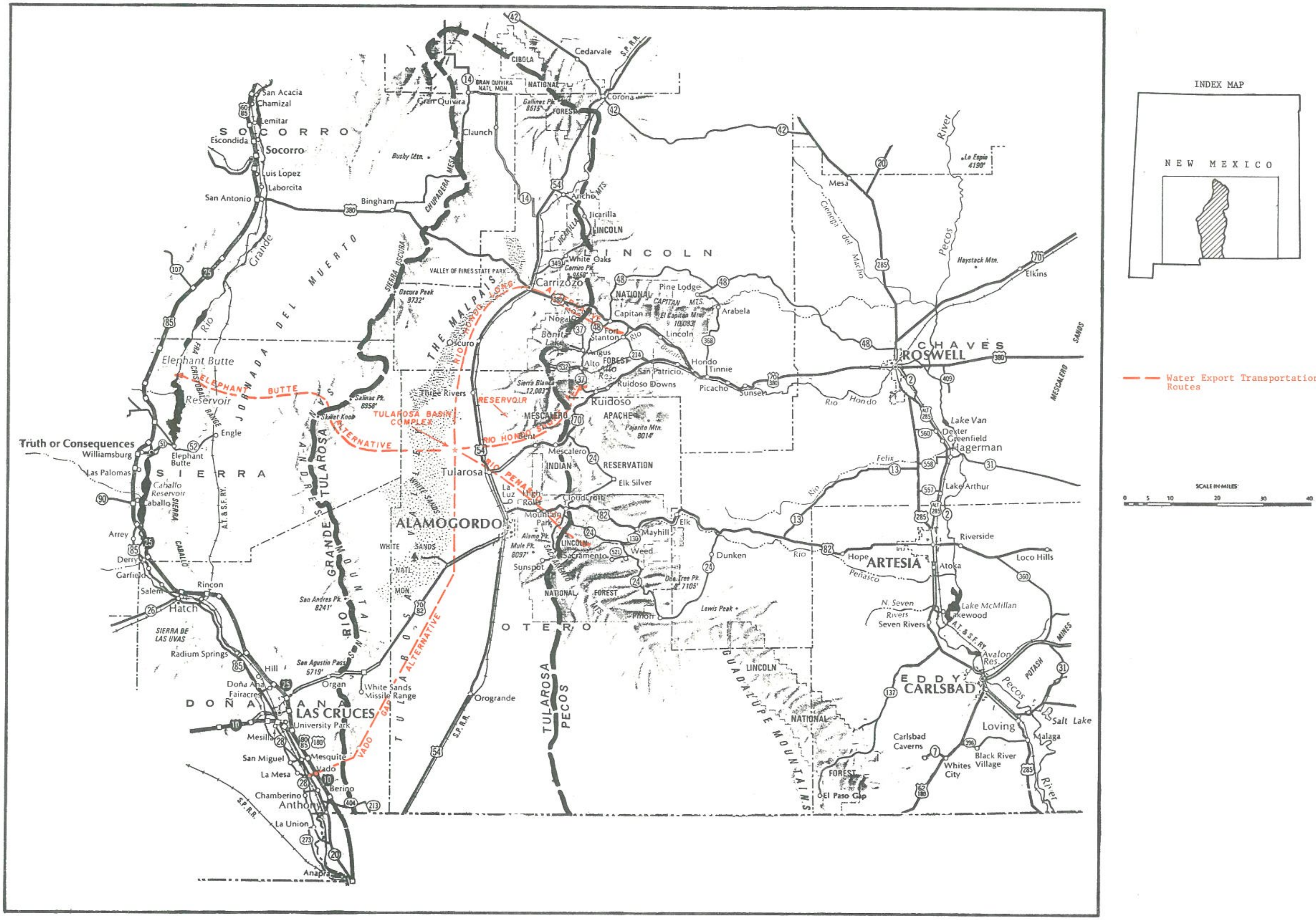


Figure 40. Drainage locations and water export transportation alternatives for Tularosa basin energy-water complex

Both alternatives for exportation to the Pecos River basin (via the Rio Hondo or Rio Penasco) are much closer to the project areas than the Rio Grande at Vado Gap or Elephant Butte (alternatives one and two for the Rio Grande). Thus, at first inspection the Pecos would be the likely choice to receive any transfer. Any conveyance system constructed would need to be only 13 to 24 miles, as opposed to 70 or more miles necessary to reach the Rio Grande.

However, upon closer inspection and analysis this appears not to be the case for at least one of the Rio Grande alternatives. First, conveyance systems designed for transfer to the Pecos would have to accommodate the Sacramento Mountains. With the change in elevation ranging from just under 3,500 feet for one possible route to the Rio Bonito (part of Rio Hondo system) to over 4,500 feet to the Rio Penasco, a closed conveyance system becomes mandatory. In addition, construction costs in mountainous terrains are tremendous. It is possible to decrease the elevation differential for the Rio Hondo alternative by running the conveyance system northward toward Carrizozo, and then southeasterly until tributaries of the Pecos River are encountered. The increase in distance would be on the order of 50 miles, with an uphill trip of 2,000 feet still necessary. Second, by having to transport water uphill over a significant portion of the conveyance system, pumps will be needed at various intervals to supply the necessary lift. Because of the distance and elevation involved, many pumps would be necessary as well as a considerable amount of electricity to maintain delivery schedules. (The pump and power requirement are also applicable to the Elephant Butte alternative in the Rio Grande).

Third, even though the distance involved in transporting water from the energy-water complex to the Rio Grande is usually much greater than those to the Pecos, much of the trip is on a slightly downhill gradient for one alternative, and for the majority of the second alternative. Only gravity flow is required in the Vado Gap alternative and this eliminates the need for a closed system, thereby reducing capital costs considerably.

Fourth, forecasts have shown that the Rio Grande basin system will have a much greater shortage of water than the Pecos in both absolute and percentage terms. Growth should be more intensive along the Rio Grande as well, thus increasing its case for the water based upon relative needs.

It would be extremely unlikely that water from the Tularosa basin would be transferred to both adjoining river systems. In addition to the probable prohibitive costs associated with such a dual transfer, potential allocation problems between the two may prove to be unsolvable. It is therefore assumed that only one of the possible transfers would take place.

However, for purposes of analysis both possible transfers will be considered below. Many simplifying assumptions are made, but the gross cost estimates obtained are believed to be reasonable and adequate for this study.

Rio Grande Conveyance Systems

Vado Gap Alternative

Based upon gradient considerations, the Vado Gap conveyance system would be built in a southwesterly direction from the complex (well field) taking advantage of the terrain (Figure 40). Delivery to the Rio Grande would occur between 20 and 30 miles below the City of Las Cruces. The well field and energy-water complex are at elevations in the 4,500 foot range, while the Rio Grande below Las Cruces is around 4,000 feet. Except for some minor terrain changes, the gradient drop is fairly gradual and continuous. Approaching the Franklin and Organ Mountains, there would be some increase in elevation for several miles, but by proper excavation the downward slope could be maintained.

Major assumptions and conveyance system design characteristics for the Vado Gap alternative are as follows:

1. 75 mile length.
2. Carrying capacity of 726 cfs or an acre-foot per minute.
3. Gradient maintained along system such that gravity flow will suffice for the transfer of water.
4. Approximately three miles of heavy excavation will be needed to breach the elevation differential just before entering the Rio Grande surface drainage basin.
5. The concrete-lined conveyance channel will be entirely on public land, thus eliminating any land or right-of-way cost components.

To be capable of carrying 726 cfs, the conveyance channel will have to be 10 to 11 feet in width at its base and eight to nine feet in height. Since the energy-water complex production schedule calls for just over 800 cfs and delivery under this alternative would be around 250,000 acre-feet in any given year, actual water (450 cfs) being conveyed in the channel will only be a portion of the desalination production. The 726 cfs requirement is to ensure that some excess capacity does exist for seasonal requirement fluctuations and future use.

In 1974 a similar sized (base and height) concrete-lined conveyance structure cost about $315,000 per mile for the NIIP[7] in northwest New Mexico. Although excavation requirements may differ between the two regions, this cost estimate will be used.

Total cost for the 75 mile 726 cfs conveyance channel from the proposed Tularosa basin project to the Rio Grande is estimated to be $23.6 million. Construction time will probably be on the order of four or five years. Costs during the construction phase are assumed to be evenly distributed.

Elephant Butte Alternative

This conveyance system would be built in a northwesterly direction from the complex (well field) following the natural gradient and terrain of the basin until the San Andres Mountains are encountered. Relift stations will lift the water over one of the several low passes in the range, where the open channel will resume its northwesterly direction to Elephant Butte reservoir (Figure 40). Actual delivery to the Rio Grande (reservoir) would probably occur just north of the Fra Cristobal Range. With the well field and energy-water complex at elevations in the 4,500-foot range, the gradient would be utilized to transport the water to the foothills of the San Andres. A series of pumps would transfer the water over a pass, where it would resume its trip to the Rio Grande via gravity flow.

Major assumptions and conveyance system design characteristics for the Elephant Butte alternative are as follows:

1. 80 mile length.
2. Carrying capacity of 800 cfs or 1.1 acre-feet a minute.
3. Gradient maintained along all portions of the system, except at the San Andres Mountains, such that gravity flow will suffice for the transfer of water along this portion.
4. Only light excavation will be needed to breach any elevation differential in order to maintain that gradient.
5. At most a 1,000-foot elevation lift would be necessary over the San Andres Mountain Range.

[7]Navajo Indian Irrigation Project--see Bureau of Reclamation yearly reports for a description.

6. Similar pumps as those used in the plant to reservoir delivery system are assumed applicable.
7. If a closed conveyance system is needed to cross the San Andres, less than a mile of concrete pipe would be required.
8. The concrete-lined conveyance channel will be entirely on public land, thus eliminating any land or right-of-way cost components.

Since the carrying capacity of the conveyance channel is similar to the Vado Gap alternative, base and height dimensions will remain the same. However, excavation requirements will be greater to the degree that costs per mile should exceed those in the Vado Gap alternative. Therefore, the $315,000 per mile of installed channel used is increased by a factor of 1.4 to account for this greater installation and excavation cost, as well as the possible mile or less length of closed concrete pipe over the San Andres.

Total conveyance channel cost for this 80 mile, 800 cfs, conveyance channel to Elephant Butte reservoir on the Rio Grande is estimated at $35.2 million. The construction schedule should be four or five years.

With a lift of 1,000 feet and utilizing pumps similar to those used in the plant to reservoir delivery system, a total of 30 pumps would be needed to transfer the 400,000 acre-feet a year over the San Andres. Water would flow at a rather uniform rate through the system. In order to ensure continuous flow capabilities, at least one spare pump would be required at each of the 10 relift stations. Therefore, total pump requirement would be 40. At $868,500 each, total initial pump cost is estimated at $34.8 million.

The pumps could be expected to have about a 15-year life, needing replacement once during the lifetime of the proposed Tularosa basin project. Replacement cost at the 15-year point is assumed to equal initial cost, or $34.8 million.

With the pumps operating fairly continuously (except for times when the complex is shut-down for routine maintenance and repairs), a total of 102 MW will be required on an average yearly basis to transfer the 400,000 acre-foot volume of water over the San Andres Mountains to Elephant Butte reservoir.

Pecos River Conveyance System

Distances from the Tularosa basin energy-water complex or well field to either the Rio Hondo or Rio Penasco will vary considerably depending upon the trade-off between increased lift and shorter distance or decreased lift and longer distance.

Rio Penasco-Rio Hondo Alternatives

For the Rio Penasco alternative, there exists several passes within the Sacrameo Mountains that are lower than others with distances over these averaging 24 miles. This possibility will not be considered further here because the magnitude of elevation change (minimum of 4,500 feet) is considerably greater than for either one of the Rio Hondo alternatives.

For some of the Rio Hondo alternatives, the average distance over the Sierra Blanca portion of the Sacramento Mountains would be around 13 miles (Figure 40), but with a tremendous elevation differential to overcome--from 4,500 feet to over 8,000 feet. By routing the conveyance system northward toward Carrizozo and then southeastward to the Rio Hondo, the elevation difference is much smaller, just over 2,000 feet. However, the distance the water must be transported increases to over 60 miles, with well over half the journey uphill.

Both alternatives to the Rio Hondo (and subsequently to the Pecos River) will be examined, but the same assumptions will apply to each. First, a closed conveyance system will be necessary. Even though a steel pipe will probably be necessary for the shorter alternative (directly over the Sacramento Range), a concrete pipe of 12-foot diameter is assumed applicable to both. Second, pumps designed for the complex to storage reservoir conveyance system are utilized. This means that each will be capable of lifting 10^5 gpm over a 100-foot static head. Therefore, three pumps (two for lift, one for backup) will be necessary for each 100-foot head to deliver 375 cfs or 250,000 acre-feet a year. Third, no conveyance losses will occur in the closed system. Fourth, the system can be designed such that no abnormal internal pressures will be present.

Rio Hondo Short Alternative[8]

The shorter alternative will require 13 miles of 12-foot concrete pipe; $300 per installed foot gives a total pipe cost of $20.6 million. Total static head will be in excess of 3,500 feet, which implies that a total of 105 pumps would be necessary. Making no allowances for replacements, the fact that dynamic heads are considerably larger than static, or the installation costs, these 105 pumps at roughly $868,500 each as in the plant to the reservoir delivery system will have a total cost of about $91 million.

Capital costs for the shorter alternative would run close to $112 million and electrical costs would be substantial. Each pump is rated at over 2,500 KW as in the plant to reservoir delivery system. Since the potential need in the Pecos River basin is between 90 and 150 thousand acre-feet during project lifetime (2000 to 2030), only a portion of the product water would be transferred during any given year. The conveyance system was overdesigned in terms of capacity to allow for seasonal fluctuations in delivery schedules and possible future growth. For simplicity, the average yearly delivery of 25 percent of production will be assumed. Therefore, 105 pumps each at 2,500 KW requires around 262 MW. Not all pumps would be operating simultaneously of course. On the average 70 pumps would be on-line, and only for 300 days or so a year. Therefore, actual MW requirements would be closer to 175 MW. On a yearly average this would amount to a 145 MW requirement, seven to eight percent of the net saleable power, to transport up to 150,000 acre-feet to the Pecos.

Rio Hondo Long Alternative

The longer alternative has of course much higher capital costs, but far less electrical power would be needed. The 60-plus miles of pipe would cost about $95 million. With a static head of 2,000 feet, and a need to deliver 375-400 gpm, 60 pumps (40 on-line, 20 spare or backup) at $868,500 each would cost $52 million. Again, assuming a 25 percent of product water delivery schedule, 150 MW would be required. Using the probable on-line pump requirements of 40 pumps for 300 days the yearly average power requirement would amount to 83 MW, about four percent of the net saleable power to transfer water to the Pecos.

SUMMARY

Summarizing both alternatives for the Pecos transfer proposal, capital costs approach $112 million for the shorter alternative and $147 million for the longer with electrical requirements

[8] Water actually delivered to the Rio Bonito which flows directly into the Rio Hondo and subsequently into the Pecos River.

of 145 MW for the shorter and 83 MW for the longer. The least cost alternatives over the 30-year life of the Tularosa basin energy-water complex depends on the interest and costs of electricity. In either case, initial capital investment is considerably more than for the Rio Grande alternatives.

Although it would have been possible to consider all of the alternatives discussed above in the benefit-cost analysis, only the Elephant Butte alternative was considered. This was based upon three primary criteria:

1. Of the two major drainage systems, the Rio Grande basin has the largest relative and absolute need based upon recent projections prepared for the New Mexico State Water Plan.
2. Of the two Rio Grande alternatives, the Elephant Butte alternative was scheduled to deliver all available product water after accounting for Tularosa basin agriculture, municipal, and industrial uses without the project to the Rio Grande in the amount of about 395,000 acre-feet. The Vado Gap alternative could have delivered only 200,000 plus acre-feet.
3. By delivering the water to Elephant Butte, all upstream users on the Rio Grande would have access to the water. The Vado Gap alternative would have most likely benefited only Dona Ana and Sierra Counties within New Mexico.

The Vado Gap alternative was designed to deliver only enough water to the Rio Grande to satisfy or meet New Mexico's commitment to Texas and Mexico, about 250,000 acre-feet when water supplies are considered full. This would have conceptually released that amount for use in the Mesilla and Rincon Valley--more than likely principally for expanded agriculture. An interstate compact and an international treaty would play an integral part in any transfer of water to Texas or Mexico, even if it is a substitute. At the very least, supplemental agreements would be needed, more probable would be new compacts and treaties to govern this water and ensure its total control by New Mexico.

By delivering the water to Elephant Butte reservoir even though the estimated cost is considerably more, upstream as well as downstream users would have access to that water. The larger proportion of growth is projected to occur above Elephant Butte in the Rio Grande basin, thus this alternative would ensure that their needs could be met with Tularosa basin water. In addition, the whole amount of product water available for export (around 395,000 acre-feet) would be transferred for the Elephant Butte alternative. This makes specification and examination of the exportation possibility in the benefit-cost analysis much more simplified than for any of the others where only a portion of that amount is projected to be transferred.

Releasing additional water into the Elephant Butte reservoir also makes additional supplies available in the San Juan by possibly negating the requirement to deliver 110,000 acre-feet to the Rio Grande from the San Juan-Chama project. If additional flows were allowed in the San Juan from release of its export commitment much of the proposed energy development in Northwest New Mexico might be much easier if the time difference involved is ignored.

In summary for the benefit-cost analysis, the Elephant Butte alternative is assumed to be most probable with associated initial capital costs of $70 million, replacement capital costs of $34-plus million at the 15-year point, and a 102 MW power requirement.

CHAPTER VII

MUNICIPAL AND INDUSTRIAL POTENTIAL

MUNICIPAL AND INDUSTRIAL WATER POTENTIAL

Municipal Sector

Municipal water demand estimates usually have consisted of two components, urban population and a per capita daily withdrawal or depletion rate. For the most part, this rate, whether in terms of water withdrawal or depletion, is based upon total water use by a specific municipality or defined area divided by the resident population. The rate then represents water use by individual households, commercial establishments, manufacturing plants (smaller less water-intensive ones--the larger and more water-intensive plants are excluded and estimated separately), governmental agencies, and public recreation areas.

These rates will differ from area to area because of the different water utilization coefficients for each separate user class, as well as the different proportions of total water use each class represents. That is, higher income households consume more water than lower income households, certain types of commercial establishments require far more water than others (e.g. a health spa vs. a real estate office), and public recreation areas require more water the drier the climate and greater the proportion devoted to green belts. In the arid and relatively non-industrialized Southwest, per capita withdrawal and depletion rates vary considerably and the higher the level of industrialization the higher the water use.

To establish a base case for potential municipal water use, three estimates of population growth and their associated water requirements were prepared by the New Mexico State Engineer Office for the State Water Plan (Table 38). The population projections can be classified as high (BBR-68), medium (OBERS-68), and low (BEA/BBR-72). This range represents some best guesses concerning probable growth in Otero County for the years 1980, 2000, and 2020. Only that portion which is projected to reside in the Tularosa basin portion of Otero County is included in Table 38. It was felt that the other residents would not reasonably be able to enjoy any of the water produced by the energy-water complex without paying a price that might be considered prohibitive because they are located within the Pecos drainage basin, which is separated from the Tularosa basin by a high mountain range. Also included in the table are population estimates for the military and rural sector. The rural sector is separate because its per capita rates are significantly smaller than those for the urban sector. This is due primarily to the lower intensive economic activity in the rural sector. The military population is separate because it also has a different water-use rate, and represents a portion of the county's population that may be considered more transient than others.

The estimates presented in Table 38 do not include any direct or indirect population increase from the Tularosa basin energy-water complex. The estimates also terminate at the year 2020, 10 years short of the 2030 completion date used for the project.

There is a considerable difference among possible growth scenarios for the Tularosa basin. Water withdrawals range from 12,630 acre-feet in 2000 for the low projection to 22,480 acre-feet for the high. In 2020 the high projection is nearly three times as large as the low, and 80 percent greater than the medium; 44,000, 14,000 and 26,000 acre-feet, respectively. The same percentage differences hold for the depletion estimates, but are of smaller numerical magnitude.

Table 38. Population and water use requirements[a] for the Tularosa basin, New Mexico

	1980			2000			2020		
	High[b]	Medium[c]	Low[d]	High[b]	Medium[c]	Low[d]	High[b]	Medium[c]	Low[d]
Population									
Urban	40,000	28,200	29,100	79,600	45,000	36,800	167,000	88,200	46,100
Rural	8,000	8,000	5,400	9,000	9,000	5,200	9,000	9,000	4,700
Military	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Total	56,800	44,200	42,500	96,600	62,600	50,000	184,000	105,200	58,800
Water Withdrawals[e] (000's acre-feet)									
Urban	8.70	6.00	6.20	17.80	10.20	8.20	39.30	20.80	10.80
Rural	0.53	0.53	0.38	0.68	0.68	0.43	0.83	0.83	0.39
Military	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Total	13.23	10.53	10.58	22.48	14.88	12.63	44.13	25.63	15.19
Water Depletions[f] (000's acre-feet)									
Urban	5.30	3.60	3.70	11.60	6.60	5.40	28.00	14.80	7.70
Rural	0.34	0.34	0.23	0.53	0.53	0.29	0.60	0.60	0.33
Military	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
Total	8.04	6.34	6.33	14.53	9.53	8.09	31.00	17.80	10.43

[a] Based on data from the New Mexico State Engineer Office prepared for the State Water Plan and the County Profiles.

[b] BBR-68, high estimate.

[c] OBERS-68, medium estimate.

[d] BEA/BBR-72, low estimate.

[e] Per capita withdrawal rates increase for the urban and rural sectors.

[f] Per capita depletion rates increase for the urban and rural sectors.

For comparison purposes, 1970 estimates of water use for all sectors, including agriculture, are given in Table 39. Subtracting out the Pecos portion, there still remains over 50,000 acre-feet of water withdrawals within the Tularosa basin. Urban, rural, and military use account for about 20 percent (10,000 acre-feet) of that amount with almost all of the remainder going to agriculture.

Also presented for comparative purposes are estimates of water use in 1970 for selected cities in the Tularosa basin. They are reported in Table 40 and will differ (when summed) from those presented in Table 39 by a small amount, for they represent actual figures from municipal system operations whereas the estimates developed above involve per capita use rates.

Present water use (withdrawals) in the Tularosa basin for the municipal sector (urban, rural, and military) is approximately 10,000 acre-feet. Projections for the year 2000 range from 13,000 to 22,000 acre-feet, while in 2020 projections range from 15,000 to 44,000 acre-feet. For purposes of this study the medium population projections (OBERS-68) will be used to establish the base (without project), and to that base estimate will be added the direct and indirect increases potentially attributable to the project (Table 41).

Industrial Sector

As mentioned in the discussion of the municipal sector, some industrial water use is

Table 39. Estimates of water use by sector for Otero County, New Mexico, for 1970

	1970 Water Requirements*	
	Withdrawals	Depletions
	- - - -(1,000 acre-feet)- -	
Irrigation, total	47.3	24.2
Tularosa Basin		
Indian	2.0	1.1
Non-Indian	22.9	11.5
Salt Basin		
Non-Indian	16.9	8.9
Pecos River Basin		
Non-Indian	5.5	2.7
Urban		
Alamogordo-Tularosa	5.3	2.7
Cloudcroft	0.0	0.0
Military, Holloman	4.0	2.4
Rural	0.5	0.3
Manufacturing	0.3	0.2
Minerals		
Rio Grande Basin	0.1	0.0
Pecos River Basin	0.0	0.0
Power	0.0	0.0
Livestock	0.5	0.5
Fish and Wildlife	0.1	0.1
Recreation, Land based	0.2	0.1
	58.3	30.5

*From the New Mexico Interstate Stream Commission, *County Profile-Otero County, Water Resources Assessment for Planning Purposes*, Santa Fe, New Mexico, 1975.

Table 40. Estimates of water use by selected cities in the Tularosa Basin, New Mexico, 1970

	1970 City Water Use*	
City	Population	Pumpage (acre-feet)
Tularosa	2,851	527
Alamogordo	23,035	4,789
Boles Acres	200	45
Cloudcroft	525	46
La Luz	600	34
Orogrande	120	11

*From Randell, A. and J. Dewbre, *Inventory of Water Diversions and Rate Structures for Cities, Towns and Villages in New Mexico*, Agricultural Experiment Station Research Report 241.

Table 41. Base case estimates of urban, rural and military population and water withdrawals in the Tularosa basin project, New Mexico

Item/year	Population				Water withdrawals			
	Urban	Rural	Military	Total	Urban	Rural	Military	Total
	- - - - (number of persons) - - - -				- - - - - - (acre-feet) - - - - - -			
BASE CASE ESTIMATES*								
2000	45,600	9,000	8,000	62,600	10,200	680	4,000	14,880
2020	88,200	9,000	8,000	105,200	20,800	830	4,000	25,630
2030	129,400	9,000	8,000	146,400	31,200	860	4,000	36,060
					- - - - - - (gpcd) - - - - - - -			
Gallons per-capita day								
2000					200	70	447	212
2020					210	80	447	217
2030					215	85	447	219

*Derived from: New Mexico Interstate Stream Commission, *County Profile-Otero County, Water Resources Assessment for Planning Purposes*, Santa Fe, New Mexico, 1975.

accounted for within that sector through use of per capita per day withdrawal rates (which includes some manufacturing plants). However, for the larger and more water-intense industries separate estimates are made based on employment in the manufacturing sector (as defined by the Bureau of Labor Statistics), using a daily per-employee withdrawal coefficient.

Manufacturing employment has also been forecasted for several different levels of possible growth. Some estimates were part of the OBERS and BEA series and some were independent of the population estimates. The per-employee withdrawal coefficient has been estimated on a statewide basis at 0.5 acre-feet per year. This has been assumed applicable across industries and regions in New Mexico, as well as remaining fairly constant through time. The manufacturing water requirements estimated for the State Water Plan will be used as the base case. The estimates used for the year 2000, 2020, and 2030 are 500, 700, and 850 acre-feet, respectively.

Increases in Local M & I Water Demand

Beginning with the construction phase through the year 2030, the potential changes in the local economy and population could be tremendous. It is conceivable that the base case population project could double and with it, of course, at least a doubling of the municipal and quadrupeling of the industrial water requirements. In the following discussion, probable and possible scenarios will be developed and examined. Much of the material will be somewhat speculative in nature, but includes data where applicable.

Construction Phase

The entire Tularosa basin energy-water complex will require a total of about eight years of construction time prior to the 2000 operational date. All facilities will not need the entire eight-year period. It is probable that all but the storage reservoir will require five years or less to complete. Therefore, the highest concentration of construction workers would occur about five years prior to completion date and remain fairly stable in total number until the year 2000. Although the absolute number of construction workers may change only slightly during the five-year period of concentrated construction, various skill requirements will fluctuate on a month-to-month basis. Thus, it is possible that a larger number of workers will be residing in the area than are actually employed at any given time.

Based on employment estimates for the construction of similar nuclear reactors, earthen-filled dam structures, and well-field developments, a probable range of actual construction employment requirements is as follows: first three years from 700 to 1,400; next five years from 3,000 to 7,500. Because of the uncertainty involved in scaling-up well fields and desalination plants from present sizes and technologies, it appears that an estimate closer to the maximum side of the range would be more appropriate. Therefore, for purposes of this study, the direct increase in construction employment that could be attributed to the project is 1,200 for each of the first three years and 6,000 for each of the next five years.

A project of this magnitude and associated construction schedule usually means that many families will accompany workers to the area. Therefore, to the projected employment increase must be added a factor to account for the families. Today the average American family is composed of about 3.2 people, and making the assumption that 75 percent of the construction workers bring their families, the increase in urban population during the construction phase is estimated as follows for the eight years: 3,180 for years one through three; and 15,900 for years four through eight. This results in a 700 acre-foot water requirement increase for the first through third years, and a 3,600 acre-feet increase in the fourth through eighth years.

Any influx of construction workers to an area for an extended length of time usually means an increase in economic activity, and a subsequent increase in secondary employment and population growth. During the eight-year construction phase some of the expanded activity can be absorbed by normal growth in the economy. However, after the first year or two, a large amount of local expansion will occur directly because of project construction. Assuming an indirect employment effect of 50 percent for the second through eighth years, and given the average family size, it might be expected that an additional 1,900-plus people in the second and third years and 9,600 people in years four through eight would become part of the urban population. Water requirements would increase by 430 acre-feet in the first case (second and third years), while increasing to 2,150 acre-feet in the second case (fifth through eighth years). Thus, during the construction phase municipal water requirements could be increased by about 1,100 to 5,600 acre-feet per year. By the construction completion date (2000) municipal water requirements might be 50 percent greater than the base case of 10,200 acre-feet (Table 42).

Operation Phase

In any major construction phase of this type in a relatively isolated area, and of a nature that infers little possible spin-off activity when construction begins to wind down and draw to a close, many of the workers move on to other sites. As the major portion of the construction force vacates the area for other job sites, the local economy would experience a temporary decline. The amount that the service or secondary economic activity, originally associated with the construction force, would decline is largely open to conjecture. However, there would be a distinct possibility (if not probability) that the operational phase of the project and the potential spin-off industrial development from the project operations would pick up the slack. But before proceeding further with the discussion of changes in the local economic activity, actual operations at the complex will be examined.

Table 42. Estimates of employment and water withdrawals for construction phase, Tularosa basin energy-water complex, New Mexico

Item	Units	Construction Phase Year 1	2	3	4	5	6	7	8
Construction Force	number	1,200	1,200	1,200	6,000	6,000	6,000	6,000	6,000
Families	number	1,980	1,980	1,980	9,900	9,900	9,900	9,900	9,900
Total	number	3,180	3,180	3,180	15,900	15,900	15,900	15,900	15,900
Water Withdrawals	ac-ft	713	713	713	3,563	3,563	3,563	3,563	3,563
Secondary Employment	number	0	600	600	3,000	3,000	3,000	3,000	3,000
Families	number	0	1,320	1,320	6,600	6,600	6,600	6,600	6,600
Total	number	0	1,920	1,920	9,600	9,600	9,600	9,600	9,600
Water Withdrawals	ac-ft	0	430	430	2,151	2,151	2,151	2,151	2,151
Total Water Withdrawals	ac-ft	713	1,143	1,143	5,714	5,714	5,714	5,714	5,714

The nuclear reactors could employ as many as 500, with the desalination plant and its associated facilities and structures requiring an additional 500 personnel. This potential 1,000-personnel requirement is far short of the 6,000-person construction force in the area just prior to the beginning of operation. However, other direct employment from the project has not been discussed yet. Employment in the mineral recovery industries, although not substantial, could be close to 500 if all of the most marketable minerals were fully recovered. Agricultural employment is projected to be a significantly larger number during the irrigation season, between 1,200 and 2,000. This is in addition to the 200 plus individual owners or operators that would be present on a year-round basis.

Thus at full operation, the project will employ directly and indirectly in actual mineral recovery and agricultural production approximately 3,700 people. With the addition of a portion of the original construction force, say 1,300, remaining in the area for probable generated construction activities, the drop in basic economic activity as a result of the completion of project construction may be fairly small and short lived. The secondary or service economic activity can be assumed to remain at or near its original level of 3,000 additional employees with the above project operations.

Municipal water requirements for the operational phase of the project would remain at approximately the same level as the latter part of the construction phase, 5,700 acre-feet. With no other major industrial development, commercial spin-offs, or supporting agricultural businesses or processing plants, municipal requirements may be expected to exceed the base use estimate by about 50 percent during the life of the project.

With mineral recovery and one large vegetable processing plant, industrial water requirements would most certainly exceed the base line case. Depending on the exact technology utilized in the mineral recovery processes and which of the minerals are recovered, water withdrawals could range from 1,000 to well over 20,000 acre-feet. Utilization of per-employee withdrawal rates are not appropriate here because of the nature of the industries involved. In addition, the rates are extremely aggregated for the state as a whole, which is not highly industrial.

Assuming that newer technologies are implemented and a large set of the mineral by-products are actually recovered and extensive recycling of water takes place, industrial water use may increase by 3,500 acre-feet each year from the total mineral recovery process and vegetable processing. This number is several orders of magnitude greater than the base line industrial water withdrawal requirement of 500 to 850 acre-feet. It is entirely possible that some mineral recovery processes will produce water, such as electrolysis that has been proposed within this project. If this is the case, then industrial water demand would be reduced accordingly. However, this possibility will be ignored in the subsequent development.

Summarizing the initial scenario's water requirements for the operational phase in each year, we have the following:

1. Additional municipal requirements of 5,700 acre-feet. (Urban-rural population from employment in nuclear reactors, desalination plant and associated facilities, mineral recovery industries, agricultural production and secondary of servicing employment development).
2. Additional industrial requirements of 3,500 acre-feet. (Vegetable process plant and mineral recovery industries).

Of course, these water requirements can be expected to increase somewhat over the life of the project as per capita use rates increase. Applying the same rate of increase used in the base line case, Scenario 1 of the operational phase when summed with the base line case is reported in Table 43.

Large-scale industrial development in the Tularosa basin could easily be hypothesized because of the availability of electricity and water in addition to the recovered minerals and significant amount of agricultural production. Industrial facilities vary greatly with respect to water requirements. Primary metals and food processing facilities require considerably more water per unit of output than most other types of manufacturers. It is, therefore, possible that large amounts of industrial water will be required if large-scale industrial development becomes a reality.

Industrial and location development analysis is beyond the scope of this study. Therefore, exact types of industries and their production potential in the Tularosa basin area will not be addressed in any comprehensive fashion. However, several possibilities will be discussed as examples to construct gross estimates of potential industrial water requirements and the associated increase in municipal requirements.

With the recent emphasis on the need for increased supplies of natural gas, coal gasification plants have been seriously proposed for Northwest New Mexico because of the availability of coal. The availability status of water in these areas has not been determined yet. In the Tularosa basin such plants would have access to the complex's energy-water commodities. One such plant produces about 250 mcf per day and requires between seven and eight thousand acre-feet of water per year. Only 10 percent of the water requirement is used in the technical process of converting the coal to natural gas, the remainder is used for dust control, cooling, and other in-plant uses. Recent requests by consortiums for water have averaged approximately 7,500 acre-feet for each plant. Therefore, for each coal gasification plant located within the basin, industrial water requirements would be increased by approximately 8,000 acre-feet each year. It is assumed that all gas produced would be shipped outside the area, thereby allowing no spin-off industries due to this now abundant gas supply.

Each plant constructed implies a peak construction force of over 1,000 workers, with an additional 250 employees to operate the plant once on-line. This will, of course, increase the municipal water requirements by about 600 acre-feet during the construction phase and over 175 acre-feet during the operational phase, however, this does not include the water requirements for service and secondary economic growth that might be attributable to the plants.

There now exists in New Mexico some small (in relation to those on the major coasts) oil refineries. Water requirements for such plants vary considerably depending on their size and intensity but could be in the range of 50 to 1,000 gallons per barrel of oil processed. A typical size inland plant is capable of refining 30,000 barrels per day, thereby requiring approximately 1,500 to 15,000 acre-feet of water a year. Actual water used in the total refinery process can be at least five times that amount, but extensive recirculation takes place and is assumed to be continued. For each refinery located within the Tularosa basin, industrial water requirements would increase by a minimum of about 1,500 acre-feet. Each refinery would take several years to build and would employ a number of people in the construction force. No estimate is made for this force, but operating personnel for each refinery could require 250 persons, and thus, stimulate another increase in municipal water requirements.

A natural development in the Tularosa basin in conjunction with the nuclear reactors would be a uranium enrichment plant and/or conversion plant. Today's enrichment facilities require hugh amounts of water and electrical power, but they employ the gaseous diffusion technology. A much more probable technology to be employed is the centrifugal diffusion process which requires less water and far less electricity. A typical uranium conversion plant in 2000 might be of the size to produce enough output to supply between 27 and 28 1,000-MW nuclear reactors of the light water type (LWR). Water requirements would be rather small in comparison to a coal gasification facility, only 800-1,000 acre-feet a year.

A conversion plant producing yellow cake on the order of 5,000 metric tons a year (enough product to supply the 27 or 28 LWRs), would require the same magnitude of water for production, 800-1,000 acre-feet a year. Construction of one or the other such facilities could require a work force as large as 4,000 for several years. In addition, operating personnel might number 1,000 for the enrichment plant and 150 for the conversion plant. Municipal water requirements would be increased appropriately.

There are, of course, many other industrial possibilities based solely upon utilization of the mineral by-products recovered. Again, however, a comprehensive analysis is not within the scope of this study. The potential could be large, as would the associated additional industrial and municipal water requirements.

From the discussion above we can see that it is likely that industrial water requirements could be increased by 30 to 50 thousand acre-feet a year, with a corresponding five to 20 thousand acre-feet increase in the municipal requirements. By assuming gradual growth and only a portion of the potential ever coming on-line in the basin, another scenario can be created. When these additional amounts are added to the Scenario 1 water requirements, local municipal and industrial demand approaches 100,000 acre-feet by the year 2030 (Table 44).

Table 43. Population, municipal and industrial water requirements for Scenario 1, basic project operation, Tularosa basin energy-water complex, New Mexico

	Population	Municipal Water	Industrial Water
		- - - -(acre-feet)- - -	
Scenario 1*			
2000	86,700	20,500	4,000
2020	129,900	33,200	4,500
2030	182,200	47,100	5,100

*Basic project operation.

Table 44. Municipal and industrial water requirements for Scenario 2, Tularosa energy-water complex, New Mexico

	Municipal* Water	Industrial* Water
	- - - -(acre-feet)- - - -	
Scenario 2**		
2000	25,000	29,500
2020	41,000	35,000
2030	56,000	38,000

*Low portion of the range added to Scenario 1 (which includes basic operation plus Tularosa basin energy-water project).

**Mixture of coal gasification, oil refinery, enrichment and conversion, plus industries based upon the products of mineral recovery.

Municipal and Industrial Water Price

The price of M & I water in New Mexico not only varies from city to city, but also among subclassifications of customer categories within many cities. Commercial and industrial customers are not only billed for total quantity delivered, but also many times for meter size differences. Thus, their rate reflects both stock and flow considerations. This makes specification of a single rate extremely difficult.

However, there is a much more basic question on water pricing involved here. Prices paid by the municipal and industrial sectors include all costs of getting the water from its natural state (whether surface or ground supplies are involved) to a form suitable for final use. This cost usually includes a well field, treatment facilities, temporary storage structures, and the whole delivery system involved. As is the case for most of New Mexico, water is treated in its natural state as a free input. Users are charged only for the production and subsequent transportation of that good.

In the proposed Tularosa basin energy-water project, processed water would be available for local M & I use at the complex itself, thus eliminating the need for local well fields. Assuming no additional treatment would be required, it would be necessary for any potential user to either take continuous delivery or construct storage facilities and transport the water from the complex to their site.

The distribution of costs between production of water and the subsequent storage and transportation of it to potential users is impossible to extract from published data sources. With the many various financing mechanisms used in today's municipal systems, it would be extremely difficult to extract the distribution even from internal budgetory data. With many of the cities charging equivalent rates for any and all quantities delivered, it would appear that water production is relatively inexpensive. No further attempt will be made to arbitrarily allocate the costs, but rather let the total cost/price of water reflect the upper bound in today's prices.

With the above in mind, estimates of prices paid by municipal and residential users in selected cities of New Mexico are presented in Table 45 for the year 1970. The price is based on average monthly billings with the final figure representing the initial acre-foot purchase and the second figure each additional acre-foot purchased. Connection charges are usually not included.

Large differences exist in the price of water among the cities of New Mexico as illustrated in Table 45. Even in the Tularosa basin, prices range from just under $100 to over $400 an acre-foot. However, the larger cities generally display lower prices, thus inferring that as cities have grown in the past, their real costs have decreased, and subsequently the price necessary to recover these costs. For small systems, the capital investment far outweighs the operating and maintenance costs of the system. As growth occurs, the variable costs begin to play an increasing role in total cost computations.

With saline water becoming more and more of a problem in the area, it would be reasonable to expect the developing municipal and industrial systems to be willing to pay higher real prices for water than is paid today. What that amount might be, or even what that amount today is, depends on the allocation of costs between production and distribution, a near impossible task and far beyond the scope of this study. Very likely, the price paid in Tularosa today of $100 an acre-foot would be the maximum.

The City of Albuquerque has contracted to purchase San Juan-Chama water to supplement vested water rights it enjoys today. This purchase allows increased pumpage from present and future well fields, and goes to offset depletion of the Rio Grande over and above that established by the

Table 45. Estimates of prices paid by municipal and residential users in selected cities of New Mexico

	Initial acre-foot purchased		Additional acre-foot purchased	
	Residential	Industrial	Residential	Industrial
	-dollars-			
Tularosa				
(Otero County)	100.40	99.40	97.70	97.70
Orogrande				
(Otero County)	325.00	325.00	325.00	325.00
Cloudcroft				
(Otero County)	407.80	407.80	407.80	407.80
Las Cruces				
(Dona Ana County)	86.00	N/A	84.70	N/A
Roswell				
(Chaves County)	80.50	80.50	78.20	78.20
Carlsbad				
(Eddy County)	*	48.00	64.00	48.00
Albuquerque				
(Bernalillo County)	69.60	69.60	65.10	65.10

*Range of $68.00 to $104.00 depending upon line size.

vested rights. The purchase price (a portion of the costs necessary to transport this water from the San Juan to the Chama) paid is an added cost to the production and delivery costs in Albuquerque today. Perhaps, this $42 purchase price could be viewed as the value of water to Albuquerqueans in the near future. Assuming that all other costs are recovered by the revenues received from sales to customers, this $42 price represents the worth of water itself.

The prices paid by or costs charged to potential M & I users for water in the Central Arizona project are in the neighborhood of $90/acre-foot. A portion of this $90 is a subsidy for agriculture, but nevertheless represents a substantial "value" attached to the access and right to use of this water by the future M & I users.

The cost of additional water in the future should be composed of two components: the higher costs of extracting this water from ground supplies (assuming this is the supply point), and the cost of obtaining rights and/or access to the water itself. For Albuquerque it has already been assumed that $42 represents the second component; as the water table drops, increased pumpage costs will enter the calculation, as well as the probability of additional wells. Local M & I users in the Tularosa basin could be expected to have higher rates than today, based upon the above rationale.

The price paid for water rights recently has generally not been recorded, however, from discussions with several knowledgeable people, estimates were made. In the Roswell area (east of the Tularosa basin), prime ground artesian rights have sold for around $900 to $1,000 an acre. This allows the purchaser to divert up to 3.2 acre-feet, and to deplete 2.1 acre-feet in any given year. Price per acre-foot (depletion) is around $450. It must be remembered that the purchase only gives one control over the water, it still must be extracted and delivered. If one were to assume an average return of 10 percent to investment, then $45 becomes a realistic estimate of the real value of this water. Shallow water aquifers in the region (where water is of lower quality and the cost of extraction is higher) bring only $400 to $600 an acre--$250 an acre-foot or around $25 for its value. In the Carlsbad area, southeast of Tularosa basin, $900 an acre has been paid for a mix of ground and surface water. With a 2.1 acre-foot depletion right, the value of water is around $42 an acre-foot.

LOCAL MUNICIPAL AND INDUSTRIAL ELECTRICAL DEMAND

In almost all studies addressing electricity demand today, distinct sectors are usually identified: residential, commercial, industrial (many times combined with commercial), public or municipal, and public lighting (primarily street and park). For purposes of this section the residential, public, and lighting sectors will be combined to form estimates for the municipal sector, with the commercial and industrial sectors defined as industrial.

These definitions do not match those in the discussion on local M & I water demand, but should not be a problem because only the total local demand will be used in the subsequent benefit-cost analysis.

Most estimates made recently on future electrical demand are generally too aggregate in nature to be used for any specific area. However, from the majority of them a per capita demand coefficient can be derived for each sector included within the particular study. None of the derived coefficients could be justified as more applicable to forecast utilization than any other. Differences exist, and most are not reconcilable because of varying basic assumptions, specifications, or differing models in terms of identification, specification, and subsequent analysis.

Since gross estimates were desired, statistics from the 1970-1972 Federal Power Commission publication series[9] were used to construct per capita coefficients (Table 46). At the end of this section, several recently constructed demand models are exercised as an alternative to the estimated electrical demand developed below. They may also serve to either substantiate or refute the developed demand estimates from per capita coefficients. As emphasized later, underlying assumptions must be examined closely if reconciliation or acceptance of differences is to take place.

The estimates in Table 46 were constructed by extracting total consumption by sector and dividing by 1970 population. By 1972, the per capita rates had increased by about nine percent. Since the majority of this study used 1974 as a base year, these rates were adjusted upward by approximately 15 percent. This is lower than might have been anticipated since in 1974 actual consumption increased only slightly over that of 1973 for some sectors, thus tempering the rise in per capita demand. The set of per capita consumption rates presented in Table 47 will serve as the basis for constructing potential local M & I electricity demand.

To remain consistent with the specification of electrical demand by the major components of the proposed project, the KWH/year estimates are transformed into the more useful coefficient for this project analysis; that is the year figure was divided by 8,760, the number of hours in a normal year, giving a flow. The flow coefficient represents the <u>average</u> continuous per capita consumption of electricity for that year. It, of course, ignores peak demand as well as the actual flow distribution. In the benefit-cost analysis, only electrical flows are used as inputs, being subsequently converted to stocks within the analysis itself. This is explained more fully on the section dealing with the benefit-cost analysis. The flow for the municipal sector is 0.26 KW, and for the industrial sector, 0.51 KW.

Almost all studies, up until a year or so ago, have assumed a continuation of the growth rates, both total and per capita, that were prevalent in the 1960's. If some of their estimates are carried to the year 2000, and assuming the trend continues unabated, residential per capita electricity consumption will more than double. Per capita rates for the other sectors are usually not considered, but where the commercial and industrial equivalent sec-

[9] The two primary ones used were *Statistics of Publicly Owned Electric Utilities in the United States* and *Statistics of Privately Owned Electric Utilities in the United States*, various years, Federal Power Commission.

Table 46. Average per capita electricity consumption by sector, 1970.

Sector	Average Per Capita Electricity Consumption (KWH/year)
Residential	1975
Public	700
Lighting	150
Municipal (total of above 3)	2825
Commercial and Industrial	3900

Source: U. S. Federal Power Commission, *Statistics of Publicly Owned Electric Utilities in the United States* and *Statistics of Privately Owned Electric Utilities in the United States*, Washington, D. C., 1974.

Table 47. Estimated average per capita electricity consumption by sector, 1974.

Sector	Estimated Average Per Capita Electricity Consumption (KWH/year)
Residential	2275
Public	800
Lighting	180
Municipal (total of above 3)	3255
Commercial and Industrial	4475

Source: U. S. Federal Power Commission, *Statistics of Publicly Owned Electric Utilities in the United States* and *Statistics of Privately Owned Electric Utilities in the United States*, Washington, D. C., 1974.

tors have been specified, a slightly less than doubling rate can be ascertained from the results.

Potential local M & I electricity demand (consumption) will be developed based upon two per capita rates for the year 2000: one equal to the 1974 rate and the other double this 1974 rate with no further growth assumed. Realizing that it would be possible to specify an extremely large number of alternatives, these were chosen as two plausible examples representing a portion of the range that has been discernable not only from recent studies, but also from news releases of the federal agencies responsible for energy policy.

Before proceeding with the actual estimates, present electrical usage in the Tularosa basin and surrounding counties will be briefly reviewed.

Utility companies usually do not keep statistics for cities but rather for sales or service districts. At times these conform very closely to political boundaries, at times not. Therefore, electricity consumption and subsequent per capita rates may not be entirely applicable to the city itself. However, they serve to put future estimates vis-a-vis present usage into their proper perspective.

The Cities of Alamogordo and Tularosa have increased their residential electrical consumption from 21,046 megawatt hours (MWH) in 1970 to more than double that amount in 1973, or 44,937 MWH. Tularosa is included in the Alamogordo service district by the Community Public Service Company. During the same period, commercial and industrial consumption increased from 17,927 MWH to 53,922 MWH implying a significant increase in economic activity. Residential consumption went from a greater-than to a lesser-than position in relation to the commercial and industrial sector. Because of the lack of good population estimates in off-census years, per capita rates will only be specified for the census years, 1960 and 1970. Residential per capita consumption was 910 KWH in 1960 and 1,590 KWH in 1970. The national average in 1970 was 1,975 KWH. Industrial, including commercial per capita consumption was 745 KWH in 1960, increasing to 1,520 KWH in 1970 (below the national average of 3,900).

Since there are no other cities or service districts in Otero County of such size that warrant separate statistics, cities in surrounding counties will be discussed.

Las Cruces, located in Dona Ana County and about 50 percent larger than Alamogordo-Tularosa, consumed 40,756 residential MWH in 1960. By 1973, residential consumption had more than doubled to 98,991 MWH. Commercial and industrial electricity consumption increased from 26,600 MWH in 1960 to 68,756 MWH by 1973. Per capita residential consumption was 1,400 KWH in 1960 and 2,620 KWH in 1970. Industrial per capita rates increased from 915 KWH in 1960 to 1,825 by 1970. Even in 1970, residential consumption was utilizing more than the commercial and industrial sector.

Roswell, located east of the Tularosa basin in Chaves County, is approximately the same size as Alamogordo-Tularosa. In 1960 residential consumption was 38,140 MWH, while the industrial-commercial usage was 45,305 MWH. By 1973 residential MWH use had increased to 71,366 and commercial-industrial to 102,972 MWH; even though population had decreased from over 39,000 to about 33,000. Per capita consumption rates were 960 and 1,150 KWH for the residential and commercial-industrial sectors respectively, increasing to 2,105 and 3,040 KWH by 1970 (similar to national averages).

Carlsbad, located southeast of the Tularosa basin in Eddy County is about two-thirds the size of Alamogordo-Tularosa. In 1960 residential electricity consumption was 26,929 MWH, increasing to 49,550 in 1973. Commercial-industrial consumption increased from 216,110 MWH in 1960 to 368,471 by 1973. Several energy-intensive industries are located around Carlsbad, specifically potash mining and processing. Per capita rates in 1960 were 1,050 and 10,150 KWH, increasing in 1970 to 1,950 and 16,380 KWH.

El Paso, the closest metropolitan city, is located just across the Texas border some 90 miles southwest of Alamogordo-Tularosa. In 1960 residential consumption of electricity totaled 235,213 MWH, increasing to 555,366 MWH in 1970. Commercial-industrial consumption in 1960 was 397,299 MWH, increasing to 1,062,102 MWH by 1973. Per capita rate changes show a similar magnitude of increase, 750 and 1,265 KWH in 1960 to 1,225 and 2,120 KWH by 1970. El Paso has significantly lower per capita rates than the national average.

As a comparison to the above cities, New Mexico is estimated to have consumed 1,300 residential KWH and 3,400 commercial-industrial KWH, all on a per capita basis, in 1970. This of course excludes the public and municipal street-park lighting sectors.

By applying the estimated per capita rates against the base case and Scenario 1 population projections developed under the M & I water use section, potential local electricity demand or consumption can be derived. Estimated electrical demand for both per capita rates, 1974 and double the 1973 rate are included in Table 48. Both remained constant over the project period, 2000 to 2030.

Several comments are in order for these estimates. The base case and Scenario 1 are rather straightforward in that per capita rates were multiplied by the population projections for each. Scenario 2, however, includes a mix of uranium enrichment and conversion plants, coal gasification plants, oil refineries, and spin-off industries based on the mineral products recovered. Therefore, estimates of actual electrical consumption was added to Scenario 1 estimates, along with small increases in the "local" industrial needs. Uranium enrichment plants of the centrifugal diffusion type are projected to require about 100 MW of electrical power. Conversion plants, a natural corollary development, require only about seven or eight MW. Oil refineries may range from three to 10 MW depending on size and type of crude product. Coal gasification plants are self-sufficient in electricity and require no outside supply.

The above estimates are of course rather crude, and in Scenario 2 somewhat speculative in nature. For purposes of the benefit-cost analysis, only those estimates derived from the 1974

Table 48. Potential local municipal and industrial electricity demand for 2000, 2020, and 2030.

	Municipal			Industrial		
	2000	2020	2030	2000	2020	2030
	-MW-					
Base Case[a] Electrical Demand						
1974 per capita flow rate[b]	16.3	27.4	38.1	32.0	53.7	74.7
Double 1974 per capita flow rate[b]	32.6	54.8	76.2	64.0	107.4	149.4
Scenario 1[a] Electrical Demand						
1974 per capita flow rate[b]	22.5	33.8	47.4	44.2	66.2	92.9
Double 1974 per capita flow rate[b]	45.0	67.6	94.8	88.4	132.4	185.8
Scenario 2[a] Electrical Demand						
1974 per capita flow rate[b]	28.2	40.1	56.8	122.8	174.0	203.2
Double 1974 per capita flow rate[b]	56.4	80.2	113.6	178.6	260.0	310.0

[a]These cases in terms of population and industrial development are explained in the local M & I water section.

[b]Average yearly continuous consumption.

per capita flow rates will be used.

Most of the recent demand equations developed to explain and/or predict electricity consumption require as input data or parameters more information than developed up to this point. Income and the price of electricity certainly enter into any present demand equation, as well as energy substitutes for electricity and measures of energy-intensiveness in many cases. In the section discussing future market potential of electricity to be produced by the proposed project (primarily export demand analysis), several demand equations were identified, with the one developed by Chapman, Mount, and Tyrrell (1973) being utilized in the analysis. For purposes of this section, primary emphasis is placed upon a variation of recent demand models developed specifically for the southwest by Randall, Ives, and Ryan (1974). Some of the variables will be specified somewhat differently however. Enough similarity remains that either of the specifications could have been used in the local analysis without significantly affecting electricity demand estimates. It is also recognized that these types of models, based strictly upon cross-sectional data, may not capture trend factors. Nevertheless, the Randall, Ives, and Ryan model is based upon data from the southwest and represents a spectrum of electricity users that may be expected to exist in the Tularosa basin by the year 2000.

The equations developed here are based upon the 1970 sales data of 22 electric company service areas within the southwest (Randall, Ives, and Ryan, 1974).

Single equation, ordinary least squares estimation techniques were used. The conceptual model for electricity demand is:

$$Q = K-b_1P+b_2G+b_3Y+b_4N+b_5H+b_6C+E$$

where:

Q = kilowatt hour consumption,

P = average price (in dollars) of electricity per kilowatt hour,

G = average price (in dollars) of gas per therm,

Y = average per capita income within the service area,

N = population within the service area,

H = average heating degree days* within the service area,

C = average cooling degree days* within the service area, and

E = random error term.

The model was then transformed to the natural log form:

$$\ln Q = K - b_1 \ln P + b_2 \ln G + b_3 \ln Y + b_4 \ln N + b_5 \ln H + b_6 \ln C + E$$

*(The long-term average number of cooling days in the Tularosa basin is 1,600 which will be used for all estimates. This average was developed from national climatological records).

Therefore, the coefficients b_1-----b_6 represent elasticities. The equation which contains only those variables with coefficients significant at the 80 percent level is:

1. Residential Demand

$$\ln Q = -5.2431 - \underset{(.209)}{1.2431 \ln P} + \underset{(.027)}{.9692 \ln N} + \underset{(.069)}{.2073 \ln C}$$

$R^2 = 98.54$ $F = 405$ $S_{y.x} = .196$

2. Commercial Demand

$$\ln Q = -8.7352 - \underset{(.362)}{1.9805 \ln P} + \underset{(.035)}{.9710 \ln N} + \underset{(.086)}{.2131 \ln C}$$

$R^2 = 98.19\%$ $F = 307$ $S_{y.x} = .245$

Further explanation of these equations (in a variant form) can be found in Randall, Ives, and Ryan (1974). No attempt will be made here to evaluate these equations, but rather just to utilize them in making alternative estimates of future electricity demand.

Although various assumptions could be made in regard to the average residential price, presently around 2.25 cents per KWH in real terms, three alternatives will be examined: (1) constant, (2) 50 percent increase by 2000 and then continuing at two percent each year, and (3) 100 percent increase by 2000 and continuing at a 3.5 percent increase each year. Population projections will be those made for the three cases: base case--no project, Scenario 1--operation phase, and Scenario 2--moderate industrial spin-off and development. Therefore, nine sets of estimates will be made for this residential equation (Table 49) as well as the commercial-industrial equation.

Table 49. Estimates of electricity demand for the residential and industrial sectors with three price alternatives for 2000, 2020, and 2030.

	Constant Electricity Price			50% Increased Electricity Price[1]			100% Increased Electricity Price[2]		
	2000	2020	2030	2000	2020	2030	2000	2020	2030
	-MW yearly continuous flows-								
Residential									
Base Case	13.7	22.9	31.6	8.4	8.5	9.1	5.6	4.1	3.7
Scenario 1	19.0	28.1	39.0	11.5	10.4	11.3	8.0	5.1	4.6
Scenario 2	21.2	31.3	43.2	12.8	11.5	12.6	9.0	5.6	5.1
Industrial									
Base Case	12.1	20.1	27.7	5.4	4.1	3.8	3.0	1.3	0.9
Scenario 1	16.6	24.6	34.2	7.4	5.0	4.7	4.2	1.6	1.1
Scenario 2	18.6	27.4	38.4	8.3	5.6	5.3	4.7	1.8	1.3

[1]With 2.0 percent increase each subsequent year.

[2]With 3.5 percent increase each subsequent year.

Note: See the section on local municipal and industrial potential for population projections specifications.

As was obvious from an examination of the equations where price was elastic (with expected negative sign), and is borne out by the above results, local M & I electrical demand would experience a tremendous decrease when prices are increased, though the number of users increased significantly. From this, it can be concluded that the per capita use becomes far less intensive, even to the point of being reduced to levels prevalent several decades ago. With the per capita rate decreasing, estimates derived from the application of these equations will be and are much lower than those obtained from the strict application of per capita rates to population projections.

With constant electricity price (in real terms) assumed, demand estimates for the residental sector are similar, but lower in all cases, to those obtained with the constant per capita rates. As mentioned earlier, the constant per capita estimates will be utilized in the benefit-cost analysis for local M & I consumption.

Estimates could also be made with the demand equations developed by Chapman, Mount, and Tyrrell (1973), but require the use of income, price of natural gas, and the price of electrical or industrial machinery in addition to population and the price of electricity. The collection or development of such a data base for all possible combinations are beyond the scope of this study. However, by extracting from the results obtained by recent exercises of these equations by Tyrrell (1974) an indication of electrical demand movement either increasing or decreasing with some gross measure of magnitude can be realized. Residential electricity needed for New Mexico is projected to quadruple by 2000 as measured by total KWH consumed, with the price of electricity rising only slightly. The commercial consumption will also quadruple while industrial consumption only triples using the same assumptions. Applying this to the Tularosa basin, residential estimates would be about double those obtained with the constant per capita methodology, and more than double those from the previous demand equations. However, several previous studies using the same equations, but with higher electricity prices obtained results closer to those estimated here. Generally they are larger, but real income has also been increasing in those studies, thereby causing some of the higher consumption.

The only conclusion to be drawn from the brief discussion on estimates of potential demand is that no matter what methodology or technique is used in constructing estimates, results will be primarily determined by the underlying assumptions behind the projected variable values.

CHAPTER VIII

IRRIGATED AGRICULTURE POTENTIAL

INTRODUCTION

The purpose of this section of the report is to present cost and return information for major field and vegetable crops using desalted water from the Tularosa basin energy-water complex. The information contained in this section was prepared to be representative of the expected cultural practices and cost of growing general crops on individually owned and operated farms of about 640 acres. Although there are relatively few farms as large as 640 acres in south central New Mexico, this farm size was selected because of apparent economies of scale in the farm sizes ranging from 400 to 1,200 acres. This assumption is supported by a recent study on the Navajo Indian Irrigation Project (Gorman, et al., 1972).

GENERAL APPROACH

The determination of economic feasibility for using desalted water for irrigation depends heavily upon the cost of the desalted water, and consequently, this cost is one of the major constraints in this multipurpose project. Depending upon the nature of the crop, the period of the year in which that crop is to be grown, the type of soil, and the kind of irrigation system employed, the price farmers will have to pay for the desalted water influences heavily the margins of profitability in this case.

It is assumed that the principal canals to take the water from the reservoir to the farmland would be built and operated by a public agency since it is highly unlikely that an off-farm irrigation system of this size could be privately financed. Each individual farmer shall provide only the on-farm irrigation system. The farmer will have to install facilities to supply water to his crops, such as pumps, pipes, sprinklers, and ditches. Consequently, the combined cost of water (the cost at the entrance of the farm, plus the associated costs of making the water available for crops) will determine to a high degree the economic feasibility of using that water for agricultural purposes.

To determine the most profitable combination of enterprises for production on the Tularosa project, a large number of irrigated crops was included. Production requirements, costs, and returns budgets were developed for selected agricultural enterprises. Budgets were prepared for four field crops, seven fresh vegetable crops, eight processing vegetable crops, and one seed crop. The crops were selected on the basis of marketability and their suitability to soil and climatic conditions of the region.

An engineering-cost approach was utilized to prepare the individual cost and return crop budgets for this report. The essence of this approach is described in the following steps: (1) determination of size and organizational structure of proposed farm or farms, (2) specification of the type or quality of management, (3) specification of the type and design of the irrigation system and consumptive irrigation requirements and application rates, (4) determination of reasonably attainable yields based on climatic conditions, soils, water availability, and management, (5) determination of the type, quantity, and prices of purchased inputs such as seeds, fertilizers, chemicals, and labor, (6) specification of generally accepted cultural practices required to produce and harvest the crop, (7) specification of the type and size of machinery and equipment appropriate for the size of farm and type of crop or crops, (8) determination of time and costs of performing cultural practices based on size and type of equipment under optimum conditions (information available from standard published sources), (9) determination of machinery efficiency rates and resulting costs based on such factors as field size, length of run, and management, and (10) specification of prices (Table 50).

Water requirements were estimated by the Blaney and Criddle (1965) method as modified by Henderson and Sorensen (1968). The consumptive-use requirements were determined and effective precipitation was subtracted to obtain the consumptive irrigation requirements of the plants. Long-term average climatic data were used for the above estimation. The irrigation water requirements were based on a 70 percent irrigation efficiency for sprinkler irrigated crops, and a 60 percent efficiency for flood irrigated crops. Water requirements per acre by crop are reported in Table 51.

Capital requirements were broken down into investment capital and operating capital requirements. Investment capital requirements were estimated by determining the initial capital required for on-farm irrigation investment and machinery investment (Table 51).

Table 50. Crop yields, product prices, and gross returns for selected crops for the agricultural enterprise, Tularosa basin project.

Crop	Units	Yield per acre	Price (dollars)	Gross Return (dollars)
Alfalfa (baled)	ton	6.75	46.00	310.50
Alfalfa (seed)	lbs	420	0.90	
(hay)	ton	1.5	46.00	447.00
Barley	cwt	40	4.40	176.00
Cotton (lint)	lbs	650	0.48	
(seed)	lbs	1,040	0.085	400.40
Grain sorghum	cwt	70	4.40	308.00
Bell pepper	cwt	126	10.35	1,304.10
Fresh carrot	cwt	300	7.20	2,160.00
Green chile (green)	lbs	18,000	0.04	
(red)	lbs	800	0.18	864.00
Fall lettuce	ctn	468	2.70	1,263.60
Spring lettuce	ctn	362	2.38	861.56
Fall onion	bag	550	2.80	1,540.00
Spring onion	bag	600	2.50	1,500.00
Asparagus	cwt	38	25.00	950.00
Lima bean	ton	2	271.00	542.00
Beets	ton	14	29.50	413.00
Processed carrots	ton	25	30.30	757.50
Cucumber	ton	5.5	107.00	588.50
Black-eye peas	cwt	27.5	16.00	440.00
Sweet potatoes	ton	7	70.00	490.00
Spinach	ton	9	39.00	351.00

Table 37. Basic per acre water requirements, on-farm irrigation and machinery investment capital requirements, operating capital requirements, and gross returns by crop for the agricultural sector, Tularosa basin project, New Mexico

Crops	Water Require-ment	Investment Capital: On-Farm Irrigation Investment: Distri-bution System	Sprinkler System	Pumps	Total	Machinery Investment: Tractor	Imple-ments	Special Machines	Total	Total Invest-ment Capital	Operating Capital: Labor: Quantity	Cost	Purchased Inputs	Fuel and Repairs	Total Operating Capital	Fixed Costs (Depreciation)	Total Costs*	Gross Returns
	(acre-feet)	- - - -	- - - -	- - - -	- - - -	- - - -	-dollars-	- - - -	- - - -	- - - -	(hours)	- - - -	- - - -	- - - -	(dollars)	- - - -	- - - -	- - - -
Alfalfa (baled)	4.00	162.00	212.50	61.87	436.37	17.81	23.17	18.33	59.31	495.68	7.72	39.81	39.60	57.87	137.28	51.88	189.16	310.50
Alfalfa (seed)	4.00	162.00	212.50	61.87	436.37	26.75	14.44	3.67	44.86	481.23	7.66	46.96	71.74	57.37	176.07	43.37	219.44	447.00
Barley	1.32	162.00	212.50	61.87	436.37	19.96	16.84	0.00	36.80	473.17	5.70	27.20	53.95	28.70	109.85	25.35	135.20	176.00
Cotton	2.90	162.00	0.00	0.00	162.00	57.43	57.14	169.64	284.21	446.21	18.34	75.31	77.45	33.59	186.35	57.95	243.70	400.40
Grain sorghum	2.05	162.00	212.50	61.87	436.37	31.58	21.86	0.00	53.44	489.81	6.90	38.60	52.88	41.12	132.60	28.28	160.88	308.00
Bell pepper	3.80	162.00	0.00	0.00	162.00	44.55	44.10	0.00	88.65	250.65	30.28	153.88	800.36	15.23	969.47	23.30	992.77	1,304.10
Fresh carrot	2.00	162.00	575.00	61.87	798.87	44.55	44.10	0.00	88.65	887.52	13.56	150.70	1,762.36	44.01	1,957.07	55.47	2,012.54	2,160.00
Green chile	3.80	162.00	0.00	0.00	162.00	39.91	45.04	0.00	84.95	246.95	36.20	144.55	394.82	14.06	553.43	22.69	576.12	864.00
Fall lettuce	1.10	162.00	0.00	0.00	162.00	50.84	51.35	0.00	102.19	264.19	26.03	140.90	832.08	16.62	989.60	24.33	1,013.93	1,263.60
Spring lettuce	0.80	162.00	0.00	0.00	162.00	50.84	51.35	0.00	102.19	264.19	26.91	123.20	656.68	16.62	796.50	24.33	820.85	861.56
Fall onion	1.80	162.00	575.00	61.87	798.87	51.30	46.76	0.00	98.06	896.93	17.28	131.00	989.27	45.49	1,165.76	57.01	1,220.77	1,540.00
Spring onion	1.90	162.00	575.00	61.87	798.87	51.30	46.76	0.00	98.06	896.93	18.08	131.42	1,042.77	131.42	1,218.97	57.01	1,275.98	1,500.00
Asparagus	2.00	162.00	575.00	61.87	798.87	14.22	7.06	0.00	21.28	820.15	6.36	66.34	410.97	32.13	509.44	86.61	596.05	950.00
Lima bean	2.00	162.00	212.50	61.87	436.37	51.93	66.36	0.00	118.29	554.66	13.25	69.95	218.78	48.49	337.22	34.50	371.72	542.00
Beets	2.00	162.00	212.50	61.87	436.37	45.75	39.11	0.00	84.86	521.23	30.71	110.63	173.67	45.18	329.48	31.49	360.97	413.00
Processed carrots	2.00	162.00	575.00	61.87	798.87	44.55	44.10	0.00	88.65	887.52	7.84	92.35	370.51	44.43	507.29	55.90	563.19	757.50
Cucumber	2.30	162.00	0.00	0.00	162.00	42.62	25.08	0.00	67.70	229.70	16.23	79.49	268.37	14.06	361.92	21.81	383.73	588.50
Black-eye peas	2.00	162.00	212.50	61.87	436.37	40.58	46.29	0.00	86.87	523.24	14.73	67.93	128.10	14.59	210.62	31.05	271.67	440.00
Sweet potatoes	2.05	162.00	212.50	61.87	436.37	61.74	33.63	0.00	95.37	531.74	15.79	74.71	168.41	51.86	294.98	30.54	325.52	490.00
Spinach	2.00	162.00	212.50	61.87	436.37	54.35	47.42	0.00	101.77	538.14	18.36	74.49	139.96	48.05	262.50	33.54	296.04	351.00

* Excludes water cost and interest on investment and operating capital.

GENERAL ASSUMPTIONS

Farm Size: Farms assumed to be approximately 640 acres with above average management.

		Crop	Type of irrigation system
Crops:	Field Crops:	Alfalfa	wheel move sprinkler
		Barley	flood
		Cotton	flood
		Grain sorghum	wheel move sprinkler
	Fresh Vegetables:	Bell peppers	flood
		Chile	flood
		Carrots	solid set sprinkler
		Spring onions	solid set sprinkler
		Fall onions	solid set sprinkler
		Spring lettuce	flood
		Fall lettuce	flood
	Processed Vegetables:	Asparagus	solid set sprinkler
		Beets	wheel move sprinkler
		Black-eye peas	wheel move sprinkler
		Carrots	solid set sprinkler
		Cucumbers	flood
		Lima beans	wheel move sprinkler
		Spinach	wheel move sprinkler
		Sweet potatoes	wheel move sprinkler
	Seed Crop:	Alfalfa	wheel move sprinkler

Machinery: Machinery costs include fuel and repairs, depreciation, insurance, and shelter. They do not include interest on investment nor taxes. Machinery efficiency is assumed to be 70 percent.

Management: A charge of five percent of the gross return per acre for management.

Labor charges: Of $2.75 per hour for general labor and $4.00 per hour for equipment operation.

Return to land: Assumed that the opportunity cost of farming the land is $1.92, the expected return from livestock grazing.

Irrigation: Those crops that are sprinkler irrigated will have an assumed efficiency of 70 percent; those that are flood irrigated will have an assumed efficiency of 60 percent.

Brokerage fee: Charged at a rate of six percent of gross return per acre on fresh market vegetables that don't normally contain this fee in the per-unit harvesting charge.

Planting and harvesting dates: Are assumed to be typical for the Tularosa basin of New Mexico.

Purchased inputs: Includes such items as seed, fertilizer, pesticides, irrigation water requirements, repair and depreciation of irrigation systems and charges for operation and maintenance of canals.

Preharvest operations:	Are based on costs of cultural practices from land preparation to harvest. Practices are determined to be typical for each crop.
Labor requirements:	Are indicated by quantity and type (general labor or machine operation) for each year and on a per-acre basis.
Labor downtime:	Based on 10 percent of the direct labor time involved in performing each operation times the specific wage rate for the specific job. The allowance includes getting to and from the field and other non-productive time.
Harvest operations:	Includes harvesting and transporting crops where applicable.
Investment capital:	Includes machinery, equipment, sprinkler systems, and the on-farm distribution system.
Operating capital:	Includes capital necessary for purchasing inputs such as seed, fertilizer, pesticides, labor, fuel, maintenance and repairs and custom operations.
Vegetable processing:	It is assumed that a four-million-can vegetable processing plant will be attracted into the region. The above vegetables for processing were assumed to be a typical line for processing. Depending upon market conditions, shifts in crops and acreages may be necessary.

OPTIMIZATION MODEL

Utilizing the budgeted information, a parametric programming model was utilized to obtain an optimal cropping pattern for the irrigated agricultural sector. The objective function of the program was to maximize net returns subject to water, land, and capital cost constraints.

In establishing the model, the price of irrigation water delivered to the farm was set up as the change parameter, for each of the interest rate optimization models (five percent, six percent, eight percent, and 10 percent). The price of irrigation water delivered to the farm gate was allowed to vary in increments of one dollar per acre-foot. The purpose of this analysis was to determine the maximum amount that the irrigated agricultural sector could pay for irrigation water at the four interest rate levels.

Objective Function

The objective function as defined for this analysis is to maximize the total net returns to agricultural sector. Net return in the parametric model includes costs for all factors of production, thus the resulting aggregate net return can be considered pure or economic profit. Therefore, the maximum amount that the irrigated agriculture sector can pay for water at each of the four interest rate levels is defined as the point where the aggregate net return for the irrigated agriculture sector is zero.

Model Coefficients

The primary coefficients (inputs) into the model were irrigation water, labor, and investment and operating capital requirements.

Soils, climatic, and marketing factors were taken into account in preparing the detailed costs and returns budgets for the different crops. Tables 51, 52, and 53 summarizes the cost, returns, and other requirements information excluding interest charges and off-farm water costs for each crop included in the model.

Water Requirements

The water requirements of each respective crop are reported in Table 51. The highest water user is alfalfa at four acre-feet/acre, and the lowest is spring lettuce at 0.8 acre-feet/acre.

Labor Requirements

The labor requirements per acre are reported in Table 51. The labor requirements per acre are the hours required to perform the operations necessary to produce and harvest each crop. The labor requirements per acre range from a high of 36.2 hours necessary to produce green chile to a low of 5.7 hours to produce barley.

Capital Requirements

Investment and operating capital requirements are reported in Table 51 and summarized in Table 52. The investment capital requirements range from a high of about $897 for spring and fall onions to a low of about $230 for cucumbers. The interest costs on the investment capital at the four interest rates are reported in Table 53.

The operating capital requirements range from a high of about $1,957 for fresh carrots to a low of about $110 for barley. The operating capital requirement period varies from one month for black-eye peas and spinach to 4.5 months for alfalfa. The interest period was estimated to be one-half of the growing season. The interest costs on the operating capital at the four interest rate levels are reported in Table 53.

Total Cost and Net Returns

The total cost excluding interest charges and water costs are reported in Table 53. These total costs include operating capital requirements as reported in Table 51 and depreciation, insurance and shelter costs on fixed assets.

The total cost including interest charges on the investment and operating capital requirements and excluding water costs are reported in Table 53 for the four interest rate levels.

Net returns to irrigation water at the four interest rate levels (Table 53) were determined by subtracting total cost including the interest charges and excluding the water cost from the gross returns.

Model Constraints

The major constraints included in the parametric model were the availability of irrigable land, quantity of desalted water available for the agricultural sector, and the selection of adaptable crops and acreage of crops, minimum and maximum operation capacity for a vegetable processing plant.

In Chapter III, it was estimated that there were at least 164,000 acres of irrigable land available in the Tularosa basin for such an agricultural project. Second, the amount of water (desalted plus blend) available was estimated to be about 394,250 acre-feet, all of which was required to be used for agricultural purposes. Third, the minimun operating capacity of a

Table 52. Investment capital requirements, operating capital requirements, and interest costs on investment and operating capital at selected interest rates by crop for the agricultural sector, Tularosa basin project, New Mexico

Crops	Investment Capital					Operating Capital					
	Investment Capital Requirement	Interest costs on Investment Capital at selected interest rates				Operating Capital Requirement	Interest Period	Interest costs on Operating Capital at selected interest rates			
		5 percent	6 percent	8 percent	10 percent			5 percent	6 percent	8 percent	10 percent
	(dollars)						(month)	(dollars)			
Alfalfa (baled)	495.68	14.87	17.84	23.79	29.74	137.28	4.5	2.57	3.09	4.12	5.15
Alfalfa (seed)	481.23	14.44	17.32	23.10	28.87	176.07	4.5	3.30	3.96	5.28	6.60
Barley	473.17	14.20	17.03	22.71	28.39	109.85	3.0	1.37	1.65	2.20	2.74
Cotton	446.21	13.39	16.06	21.42	26.77	186.35	4.0	2.80	3.35	4.47	5.59
Grain sorghum	489.81	14.69	17.63	23.51	29.39	132.60	3.0	1.66	1.99	2.65	3.32
Bell pepper	250.65	7.52	9.02	12.03	15.04	969.47	3.0	12.12	14.54	19.39	24.24
Fresh carrot	887.52	26.63	31.95	42.60	53.25	1,957.07	2.5	20.35	24.42	32.57	40.71
Green chile	246.95	7.41	8.89	11.85	14.82	553.43	3.0	6.92	8.30	11.07	13.84
Fall lettuce	264.19	7.93	9.51	12.68	15.85	989.60	2.0	8.25	9.90	13.20	16.50
Spring lettuce	264.19	7.93	9.51	12.68	15.85	796.50	2.0	6.64	7.97	10.62	13.27
Fall onion	896.93	26.91	32.29	43.05	53.82	1,163.76	4.0	17.46	20.95	27.93	34.91
Spring onion	896.93	26.91	32.29	43.05	53.82	1,218.97	4.0	18.28	21.94	29.26	36.57
Asparagus	820.15	24.60	29.53	39.37	49.21	509.44	3.0	6.37	7.64	10.19	12.74
Lima bean	554.66	16.64	19.97	26.62	33.28	337.22	1.5	2.11	2.53	3.37	4.21
Beets	521.23	15.64	18.76	25.02	31.27	329.48	1.5	2.06	2.47	3.29	4.12
Processed carrots	887.52	26.63	31.95	42.60	53.25	507.29	2.5	5.28	6.33	8.44	10.55
Cucumber	229.70	6.89	8.27	11.03	13.78	361.92	2.0	3.02	3.62	4.83	6.03
Black-eye peas	523.24	15.70	18.84	25.12	31.39	240.62	1.0	1.00	1.20	1.60	2.00
Sweet potatoes	531.74	15.95	19.14	25.52	31.90	294.98	2.5	3.07	3.68	4.91	6.14
Spinach	538.14	16.14	19.37	25.83	32.29	262.50	1.0	1.09	1.31	1.75	2.19

Table 53. Gross returns, total costs excluding water and interest costs, total costs excluding water costs and including interest costs, and net returns to irrigation water at selected interest rates by crop for the agricultural sector, Tularosa basin project, New Mexico

Crops	Gross Returns	Total Cost (excluding water cost and interest cost)	Total Cost excluding water cost and including interest cost at selected interest rates				Net Return to irrigation water at selected interest rates			
			5 percent	6 percent	8 percent	10 percent	5 percent	6 percent	8 percent	10 percent
	dollars									
Alfalfa (baled)	310.50	189.16	206.60	210.09	217.07	224.05	103.90	100.41	93.43	86.45
Alfalfa (seed)	447.00	219.44	237.18	240.72	247.82	254.91	209.82	206.28	199.18	192.09
Barley	176.00	135.20	150.77	153.88	160.11	166.33	25.23	22.12	15.89	9.67
Cotton	400.40	243.70	260.49	263.71	270.19	276.66	139.91	136.69	130.21	123.74
Grain sorghum	308.00	160.88	162.54	180.50	187.04	193.59	145.46	127.50	120.96	114.41
Bell pepper	1,304.10	992.77	1,012.41	1,016.33	1,024.19	1,032.05	291.69	287.77	279.91	272.05
Fresh carrot	2,160.00	2,012.54	2,059.61	2,069.00	2,087.80	2,106.59	100.39	91.00	72.20	53.41
Green chile	864.00	576.12	590.45	593.31	599.04	604.78	273.55	270.69	264.96	259.22
Fall lettuce	1,263.60	1,013.93	1,030.11	1,033.34	1,039.81	1,046.28	233.49	230.26	223.79	217.32
Spring lettuce	861.56	820.83	835.39	838.30	844.12	849.94	26.17	23.26	17.44	11.62
Fall onion	1,540.00	1,220.77	1,265.15	1,274.02	1,291.76	1,309.51	274.85	265.85	248.24	230.49
Spring onion	1,500.00	1,275.98	1,321.17	1,330.21	1,348.29	1,366.37	178.83	169.79	151.71	133.63
Asparagus	950.00	596.05	627.02	633.22	645.61	658.00	322.98	316.78	304.39	292.00
Lima bean	542.00	371.72	390.47	394.22	401.71	409.21	151.53	147.78	140.29	132.79
Beets	413.00	360.97	378.66	382.19	389.27	396.35	34.34	30.81	23.73	16.65
Processed carrots	757.50	563.19	595.10	601.47	614.23	626.99	162.40	156.03	143.27	130.51
Cucumber	588.50	383.73	393.64	395.62	399.59	403.54	194.86	192.88	188.91	184.96
Black-eye peas	440.00	271.67	288.38	291.72	298.40	304.97	151.62	148.28	141.60	135.03
Sweet potatoes	490.00	352.52	344.54	348.34	355.95	363.56	145.46	141.66	134.05	126.44
Spinach	351.00	296.04	313.27	316.92	323.62	330.52	37.73	34.08	27.38	20.48

processing plant, which required certain minimum inflow of vegetables to operate efficiently, required minimum acreages of the eight processable vegetables.

Each unit of the vegetable processing plant would require 2,000 acres of asparagus, 2,000 acres of lima beans, 250 acres of beets and carrots, 800 acres of cucumbers, 500 acres of black-eye peas, 700 acres of sweet potatoes, and 200 acres of spinach. The above acreages were considered to be the minimum required to continuously operate a processing plant over a nine to 10 month period annually. The processing plant was permitted to triple in size.

Additional constraints were imposed to provide minimum and maximum acreage levels for proper crop rotation which provides soil conservation, weed and pest control, and risk aversion. A minimum of one-third of the project irrigated acreage was required to be in broadcast crops such as alfalfa and barley, of which alfalfa should be about 70 percent of this acreage. The largest allowable acreage of any single crop should not exceed approximately one-third of the total irrigated acreage. Fresh vegetable production was limited to approximately one-fifth of the total irrigated acreage, primarily because of high financial risk situations.

RESULTS

The results presented in the following sections include the optimum cropping patterns consistent with the crop rotational requirements presented earlier at the four interest rate levels. Results at each interest rate level (five percent, six percent, eight percent, and 10 percent) are presented for the price of irrigation water per acre-foot level that results in aggregate net returns immediately above and immediately below zero.

Five Percent Interest Rate

The optimal cropping pattern, water requirements, costs and returns when an interest rate of five percent is imposed on investment and operating capital and on irrigation water costs are summarized in Tables 54 and 55. At the five percent interest rate level, the maximum level that the irrigated agriculture sector can pay for irrigation water is between \$55 and \$56 per acre-foot. At \$55 per acre-foot for irrigation water, revenues generated would be in excess of \$73 million, total costs slightly over \$72 million, and net returns are expected to be \$303,741 (\$2.03 per acre) and at \$56 per acre-foot, net returns are expected to be -\$110,102 (-\$0.74 per acre). The cropping pattern would result in 150,000 acres being cropped at both price levels for irrigation water. About 66 percent of this acreage would be in field crops, and 34 percent would be in vegetable crops. Irrigation water utilization would be 394,250 acre-feet. The only difference between the two prices of irrigation water is the additional one dollar charge for irrigation water and associated interest charge.

Six Percent Interest Rate

The optimal cropping pattern, water requirements, costs and returns for an interest rate charge of six percent on investment and operating capital, and on irrigation water costs are summarized in Tables 56 and 57. At the six percent interest rate level, the maximum level that the irrigated agriculture sector can pay for irrigation water is between \$52 and \$53 per acre-foot. At \$52 per acre-foot for irrigation water, gross returns would remain the same as the five percent alternative, total costs would increase substantially at \$52 per acre-foot of water from the five percent alternative, thus, net returns are expected to be \$58,890 (\$0.39 per acre) and at \$53 per acre-foot, net returns are expected to be -\$358,659 (-\$2.39 per acre). The crop-

Table 54. Cropping pattern, irrigation water requirements, costs and returns including an interest charge on capital--5 percent interest rate, $55.00 per acre-foot irrigation water cost, Tularosa basin project, New Mexico

Crops	Acres	Water Requirements Per acre	Water Requirements Total	Gross Return Per acre	Gross Return Total	Water Costs Per acre	Water Costs Total	Other Costs* Per acre	Other Costs* Total	Net Return Per acre	Net Return Total
		(ac-ft)	(ac-ft)	- - - -	- - - -	- - - -	- - - - (dollars)	- - - -	- - - -	- - - -	- - - -
Alfalfa (baled)	34,000	4.00	136,000	310.50	10,557,000	231.00	7,854,000	206.60	7,024,400	-127.10	-4,321,400
Alfalfa (seed)	0										
Barley	14,000	1.32	18,480	176.00	2,464,000	76.23	1,067,220	150.77	2,110,780	- 51.00	- 714,000
Cotton	0										
Grain Sorghum	51,000	2.05	104,550	308.00	15,708,000	118.39	6,037,890	162.54	8,289,540	27.07	1,380,570
Bell pepper	1,500	3.80	5,700	1,304.10	1,956,150	219.45	329,175	1,012.41	1,518,615	72.24	108,360
Fresh carrot	69	2.00	138	2,160.00	149,040	115.50	7,970	2,059.61	142,113	- 15.11	- 1,043
Green chile	19,831	3.80	75,357	864.00	17,133,984	219.45	4,351,913	590.45	11,709,214	54.10	1,072,857
Fall lettuce	4,000	1.10	4,400	1,263.60	5,054,400	63.53	254,120	1,030.11	4,120,440	119.96	679,840
Spring lettuce	1,500	0.80	1,200	861.56	1,292,340	46.20	69,300	835.39	1,253,085	- 20.03	- 30,045
Fall onions	2,000	1.80	3,600	1,540.00	3,080,000	103.95	207,900	1,265.15	2,530,300	170.90	341,800
Spring onions	2,000	1.90	3,800	1,500.00	3,000,000	109.73	219,460	1,321.17	2,642,340	69.10	138,200
Asparagus	6,000	2.00	12,000	950.00	5,700,000	115.50	693,000	627.02	3,762,120	207.48	1,244,880
Lima bean	6,000	2.00	12,000	542.00	3,252,000	115.50	693,000	390.47	2,342,820	36.03	216,180
Beets	750	2.00	1,500	413.00	309,750	115.50	86,625	378.66	283,995	- 81.16	- 60,870
Processed carrots	750	2.00	1,500	757.50	568,125	115.50	86,625	595.10	446,325	46.90	35,175
Cucumber	2,400	2.30	5,520	588.50	1,412,400	132.83	318,792	393.64	944,736	62.03	148,872
Black-eye peas	1,500	2.00	3,000	440.00	660,000	115.50	173,250	288.38	432,570	36.12	54,180
Sweet potatoes	2,100	2.05	4,305	490.00	1,029,000	118.39	248,619	344.54	723,534	27.07	56,847
Spinach	600	2.00	1,200	351.00	210,600	115.50	69,300	313.27	187,962	- 77.77	- 46,662
Totals	150,000	2.63	394,250	490.25	73,536,789	151.79	22,768,159	336.43	50,464,889	2.03	303,741

* Other costs are: Total cost excluding water cost and including interest cost at 5 percent interest, (Table 51).

Table 55. Cropping pattern, irrigation water requirements, costs and returns including an interest charge on capital--5 percent interest rate, $56.00 per acre-foot irrigation water cost, Tularosa basin project, New Mexico

Crops	Acres	Water Requirements		Gross Return		Water Costs		Other Costs*		Net Return	
		Per acre	Total	Per acre	Total	Per acre	Total	Per acre	Total	Per acre	Total
		(ac-ft)	(ac-ft)	(dollars)							
Alfalfa (baled)	34,000	4.00	136,000	310.50	10,557,000	235.20	7,996,800	206.60	7,024,400	- 131.30	-4,464,200
Alfalfa (seed)	0										
Barley	14,000	1.32	18,489	176.00	2,464,000	77.62	1,086,680	150.77	2,110,780	- 52.39	- 733,460
Cotton	0										
Grain Sorghum	51,000	2.05	104,550	308.00	15,708,000	120.54	6,147,540	162.54	8,289,540	24.92	1,270,920
Bell pepper	1,500	3.80	5,700	1,304.10	1,956,150	223.44	335,160	1,012.41	1,518,615	68.25	102,375
Fresh carrot	69	2.00	138	2,160.00	149,040	117.60	8,114	2,059.61	142,113	- 17.21	- 1,187
Green chile	19,831	3.80	75,357	864.00	17,133,984	223.44	4,431,038	590.45	11,709,214	50.11	993,732
Fall lettuce	4,000	1.10	4,400	1,263.60	5,054,400	64.68	258,720	1,030.11	4,120,440	168.81	675,240
Spring lettuce	1,500	0.80	1,200	861.56	1,292,340	47.04	70,560	835.39	1,253,085	- 20.87	- 31,305
Fall onions	2,000	1.80	3,600	1,540.00	3,080,000	105.84	211,680	1,265.15	2,530,300	169.01	338,020
Spring onions	2,000	1.90	3,800	1,500.00	3,000,000	111.72	223,440	1,321.17	2,642,340	67.11	134,220
Asparagus	6,000	2.00	12,000	950.00	5,700,000	117.60	705,600	627.02	3,762,120	205.38	1,232,280
Lima bean	6,000	2.00	12,000	542.00	3,252,000	117.60	705,600	390.47	2,342,820	33.93	203,580
Beets	750	2.00	1,500	413.00	309,750	117.60	88,200	378.66	283,995	- 83.26	- 62,445
Processed carrots	750	2.00	1,500	757.50	568,125	117.60	88,200	595.10	446,325	44.80	33,600
Cucumber	2,400	2.30	5,520	588.50	1,412,400	135.24	324,576	393.64	944,736	59.62	143,088
Black-eye peas	1,500	2.00	3,000	440.00	660,000	117.60	176,400	288.38	432,570	34.02	51,030
Sweet potatoes	2,100	2.05	4,305	490.00	1,029,000	120.54	253,134	344.54	723,534	24.92	52,332
Spinach	600	2.00	1,200	351.00	210,600	117.60	70,560	313.27	187,962	- 79.87	- 47,922
Totals	150,000	2.63	394,250	490.25	73,536,789	154.55	23,182,002	336.43	50,464,889	- 0.74	- 110,102

* Other costs are: Total cost excluding water cost and including interest cost at 5 percent interest, (Table 51).

Table 56. Cropping pattern, irrigation water requirements, costs and returns including an interest charge on capital--6 percent interest rate, $52.00 per acre-foot irrigation water cost, Tularosa basin project, New Mexico

Crops	Acres	Water Requirements		Gross Return		Water Costs		Other costs*		Net Return	
		Per acre	Total	Per acre	Total	Per acre	Total	Per acre	Total	Per acre	Total
		(ac-ft)	(ac-ft)	(dollars)							
Alfalfa (baled)	34,000	4.00	136,000	310.50	10,557,000	220.48	7,496,320	210.09	7,143,060	- 120.07	-4,082,380
Alfalfa (seed)	0										
Barley	14,000	1.32	18,489	176.00	2,464,000	72.76	1,018,640	153.88	2,154,320	- 50.64	- 708,960
Cotton	0										
Grain sorghum	51,000	2.05	104,550	308.00	15,708,000	113.00	5,763,000	180.50	9,205,500	14.50	739,500
Bell pepper	1,500	3.80	5,700	1,304.10	1,956,150	209.46	314,190	1,016.33	1,524,495	78.31	117,465
Fresh carrot	69	2.00	138		149,040	110.24	7,607	20.69	142,761	- 19.24	- 1,328
Green chile	19,831	3.80	75,357	864.00	17,133,984	209.46	4,153,801	593.31	11,765,930	61.23	1,214,253
Fall lettuce	4,000	1.10	4,400	1,263.60	5,054,400	60.63	242,520	1,033.34	4,133,360	169.63	678,520
Spring lettuce	1,500	0.80	1,200	861.56	1,292,340	44.10	66,150	838.30	1,257,450	- 20.84	- 31,260
Fall onions	2,000	1.80	3,600	1,540.00	3,080,000	99.22	198,440	1,274.02	2,548,040	166.76	333,520
Spring onions	2,000	1.90	3,800	1,500.00	3,000,000	104.73	209,460	1,330.21	2,660,420	65.06	130,120
Asparagus	6,000	2.00	12,000	950.00	5,700,000	110.24	661,440	633.22	3,799,320	206.54	1,239,240
Lima bean	6,000	2.00	12,000	542.00	3,252,000	110.24	661,440	394.22	2,365,320	37.54	225,240
Beets	750	2.00	1,500	413.00	309,750	110.24	82,680	382.19	286,643	- 79.43	- 59,573
Processed carrots	750	2.00	1,500	757.50	568,125	110.24	82,680	601.47	451,102	45.79	34,343
Cucumber	2,400	2.30	5,520	588.50	1,412,400	126.78	304,272	395.62	949,488	66.10	158,640
Black-eye peas	1,500	2.00	3,000	440.00	660,000	110.24	165,360	291.72	437,580	38.04	57,060
Sweet potatoes	2,100	2.05	4,305	490.00	1,029,000	113.00	237,300	348.34	731,514	28.66	60,186
Spinach	600	2.00	1,200	351.00	210,600	110.24	66,144	316.92	190,152	- 76.16	- 45,696
Totals	150,000	2.63	394,250	490.25	73,536,789	144.88	21,731,444	344.98	51,746,455	.39	58,890

* Other costs are: Total cost excluding water cost and including interest cost at 6 percent interest, (Table 51).

Table 57. Cropping pattern, irrigation water requirements, costs and returns including an interest charge on capital--6 percent interest rate, $53.00 per acre-foot irrigation water cost, Tularosa basin project, New Mexico

Crops	Acres	Water Requirements		Gross Return		Water Costs		Other Costs*		Net Return	
		Per acre	Total	Per acre	Total	Per acre	Total	Per acre	Total	Per acre	Total
		(ac-ft)	(ac-ft)	- - - -	- - - -	- - - -	- - - - (dollars)	- - - -	- - - -	- - - -	- - - -
Alfalfa (baled)	34,000	4.00	136,000	310.50	10,557,000	224.72	7,640,480	210.09	7,143,060	- 124.31	-4,226,540
Alfalfa (seed)	0										
Barley	14,000	1.32	18,480	176.00	2,464,000	74.16	1,038,240	153.88	2,154,320	- 52.04	- 728,560
Cotton	0										
Grain sorghum	51,000	2.05	104,550	308.00	15,708,000	115.17	5,873,670	180.50	9,205,500	12.33	628,830
Bell pepper	1,500	3.80	5,700	1,304.10	1,956,150	213.48	320,220	1,016.33	1,524,495	74.29	111,435
Fresh carrot	69	2.00	138	2,160.00	149,040	112.36	7,753	2,069.00	142,761	- 21.36	- 1,474
Green chile	19,831	3.80	75,357	864.00	17,133,984	213.48	4,233,522	593.31	11,765,931	57.21	1,134,531
Fall lettuce	4,000	1.10	4,400	1,263.60	5,054,400	61.80	247,200	1,033.34	4,133,360	168.46	673,840
Spring lettuce	1,500	0.80	1,200	861.56	1,292,340	44.94	67,410	838.30	1,257,450	- 21.68	- 32,520
Fall onions	2,000	1.80	3,600	1,540.00	3,080,000	101.12	202,240	1,274.02	2,548,040	164.86	329,720
Spring onions	2,000	1.90	3,800	1,500.00	3,000,000	106.74	213,480	1,330.21	2,660,420	63.05	126,100
Asparagus	6,000	2.00	12,000	950.00	5,700,000	112.36	674,160	633.22	3,799,320	204.42	1,226,520
Lima bean	6,000	2.00	12,000	542.00	3,252,000	112.36	674,160	394.22	2,365,320	35.42	212,520
Beets	750	2.00	1,500	413.00	309,750	112.36	84,270	382.19	286,643	- 81.55	- 61,163
Processed carrots	750	2.00	1,500	757.50	568,125	112.36	84,270	601.47	451,102	43.67	32,753
Cucumber	2,400	2.30	5,520	588.50	1,412,400	129.21	310,104	395.62	949,488	63.67	152,808
Black-eye peas	1,500	2.00	3,000	440.00	660,000	112.36	168,540	291.72	437,580	35.92	53,880
Sweet potatoes	2,100	2.05	4,305	490.00	1,029,000	115.17	241,857	348.34	731,514	26.49	55,629
Spinach	600	2.00	1,200	351.00	210,600	112.36	67,416	316.92	190,152	- 78.28	- 46,968
Totals	150,000	2.63	394,250	490.25	73,536,789	147.66	22,148,992	344.98	51,746,456	- 2.39	- 358,659

* Other costs are: Total cost excluding water cost and including interest cost a 6 percent interest, (Table 51).

ping pattern and irrigation water requirements do not change from the five percent level. The additional costs result from the higher interest rate charge of six percent.

Eight Percent Interest Rate

The optimal cropping pattern, water requirements, costs and returns when an interest rate of eight percent is imposed on investment and operating capital, and on irrigation water costs, are summarized in Tables 58 and 59. At the eight percent interest rate level alternative, the maximum level that the irrigated agriculture sector can pay for irrigation water is reduced to between $48 and $49 per acre-foot because of the increased interest charge on capital and irrigation water. At $48 per acre-foot for irrigation water, net returns are expected to be $288,601 ($1.92 per acre) and at $49 per acre-foot, net returns are expected to be -$137,597 (-$0.92 per acre). The cropping pattern changes slightly with the 69 acres of fresh carrots shifted to barley and green chile production.

Ten Percent Interest Rate

The optimal cropping pattern, water requirements, costs and returns for an interest rate charge of 10 percent on investment and operating capital, and on irrigation water costs are summarized in Tables 60 and 61. At the 10 percent interest rate level alternative, the maximum level that the irrigated agriculture sector can pay for irrigation water is between $45 and $46 per acre-foot. At $45 per acre-foot for irrigation water, net returns are expected to be $146,295 ($0.98 per acre), and at $46 per acre-foot, net returns are expected to be -$287,086 (-$1.91 per acre). The cropping pattern and irrigation water requirements do not change from the eight percent level. Again the maximum level that the irrigated agriculture sector can pay for irrigation water is reduced because of the higher interest charge on capital and irrigation water.

IMPLICATIONS

From the results presented in Tables 54 through 61, several major implications can be drawn about the economic feasibility of using desalted water in the Tularosa basin for irrigated agriculture.

In looking at the per-crop acreages, two of the major land-using crops (alfalfa and barley) are very sensitive to moderate and high prices of water and are large water-consuming crops. Acreages of these two crops must be included for crop rotational purposes. If the alfalfa acreage could be eliminated or reduced significantly, then the price of irrigation water that irrigated agriculture could afford to pay could be increased substantially. Grain sorghum, among the large land-using crops and relatively low water-using crop, is profitable at relatively high prices for water. Spring lettuce and beets are two crops with very small profit margins, but they were held at minimum fixed acreages and would be cropped at any price of water in order to maintain the production of other vegetables for processing and fall lettuce. Further research is required to determine the effects on the soils in the Tularosa basin of a restricted crop rotation.

Increasing the interest rate from five to 10 percent does not drastically affect the cropping pattern or water use but decreases the amount that the agriculture sector can pay for irrigation water from between $55 and $56 per acre-foot to $45 to $46 per acre-foot.

Table 58. Cropping pattern, irrigation water requirements, costs and returns including an interest charge on capital--8 percent interest rate, $48.00 per acre-foot irrigation water cost, Tularosa basin project, New Mexico

Crops	Acres	Water Requirements Per acre	Water Requirements Total	Gross Return Per acre	Gross Return Total	Water Costs Per acre	Water Costs Total	Other Costs* Per acre	Other Costs* Total	Net Return Per acre	Net Return Total
		(ac-ft)	(ac-ft)	(dollars)							
Alfalfa (baled)	34,000	4.00	136,000	310,50	10,557,000	207.36	7,050,240	217.07	7,380,380	- 113.93	- 3,873,620
Alfalfa (seed)	0										
Barley	14,050	1.32	18,546	176.00	2,472,800	68.43	961,442	160.11	2,249,546	- 52.54	- 738,188
Cotton	0										
Grain sorghum	51,000	2.05	104,550	308.00	15,708,000	106.27	5,419,770	187.04	9,539,040	14.69	749,190
Bell pepper	1,500	3.80	5,700	1,304.10	1,956,150	196.99	295,485	1,024.19	1,536,285	82.92	124,380
Fresh carrot	0										
Green chile	19,850	3.80	75,430	864.00	17,150,400	196.99	3,910,252	599.04	11,890,944	67.97	1,349,204
Fall lettuce	4,000	1.10	4,400	1,263.60	5,054,400	57.02	228,080	1,039.81	4,159,240	166.77	667,080
Spring lettuce	1,500	0.80	1,200	861.56	1,292,340	41.47	62,205	844.12	1,266,180	- 24.03	- 36,045
Fall onions	2,000	1.80	3,600	1,540.00	3,080,000	93.31	186,620	1,291.76	2,583,520	154.93	309,860
Spring onions	2,000	1.90	3,800	1,500.00	3,000,000	98.50	197,000	1,348.29	2,696,580	53.21	106,420
Asparagus	6,000	2.00	12,000	950.00	5,700,000	103.68	622,080	645.61	3,873,660	200.71	1,204,260
Lima bean	6,000	2.00	12,000	542.00	3,252,000	103.68	622,080	401.71	2,410,260	36.61	219,660
Beets	750	2.00	1,500	413.00	309,750	103.68	77,760	389.27	291,953	- 79.95	- 59,963
Processed carrots	750	2.00	1,500	757.50	568,125	103.68	77,760	614.23	460,672	39.59	29,693
Cucumber	2,400	2.30	5,520	588.50	1,412,400	119.23	286,152	399.59	959,016	69.68	167,232
Black-eye peas	1,500	2.00	3,000	440.00	660,000	103.68	155,520	298.40	447,600	37.92	56,880
Sweet potatoes	2,100	2.05	4,305	490.00	1,029,000	106.27	223,167	355.95	747,495	27.78	58,338
Spinach	600	2.00	1,200	351.00	210,600	103.68	62,208	323.62	194,172	- 76.30	- 45,780
Totals	150,000	2.63	394,251	489.42	73,412,965	136.25	20,437,821	351.24	52,686,543	1.92	288,601

* Other costs are: Total cost excluding water cost and including cost at 8 percent interest, (Table 51).

Table 59. Cropping pattern, irrigation water requirements, costs and returns including an interest charge on capital--8 percent interest rate, $49.00 per acre-foot irrigation water cost, Tularosa basin project, New Mexico

Crops	Acres	Water Requirements		Gross Return		Water Costs		Other Costs*		Net Return	
		Per acre	Total	Per acre	Total	Per acre	Total	Per acre	Total	Per acre	Total
		(ac-ft)	(ac-ft)	(dollars)							
Alfalfa (baled)	34,000	4.00	136,000	310.50	10,557,000	211.68	7,197,120	217.07	7,380,380	- 118.25	- 4,020,500
Alfalfa (seed)	0										
Barley	14,050	1.32	18,546	176.00	2,472,800	69.85	981,393	160.11	2,249,546	- 53.96	- 758,139
Cotton	0										
Grain sorghum	51,000	2.05	104,550	308.00	15,708,000	108.49	5,532,990	187.04	9,539,040	12.47	635,970
Bell pepper	1,500	3.80	5,700	1,304.10	1,956,150	201.10	301,650	1,024.19	1,536,285	78.81	118,215
Fresh carrot	0										
Green chile	19,850	3.80	75,430	864.00	17,150,400	201.10	3,991,835	599.04	11,890,944	63.86	1,267,621
Fall lettuce	4,000	1.10	4,400	1,263.60	5,054,400	58.21	232,840	1,039.81	4,159,240	165.58	662,320
Spring lettuce	1,500	0.80	1,200	861.56	1,292,340	42.34	63,510	844.12	1,266,180	- 24.90	- 37,350
Fall onions	2,000	1.80	3,600	1,540.00	3,080,000	95.26	190,520	1,291.76	2,583,520	152.98	305,960
Spring onions	2,000	1.90	3,800	1,500.00	3,000,000	100.55	201,100	1,348.29	2,696,580	51.16	102,320
Asparagus	6,000	2.00	12,000	950.00	5,700,000	105.84	635,040	645.61	3,873,660	198.55	1,191,300
Lima bean	6,000	2.00	12,000	542.00	3,252,000	105.84	635,040	401.71	2,410,260	34.45	206,700
Beets	750	2.00	1,500	413.00	309,750	105.84	79,380	389.27	291,953	- 82.11	- 61,583
Processed carrots	750	2.00	1,500	757.50	568,125	105.84	79,380	614.23	460,672	37.43	28,073
Cucumber	2,400	2.30	5,520	588.50	1,412,400	121.72	292,128	399.59	959,016	67.19	161,256
Black-eye peas	1,500	2.00	3,000	440.00	660,000	105.84	158,760	298.40	447,600	35.76	53,640
Sweet potatoes	2,100	2.05	4,305	490.00	1,029,000	108.49	227,829	355.95	747,495	25.56	53,676
Spinach	600	2.00	1,200	351.00	210,600	105.84	63,504	323.62	194,172	- 78.46	- 47,076
Totals	150,000	2.63	394,251	489.42	73,412,965	139.09	20,864,019	351.24	52,686,543	- .92	- 137,592

* Other costs are: Total cost excluding water cost and including cost at 8 percent interest, (Table 51).

Table 60. Cropping pattern, irrigation water requirements, costs and returns including an interest charge on capital--10 percent interest rate, $45.00 per acre-foot irrigation water cost, Tularosa basin project, New Mexico

Crops	Acres	Water Requirements Per acre (ac-ft)	Water Requirements Total (ac-ft)	Gross Return Per acre	Gross Return Total	Water Costs Per acre	Water Costs Total	Other Costs* Per acre	Other Costs* Total	Net Return Per acre	Net Return Total
				(dollars)							
Alfalfa (baled)	34,000	4.00	136,000	310.50	10,557,000	198.00	6,732,000	224.05	7,617,700	-111.55	-3,792,700
Alfalfa (seed)	0										
Barley	14,050	1.32	18,546	176.00	2,472,800	65.34	918,027	166.33	2,336,937	- 55.67	- 782,164
Cotton	0										
Grain sorghum	51,000	2.05	104,560	308.00	15,708,000	101.48	5,175,480	193.59	9,873,090	12.93	659,430
Bell pepper	1,500	3.80	5,700	1,304.10	1,956,150	188.10	282,150	1,032.05	1,548,075	83.95	125,925
Fresh carrot	0										
Green chile	19,850	3.80	75,430	864.00	17,150,400	188.10	3,733,785	604.78	12,004,883	71.12	1,411,732
Fall lettuce	4,000	1.10	4,400	1,263.60	5,054,400	54.45	217,800	1,046.28	4,185,120	162.87	651,480
Spring lettuce	1,500	0.80	1,200	861.56	1,292,340	39.60	59,400	849.94	1,274,910	- 27.98	- 41,970
Fall onions	2,000	1.80	3,600	1,540.00	3,080,000	89.10	178,200	1,309.51	2,619,020	141.39	282,780
Spring onions	2,000	1.90	3,800	1,500.00	3,000,000	94.05	188,100	1,366.37	2,732,740	39.58	79,160
Asparagus	6,000	2.00	12,000	950.00	5,700,000	99.00	594,000	658.00	3,948,000	193.00	1,158,000
Lima bean	6,000	2.00	12,000	542.00	3,252,000	99.00	594,000	409.21	2,455,260	33.79	202,740
Beets	750	2.00	1,500	413.00	309,750	99.00	74,250	396.35	297,263	- 82.35	- 61,763
Processed carrots	750	2.00	1,500	757.50	568,125	99.00	74,250	626.99	470,243	31.51	23,632
Cucumber	2,400	2.30	5,520	588.50	1,412,400	113.85	273,240	403.54	968,496	71.11	170,664
Black-eye peas	1,500	2.00	3,000	440.00	660,000	99.00	148,500	304.97	457,455	36.03	54,045
Sweet potatoes	2,100	2.05	4,305	490.00	1,029,000	101.48	213,108	363.56	763,476	24.96	52,416
Spinach	600	2.00	1,200	351.00	210,600	99.00	59,400	330.52	198,312	- 78.52	- 47,112
Totals	150,000	2.63	394,251	489.42	73,412,965	130.11	19,515,690	358.34	53,750,980	.98	146,295

* Other costs are: Total cost excluding water cost and including interest cost at 8 percent interest, (Table 51).

Table 61. Cropping pattern, irrigation water requirements, costs and returns including an interest charge on capital--10 percent interest rate, $46.00 per acre-foot irrigation water cost, Tularosa basin project, New Mexico

Crops	Acres	Water Requirements Per acre	Water Requirements Total	Gross Return Per acre	Gross Return Total	Water Costs Per acre	Water Costs Total	Other Costs* Per acre	Other Costs* Total	Net Return Per acre	Net Return Total
		(ac-ft)	(ac-ft)	(dollars)							
Alfalfa (baled)	34,000	4.00	136,000	310.50	10,557,000	202.40	6,881,600	224.05	7,617,700	- 115.95	- 3,942,300
Alfalfa (seed)	0										
Barley	14,050	1.32	18,546	176.00	2,472,800	66.79	938,400	166.33	2,336,936	- 57.12	- 802,536
Cotton	0										
Grain sorghum	51,000	2.05	104,550	308.00	15,708,000	103.73	5,290,230	193.59	9,873,090	10.68	544,680
Bell pepper	1,500	3.80	5,700	1,304.10	1,956,150	192.28	288,420	1,032.05	1,548,075	79.77	119,655
Fresh carrot	0										
Green chile	19,850	3.80	75,430	864.00	17,150,400	192.28	3,816,758	604.78	12,004,883	66.94	1,328,759
Fall lettuce	4,000	1.10	4,400	1,263.60	5,054,400	55.66	222,640	1,046.28	4,185,120	161.66	646,640
Spring lettuce	1,500	0.80	1,200	861.56	1,292,340	40.48	60,720	849.94	1,274,910	- 28.86	- 43,290
Fall onions	2,000	1.80	3,600	1,540.00	3,080,000	91.08	182,160	1,309.51	2,619,020	139.41	278,820
Spring onions	2,000	1.90	3,800	1,500.00	3,000,000	96.14	192,280	1,366.37	2,732,740	37.49	74,980
Asparagus	6,000	2.00	12,000	950.00	5,700,000	101.20	607,200	658.00	3,948,000	190.80	1,144,800
Lima bean	6,000	2.00	12,000	542.00	3,252,000	101.20	607,200	409.21	2,455,260	31.59	189,540
Beets	750	2.00	1,500	413.00	309,750	101.20	75,900	396.35	297,263	- 84.55	- 63,413
Processed carrots	750	2.00	1,500	757.50	568,125	101.20	75,900	626.99	470,242	29.31	21,983
Cucumber	2,400	2.30	5,520	588.50	1,412,400	116.38	279,312	403.54	968,496	68.58	164,592
Black-eye peas	1,500	2.00	3,000	440.00	660,000	101.20	151,800	304.97	457,455	33.83	50,745
Sweet potatoes	2,100	2.05	4,305	490.00	1,029,000	103.73	217,833	363.56	763,476	22.71	47,691
Spinach	600	2.00	1,200	351.00	210,600	101.20	60,720	303.52	198,312	- 80.72	- 48,432
Totals	150,000	2.63	394,251	489.42	73,412,965	132.99	19,949,073	358.34	53,750,978	- 1.91	- 287,086

* Other costs are: Total cost excluding water cost and including interest cost at 10 percent interest, (Table 51).

CHAPTER IX

ELECTRICITY MARKET POTENTIAL

INTRODUCTION

In this section, estimates of the current supply and future demand for electricity in the Southwestern United States are presented. A region comprised of the states of Arizona, California, Colorado, Nevada, New Mexico, Utah, and Wyoming was chosen as the relevant market area for this purpose. Each state is served by transmission interconnections which make generation capacity in one state available to others. Projected additions to the network will serve to strengthen the interdependence of electricity producers and consumers in each state.

In the first sub-section, historical data of consumption within the region by various types of users is presented. Load centers are reported and peak loading is discussed. Production is then analyzed by energy sources and generation location. The fuel mix in generation is described, as are the major utilities in the Southwest and the major transmission loop which interconnects them.

Econometric analysis of demand is reported in the second sub-section. The analysis suggests that the price elasticity of demand for electricity is elastic in most consuming sectors.

The final sub-section deals with projected electricity demand and the effect that changes in price and other factors could exert on demand. Maximum and minimum demand estimates are presented. The potential for additional generating capacity is then derived.

THE CONSUMPTION AND PRODUCTION OF ELECTRICITY IN THE SOUTHWEST: AN OVERVIEW

Consumption

In 1960, the Southwest region utilized 77,988 million kilowatt hours of electricity. This represented 11.4 percent of the nation's total consumption. By 1972, regional consumption totaled 188,579 million kilowatt hours, or 11.9 percent of the national total (U. S. Federal Power Commission, 1960-73). Thus, during the 1960-1972 time frame, electricity consumption in the Southwest more than doubled. During the period, the average compound growth rate was 7.7 percent, which slightly exceeded the national average of 7.3 percent.

Within the region, consumption growth rates varied from a low of 5.9 percent in New Mexico to a high of 14.3 percent in Wyoming. However, the two states utilized only six percent of the total electricity consumed in the Southwest. California, on the other hand, consumed over 70 percent of the electric energy used in the region. During the 1960-1972 period, California experienced an average compound growth rate of 7.5 percent, similar to both national and regional averages (U. S. Federal Power Commission, 1960-73).

Total electricity consumption in each state of the Southwest region and in the region as a whole is presented in Table 62. As shown by the table, California utilized 8.3 percent and 8.5 percent of all the electricity used in the nation in 1960 and 1972 respectively. However, California's consumption as a percentage of total regional consumption decreased slightly, during the 1960-1972 period, primarily because consumption in other states, especially Arizona, expanded rapidly.

Table 62 does not reflect electrical energy produced and consumed for internal industrial use within the region. In 1960, about 4,117 million kilowatt hours were so generated and

Table 62. Electricity sales to ultimate consumers and percentage of sales by state

	1960		1965		1970		1972	
	Million KWH	Per cent	Million KWH	Per cent	Million KWH	Per cent	Million KWH	Per cent
Wyoming	719	0.9	1,703	1.5	3,704	2.3	3,567	1.9
Colorado	4,837	6.2	6,938	6.1	10,787	6.6	12,886	6.8
New Mexico	3,383	4.3	4,869	4.3	5,603	3.4	6,627	3.5
Arizona	6,138	7.9	8,631	7.6	13,714	8.4	17,390	9.2
Utah	3,474	4.5	4,513	4.0	5,227	3.2	6,092	3.2
Nevada	2,167	2.8	3,812	3.4	5,694	3.5	6,737	3.6
California	57,270	73.4	82,703	73.1	118,619	72.6	135,280	71.8
Region	77,988	100.0	113,169	100.0	163,348	100.0	188,579	100.0

Source: U. S. Federal Power Commission, *Electric Power Statistics*, monthly, 1960-1973.

consumed. Twelve years later, industry produced over 6,000 million kilowatt hours. A third of this production occurred in Utah. The remainder of internal industrial production occurred primarily in California and Arizona where approximately 3,000 million kilowatt hours were generated in 1972. Because the two states consumed four-fifths of the electricity used in the region, the additional internal industrial generation only slightly alters the gross totals and percentages presented in Table 62 (U. S. Federal Power Commission, 1960-73).

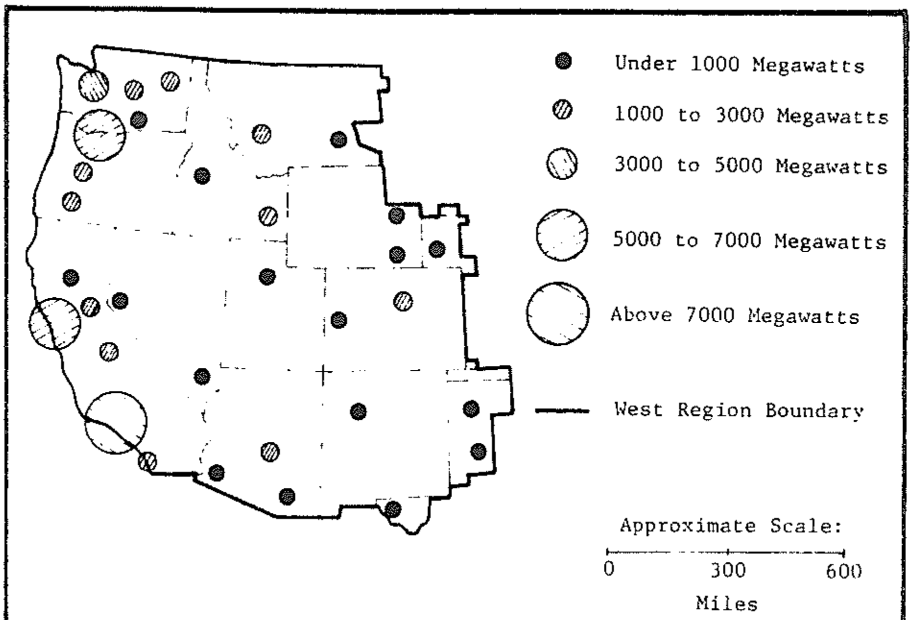
Consumption Load Centers

Within the Southwest region, the major urban areas are also the major consumptive load centers. Figure 41 delineates primary load centers within the region and shows the peak noncoincidental demand for each center in 1970. Peak demand is the maximum amount of electricity, measured in megawatts, demanded at any one moment. The loads are noncoincidental in that peak demands are not simultaneous throughout the region and are experienced at different times by each load center. Differential climatic and end-use factors are primarily responsible for noncoincidence of peak demand.

The region is characterized by large load centers along the Pacific Coast and long distances between load centers. The Federal Power Commission has identified 26 separate urban load centers within the region. Table 63 reveals that five of the six largest centers are in California. The single largest multiple load center is obviously the Southern California megalopolis. For example, peak demand for Los Angeles totaled over 9,000 megawatts in 1970.

Load Seasonality

Peak demand is seasonal and varies somewhat among the Southwestern states. Electricity consumption is highest throughout the summer months and reaches a maximum in August. For example, regional consumption for August 1972 totaled 17,180 million kilowatt hours, or 19 percent greater than the amount used in April. Variances occur, however, in the states of



Source: United States Federal Power Commission, *The 1970 National Power Survey*, 1969, p. III-3-1.

Figure 41. Primary load centers and peak noncoincidental demand for electricity in Southwest region, 1970

Wyoming, Colorado, and New Mexico where winters are harsh. These three states usually experience higher sales of electricity during the winter months, especially December. Demand peaks for the largest electricity consumers, Arizona and California, almost invariably occur during the summer months (U. S. Federal Power Commission, 1960-73).

During the summer, two separate daily demand peaks occur. The first peak occurs during midday, usually between 1:00 and 2:00 p.m. The second peak takes place in the early evening, usually between 7:00 and 8:00 p.m. Winter demand varies somewhat with the primary peak occurring in the early evening, between 5:00 and 7:00 p.m. A secondary peak occurs in mid-morning, usually between 9:00 and 11:00 a.m. (U. S. Federal Power Commission, 1969).

Electricity Sales by End Uses

The major electricity user categories are broadly defined as: (1) rural and residential; (2) commercial; (3) industrial; and (4) all other. The latter classification includes miscellaneous uses such as street and highway lighting and electrified transportation. Residential use is partially a function of population while commercial and industrial use per customer may vary considerably, depending upon the type of enterprise (U. S. Federal Power Commission, 1969).

Table 64 reveals sales to ultimate end-use categories in each of the Southwestern states for 1960 and 1972. (Sales for resale and internal industrial production are not included). Historically, the industrial category was the largest purchaser of electricity in the Southwest. A trend toward a balance in consumption by the three major-use categories is, however, evident. For example, by 1972, both industrial and commercial users consumed one-third of the total energy utilized, while residential users consumed only slightly less than 31 percent. National sales figures for 1972 are also presented in Table 64 for comparative purposes.

Table 63. Load center peak noncoincident demand in the Southwest region, 1970

State and City	Load Center Peak Noncoincident Demand (MW)
Wyoming	
Casper	249
Cheyenne	172
Cody	115
Colorado	
Denver	1360
Colorado Springs	423
Montrose-Grand Junction	223
Poncha	106
New Mexico	
Hobbs	389
Albuquerque	496
Arizona	
Phoenix	2000
Tucson	668
Yuma	908
Utah	
Salt Lake City	880
Cedar City	86
Nevada	
Las Vegas	688
Reno	320
California	
San Francisco	5060
Sacramento	2370
Fresno	1970
Red Bluff	815
Los Angeles	9150
San Diego	1210
San Bernadino	1704
Ventura	530
Tulare	365
Brawley	155
Total	32412

Source: U. S. Federal Power Commission, *The 1970 National Power Survey*, 1969, pp. III-3-26, 7.

Residential users in the Southwest purchased 31 percent of electricity sold in 1972 while nationally, residential users purchased 34 percent. The difference is probably due to the moderate Southwestern climate which reduces the need for electric heating and the availability of natural gas for home heating purposes in the Southwest. The data also indicate that as compared to the nation, the region's industrial sector utilized less energy on a percentage basis. Commercial usage, however, is considerably higher on a percentage basis in the Southwest.

Gross Power Production

More electricity is produced in the Southwest region each year than is consumed. Yet because of transmission losses and the lack of sufficient interconnections to optimize the distribution of production, electric power must be imported.

In 1960, utilities produced 88,312 million kilowatt hours of electricity, while ultimate consumers utilized 77,988 million kilowatt hours. Twelve years later, sales amount to 188,579

Table 64. Sales by use to ultimate consumers in the Southwest region

State	Residential Million KWH	Residential Per cent	Commercial Million KWH	Commercial Per cent	Industrial Million KWH	Industrial Per cent	Other Million KWH	Other Per cent	Total Million KWH	Total Per cent
					1960					
Wyoming	275	38	129	18	270	38	45	6	719	100
Colorado	1776	37	1530	32	1289	27	242	4	4837	100
New Mexico	872	26	603	18	1548	46	360	10	3383	100
Arizona	1355	22	1360	22	1481	24	1942	32	6138	100
Utah	1012	29	556	16	1822	52	84	3	3474	100
Nevada	719	33	589	27	793	37	66	3	2167	100
California	14975	26	17100	30	20190	35	5005	9	57270	100
Region	20984	27	21867	28	27393	35	7744	10	77988	100
					1972					
Wyoming	701	20	660	19	2121	59	85	2	3567	100
Colorado	4663	36	5303	41	2353	18	568	5	12886	100
New Mexico	1775	27	2133	32	2168	33	551	8	6627	100
Arizona	5821	34	4866	28	5631	32	1072	6	17390	100
Utah	2023	33	1773	29	1843	30	453	8	6092	100
Nevada	2454	37	2175	32	1828	27	279	4	6737	100
California	41264	30	44406	33	47167	35	2443	2	135280	100
Region	58701	31	61316	33	63111	33	5451	3	188579	100
U.S.	538762	34	358696	23	636256	40	54797	3	1588511	100
Regional Sales as a Percentage of U.S. Sales		11		17		10		10		12

Source: U. S. Federal Power Commission, *Electric Power Statistics*, monthly, 1960-1973.

million kilowatt hours, or 4.6 percent less than the total production of 197,588 million kilowatt hours. Table 65 presents information as to the total production in the Southwest region, production by states within the region, the percentage of total energy produced by each state, and the United States production.

A review of Table 65 reveals that California utilized 71.8 percent of energy sold in the Southwest in 1972, but that the state produced only 63.4 percent of regional output. The deficit was made up by importing energy from surplus-production states both within the region and in the Northwest. Arizona and Utah also import electric power. All other states produce more electricity than they consume, with New Mexico being the region's second largest energy producer. The Four Corners Plant in New Mexico is primarily utilized to provide energy to California and Arizona. The Mohave installation in Nevada functions in a similar manner, while the Dave Johnston coal units in Wyoming also produce primarily for export. In 1972, the exporting states produced nearly 40,000 million kilowatt hours, while consuming only about 17,000 (U. S. Federal Power Commission, 1960-73).

Power Production and the Hydro Contribution

In the Southwest, a smaller proportion of electricity is generated by fossil fuels than for the United States as a whole. Hydro-electric generation in 1960 provided for 27.6 percent of regional production or 24,332 million kilowatt hours, and in 1972 provided 22.2 percent or

Table 65. Electricity production by utilities in the Southwest region

State	1960 Million KWH	1960 Regional per cent	1965 Million KWH	1965 Regional per cent	1970 Million KWH	1970 Regional per cent	1972 Million KWH	1972 Regional per cent
Wyoming	1589	1.8	3570	2.8	6485	3.7	8236	4.2
Colorado	5568	6.3	7720	6.1	11805	6.7	13446	6.8
New Mexico	3029	3.4	8309	6.5	15000	8.5	18212	9.2
Arizona	8626	9.8	8672	6.8	13016	7.3	16051	8.1
Utah	3034	3.4	2950	2.3	2950	1.7	3365	1.7
Nevada	2655	3.0	3373	2.6	5583	3.1	13004	6.6
California	63811	72.3	92739	72.9	122014	69.0	125274	63.4
Total	88312	100	127333	100	176853	100	197588	100
United States	752962	--	1054790	--	1529581	--	1747323	--
Region/United States		11.7		12.1		11.6		11.3

Source: U. S. Federal Power Commission, *Electric Power Statistics*, monthly, 1960-73.

43,790 million kilowatt hours. Throughout the nation, hydro-electricity provided 19.3 percent of total electricity produced in 1960 and 15.6 percent in 1972. Table 66 presents national, regional, and state production by method for 1960 and 1972. The data indicate that California and Arizona are responsible for most of the hydro-production. In 1970, 54 major hydro-sites were operative in California, and six in Arizona, including the 1,345-megawatt Hoover generating complex on the Colorado River at the Nevada border. In comparison, the largest fossil fuel fired generating site in the region, the Four Corners Plant, had a capacity of 2,220 megawatts in 1970. (U. S. Federal Power Commission, 1969).

Table 66. Generation methods of utilities in the Southwest region

	Hydro (1)		Fuels (2)		Total (3)	
State	Million KWH	1/3(%)	Million KWH	2/3(%)	Million KWH	3/3(%)
1960						
Wyoming	609	38.3	980	61.7	1589	100
Colorado	966	17.3	4602	82.7	5568	100
New Mexico	69	2.3	2959	97.7	3028	100
Arizona	2990	34.7	5636	65.3	8626	100
Utah	304	10.0	2730	90.0	3034	100
Nevada	1968	74.1	688	25.9	2656	100
California	17426	27.3	46385	72.7	63811	100
Southwest Total	24332	27.6	63980	72.4	88312	100
United States Total	145512	19.3	607450	80.7	752962	100
Region/United States		16.7		10.5		11.7
1972						
	Hydro (4)		Fuels (5)		Total (6)	
	Million KWH	4/6(%)	Million KWH	5/6(%)	Million KWH	6/6(%)
Wyoming	1172	14.2	7064	85.8	8236	100
Colorado	1242	9.2	12204	90.8	13446	100
New Mexico	20	.1	18192	99.8	18212	100
Arizona	6771	42.2	9280	57.8	16051	100
Utah	1220	36.3	2145	63.7	3365	100
Nevada	1563	12.0	11441	88.0	13004	100
California	31802	25.4	93472	74.6	125274	100
Southwest Total	43790	22.2	153798	77.8	197588	100
United States Total	272734	15.6	1474589	84.4	1747323	100
Region/United States		16.1		10.4		11.3

Source: U. S. Federal Power Commission, *Electric Power Statistics*, monthly, 1960-73.

The Southwest also is the site of geothermal electric production. In 1960, the Pacific Gas and Electric Company became the first utility in the United States to produce electric power from geothermal energy at the Geysers complex in Northern California. The complex had a capacity of 80 megawatts in 1970, or about one-thirteenth of the company's total capacity. No other such units are operative in the region or the nation (U. S. Federal Power Commission, 1969).

The Fuel Mix in Thermal Generation

As indicated in the previous section, hydro-electricity plays an important role in total power generation in the Southwest. Hydro-electric generation since 1960 has increased absolutely but has decreased as a percentage of total production. Consumption of power has increased dramatically and hydro-capacity has increased at a lesser rate as potential sites are exhausted. Moreover, environmental and cost considerations have tended to favor the use of fossil fuels. Table 66 shows that in 1972, thermal plants provided 77.8 percent of the region's electricity. Estimates suggest that during the same year, coal provided 21.1 percent of the electricity produced in the region; oil, 14.0 percent; gas, 42.7 percent; and hydro-electricity, 27.7 percent.[10] Nuclear power was nominal.

Table 67 displays fuel consumption by thermal plants for each state in the region, the Southwest, and the nation for 1960 and 1972. Conversions to British Thermal Units (BTU) are also included. The data contained in Table 67 points out several important characteristics of thermal energy production in the Southwest.

First, natural gas is by far the most important fuel utilized for electricity generation. In 1960, gas provided 67.7 percent of the BTU's utilized to produce electricity. Twelve years later, its share had declined to 53.7 percent, still over one-half. Gas showed an absolute increase in usage during the period, nearly doubling in consumption, although its percentage share dropped.

The preference for natural gas in electricity generation is based on two factors. Gas is by far the least environmentally damaging of the fossil fuel alternatives. There is essentially no water pollution other than thermal discharge; total air pollution is less than five percent of the pollution resulting from a coal system and significantly less than an oil system (U. S. Council on Environmental Quality, 1973). Natural gas has also been cheaper than its main competitor, oil. Coal is even less expensive, but availability, transportation costs, and pollution abatement costs have restricted its utilization until recently (U. S. Federal Power Commission, 1969).

Due partially to the relative scarcity of natural gas, coal has, however, become a major fuel source in recent years. As shown in Table 67, coal provided the fuel for only 8.3 percent of the thermally generated electricity in the Southwest in 1960 and was important only in the states of Wyoming, Utah, and Colorado. By 1972, coal was utilized to produce 26.6 percent of the electricity generated within the region and was the major fuel source in all states but California and Arizona. California does not utilize coal for electricity generation. The state does not have large coal reserves and environmental standards almost prohibit its use (U. S. Federal Power Commission, 1969).

Oil has remained a relatively important fuel source. By far, the greatest amount of oil

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[10] Derived from production figures in U. S. Federal Power Commission, *Electric Power Statistics*, monthly.

Table 67. Fuel consumption by utilities in the Southwest region in 1960 and 1972

	COAL			OIL			NATURAL GAS			NUCLEAR			
	Short Tons (10^3)	BTU (10^9) [a]	Coal BTU / State BTU	BBLS	BTU (10^9) [b]	Oil BTU / State BTU	Cubic Ft. (10^6)	BTU (10^9) [c]	Gas BTU / State BTU	Short Tons	BTU (10^9) [d]	Nuclear BTU / State BTU	Total State BTU
1960													
Wyoming	815	18,428	96.0	10,979	69	0.4	681	702	3.6	0	0	0	19,199
Colorado	1,221	27,597	41.5	113,966	717	1.1	37,047	38,195	57.4	0	0	0	66,509
New Mexico	25	571	1.6	117,452	738	2.1	33,548	34,588	96.3	0	0	0	35,897
Arizona	0	0	0	41,338	260	0.5	53,930	55,602	99.5	0	0	0	55,862
Utah	515	11,636	38.9	2,301,885	14,473	48.4	3,657	3,771	12.7	0	0	0	29,880
Nevada	0	0	0	47,731	300	4.4	6,339	6,535	95.6	0	0	0	6,835
California	0	0	0	24,050,802	151,207	31.2	322,881	332,890	68.8	*	*	-	484,097
TOTAL	2,576	58,232	8.3	26,684,253	167,764	24.0	458,083	472,283	67.7	-	-	-	698,279
United States	176,569	3,990,452		85,270,817	536,097		1,722,729	1,776,133					
Region/Nation	1.5			31.3			26.6						
1972													
Wyoming	4,553	102,892	96.5	122,950	773	0.7	2,857	2,946	2.8	0	0	0	106,611
Colorado	3,404	76,925	51.5	531,388	3,340	2.2	66,929	69,059	46.3	0	0	0	149,324
New Mexico	6,849	154,784	70.8	439,723	2,764	1.3	59,141	60,975	27.9	0	0	0	218,523
Arizona	348	7,864	8.1	1,520,105	9,557	9.8	77,715	80,124	82.1	0	0	0	97,545
Utah	594	13,419	53.5	1,247,315	7,842	31.2	3,718	3,833	15.3	0	0	0	25,094
Nevada	3,576	80,813	65.7	131,387	826	0.7	40,043	41,284	33.6	0	0	0	122,923
California	0	0	0	42,070,282	264,496	28.7	605,791	624,570	67.6	NA	33,845	3.7	922,911
TOTAL	19,324	436,697	26.6	46,063,150	289,598	17.6	856,194	882,791	53.7	NA	33,845	2.1	1,642,931
United States	351,315	7,939,722		493,926,941	3,105,318		3,978,673	4,102,012		NA	576,000		
Region/Nation	5.5			9.3			21.5				5.9		

[a] Heat values employed for coal are 22,600,000 BTU/short ton.

[b] Heat values employed for oil are 6,280,000 BTU/barrel.

[c] Heat values employed for natural gas are 1,031 BTU/cubic foot.

[d] Nuclear power is converted at the average heat rate of 10,660 BTU/net kilowatt hour of electricity generated.

*Insignificant amount

Sources: U. S. Federal Power Commission, *Electric Power Statistics*, monthly.
U. S. Federal Power Commission, National Power Survey, 1969, p. III-3-89.
U. S. Federal Power Commission, *Statistics of Privately Owned Electric Utilities in the United States*, 1972, 1973, p. 702.
U. S. Department of the Interior, *Minerals Yearbook 1972*, 1973, Volume I, p. 26.

is used in California. This is partially due to stringent air quality standards. Natural gas, of course, is more desirable from an environmental perspective, but it is relatively scarce. Thus, the supply is interruptible, and fuel oil is used as a substitute (U. S. Federal Power Commission, 1969).

Nuclear power is, as yet, of no great consequence in the Southwest. In 1972, nuclear units produced 3,175 million kilowatt hours of electricity within the region, or 1.6 percent of all power generated by utilities. By 1972, there were two operative nuclear plants, both located in California. The first, a 65-megawatt plant owned by Pacific Gas and Electric Company at Humboldt Bay in the north, produced 363 million kilowatt hours. A 435-megawatt plant owned by Southern California Edison and San Diego Gas and Electric and located in the south, produced 2,812 million kilowatt hours (U. S. Federal Power Commission, 1973). The switch to nuclear power in the Southwest has been retarded because of high capital requirements, the abundance of fossil fuels, lack of public acceptance, and stringent environmental and safety standards (U. S. Federal Power Commission, 1969).

Major Electric Utilities in the Southwest

There are 12 major utilities responsible for electricity sales to ultimate users in the region. Nine are privately owned, three are public; together they account for about 84.2 percent of all electricity sold to ultimate consumers in 1972. Table 68 enumerates the utilities and indicates their approximate share of regional sales during 1972. As is evident, three California utilities, Pacific Gas and Electric, Southern California Edison, and the City of Los Angeles were the major utilities, selling 59.2 percent of all electricity.

A marked characteristic of Southwestern utilities is their varied and numerous generating plants. For example, in 1972, Pacific Gas and Electric operated 10 fossil fuel thermal plants, 65 hydro-electric stations, one internal combustion plant, the nuclear units at Humboldt Bay and the geothermal units at the Geysers (U. S. Federal Power Commission, 1973). Southern California Edison operated 56 different plants utilizing hydro, fossil fuel, and nuclear power; Arizona Public Service, 12; Public Service of Colorado, 11, and Public Service of New Mexico, four, all fossil fuel thermal (U. S. Federal Power Commission, 1973).

Southwest Transmission Interties

Transmission of electric power in the West is characterized to a large degree by long distances between hydro or remotely located thermal power sources and the load centers. The composite of interconnected systems comprises a large network referred to as the Western Loop. The loop basically circles around Nevada, connecting the major load centers along the Pacific Coast with generating centers inland and in the Pacific Northwest (U. S. Federal Power Commission, 1969). The Western Loop is shown in Figure 42. The interties are designed to transfer power between adjacent producers and serve to optimize the distribution of available electricity within the region. It should be noted that the loop is closed to utilities east of New Mexico and Colorado, and that the only important interregional interties are between California and generating centers in the Pacific Northwest. Minor interties are also maintained between the generating site in Wyoming and other load centers and production sites in the Northwest and Utah. No major interties to power loops further east are projected.

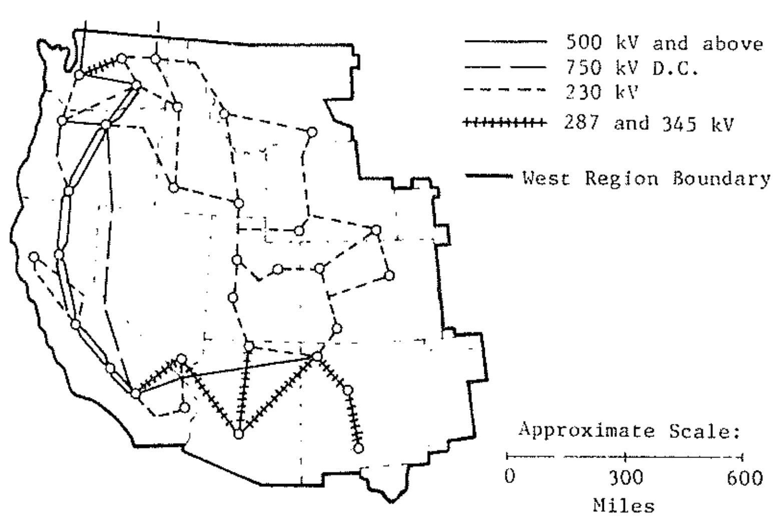
The Future Demand for Electricity in the Southwest

Histocially, electricity consumption in both the United States and the Southwest has doubled every 10 years. Most projections of future electricity use implicitly assume that

Table 68. Major electric utilities in the Southwest and 1972 sales

Utility	1972 sales (million KWH)	Percent of regional total (percent)
Private Utilities		
Arizona Public Service	6463	3.4
Tucson Gas and Electric	3236	1.7
Pacific Gas and Electric	47027	24.9
San Diego Gas and Electric	7401	3.9
Southern California Edison	47910	25.4
Public Service Company of Colorado	8011	4.3
Nevada Power Company	3590	1.9
Public Service Company of New Mexico	2470	1.3
Utah Power and Light	6349	3.4
Public Utilities		
City of Los Angeles	16852	8.9
City of Sacramento	3934	2.1
Salt River Project (Arizona)	5607	3.0
Subtotal	158850	84.2
Others	29729	15.8
Total	188579	100.0

Sources: U. S. Federal Power Commission, *Electric Power Statistics*, monthly, 1960-73.
U. S. Federal Power Commission, *Statistics of Privately Owned Electric Utilities in the United States 1972.*
U. S. Federal Power Commission, *Statistics of Publicly Owned Electric Utilities in the United States 1972.*



Source: United States Federal Power Commission, The 1970 National Power Survey, *The Future of Power in the Western Region*, 1969, p. III-3-5.

Figure 42. Electric transmission in the West region, 1970.

this trend will continue. A comprehensive study of future electricity demand and supply, the 1970 National Power Survey, (U. S. Federal Power Commission, 1969), projects that electricity consumption in the Southwest will double by 1980 and quadruple by 1990. According to the survey, consumption within the region is projected to increase to about 367,000 million kilowatt hours in 1980 and to approximately 750,000 million kilowatt hours in 1990[11] (U. S. Federal Power Commission, 1969, III-3-37).

Several assumptions are inherent in this forecast. First, an annual economic growth rate of 3.5 to 4.0 percent is assumed. A 2.2 percent annual increase in personal income and 1.5 to 2.0 percent annual increase in the general price level is also assumed. Fuel prices were projected to increase at a slower rate than the general price level, and electricity prices were not projected to increase significantly.

The National Power Survey concluded that "...there is little or no evidence of a direct relationship for most classes of service between the cost of electricity and its volume of use." It is also stated that cost increases because of inflation, additional distribution costs, and environmental restrictions will have a negligible effect on consumption.

Econometric analysis suggests, however, that the assumption upon which the National Power Survey results are based may be incomplete or incorrect. The major factors which have been found through analysis to influence the demand for electricity include: (1) the price of electricity; (2) population; (3) income; (4) geographic variables; (5) the price of substitute energy resources; and (6) the price of electrical machinery and appliances. Numerous studies of the relationship between several of these factors and electricity demand have been published. The magnitude of the relationship between demand and each factor is usually expressed as an elasticity where elasticity is defined as the percentage change in the quantity of electricity demanded in response to a one percent increase in the magnitude of each factor. For example, if income increases one percent, an income elasticity of .95 indicates that demand will increase .95 percent, all other things equal. Similarly, if the price of electricity increases one percent, a price elasticity of -1.2 indicates that demand will be reduced by 1.2 percent.

Reliable elasticity estimates are essential for an analysis of the impact of changing market forces upon the quantity of electricity demanded. For example, the price of electricity relative to other goods may rise in the future due to increasing fuel costs, taxes, or other factors. Price elasticities provide information as to how much the quantity of electricity demanded will be expected to change as a result of such price increases.

Previous Studies

A review of the economic literature reveals that studies of electricity demand have produced various results. Price and income elasticities obtained from several studies for residential, commercial, and industrial demand are presented in Table 69.

An examination of Table 69 reveals that the range of estimated elasticities for any one consumer class is quite substantial. However, it is important to note that the long-run price elasticity of demand is estimated to be elastic in 10 of the 11 studies reviewed. That is, a one percent increase in price results in more than a one percent decrease in the quantity of electricity demanded.

[11] Derived from 1970 National Power Survey projections for Power Supply Areas (PSA) 31, 32, 36, 39, 41, 46, 47, and 48 and reduced proportionately when necessary to coincide with the seven-state region of this study.

Table 69. Estimated price and income elasticities of electricity demand

Type of Demand	Price Elasticity Short-Run	Price Elasticity Long-Run	Income Elasticity Short-Run	Income Elasticity Long-Run
Residential:				
Houthakker	-0.89		1.16	
Fisher & Kaysen	≃-0.15	≃0	0.10	
Houthakker & Taylor	-0.13	-1.89	0.13	1.94
Wilson		-2.00		≃0
Mount, Chapman, & Tyrrell	-0.14	-1.20	0.02	0.20
Anderson		-1.12		0.80
Lyman	(≃ -0.90)		(≃ -0.20)	
Houthakker, Verleger, & Sheehan	-0.90	-1.02	0.14	1.64
Commercial:				
Mount, Chapman, & Tyrrell	-0.17	-1.36	0.11	0.86
Lyman	(≃-2.10)			
Industrial:				
Fisher & Kaysen		≃ -1.25		
Baxter & Rees		≃ -1.50		
Anderson		-1.94		
Mount, Chapman, & Tyrrell	-0.22	-1.82		
Lyman	(-1.40)			

Source: Taylor, Lester D., "The Demand for Electricity: A Survey," *The Bell Journal of Economics*, 6, pp. 74-110, 1975.

The impact of income levels on electricity consumption is much more ambiguous than that of price. Logic suggests that an increase in income results in an increase in demand. However, as shown in Table 69, previous studies have produced inconclusive results. A probable reason for this is that technology has provided a myriad of low-cost electrical appliances and machinery over the years which most Americans purchase regardless of their income level. Further, the real price of electricity has tended downward. The outcome has been a fairly constant increase in electricity use per capita (despite income restrictions) as more and more goods, using cheap electricity, enter the marketplace.

As would be expected, previous studies have found that the elasticity of demand with respect to the number of users is almost unitary for all sectors (Taylor, 1975). Annual cooling degree days, an indicator of air conditioner usage is a factor which affects energy requirements in warm climates such as the Southwest (Randall, 1974). On the other hand, the relationship between the demand for electricity and the price of substitutes, such as natural gas, remains unresolved. Mount, et al. (1973), obtained a cross-elasticity to residential demand of .2 for natural gas. The cross-elasticity was, however, found to be statistically insignificant for the industrial and commercial sectors. In other words, a change in the relative price of natural gas may have little effect upon the quantity of electricity consumed.

Although the econometric models of electricity demand discussed above provide insight to the factors which influence the demand for electricity, the results must be used with caution for the purpose of predicting the future consumption of electricity in the Southwest. For example, Myrah points out that current elasticity estimates may not be applicable in future time periods (Myrah, 1974). This is because current estimates are based upon a multi-fuel economy where electricity, natural gas, and petroleum all have a major role in meeting energy needs. But, natural gas and petroleum are anticipated to be in increasingly short supply. If the demand for energy is price inelastic in the aggregate, then electricity use may increase substantially as energy resources which are substitutes for electricity become relatively more expensive. In other words, "adjustments to the energy crisis may result in major structural changes in the market for electricity" (Randall, 1974). Further Taylor points out that the elasticity values listed in Table 69 are "...likely to reflect biases, but of indeterminate size and sign" (Taylor, 1975). This bias is due to a host of factors including misspecification of the demand models.

For the purpose of predicting the future demand for electricity in the Southwest, an analysis which minimizes the problems discussed above is required. The analysis must also account for the economic and physical characteristics unique to the Southwest region which influence the demand for electrical energy.

The Demand Model

The demand model used in this study is an adaptation of a model developed by Mount, Chapman, and Tyrrell (1973). A separate model was developed for each of the residential, commerical, and industrial sectors. The residential model is expressed as:

$$\begin{aligned} \text{Ln } Q_t = \alpha + \underset{(119.2)}{.8837} \text{ Ln } Q_{t-1} + \underset{(15.3)}{.1172} \text{ Ln } P_t + \underset{(3.3)}{\frac{9.7821}{P_t}} + \underset{(0.6)}{.0195} \text{ Ln } Y_t + \\ \underset{(0.2)}{\frac{-.0139}{Y_t}} \underset{(7.7)}{-.1552} \text{ Ln } PE_t + \underset{(0.9)}{\frac{-.3304}{PE_t}} + \underset{(6.25)}{.0225} \text{ Ln } PG_{t-1} \underset{(2.5)}{-.0486} \text{ Ln } API_{t-1} \end{aligned} \qquad (1)$$

where:

Q_t = The quantity demanded in time 't', in million kilowatt hours.

Q_{t-1} = The demand in the previous year.

P_t = Population in time 't', in thousands.

Y_t = Real income in 't', in thousands of dollars.

PE_t = Average price of electricity in time 't', in mills per kilowatt hour, in 1970 dollars.

PG_{t-1} = Price of gas per thousand therms in the previous time period, in 1970 dollars.

API_{t-1} = Electrical appliance price index in the previous period, corrected to 1970 dollars.

Note: t statistics are included in parenthesis below each estimated coefficient.

The demand models for the commercial and industrial sectors are presented in equations 2 and 3, respectively.

$$\operatorname{Ln} Q_t = \alpha + \underset{(75.7)}{.8724} \operatorname{Ln} Q_{t-1} + \underset{(10.2)}{.1333} \operatorname{Ln} P_t + \underset{(1.6)}{\frac{10.5007}{P_t}} + \underset{(2.5)}{.1486} \operatorname{Ln} Y_t + \tag{2}$$

$$\underset{(1.0)}{\frac{.1432}{Y_t}} - \underset{(6.2)}{.2925} \operatorname{Ln} PE_t \quad \underset{(2.0)}{\frac{-2.4014}{PE_t}} + \underset{(1.1)}{.0082} \operatorname{Ln} PG_{t-1}$$

$$\operatorname{Ln} Q_t = \alpha + \underset{(76.5)}{.8765} \operatorname{Ln} Q_{t-1} + \underset{(7.5)}{.1220} \operatorname{Ln} P_t + \underset{(1.0)}{\frac{-11.7364}{P_t}} + .0000 \operatorname{Ln} Y_t + \tag{3}$$

$$\underset{(3.6)}{\frac{-.2358}{Y_t}} - \underset{(8.9)}{.3097} \operatorname{Ln} PE_t + \underset{(8.9)}{\frac{-.9290}{PE_t}}$$

Mount, Chapman, and Tyrrell (1973) used cross-section and time-series data (47 states and 23 years) to obtain the coefficients associated with each independent variable in equations 1, 2, and 3. Both the model specification and the estimation procedures are particularly suitable for the purpose of predicting future levels of demand.

First, the use of pooled cross-section and time-series data reduce the possibility of inaccurate elasticity values. Since the independent variables have all followed a well-behaved trend over time, use of the time-series data alone would tend to result in a high intercorrelation between variables which make the elasticity estimates inaccurate. If only cross-sectional data are used, there is no reason to expect that the estimated elasticities would be suitable for predictive purposes. This is because most policy considerations are related to changes through time. Use of pooled cross-section and time-series data tend to reduce these problems.

Second, the model is specified so that the quantity of electricity demanded in any time period 't', is a function of the demand in the previous period. This is because:

> "...electricity consumption is related to the stocks of electrical machinery and appliances, and the sizes of these stocks reflect past as well as current decisions. The current quantity of electricity demanded is also related to past as well as current values of explanatory variables" (Mount, et al. 1973).

Third, the model allows for variations in elasticity values between states and/or regions. Since the elasticity value varies with the level of the independent variable.[12]

Finally, the constant term (α), which captures the influence of demographic, climatic, and geographical factors upon demand may be calculated for each region and/or area of interest.

Model Verification

In order to test the accuracy of the model, demand, population, income, and price data for the Southwest region for the 1961-73 period were obtained from the sources specified in

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[12] For example, the long-run price elasticity for the residential sector is expressed as:

$$\frac{-.1552 - \frac{-.3304}{PE_t}}{(1-.8837)}$$

. Thus, the price elasticity value for a particular region is a function of the price of electricity of that region.

Table 70. The demand models were then initialized with 1961 demand data and used to estimate annual demand. The estimated annual demand was then compared to actual demand and the percent error between actual and predicted demand calculated. The error was minimized by an exogenous specification of the (α) term which reflects the influence of geographic, demographic, and climatic factors.

Estimated demand is compared to actual demand for each consuming sector in Tables 71, 72, and 73. The value of (α) as well as those of the independent variables are also reported in Tables 71, 72, and 73. For the residential sector, the error between the estimated and actual demand is less than three percent. Estimation errors for the industrial and commercial sectors was no greater than seven percent and 21 percent, respectively. The relatively large error for the commercial sector in 1966 is the result of a sharp one-year increase in demand which the model cannot explain.

Table 74 indicates the accuracy of the models for the industry as a whole. The actual demand reported in Table 74 is the total for the three sectors plus sales to public authorities, railroads, and electricity used within electric utilities. Those uses have historically

Table 70. Specifications and sources of historic data

Variable	Consumer Class*	Units of Measurement	Source
1. Quality Demanded	R,C,I	Million Kilowatt hours (KWH)	Edison Electrical Institute Yearbook
2. Population	Same	Thousands	Statistical Abstract of the United States
3. Income	Same	Thousand of 1970 dollars per capita (adjusted by Consumer Price Index).	Statistical Abstract of the United States
4. Price of Electricity	R,C,I	Average mills per KWH received by utilities in 1970 dollars.**	Edison Electrical Institute Yearbook
5. Price of Gas***	R,C	Average dollars per thousand therms received by utilities, in 1970 dollars,** lagged one year.	Gas Facts
6. Price of Household Appliances	R	Index of appliance prices corrected to 1970 dollars, lagged one year.	Survey of Current Business

*"R,C,I" implies that the variable is different for each of the three consumer classes. "Same" implies that no distinction is made between classes.

**Residential prices are adjusted by the Consumer Price Index. Commerical and industrial prices are adjusted by the Wholesale Price Index.

***Sales of natural, liquid petroleum, manufactured, and mixed gas are included, but natural gas is by far the largest source.

Table 71. Model verification for the residential sector*

Year	Population (thousands)	Average Income** (thousands) ($1,000)	Average Gas Price** (Lagged) ($/1,000 therms)	Average Electricity Price** (mills/KWH)	Actual Electricity Demand (million KWH)	Estimated Electricity Demand (million KWH)	Percentage Error (percent)
1962	23,064	3.541	113.29	32.10	23,942	23,949	.03
1963	23,675	3.578	112.45	30.88	26,281	26,255	-.10
1964	24,234	3.674	110.59	29.41	29,066	28,795	-.94
1965	24,893	3.761	105.89	28.04	31,479	31,560	.26
1966	25,019	3.905	103.34	26.43	34,681	34,586	-.28
1967	25,420	4.050	100.69	25.37	37,640	37,822	.48
1968	25,815	4.224	98.00	24.11	40,184	41,271	2.63
1969	26,481	4.234	94.64	22.49	44,538	45,069	1.18
1970	26,925	4.251	90.85	21.56	47,606	49,060	2.96
1971	27,105	4.264	89.87	21.15	52,180	52,969	1.49
1972	27,820	4.455	90.84	21.71	55,932	56,684	1.33
1973	28,270	4.551	92.45	21.31	60,557	60,476	-.13

* α = .4945
**Adjusted to 1970 dollars; see Table 70 for the definition of variables.

Table 72. Model verification for the commercial sector*

Year	Population (thousands)	Average Income** (thousands) ($1,000)	Average Gas Price** (Lagged) ($/1,000 therms)	Average Electricity Price** (mills/KWH)	Actual Electricity Demand (million KWH)	Estimated Electricity Demand (million KWH)	Percentage Error (percent)
1962	23,064	3.541	75.93	24.77	22,607	23,499	3.80
1963	23,675	3.578	75.37	23.71	27,425	26,203	- 4.67
1964	24,234	3.674	74.63	22.20	31,853	29,346	- 8.54
1965	24,893	3.761	71.74	21.31	36,673	32,827	-11.71
1966	25,019	3.905	69.82	19.61	44,499	36,900	-20.59
1967	25,420	4.050	67.17	19.65	46,268	41,092	-12.60
1968	25,815	4.224	67.70	18.88	50,112	45,756	- 9.52
1969	26,481	4.234	65.95	18.30	52,403	50,683	- 3.39
1970	26,925	4.251	64.70	17.81	56,145	55,793	- .63
1971	27,105	4.264	64.75	17.96	59,340	60,667	2.19
1972	27,820	4.455	65.92	18.13	64,458	65,735	1.94
1973	28,270	4.551	65.52	17.15	67,854	71,441	5.02

* α = .8125
**Adjusted to 1970 dollars; see Table 70 for the definition of variables.

Table 73. Model verification for the industrial sector*

Year	Population (thousands)	Average Income** (1,000/$)	Average Electricity Price** (mills/KWH)	Actual Electricity Demand (million KWH)	Estimated Electricity Demand (million KWH)	Percentage Error (percent)
1962	23,064	3.541	12.80	39,138	37,285	-4.97
1963	23,675	3.578	12.39	38,763	37,884	-2.32
1964	24,234	3.674	12.18	40,364	38,748	-4.17
1965	24,893	3.761	11.06	39,868	40,602	1.81
1966	25,019	3.905	10.30	40,714	43,096	5.53
1967	25,420	4.050	10.58	42,317	45,333	6.65
1968	25,815	4.224	10.29	45,655	47,913	4.71
1969	26,481	4.234	9.89	48,997	50,866	3.67
1970	26,925	4.251	9.65	52,270	54,010	3.22
1971	27,105	4.264	9.80	54,510	56,788	4.01
1972	27,820	4.455	10.01	58,789	59,398	1.03
1973	28,270	4.551	10.02	61,781	61,963	.29

* α = 1.0080
**Adjusted to 1970 dollars; see Table 70 for the definition of variables.

Table 74. Model verification for total sales

Year	Actual Total Electricity Sales* (million KWH)	Estimated Total Electricity Sales (million KWH)	Percent Error (percent)
1962	89,600	89,113	- .54
1963	97,037	95,013	-2.09
1964	106,100	101,898	-3.96
1965	112,785	110,417	-2.10
1966	127,018	120,506	-5.13
1967	134,588	130,671	-2.91
1968	144,553	141,916	-1.82
1969	155,534	154,198	- .86
1970	166,583	167,076	.30
1971	176,816	179,235	1.37
1972	191,016	191,217	.11
1973	202,301	203,904	.79

*Does not correspond exactly to the consumption reported in the first subsection due to variations in the data utilized. Federal Power Commission monthly data does not include internal industrial sales whereas the above does.

accounted for about 5.17 percent of total annual sales. Estimated annual demand is the total predicted for the three major classifications plus 5.17 percent.

Elasticities

The long-run price elasticity of demand in the Southwest region is currently estimated to be approximately -1.20, -1.20, and -1.76 for the residential, commercial, and industrial sectors, respectively.[14] Thus, price definitely affects the amount of electricity purchased. If the relative price of electricity increases significantly in the future because of increased taxes, fuel scarcity or environmental restrictions, the growth in demand could be reduced dramatically.

The elasticity of demand with respect to population is close to unity in all sectors. The information, however, indicates that income is a statistically insignificant factor in predicting the residential demand for electricity. Yet, the level of income does appear to exert some influence upon the quantity of electricity demanded by the commercial and industrial sectors.[15] Demand responds to the income level in these sectors primarily because income represents a proxy for the level of commercial sales and industrial production.

The elasticity of demand with respect to the price of natural gas is .19 for the residential sector. However, the elasticity for the commercial and industrial sectors is not significantly different from zero.

Demand Projections

In order to project the demand for electricity, the magnitude in future time periods of the factors which influence the demand for electricity must be estimated.

[14] Unless otherwise indicated, all elasticity values are statistically significant at the 95 percent confidence level (Mount, et al., 1973).

[15] The income elasticity of demand was found to be .92 and .42 for the commercial and industrial sectors, respectively.

The Price of Electricity

As discussed above, a principal factor affecting the demand for electricity is price. Increases in relative price or cost of electricity may result because of increases in the cost of fuel used for generation purposes, an increase in the rate structure, electrical energy taxes or increased environmental protection costs.

With respect to the latter factor, pressures are mounting to increase environmental controls placed upon all electrical energy production systems. The Amendments to the Clean Air Act, the 1972 Federal Water Pollution Control Act Amendments, and the pending Power Plant Siting and Surface Mining Legislation are examples of environmental regulations which may increase the price of electricity relative to other commodities.

A preliminary analysis conducted by the Council on Environmental Quality indicates that compliance with the environmental regulations discussed above could increase the cost of electrical energy production significantly. Although most of the anticipated increase is associated with the reduction of sulfur emission, substantial costs may also be incurred for the control of water pollutants and land reclamation (U. S. Council on Environmental Quality, 1973).

Exact cost estimates for increased pollution control cannot, however, be derived since the necessary controls vary widely from site to site and by the type of plant. However, it is estimated that recent environmental regulations will, on the average, result in a nine to 14 percent increase in the cost of electricity generated by fossil fuel plants and a seven percent increase for nuclear plants over 1973 levels (U. S. Council on Environmental Quality, 1973).

Further increases in the cost of electricity may result due to rising fuel prices. A recent study suggests that the real price of electricity may double by the year 1995 (which represents a rate of increase of three and one-half percent per year) due to this phenomena (Mount, et al., 1973). Other studies are more optimistic. Nordhaus (1973), for example, predicts that the real price of electricity will increase by only 1.1 percent per year for the remainder of the century. For the purpose of this analysis, three alternative price conditions are assumed: (1) maintenance of constant prices; (2) a 1.1 percent annual increase in real price; and (3) a 3.5 percent annual increase in real prices.

The Price of Natural Gas

The real price of natural gas, which is a substitute for electricity in some applications, is also expected to increase over the remainder of the century. For the purpose of predicting the future demand for electricity, it is assumed that natural gas prices will: (1) increase at 3.5 percent per year; and (2) increase at seven percent per year. It is important to note that if both natural gas and electricity prices increase at 3.5 percent per year, the relative price of electricity remains unchanged. Thus, there would be little incentive, all other things equal, to switch from natural gas to electricity. However, if natural gas prices increase at seven percent per year, the demand for electricity may be expected to grow relative to the demand for natural gas.

Other Factors

Projections prepared by the Department of Commerce (Survey of Current Business, April 1974) indicate that for the 1973-2000 period the population within the region is expected to grow 1.2 percent per year and real income is projected to increase 2.93 percent per year. The electrical appliance price index is assumed to remain constant at 1973 levels.

Projected Demand

Alternative demand projections for each sector for the 1975-2000 period are presented in Table 75.

If electricity prices remain at current levels throughout the remainder of the century and gas prices increase at an annual rate of 3.5 percent, the total demand for electricity is

Table 75. Projected demand for electricity

Year	Price Assumption*	Residential Demand	Commercial Demand	Industrial Demand	Total** Demand
		(million KWH)			
1975	Constant electricity	67,499	82,034	66,519	216,052
1980	prices;	85,758	113,208	78,672	277,728
1985	3.5 percent annual	103,142	148,011	90,538	341,691
1990	increase in the	120,414	188,660	102,169	411,243
1995	price of gas.	138,321	237,795	113,887	490,003
2000		157,489	298,463	125,847	581,799
1975	Constant electricity	67,645	82,098	66,519	216,262
1980	prices;	87,204	113,886	78,762	279,852
1985	7 percent annual	107,287	150,079	90,538	347,904
1990	increase in the	128,689	193,079	102,169	423,937
1995	price of gas.	152,240	245,806	113,887	511,933
2000		178,739	311,719	125,847	616,305
1975	1.1 percent annual	67,202	81,638	66,064	214,904
1980	increase in the	82,869	109,044	74,697	266,610
1985	price of electricity;	95,123	135,447	79,911	310,481
1990	3.5 percent annual	105,018	162,251	82,734	350,003
1995	increase in the	113,497	190,882	83,911	388,290
2000	price of gas.	121,225	222,554	83,932	427,711
1975	1.1 percent annual	67,347	81,702	66,064	215,113
1980	increase in the	84,947	109,697	74,697	269,341
1985	price of electricity;	98,947	137,339	79,912	316,198
1990	7 percent annual	112,236	166,051	82,734	361,021
1995	increase in the	124,918	197,313	83,911	406,142
2000	price of gas.	137,582	232,439	83,932	453,953
1975	3.5 percent annual	66,567	80,775	65,089	212,431
1980	increase in the	76,945	100,013	66,402	243,360
1985	price of electricity;	79,661	109,414	60,199	249,274
1990	3.5 percent annual	77,844	111,388	50,793	240,025
1995	increase in the	73,460	108,487	40,921	222,868
2000	price of gas.	68,004	102,645	31,941	202,590
1975	3.5 percent annual	66,711	80,838	65,089	212,638
1980	increase in the	78,243	100,612	66,402	245,257
1985	price of electricity;	82,964	110,943	60,199	254,106
1990	7 percent annual	83,194	113,997	50,793	247,984
1995	increase in the	80,852	112,142	40,921	233,915
2000	price of gas.	77,180	107,204	31,941	216,325
1975	Combination of	68,045	83,102	67,442	218,949
1980	annual decline	94,436	124,216	87,360	306,012
1985	over the previous	128,815	180,453	114,724	423,992
1990	13 years.	174,034	253,738	150,404	578,176
1995		233,062	343,309	195,234	771,605
2000		309,290	443,673	249,769	1,002,732

*Gas prices are not a significant variable for the purpose of industrial demand projections.

**Excludes use in public sector such as transportation, street lighting, etc.

expected to more than double by 1995. As the price of natural gas increases relative to the price of electricity, the total demand for electricity increases at a faster rate. This result may be expected since an increase in the price of gas relative to the price of electricity is expected to create an incentive for users to switch to electricity.

If the price of electricity increases by 1.1 percent per year, the total demand for electricity is not expected to double until the year 2000. However, if the price of electricity increases by as much as 3.5 percent per year, the total demand for electricity is projected to remain relatively constant throughout the remainder of the century. On the other hand, if gas prices remain constant and if the price of electricity falls in the future as it has in the past, the growth in demand doubles approximately every 10 years. This represents the assumption utilized in most past planning studies.

It is therefore clear that increases in the real price of electricity will result in a reduction in the rate of demand growth. As noted above, real price increases may result due to increased environmental production costs, an inversion of rate structure, energy taxes, or increased fuel costs. If the price of electricity increases by as much as 3.5 percent per annum, the results indicate that rather dramatic changes in our level of consumption may occur. The results are, however, subject to several qualifications.

Qualifications

The first major qualification of the analysis is that decreasing block pricing is not adequately considered. As stated by Taylor:

> "The use of a single quantity for the price of electricity-whether an average price or a marginal rate-is not adequate. In principal, the entire price schedule should be represented in the demand function, but practical considerations rule this out" (Taylor 1975).

Use of average price in the demand model, as is done here, may lead to a biased estimate of both the price and income elasticity values.

Second, the industrial demand for electricity is not explicitly related to the process of capital formation and technological change (Taylor 1975). The results indicate that the industrial demand for electricity in the Southwest is highly price elastic in the long run. This implies that as the relative price of electricity increases, technological changes will be induced which will result in a reduction in the consumption of electricity. Many industries, particularly those in the Southwest, are dependent upon a physical natural resource base such as minerals, timber, etc. Once the firm is sited and the capital stock installed, increases in the price of electricity may induce some technological change. However, the range over which this can occur is limited. Thus, the failure to explicitly account for technological change reduces the predictive capability of the demand model.

Finally, the predictive power of the model is somewhat limited if major structural changes in the market for energy occur between now and the end of the century. According to the conventional wisdom, gas and petroleum will be in increasingly short supply, and the demand for electricity will increase as gas and oil become relatively more expensive. Yet, natural gas and oil are currently the most important fuels utilized for the generation of electricity in the Southwest. Therefore, increases in the price of natural gas and oil will result in an increase in the price of electricity. This means that relative prices may not, in the short run, be altered significantly as a result of gas and oil shortages. The price of electricity relative to other energy sources is not expected to change dramatically unless nuclear power or coal becomes the predominant fuel utilized for generation purposes. Even if this occurs, increasing capital costs of nuclear development and environmental restrictions placed upon coal resource development may mean that substantial increases in the price of electricity relative to non-energy goods and services will result.

Generating Capacity Requirements

Three of the alternative demand projections presented in Table 76 were chosen to illustrate the possible range in future generating capacity required to serve the Southwest region. The first demand forecast assumes a continuation of historic trends. That is, a continuation of the decline in the real price of electricity which occurred over the past 13 years is assumed. This projection is commensurate with the continued increases in technological advance, low-cost fuels, and the relaxation of environmental standards.

The second forecast assumes that both the price of electricity and the price of natural gas increases at an annual rate of 3.5 percent. The final projection assumes that the price of electricity increases at 1.1 percent per annum and that the price of gas increases at 3.5 percent per year.

The generating capacity needed to meet each forecast was derived by first increasing each total demand projection by 5.17 percent in order to account for the consumption of electricity by the public sector. Total demand was also increased by 10 percent to account for transmission losses. Projected demand, in million KWH, was then converted to average load in megawatts (MW). Since consumption within the region peaks in August, future capacity must be designed to meet the peak coincident momentary load during that month. Historically, peak load has averaged about one-third higher than the average momentary load (U. S. Federal Power Commission, 1960-73). Therefore a 33 percent peak load increment was added. Finally, a 15 percent reserve capacity was included to derive the total required capacity in megawatts.

The generating capacities required to meet the three demand projections are presented in

Table 76. Generation capacity requirements

Year	Actual or Planned Capacity*	Projected Requirements		
		Projection 1	Projection 2	Projection 3
		(MW)		
1970	40,649			
1980	70,000	61,810	49,156	53,853
1990		116,796	48,483	70,697
2000		202,542	40,921	86,393

*Sources: U. S. Atomic Energy Commission, *1974 Annual Report to Congress*.
U. S. Federal Power Commission, *Electric Power Statistics*.
U. S. Federal Power Commission, *Hydraulic Plant Construction Cost and Annual Production Expenses, 1972*.
U. S. Federal Power Commission, *Steam-Electric Plant Construction Cost and Annual Production Expenses, 1972*.

Table 76. Also included in this table is the regional generating capacity in 1970, as well as the planned capacity for 1980. The planned capacity was derived from utility applications to the Federal Power Commission (through 1972) and to the Atomic Energy Commission (through 1974). Because site location is often met with stiff opposition by environmental and regulatory entities, an estimation of planned generating capacity beyond 1980 is not attempted.

An examination of Table 76 reveals that existing capacity plus the planned capacity is more than sufficient to meet the maximum 1980 demand projection. Further, the capacity planned by 1980 will be more than sufficient to fulfill the minimum demand projected for 1990 and 2000. However, the maximum projected demand in these years is much greater than the minimum. The results clearly indicate that a wide range of alternative futures are possible depending upon the policies adopted affecting the price of electricity.

On the basis of this information, the market potential for electrical energy generated at the Tularosa facility may be estimated. If the price of electricity increases by 3.5 percent per year, no additional capacity is necessary, but replacement of some existing capacity will be required. At most, if past price trends continue, an additional 47,000 MW of new capacity will be required by 1990. It would therefore appear that either additional or replacement capacity may be required and that a market potential may exist for the 2,000 MW which could be produced by the Tularosa facility. This finding, however, implicitly assumes that the energy produced by the Tularosa facility will be competitively priced. That is, nuclear power must be provided by the Tularosa facility at a price equal to or below the cost of production by alternative generating methods or sites.

CHAPTER X

MINERAL BY-PRODUCT MARKET POTENTIAL

INTRODUCTION

The economic feasibility of the multipurpose Tularosa basin desalination project depends in part upon the market potential for and net revenues which may be derived from the sale of mineral by-products. It is assumed that magnesium metal and potash are the primary products which may be extracted from the brine. In this section, demand equations for these commodities are presented. From this information, the market potential for magnesium metal and potash is derived.

Barium, sodium chloride, magnesium oxide, sodium oxide, and sodium hydroxide may also be extracted from Tularosa basin brines. The market potential for these minerals is estimated by an examination of the characteristics of each industry.

MAGNESIUM METAL

Magnesium and alloys containing magnesium are utilized primarily in the transportation industry. The world's largest single consumer of magnesium, Volkswagen Works, uses metal imported from the United States to case engine blocks (Stamper, 1974). Because of its light weight and rigidity, magnesium and its alloys are also used in portable ramps, bulk shipping containers, and for the protection of pipelines, ships, and storage tanks. Other structural applications include the use of magnesium alloys for chain saws, lawn mowers, and machinery (Table 77).

Magnesium is the third most abundant structural element in the earth's crust and is extracted commercially from sea water, well and lake brine, magnesite, and dolomite (Chin, 1972). Sea

Table 77. Magnesium metal utilization patterns, 1972

Economic Sector	Magnesium Metal (Thousand Short Tons)	Percent of Total Utilization
Transportation	43	39
Machinery	35	32
Primary Metal Industry	11	10
Chemicals	13	12
Other	9	7
Total	111	100

Source: MacMillian, R. T., "Minerals Facts and Problems," U. S. Bureau of Mines, U. S. Department of Interior, 1972.

water with magnesium content of 0.13 weight-percent may be considered a resource which is potentially inexhaustible. Reserves of magnesium salts are also contained in brines such as those found in the Tularosa basin and the Great Salt Lake.

World production of magnesium metal in 1972 totaled 256,000 short tons. In the same year, the United States produced 47 percent of this total. In 1972, the United States exported 18,000 tons of this metal and continues to be a net exporter (Stamper, 1974). Total domestic consumption is compared to production in Figure 43.

Demand Model

In order to formulate an economic demand model for magnesium metal, several factors, which may influence the quantity of magnesium consumed, were considered. These include: (1) the gross national product; (2) population; (3) the price of magnesium; (4) net exports; (5) aluminum prices; (6) personal income; (7) the transportation equipment production index; and (8) the automobile production index. Variables with high inter-correlations were not used in the same model. Time series regression analysis was utilized to construct several preliminary demand models. Primary input data were obtained for the 1953-1972 period from the Bureau of Mines (U. S. Department of Interior, Bureau of Mines, 1953-72). Models and variables which proved statistically inferior and/or insignificant were eliminated from further consideration.

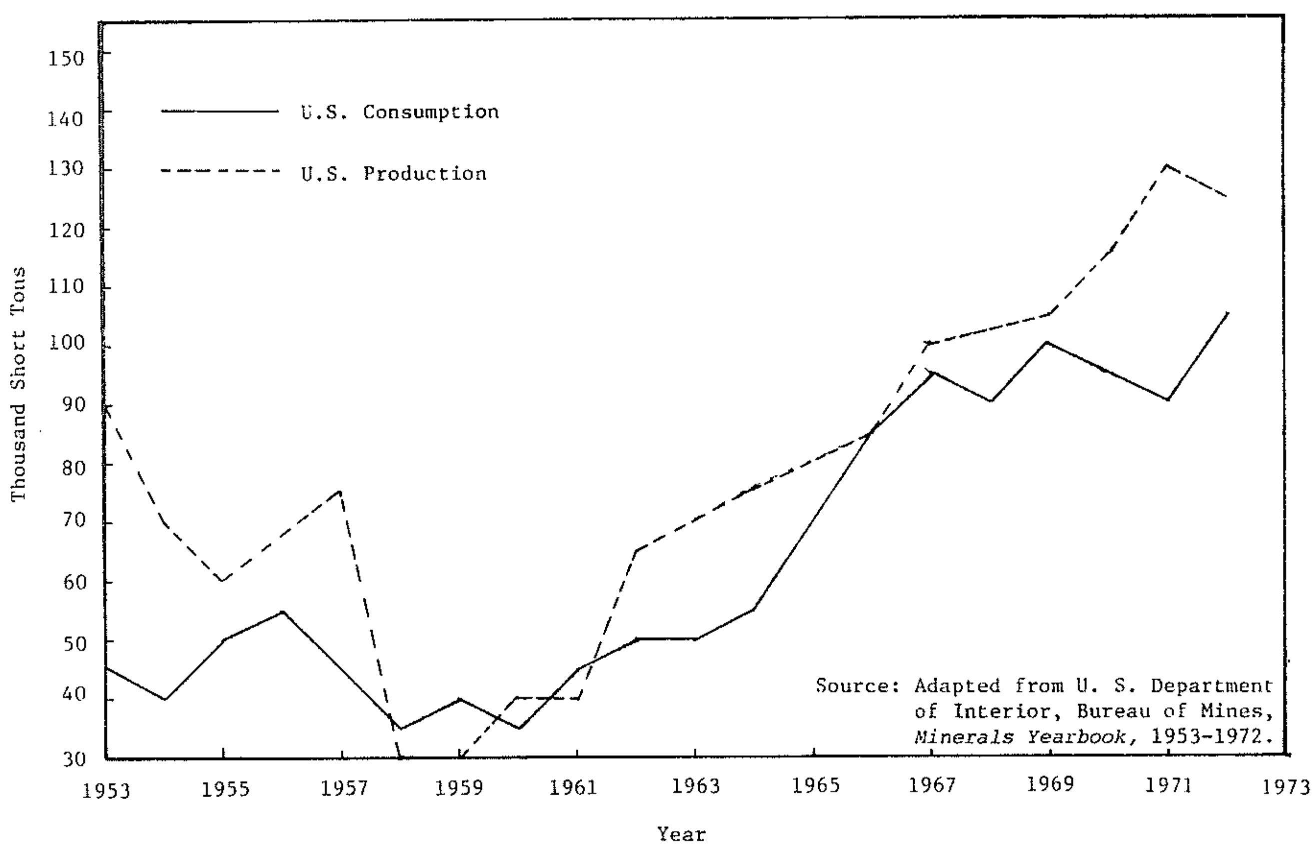

Figure 43. Magnesium consumption and production relationship.

On the basis of this procedure, three alternative models were found to be superior for the purpose of predicting the consumption of magnesium:

(1) Magnesium consumption = $\alpha - \beta_1$ (MGP) + β_2 (ALP) + β_3 (PI) + β_4 (TPI)

(2) Log magnesium consumption = $\alpha - \beta_1$ (MGP) + β_2 (ALP) + β_3 (PI) + β_4 (TPI)

(3) Log magnesium consumption = $\alpha - \beta_1$ (MGP) + β_2 (ALP) + β_3 (log PI) + β_4 (TPI)

where MGP is the price of magnesium, ALP is the price of aluminum, PI, personal income, and TPI the transportation production index.

Current price levels were utilized in each model. Price level trends were initially incorporated by including a price index as an additional variable. However, the estimated coefficient for this variable was found to be statistically insignificant. Aluminum price was used in each model since aluminum is a primary substitute for magnesium. Personal income is used as a proxy to account for the large amount of magnesium used in the production of consumer goods, (other than automobiles) such as lawn mowers, chain saws, and small power tools. The transportation equipment production index was included in order to account for the consumption of magnesium in the manufacture of automobiles, airplanes, trains, and ships. Changes in transportation modes through time (i.e. from private auto to mass transportation) are accounted for in the model through the transportation equipment production index variable.

Models two and three are deviations of model one, and contain data transformations to the natural log form. Both magnesium consumption and personal income over the 20-year period from 1953 through 1972 exhibit a slight exponential growth pattern. Because of this pattern, log-linear models were considered. However, the linear equation provided a better fit to the data. Thus, models two and three were eliminated from consideration. Model (1) is presented below in detail:

$$\text{Magnesium consumption (tons)} = 8900.27 - \underset{\substack{S.E. = 93,236.28 \\ t = 1.79}}{167,142.44\,(MGP)} + \underset{\substack{S.E. = 125,261.1 \\ t = .76}}{95,750.00\,(ALP)} \qquad (1)$$

$$+ \underset{\substack{S.E. = 15.37 \\ t = 4.75}}{72.996\,(PI)} + \underset{\substack{S.E. = 123.1 \\ t = 5.06}}{623.26\,(TPI)}$$

S. E. of estimate = 5298.510

F = 85.11

R^2 = 95.78

Durban-Watson = 2.059

The estimated elasticity of demand with respect to the price of magnesium is -.91. This indicates that a one percent increase in price may be expected to result in a .91 percent decrease in the quantity consumed. The cross-elasticity with respect to the price of aluminum is approximately .37. This result may be less reliable since the estimated coefficient with respect to the price of aluminum is statistically insignificant at the 90 percent level. Elasticity of demand with respect to income is approximately .60. These results indicate that the demand for magnesium is inelastic with respect to the price of aluminum and income. However, demand may be slightly elastic with respect to the price of magnesium since the calculated price elasticity is not significantly different from -1.0.

Projected Demand

In order to use the model to estimate the demand for magnesium metal in the year 2000, projected values for the independent variables were derived from the U. S. Water Resources Council (1972) and from the U. S. Bureau of Mines (Table 78) (Stamper, 1974). On the basis of the information presented in Table 78, the model projected demand to total 417,593 short tons in the year 2000. This compares favorably with the Bureau of Mines project of 300 to 700 thousand short tons in the same year (Stamper, 1974).

Market Potential and Product Price Patterns

The market potential for magnesium metal is initially estimated by taking the difference between current production and the projected demand in the year 2000. Current domestic production totals approximately 125,000 tons annually. If the real price of magnesium metal remains constant at \$.39 per pound, demand is estimated to total 417,593 tons in the year 2000.[16] The maximum market potential is therefore initially estimated to be approximately 293,000 tons in the year 2000 if there is no increase in production from other sources. However, if production from sources other than Tularosa brines continues as it has in the past, primary magnesium metal production in the year 2000 is estimated to be 192,000 tons (Stamper, 1974). Therefore, the actual market potential for magnesium metal produced by the Tularosa facility is estimated to be approximately 226,000 tons in 2000.

However, the Dow Chemical Company currently manufactures 99 percent of the primary magnesium metal produced in the United States at its Freeport, Texas plant. The major consuming areas are Michigan, California, Texas and Colorado. Thus, the market potential will depend to a large degree upon the cost of production and transportation from the Tularosa location relative to that from Freeport, Texas.

POTASH

Approximately 75 percent of the economically recoverable domestic potassium reserve is found in bedded deposits, while 25 percent is contained in brines. The primary bedded deposits are located in Southeastern Utah, Southwestern Colorado, and in southeastern New Mexico. High-grade ore in the bedded deposits of New Mexico will be depleted in less than 20 years. The potential for new discoveries in this region is not promising. However, relatively large quantities of low-grade ore are still available. This ore might be extracted if lower-cost mining and refining technology is developed.

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[16] The demand model discussed above may be used to estimate the market potential under various assumptions with regard to the price of aluminum, the level of personal income and transportation production in future time periods. For example, if the future price of aluminum is more than anticipated, the market potential for magnesium will be increased.

It is important to note that the assumption with respect to the future market price of magnesium metal is of particular importance for the determination of the market potential and gross revenues which might be obtained from the production of magnesium. The price of magnesium metal in constant dollars has trended downward since 1957 in spite of increases in demand. It may be hypothesized then, that the industry has been characterized by decreasing production costs due to the extensive magnitude of accessible deposits and technological advances. Although increasing energy prices may result in a slight upward price trend, nearly constant prices are expected to be maintained for at least the next two decades (U. S. Bureau of Economics Analysis, 1972).

Table 78. Projected values of explanatory variables--magnesium demand model[a]

Variable	Year 1980	Year 1990	Year 2000
TPI	158.85	224.96	328.77
PI (billion dollars)	1,412.53	2,505.62	3,218.79
MGP (dollars/pound)	.39	.39	.39
ALP (dollars/pound)	.33	.35	.36

[a]All values in 1972 dollars and/or a 1972 base year index.

Source: Stamper, J., *Commodity Statements*, U.S. Department of the Interior, Bureau of Mines, January 1974.

U.S. Water Resources Council, "OBERS Projections," 1972.

The known economically recoverable potassium brine resource is located in the Great Salt Lake, Utah, and at Searle Lake, California. Theoretically, potassium is available in almost unlimited quantities from other brines and saline waters.

In 1972, four million tons of potassium were used in the United States. Approximately 94 percent was utilized in the agricultural sector (mixed fertilizer), and the remaining six percent was consumed by the chemical industry (Tennessee Valley Authority, 1973). Of the potassium compounds utilized for agricultural purposes, only a small amount is applied directly as a single-element fertilizer. It should be noted that there are no substitutes for potassium compounds in agricultural applications.

The potassium industry is currently characterized by excess capacity. The recent development of new sources in Canada, together with expanded capacity in other areas of the world indicates that a world surplus will exist at least through 1976 (Table 79).

The United States was the world's largest producer of potassium until 1967, but dropped to fifth place in 1970. In 1972, Canada was the second largest producer, while operating at less than 50 percent of potential capacity (Department of Interior, U. S. Bureau of Mines, 1953-72). The vast Canadian deposits are largely responsible for the excess capacity in recent years. The result of excess capacity is increased competition which results in a lowering of price, expansion of consumption rates, and a shift in supply patterns.

The United States has been a net importer of potassium over the past 15 years, and it is estimated that this trend will continue. The major portion of U. S. imports come from the Canadian sources.

The Canadian producers appear to have a production cost advantage of $.02 to $.03 per unit of K_2O as compared to domestic producers. This is partially attributable to the highly mechanized Canadian mining technique. U. S. producers are faced with a diminishing resource base and will continue to hold only those markets in which they have a major transportation cost advantage.

Table 79. World potassium resources*

	Million Short Tons
North America	
Canada	21,300
United States	295
Other	5
Total	21,600
South America	
Chile	20
Other	40
Total	60
Europe	
France	200
East Germany	6,640
West Germany	6,320
Italy	50
Spain	200
USSR	10,000
United Kingdom	100
Other	190
Total	23,700
Asia	
Israel and Jordan	1,270
Other	10
Total	1,280
Oceania	10
Other	50
World Total	46,700

*Based on a recovery price of $55 per short ton.

Market Area

From an analysis of transportation costs facing U. S. and Canadian producers, a primary market area for each major producer may be determined. Freight rates for the analysis were obtained for shipments of nitrate of potash (KCL) from points of origin in the U. S. and Canada to various destinations in the U. S. (U. S. Bureau of Business Economics, 1971). Based on a minimum weight of 40 tons of KCL per car (Table 80), U. S. producers appear to have a shipping cost advantage to points south of a line extending from the northeastern corner of Idaho to Concord, New Hampshire. Canadian producers have an advantage for shipment to points north of this line (Figure 44).

For KCL produced in New Mexico, the primary market area is Texas, Louisiana, Arkansas, Mississippi, Oklahoma, Tennessee, Alabama, North Carolina, South Carolina, Georgia, and Florida (Figure 45 and Table 80). California producers ship solely to intrastate markets. From both Wendover, Utah, and Potash, Utah, the market area includes Montana, Wyoming, and Colorado. From Saskatchewan, the market area in the United States includes North Dakota, Nebraska, South Dakota, Missouri, and Minnesota (see Figure 45).

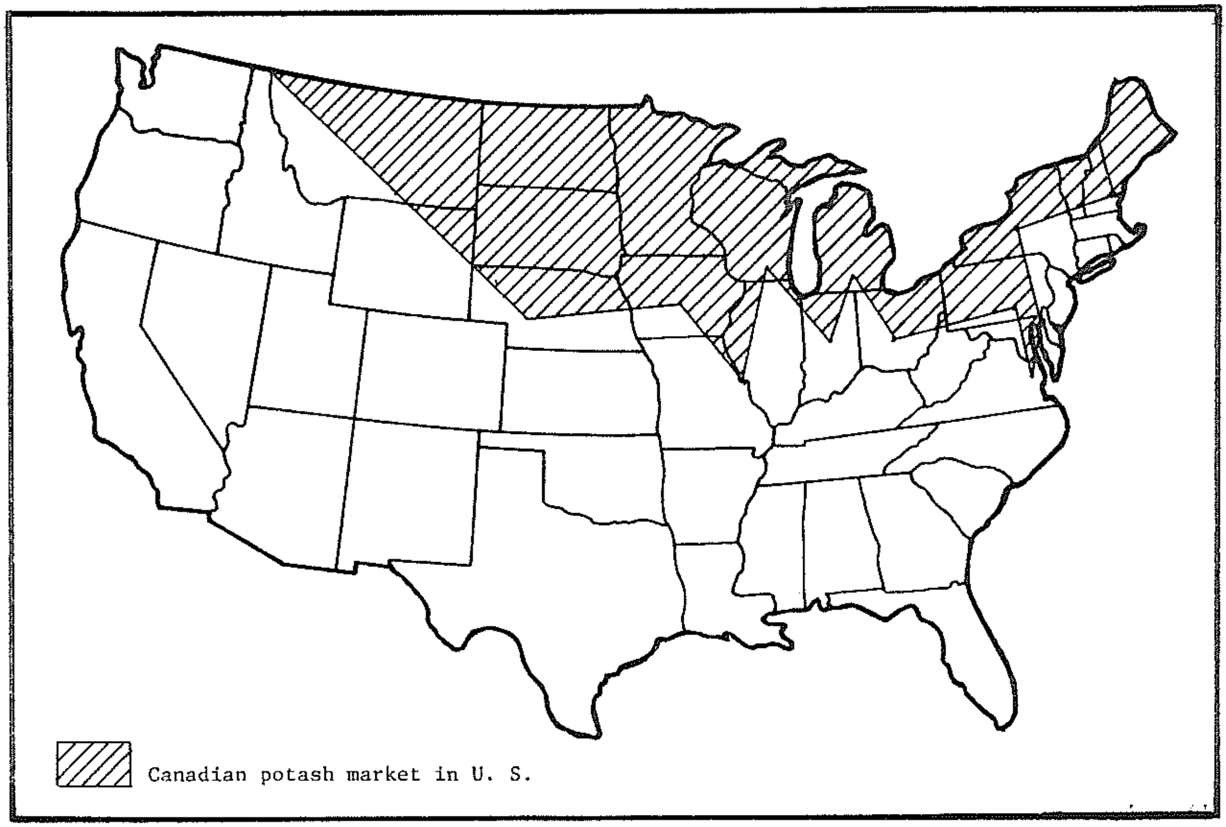

Figure 44. Canadian potash market in the United States.

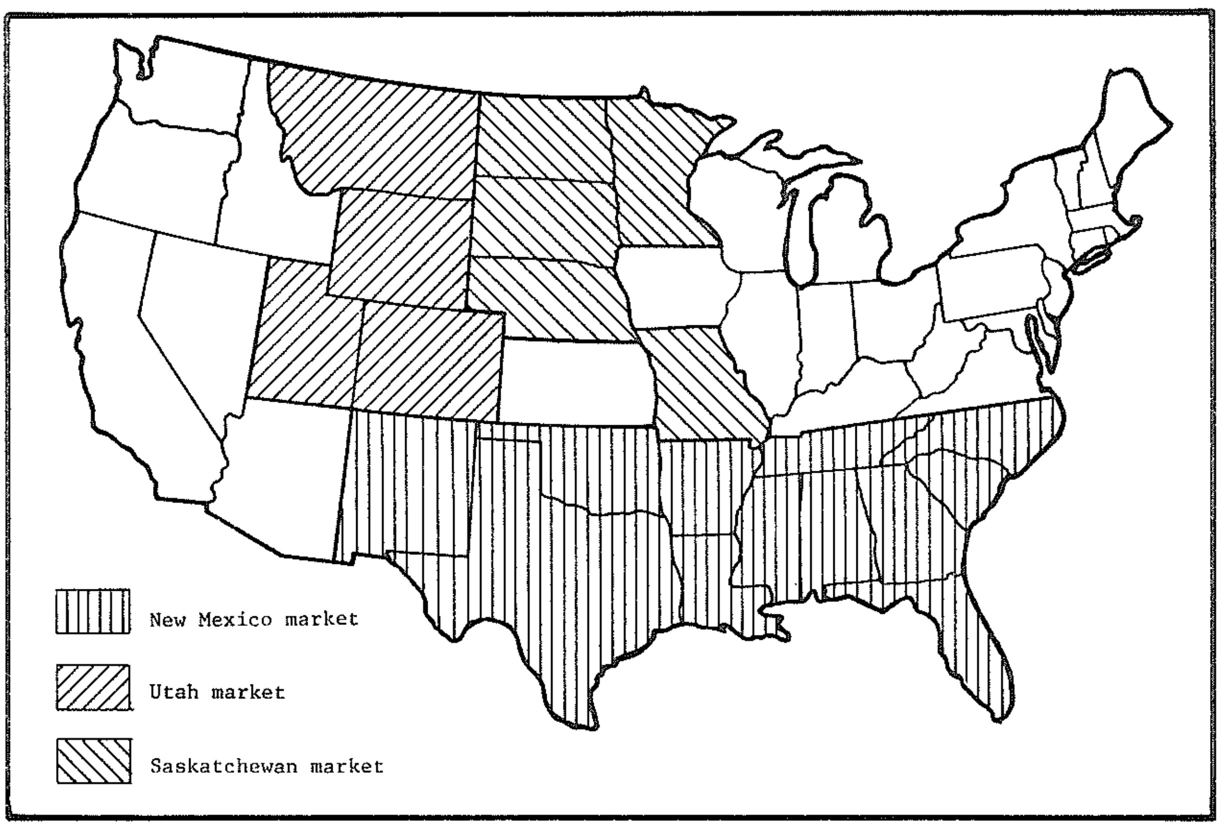

Figure 45. Potash market areas by producer.

Table 80. Potash transportation rates by origin and destination

Destination	Carlsbad N. Mex.	Trona Calif.	Wendover Utah	Potash Utah	Saskatchewan Canada
	------------	----	-dollars per ton-	----	----------
Atlanta, Ga.	19.89*	21.78	21.14	20.97	21.87
Baltimore, Md.	22.74*	24.95	24.95	22.74*	22.74*
Baton Rouge, La.	16.96*	20.44	19.63	19.11	20.98
Billings, Mont.	18.77	20.44	16.98*	16.98*	16.98*
Bismarck, N.D.	17.13	20.44	17.18	17.18	16.05*
Cooper, Wy.	17.18	19.72	16.77	14.96*	18.77
Chicago, Ill.	18.86*	21.70	19.51	18.86*	18.86*
Columbia, S. C.	20.51*	22.41	21.14	21.62	22.76
Columbus, Ohio	20.79*	22.73	21.43	20.79*	20.79*
Concord, N. H.	23.38*	25.60	25.60	23.38*	23.38*
Denver, Colo.	17.18	19.72	17.18	9.21*	19.62
Des Moines, Iowa	16.71*	19.76	16.71*	16.71*	16.71*
Harrisburg, Pa.	22.74*	24.95	24.99	22.74*	22.74*
Indianapolis, Ind.	20.54*	22.47*	21.18	20.54*	20.54*
Jackson, Miss.	17.30*	19.62	18.99	18.75	20.09
Jacksonville, Fla.	20.30*	22.15	21.52	21.37	22.76
Lansing, Mich.	20.79*	22.73	21.43	20.79*	20.79*
Lexington, Ky.	20.79*	21.78	21.49	20.79*	20.98
Little Rock, Ark.	17.11*	20.44	19.63	19.11	20.98
Madison, Wis.	17.31*	20.60	17.31*	17.31*	17.31*
Montgomery, Ala.	18.74*	20.65	20.00	19.81	20.98
Nashville, Tenn.	19.25*	21.15	20.51	20.40	20.38
North Platte, Neb.	17.18	19.72	17.18	17.18	17.31*
Okla. City, Okla.	11.74*	17.39	19.63	19.11	20.98
Pierre, S. Dak.	17.18	20.44	17.18	17.18	16.87*
Pocatello, Idaho	23.41	20.38	11.20*	17.29	23.36
Portland, Oreg.	21.57	18.35*	18.35*	18.35*	21.57
Raleigh, N. C.	21.78*	23.68	23.04	22.92	22.76
Richmond, Va.	22.74*	24.10	24.95	22.74*	22.74*
Seattle, Wash.	22.28	19.08*	19.08*	19.08*	22.38
St. Louis, Mo.	17.18*	20.44	17.18*	17.18*	17.31
St. Paul, Min.	17.18	20.44	17.31	17.18	16.28*
Syracuse, N. Y.	22.74	24.95	24.95	22.74*	22.74*
Texarkana, Tex.	13.65*	17.39	19.63	19.11	21.57
Wichita, Ks.	16.71*	19.72	16.71*	16.71*	19.62

* Denotes minimum transportation cost in dollars per ton

Source: U. S. Department of Commerce, Bureau of Business Economics, *Business Statistics*, Washington, D.C., 1971.

Demand Model

Several factors which may influence the quantity of potash consumed within the New Mexico market area were considered. These include: (1) the price of all marketable potassium products; (2) farm income; (3) the price of murites of potash fertilizer (60 percent potash); (4) crop yield per acre; (5) total acres under cultivation; and (6) the value of crop production.

Time series regression analysis was utilized to develop several preliminary demand models. Variables with high inter-correlations were not included in the same model. On the basis of this procedure, only one model was found to be theoretically and statistically valid. This model did, however, contain a high degree of serial correlation. The correlation was reduced through data transformation. The resulting demand equation is:

$$\text{Potash consumption} = 1.2356 - .02788(MP) + .02025(CPD)$$

$$\begin{array}{ll} S.E. = .00988 & S.E. = .00618 \\ t = 2.82 & t = 3.28 \end{array}$$

$$\begin{array}{ll} \text{S.E. of estimate} & = .12338 \\ \text{F value} & = 13.56 \\ R^2 & = 62.89 \\ \text{Durban-Watson} & = 1.211 \end{array}$$

where MP is the price of murite fertilizer in constant 1972 dollars, and CPD is the value of crop production. The price of murite fertilizer was utilized since potash is primarily utilized as an agricultural fertilizer.

The elasticity of demand with respect to the price of potash is estimated to be -1.75. This indicates that a one percent increase or decrease in price may be expected to result in a 1.75 percent decrease or increase in the quantity consumed. This high degree of price response is due to the fact that crop yield is quite insensitive to the quantity of potash based fertilizer applied. The elasticity of demand with respect to crop value is approximately .56. This indicates that the demand for potash is inelastic with respect to the value of the crops produced.

Projected Demand and Market Potential

The value of crop production in the New Mexico potash market area for the year 2000 was derived from Water Resource Council (1972) projections. The anticipated future price of murite fertilizer was obtained from the U. S. Department of Interior, Bureau of Mines (1972). The New Mexico potash market area demand in the year 2000 is projected to total 2,426,000 tons if price remains at approximately $40 per ton.

In 1972, approximately 2,200,000 tons of potash was produced at Carlsbad, New Mexico. Thus, the maximum market potential is estimated to be approximately 200,000 tons. However, it is anticipated that the Carlsbad deposit will be exhausted in less than 20 years. Therefore, a market potential of approximately two million tons may exist by the year 2000.

BARIUM

Forty (40) percent of the known world barium resource is found in the United States. The principal domestic deposits are located in the states of Missouri, Georgia, Nevada, Arkansas, California, Tennessee, and Alaska in both bedded and residual deposits. Twenty other states have barium deposits but none are commercial quality at the present time (Amprose, 1973). The known domestic barium reserve appears to be ample to supply foreseeable future domestic needs at current price levels.

At the present time, 80 percent of the barium utilized is consumed by the oil and gas-well drilling industry. This stems from a need for weighted drilling muds. The relatively low cost of barium eliminates the use of substitute drilling substances. The principal consuming area includes the states of Texas, New Mexico, and Oklahoma.

Other uses for barium in the United States are as a flux and oxidizer in making glass, as a filler in paint and rubber, and as a raw material in the manufacture of barium chemicals (Ambrose, 1973).

Projected Consumption

The projection of the consumption of barium in the year 2000 is based upon alternative estimates of future oil and gas-well drilling rates (Figure 46). First barium consumption per foot drilled was determined by an examination of historical data (McLean, 1973). On the basis of this information, consumption per foot appears to have increased slightly over time (Figure 47). Least squares analysis was then utilized to predict the consumption per foot in future time periods. The estimate of the average total footage drilled (Figure 47) was then utilized to predict the future consumption of barium. Consumption projections for the year 2000 are shown in Table 81.

Market Potential and Price Patterns

The maximum market potential in the year 2000 was derived by subtracting the current production from the predicted demand in 2000. This procedure yielded a maximum market potential of 873,000 short tons (based upon a predicted demand of 1,380,000 short tons and the current production of 507,000 short tons). The actual market potential for the year 2000 was derived by subtracting predicted production from predicted demand. Given the assumption that the production of barium continues to follow past trends in relation to demand, the market potential for the Tularosa desalination project could be as much as 557,000 short tons. Any production above 557,000 short tons would yield a surplus of barium produced in the year 2000.

The real price of barium over the past 20 years has decreased approximately 3.8 percent (Table 81). This indicates that the industry is characterized by more or less constant (slightly decreasing) production costs and that future price levels will remain at or below those currently prevailing.

Table 81. United States barium consumption and prices, 1953-2000

Year	Drilling Consumption	Total Consumption	Actual Price/Ton	Price in Constant 1972 Dollars/Ton
	(tons)		(dollars)	
1953	514,400	643,000	17.85	29.50
1954	544,800	681,000	17.21	28.08
1955	654,400	818,000	17.42	28.01
1956	912,000	1,140,000	18.54	28.83
1957	748,800	936,000	20.10	30.13
1958	536,000	670,000	22.16	32.40
1959	625,600	782,000	20.39	29.30
1960	532,800	666,000	21.44	30.33
1961	632,200	779,000	20.84	29.11
1962	542,400	678,000	20.39	28.16
1963	551,200	689,000	20.38	27.77
1964	572,000	715,000	21.08	28.30
1965	621,600	777,000	21.36	28.14
1966	632,000	790,000	21.23	27.22
1967	588,800	736,000	21.54	26.76
1968	616,800	771,000	23.16	27.67
1969		899,000	24.12	27.50
1970		787,000	25.13	27.14
1971		759,000	26.85	27.71
1972		827,000	28.36	28.36
1985	840,000	1,050,000		
2000	1,104,000	1,380,000		

Source: Adapted from U.S. Department of Interior, Bureau of Mines, *Minerals Yearbook*, 1953-1972.

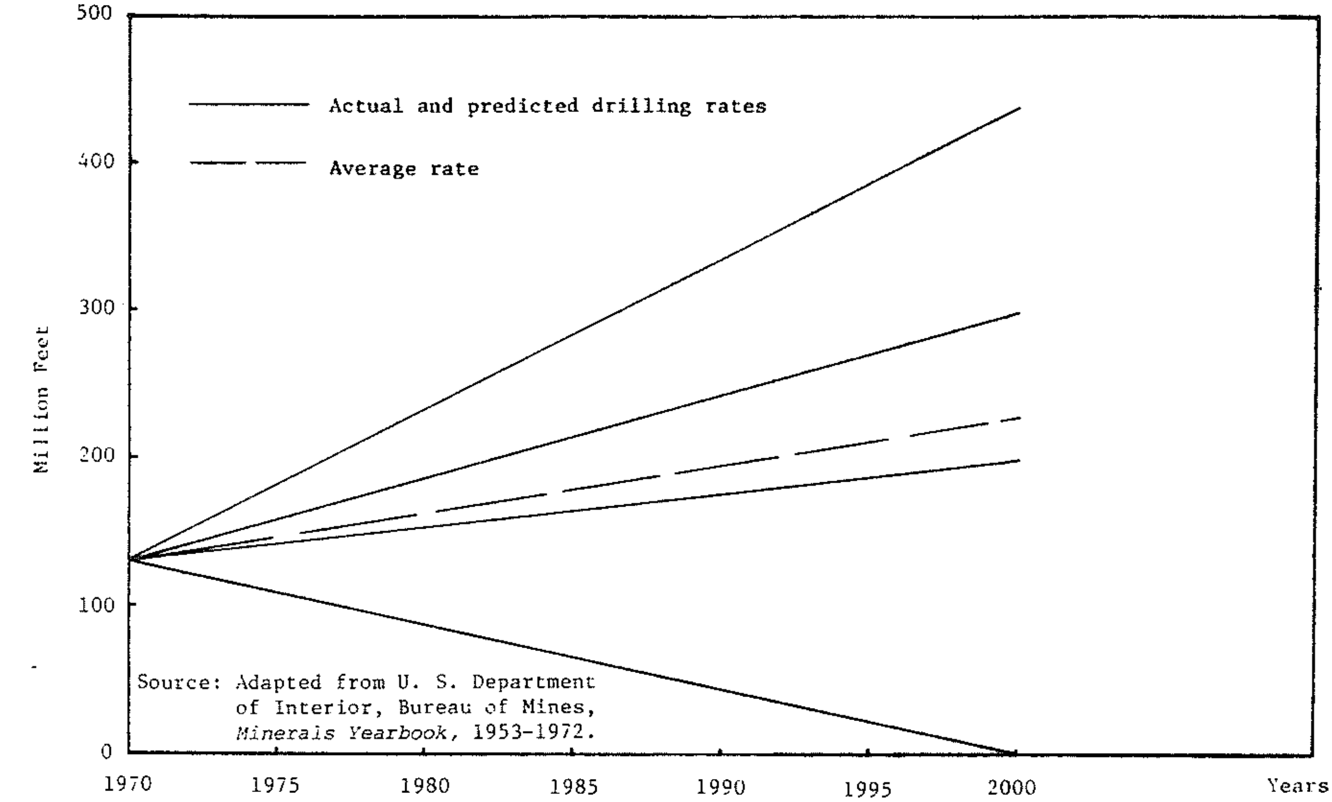

Figure 46. Gas and oil drilling rates.

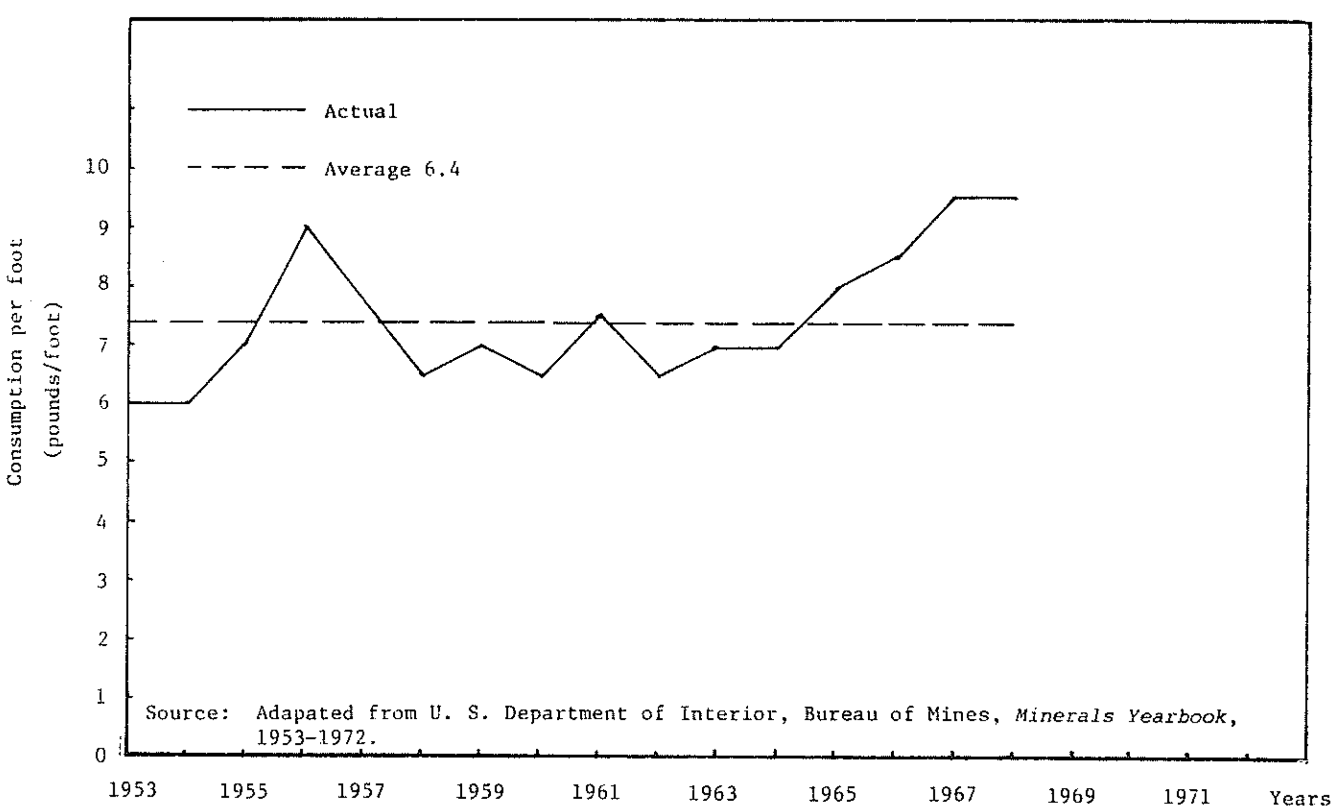

Figure 47. Consumption of barium per foot drilled.

SODIUM CHLORIDE

In 1972, sodium chloride (salt) was produced in 17 states with Louisiana and Texas producing 52 percent of the total. High-quality native rock salt is so abundant in the United States that the total supply of this compound is adequate to meet any foreseeable future demand. In addition, the supply of salt is augmented by extensive deposits of sodium minerals and various underground brines, saline lakes, and the ocean (Klingman, 1972). Thus, the total United States supply of salt and sodium derivatives is virtually inexhaustible.

Projections

Although supplies are adequate for the nation as a whole, transportation costs between sources of supply and points of consumption create local supply problems. This is particularly true if low-cost compounds such as rock salt and salt-in-brine are utilized. For this reason, foreign sources of salt compete successfully with domestic supplies in certain markets.

Mexico became the chief exporter to the United States in 1972. Mexico supplies 36 percent of the total quantity imported, and Canada, formerly our chief supplier, was second with 29 percent. However, imports represented only about 7.3 percent of the total United States consumption in 1972 (Klingman, 1972).

Since Mexico is the major supplier of imported salt, it is possible that salt production in New Mexico could compete in those market areas now supplied by Mexican imports. This area includes California, Colorado, Nevada, New Mexico, Utah, and Wyoming. This market area currently consumes approximately 27 percent of the salt utilized in the United States. However, the feasibility of salt production in New Mexico rests mainly upon the relative cost of production and transportation.

SODIUM OXIDE

Sodium oxide is used in the manufacture of cement, ceramics, glass glazes, and enamels. These uses account for approximately 75 percent of the total consumption of sodium oxide (U. S. Bureau of Mines, 1953-1972).

Projections and Market Potential

In the past 20 years, the real price of sodium oxide has increased 16.6 percent (Figure 48). Since the total domestic supply of sodium and its compounds is virtually inexhaustible, it may be postulated that there would be no significant change in the price of sodium oxide in the future as a result of foreseeable changes in production or consumption.

Approximately 42 percent of the total sodium produced in the U. S. is consumed as sodium oxide (Klingman, 1972). The maximum market potential was derived by subtracting the current production of sodium oxide (7.9 million tons) from the predicted demand (28.2 million tons) in the year 2000 (U. S. Department of Interior, Bureau of Mines, 1974). The maximum market potential for sodium oxide was estimated to be 20,271,300 short tons. If, however, the 1972 ratio between supply and demand is taken as constant and prevails to the year 2000, the market potential is estimated to be 1,260,000 short tons. If the past 20-year production trend prevails, the market potential is estimated to be 12,432,000 short tons (U. S. Department of Interior, Bureau of Mines, 1974). This is expected to exist in the sodium oxide market by the year 2000.

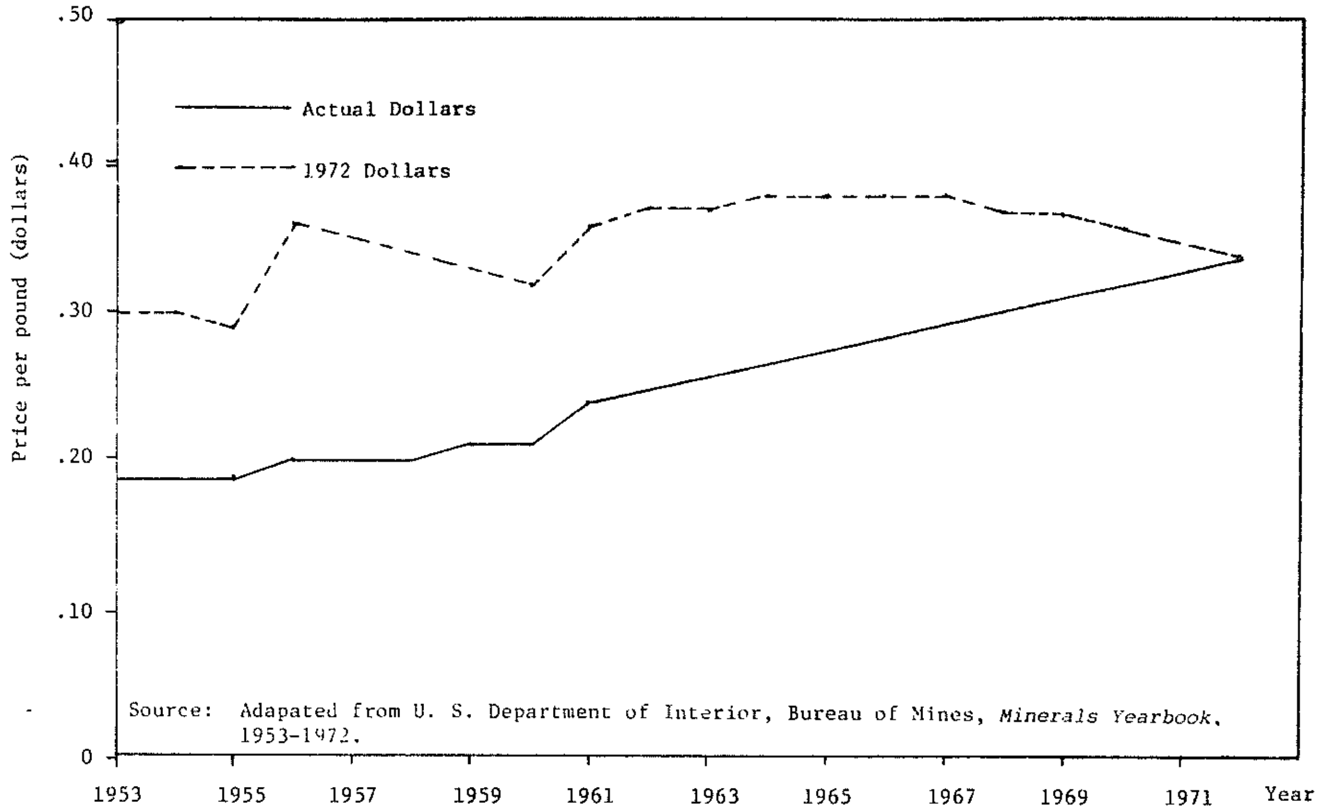

Figure 48. Sodium oxide price trend.

MAGNESIUM OXIDE

Magnesium oxide is primarily utilized in the manufacture of refractories. Other uses of the compound include the production of magnesium metal, production of exychloride cements, mixed fertilizers and heating elements. Reactive grades of magnesium oxide are used in the pharmaceutical industry (U. S. Department of Interior, Bureau of Mines, 1972).

Market Potential

The price of magnesium oxide has increased only 5.8 percent in constant 1972 dollars over the last 20 years (Figure 49). This very low rate of increase in price indicates that foreseeable increases in consumption will probably have very little effect upon the price of magnesium oxide.

The maximum market potential for magnesium oxide in the year 2000 was derived by subtracting the current production of magnesium oxide (701,520 tons) from the predicted demand in the year 2000 (1,598,400 tons) (U. S. Department of Interior, Bureau of Mines, 1974). The maximum market potential for magnesium oxide was therefore estimated to be 876,880 short tons. However, if the current ratio between supply and demand prevails to the year 2000, the market potential is estimated to be 79,920 short tons. If production trends over the past 20 years prevail, the estimated market potential is 584,600 short tons. Thus, the market potential for the Tularosa desalination project could range between 79 and 584 thousand short tons.

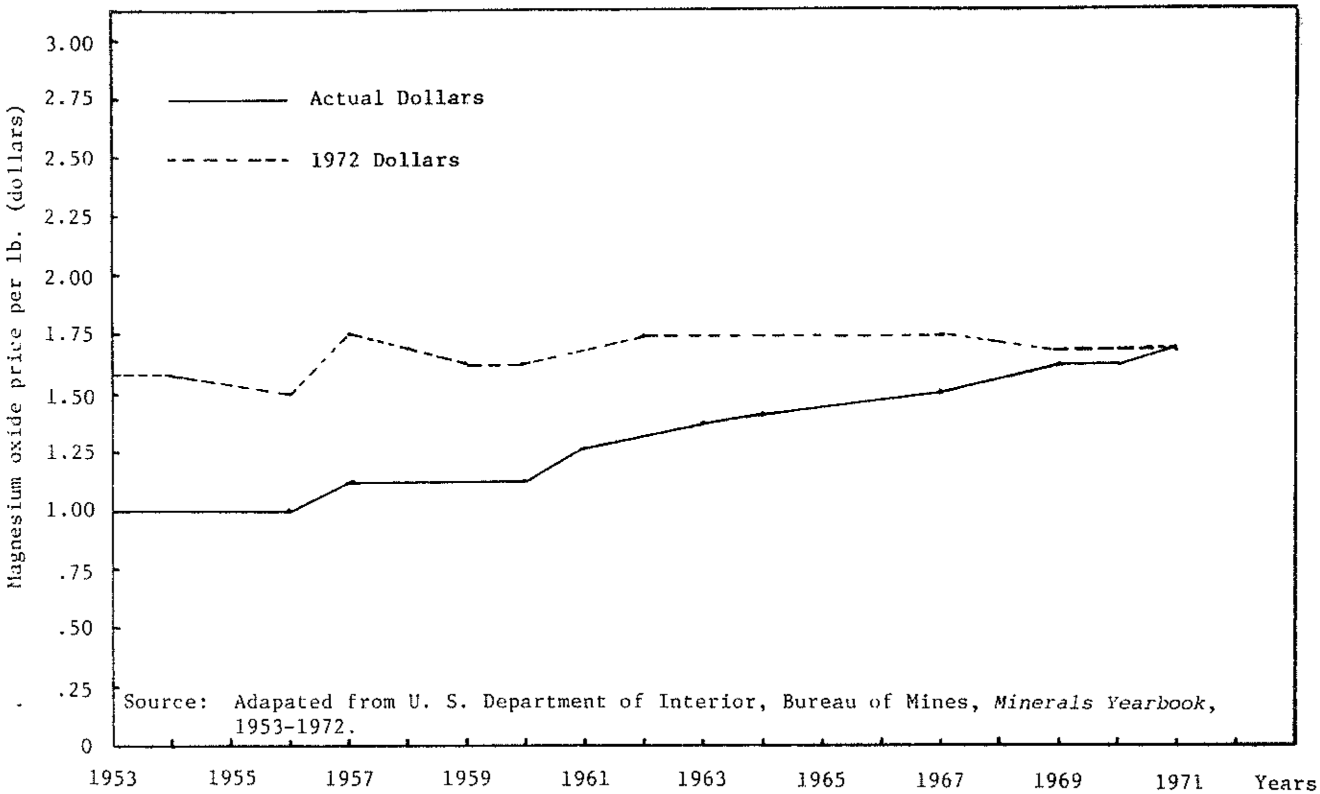

Figure 49. Magnesium oxide price trend.

SODIUM HYDROXIDE

Sodium hydroxide (caustic soda) is utilized in the manufacture of chemicals. At the present time the chemical industry utilizes 42 percent of the caustic soda consumed in the United States. Caustic soda is also used in rayon manufacture (10 percent), pulp and paper production (10 percent), the production of aluminum (seven percent), and petroleum (six percent) (U. S. Department of Interior, Bureau of Mines, 1953-1972).

Projections and Market Potential

The price of sodium hydroxide, in constant dollars, increased approximately 16 percent over the past 20 years (Figure 50). Over the same period, the consumption of sodium hydroxide increased approximately 86 percent. This information, in combination with the fact that the supply is virtually unlimited, tends to indicate that the future price of sodium hydroxide (in constant dollars) will remain fairly stable.

Nearly 7.5 percent of the total sodium produced in the U. S. is consumed as sodium hydroxide (Klingman, 1972). The maximum market potential for sodium hydroxide in the year 2000 was derived by subtracting 7.5 percent of the current production of sodium (1.4 million tons) from 7.5 percent of the predicted sodium demand (5 million tons) in the year 2000 (U. S. Department of Interior, Bureau of Mines, 1974). Using this method, the maximum market potential for sodium hydroxide is estimated to be 3,619,875 short tons. If the current ratio between supply and demand is taken as constant and prevails to the year 2000, a market potential of 225,000 short

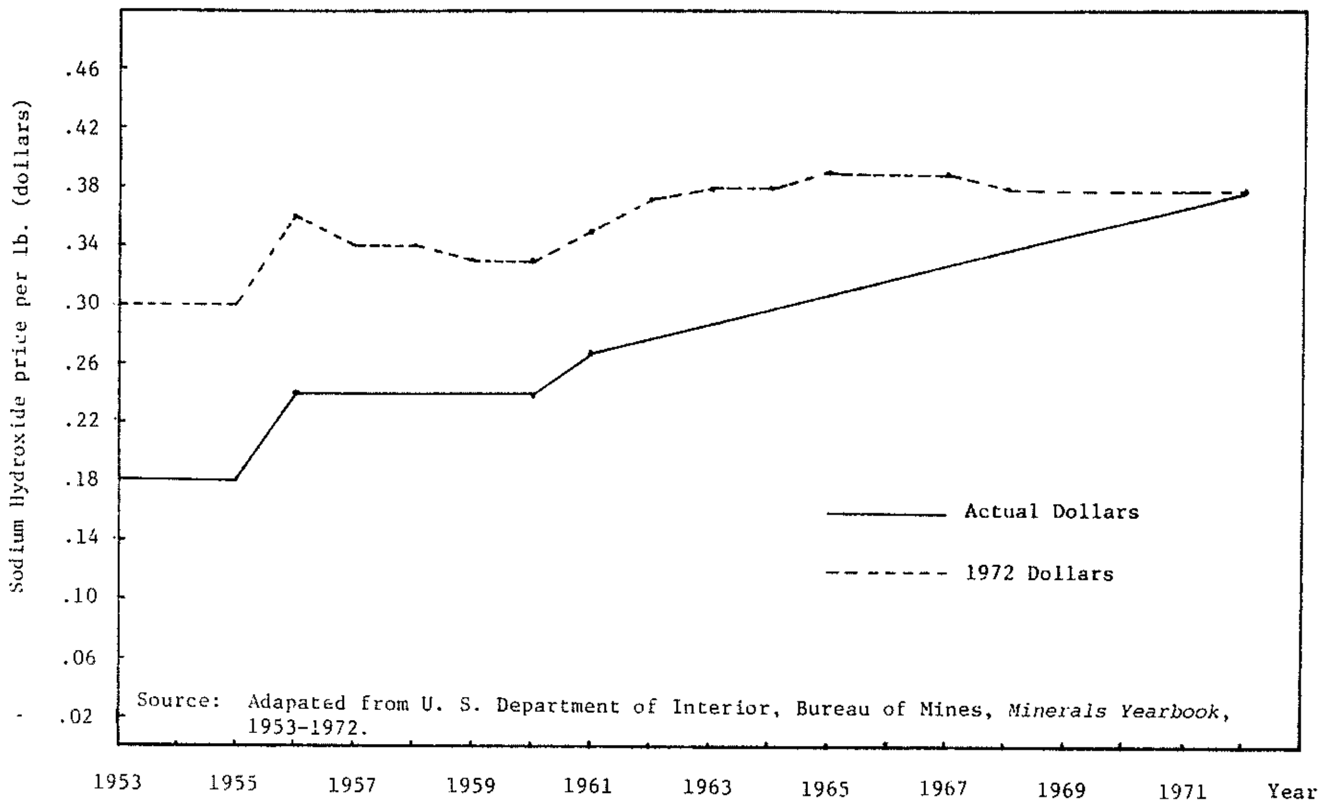

Figure 50. Sodium Hydroxide price trend.

tons is estimated (U. S. Department of Interior, Bureau of Mines, 1974). If the past 20-year production trend prevails, a market potential of 2,220,000 short tons is estimated (U. S. Department of Interior, Bureau of Mines, 1974).

Therefore, if the production of sodium hydroxide continues to follow past trends, the market potential for the Tularosa desalination plant could be as much as 2,220,000 short tons. Any production above this amount could yield a surplus of sodium hydroxide (at present price levels) in the year 2000.

CHAPTER XI

PRELIMINARY ANALYSIS OF ECONOMIC FEASIBILITY

The purposes of this chapter are to make a preliminary evaluation of economic feasibility for the proposed nuclear-desalting complex in the Tularosa basin in New Mexico and to examine the results of the analysis in terms of other data or assumptions than those used. The benefit-cost (B/C) methodology used in assessing the economic feasibility is examined briefly and three possible Alternatives within the actual B/C analysis are described. Costs and benefits associated with the major components of the Alternatives are summarized in detail, with results of the B/C analysis immediately following.

The sensitivity discussion includes identification of some costs that have been excluded from the analysis and a summary of actual costs attributable to desalting. Contributions to economic feasibility are examined also on a component-by-component basis. Finally, economic impact of possible technological advances for several of the major project components are considered and technological alternatives to nuclear power for desalting in the Tularosa basin in New Mexico are identified.

A properly constructed benefit-cost (B/C) analysis must include all direct costs and benefits associated with a proposed project and indirect costs such as potential environmental damages and associated risks. If benefits exceed costs and if the chosen project design is such that net benefits (benefits minus costs) are greatest, the criterion of economic efficiency is satisfied and feasibility is assured. However, since environmental costs or risks associated with construction of the proposed Tularosa basin project have not been assessed, the B/C analysis is incomplete and is therefore termed preliminary. The achievement of feasibility in this analysis implies only that further evaluation is worthwhile to check if environmental and other costs may also be covered by project benefits.

METHODOLOGY

Measurement of Benefits

The proper criterion for the measurement of benefits is willingness to pay (Maass, et. al., 1962). But, in most cases considerable simplification is justified. In Figure 51-A, D is the demand curve for a commodity made available by a proposed project where P denotes price and Q quantity. Q_1 is supplied at price P_1 by existing sources. If the proposed project increases supply to Q_2 the addition of willingness to pay (the precise measure of benefits) is the shaded area marked A. If projected revenue (initial price times the addition to quantity, $P_1 \cdot (Q_2 - Q_1)$) is used as a proxy for willingness to pay, benefits are overestimated by the small shaded area B in Figure 51-A. If the addition to supply made by a proposed project is small, revenue becomes a good proxy for benefits. But if a project is the sole source of supply, as shown in Figure 51-B, revenue (shaded area A) is a poor proxy (underestimate) for benefits (areas A + B) associated with providing Q*, unless, as shown in Figure 51-C, demand is extremely elastic. Applied to proposed Tularosa basin project, Figure 51-A illustrates benefits from sale of electricity and mineral by-products from desalting; Figure 51-B, recreation benefits from a reservoir to store desalted water; and Figure 51-C, benefits from sale of water to local agriculture where a slight increase in the price of water makes agriculture infeasible.

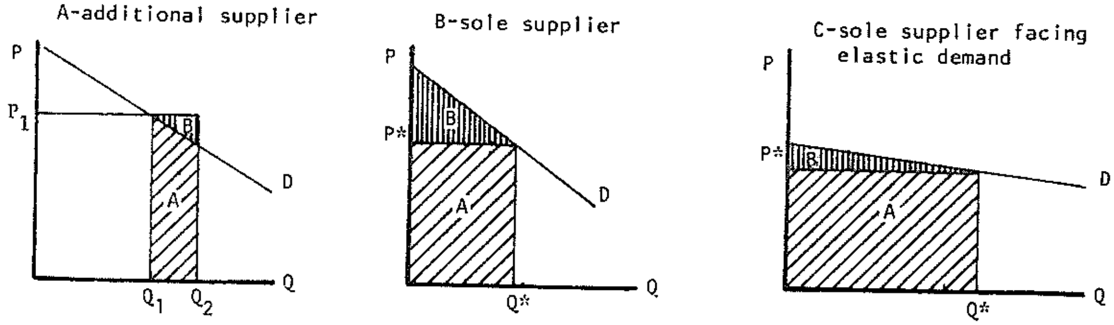

Figure 51. Measurement of benefits (willingness to pay) diagrams: A-additional supplier, B-sole supplier, and C-sole supplier facing elastic demand.

Costs, Project Scale, and Selection Criteria

Given a fixed project design, the estimation of costs is a rather straightforward procedure, based primarily on engineering considerations. However, project scale is important in determining feasibility since many components may show increasing returns to scale up to some critical point. The proposed project design is a first approximation made by individual judgment of the appropriate technology and scale factors.

Since three Alternatives based on the initial project design are considered, it is important to establish proper criteria for selection among competing Alternatives. Net benefits (benefits minus costs), the benefit-cost ratio, and the internal rate of return are inconsistent criteria for selection among Alternative projects (Eckstein, 1958). Assuming Alternatives are mutually exclusive, net benefits are the proper criterion where the Alternative with the grestest net benefit should be selected.

Choice of Discount Rate

Numerous economists (for examples, Marglin 1963, Baumol 1968, and Usher 1969) have attempted to determine the proper discount rate for public projects. The controversy concerns the divergence between the rate of return to investors (three to four percent) and the actual corporate rate of return on capital (17 to 25 percent) in real terms. This divergence arises (1) because of positive transaction costs in capital markets, (2) corporate taxes on earnings, and (3) possible deviation from competitive economic behavior. Usher (op. cit.) says that under reasonable assumptions the proper discount rate lies between these extremes. It was decided in light of the analysis above to use discount rates of five, six, eight, and 10 percent to check the sensitivity of the results to changes in discount rate over a reasonable range.

DESCRIPTION OF ALTERNATIVES

The feasibility analysis will include evaluation of three distinct Alternatives based on the initial project design. The first Alternative is the project itself as originally designed: production of 500,000 acre-feet of water and 2,000 MW of electrical power from a dual-plant complex, and recovery of certain minerals from the reject brine. All water production would be used within the Tularosa basin by a greatly-expanded agricultural sector and increased municipal and industrial development. Electricity production (after satisfying internal project power requirements) would be primarily exported to surrounding regions in the Southwest, with only enough designated for the basin (excluding internal requirements) to satisfy local needs.

The second Alternative is the production of power only. Water production would be limited to an amount sufficient for satisfying cooling requirements. All power produced would be exported to surrounding regions in the Southwest.

The third Alternative is similar to the first since water production, power generation, and mineral recovery are equivalent. However, all water over and above Tularosa basin needs (those that would have occurred without the project) would be exported to the Rio Grande. Only enough water to supply a "without project" local economy would be maintained within the basin. All water in excess of the 500,000 acre-feet would be transferred. All net power produced (excluding internal requirements) would be exported to other regions in the Southwest.

Before discussing each Alternative several points must be stated. Although not always applicable to all three Alternatives in precisely the same manner, they are an inherent base for subsequent feasibility analysis.

1. All costs for capital, operating, maintenance, or replacement expenditures are specified in 1974 dollars.
2. All costs have been extracted from the individual component discussions elsewhere in the text.
3. All internal requirements for electrical power and water are subtracted from gross production before computing the net quantities available for sale or transfer.
4. All quantities of water in the analysis are specified in stock terms--acre-feet, although flows such as gpm--are used sometimes to clarify delivery schedules.
5. All quantities of electricity in the analysis are specified in flow terms--megawatts (MW). Average yearly continuous power requirements in MW flows were computed for all internal components as if their operation was continuous over the whole year.
6. Construction schedule for all components except the reservoir was assumed to be five years with costs evenly distributed over the period. The reservoir construction is scheduled for eight years and the costs specified for each year.
7. Because the water produced from the MSF desalination process is of considerably higher quality than needed by the major user, agriculture, only a portion of the 500,000 acre-feet pumped from the well field is actually desalted. Saline water direct from the well field is blended with the fresh water to make available a given quality of water.
8. Before any water can be exported from the Tularosa basin, all local needs that would have occurred without the project must be satisfied (agricultural, municipal, industrial, or military).

Each Alternative will be described below in terms of its major components and their relationships to the analysis. Major component costs are summarized as they are used within the analysis. Benefits and revenues from each Alternative are summarized following the presentation of major component costs.

Alternative 1

This Alternative encompasses all major project components (except the export conveyance system which will be used in Alternative 3). A dual-plant concept is the basis for this Alternative, with power and water considered as joint products. Two nuclear reactors capable of producing approximately 1,000 MW of net power each on an average yearly continuous basis are operated in conjunction with a desalination plant composed of two large 250-million-gallon-per-day (mgd) MSF trains, each of which has 10 separate 25 mgd components.

The well field, located north of the dual-plant complex, is composed of 400 wells. Each well has a rated capacity of 1,000 gallons per minute (gpm). From these 400 wells (365 operating at any one time with 35 serving as back-ups), 500,000 acre-feet of water will be pumped and delivered via a collection and transportation system to the desalting complex. The well field is so designed that no further drilling or additional wells are required to ensure adequate facilities to meet delivery schedules. All pumps, motors, and controls are included in well-field design, as well as the collection and conveyance systems. Transmission lines to each well follow the collection system grid.

Because nuclear reactors and desalination plants cannot maintain a continuous operating schedule year round, an on-line stream factor of 85 percent has been designed into most components of this Alternative. For approximately seven weeks, all operations dependent on the nuclear reactor and desalination plant will be shut down while yearly maintenance and refueling are accomplished. This seven weeks also includes periods in which non-routine maintenance may be necessary. This operation schedule of only 310 days a year forces all components to be capable of meeting their production requirements during a reduced portion of the year. Thus, most components are over-designed to ensure that adequate capacity is available to meet all requirements (project design parameters such as 500,000 acre-feet water production from the well field and 2,000 MW net electrical power each year of the proposed project).

Product water from the dual-plant complex will be transferred to a reservoir for storage or directly to the final users. Since most product water is initially obligated to agriculture, 80 percent or 400,000 acre-feet will be transported via a 10-mile length of 12-foot diameter concrete pipe to a storage reservoir during the non-agricultural season, and directly to the off-farm distribution system during the irrigation season. This involves delivering about 225,000 acre-feet a year to the reservoir and 175,000 acre-feet directly to the farms. Because the storage reservoir is about 1,000 feet above the dual-plant complex, relift pumping stations are needed at every 100-foot elevation change along the closed conveyance system. Forty pumps are required (30 on-line and 10 spares) to lift the 225,000 acre-feet of water during the six- or seven-month non-agricultural season.

A minimum recreational pool of 15,000 acre-feet will be maintained at the reservoir. Since the reservoir will be filled and drained every year, actual surface area available for recreation will be significantly greater than that created by the minimum pool.

Water from the storage reservoir will be released at specific intervals during the irrigation season to the off-farm distribution system, consisting of all necessary canals and laterals to ensure adequate deliveries to each farm gate. This off-farm distribution system requires no pumps due to the downhill gradient to each farm.

Reject brine from the desalination plant is to be transported to a mineral recovery processing plant where it will serve as feed. The 21,000 acre-feet of reject brine will undergo electrolysis to recover magnesium metal, potash, and sodium sulfate for sale. All water requirements will be met from the reject brine itself, with power requirements being supplied from the project reactors.

To obtain net saleable water, the amounts for several internal uses must be subtracted from the 500,000 acre-feet production. First, 6,500 acre-feet each year is lost to evaporation at the dual-plant complex from holding ponds outside the MSF distallation plant. The maintenance of a two-day supply will cover the possibility of minor breakdowns in either the well field (wells or the collection system) or the MSF desalting plant. Second, 21,000 acre-feet will be lost to the reject brine in the process of desalting 385,000 acre-feet. There is a possibility that within the mineral recovery process, fresh water would be produced from electrolysis, however, this amount will be ignored due to its uncertainty. Third, evaporation loss of 5,000 acre-feet at the reservoir site plus 2,000 acre-feet of projected conveyance losses will occur. Fourth, power generation by the nuclear reactors requires about 16,000 acre-feet of cooling water each year, even though much of the excess heat has been transferred to the desalination plant. This leaves approximately 450,000 acre-feet available for agricultural, municipal, or industrial use. Agriculture is programmed for 396,000 acre-feet initially, with the local M & I users requiring around 54,000 acre-feet.

As the municipal sector increases and the industrial sector experiences economic growth, their water requirements will be met by retiring agricultural acreage and water needs. By the year 2030, approximately 40,000 acre-feet will have been transferred from agriculture to M & I, requiring the retirement of about 14,000 acres from production.

Similar reductions from net power are necessary before estimating actual electricity available outside of the project. From the 2,000 MW of electricity production all internal requirements must be satisifed first. The MSF distallation process consumes 129 MW a year. Mineral recovery by electrolysis requires 151 MW on the average. Pumping 500,000 acre-feet a year from the well field consumes increasing amounts of power, from 43 MW in the year 2000 to 122 MW by 2030. Transporting water from the dual-plant complex to the reservoir requires an average of 60 MW a year. This leaves approximately 1,610 MW available for outside project consumption. Local M & I demand is projected to increase from 151 MW in 2000 to 260 MW by 2030. Moderate industrial development has been programmed for the project period. A mix of industries using recovered minerals, oil refineries, uranium enrichment and conversion plants, and coal gasification plants is included within the development schema. After subtracting amounts needed by local M & I, the residual is exported to other regions in the Southwest outside of the Tularosa basin. Each year as local needs grow, they are met by making less available for export.

A more detailed discussion of each component, including the derivation of local demands, can be found in preceding chapters.

Alternative 1 can be summarized as follows: a 400-well system is to deliver 500,000 acre-feet of saline groundwater as feed to a dual-plant complex consisting of two steam-cycle HTGR nuclear reactors and a desalting plant. The desalting plant is composed of two large 250 mgd MSF trains, each of which has 10 separate 25 mgd components. Both the nuclear reactors and desalting plant are to operate with an 85 percent stream factor. Of the 479,000 acre-feet of product water (1,000 ppm), a little less than half is transported to a storage reservoir, and the remainder is transferred directly to agricultural, municipal, and industrial users or to internal requirements. Magnesium, potash, and sodium sulfate will be recovered from the reject brine. A portion of the 2,000 MW of power produced will satisfy internal requirements. The remainder will be sold locally or exported to other areas of the Southwest.

Alternative 2

This Alternative has only two components: the two steam-cycle HTGR nuclear reactors and a relatively small well field. The nuclear reactors have the same basic design as in the dual-plant concept, except that additional turbines are used to capture more low-temperature steam for power generation.

Approximately 49,000 acre-feet of water are required for cooling because no heat is transferred to the desalting plant. This cooling water will come from 40 wells located just north of the reactors. The collection system is considerably scaled down since a small portion of that required for Alternative 1 is needed here.

Net power is considerably greater than in Alternative 1 because of increased gross production and very small internal power requirements, six MW in the year 2000 increasing to 14 MW in 2030 for the well field. All net power is to be exported to other regions in the Southwest, and all local demand is assumed to be satisfied by present suppliers.

Capital costs for the nuclear reactors will be slightly larger than in Alternative 1 because of the additional turbines, but operating, maintenance, and refueling costs are equivalent. Thus, costs per MWH are less in this Alternative.

Alternative 3

This Alternative encompasses four of the major components in Alternative 1: well field, dual-plant concept of nuclear reactors and a desalting plant, and a mineral recovery processing plant. All design and operating characteristics are the same as in Alternative 1.

In this Alternative, all water produced over and above internal requirements and normal local demand (which would have occurred without the project) is to be exported or transferred to the Rio Grande. Although four major options for export were discussed in the main text, only the Elephant Butte option to the Rio Grande will be considered for this Alternative. An open conveyance channel of about 80 miles will run northwesterly from the dual-plant complex over a mountain range to the northeast corner of Elephant Butte reservoir. Most of the route will take advantage of natural gradients, thus utilizing gravity flow to transport water over much of the 80 miles. However, 40 pumps (30 on-line and 10 spares) are required to lift water over a 1,000-foot pass in the San Andres Mountains, about 35 miles from the dual-plant complex. Since the pumps are the same size as those used in the delivery system from the energy-water complex to the reservoir in Alternative 1, power requirements will be similar. But the amount of water to be transported is about 80 percent greater than that in Alternative 1, and there is a 1,000-foot elevation differential. Therefore, total power needs, about 102 MW, are higher.

There is a good chance that the well field might affect local supplies for normal needs without the project in the Tularosa basin. To take account of this possibility, local needs will be supplied from available water production before any is exported. These are projected to increase from 25,000 acre-feet in the year 2000 to 52,000 acre-feet by 2030.

The amount of water available for export or transfer is computed by first accounting for all internal or local needs. Internal needs are 21,000 acre-feet for reject brine; 6,500 acre-feet for evaporation losses from the two-day holding pond supply; 16,000 acre-feet for nuclear reactor cooling needs; and 2,000 acre-feet due to conveyance channel (well field and export channel) losses. Local needs are 30,000 acre-feet for agriculture in the Tularosa basin and 25,000-52,000 acre-feet for projected municipal and industrial demand. Subtracting all these requirements from the 500,000 acre-foot well production leaves about 400,000 acre-feet of product water available for export to the Elephant Butte reservoir on the Rio Grande. As local M & I needs grow during the life of the project, they will be satisfied by making less water available for export.

As in Alternative 1, internal power requirements are to be satisfied before electricity is available for local needs or export. Power requirements for the desalting portion of the dual-plant complex, mineral recovery processing, and well-field water production are the same as those in Alternative 1: 129 MW, 151 MW, and 43 to 121 MW, respectively. However, water transportation will require 102 MW, as opposed to 60 MW when a small portion of the water has to be pumped uphill. This leaves between 1,575 MW in the year 2000 and 1,500 MW in 2030 available to outside users. Local municipal and industrial demands with no industrial development comparable to that projected in Alternative 1 will increase from 67 MW in the year 2000 to 139 MW by 2030. Thus, export to other regions in the Southwest would be between 1,325 and 1,500 MW.

SUMMARY OF COST COMPONENTS

In establishing a common basis for the B/C analysis, each of the major components has been specified in 1974 dollars. Where necessary, minor changes were made to ensure consistency. Costs in 1974 dollars for the following components of the Tularosa basin complex were listed in individual sections: desalting, water delivery, mineral recovery, and export systems. Costs of nuclear plants were estimated in 1975 dollars (HTGR type), adjusted to 1974; and the well-field cost was specified in 1972 dollars, adjusted upward to 1974. Total project costs are described below according to eight major components.

Nuclear Reactor (Both Dual and Power Only)

Costs for the HTGR reactor type were adjusted to 1974 dollars by examining and reviewing several recent engineering studies for private utility companies. Although four Alternatives (two LWR and two HTGR) were considered, the steam cycle HTGR was chosen as the most applicable to today's technology. An inflation rate of 12 percent was typical for estimates in 1974-75. This implies that an equivalent power plant would cost 12 percent more to construct in 1975 than in 1974. All cost estimates for the steam-cycle HTGR nuclear reactors were in 1975 dollars and were divided by 1.12 to obtain 1974 dollar estimates.

All nuclear costs were developed as if the plant operated continuously. An 85 percent stream or on-line factor was assumed, based on the four to five week downtime for refueling and maintenance, two or three weeks for unscheduled repairs. This stream factor was also used in all other component cost estimates. The adjusted 1974 cost figures were increased by 18 percent to account for capital expansion. Increased plant capacity was needed to ensure that the 386,000 acre-foot product water requirement could be met within any given year (on-line 85 percent of the time). The increased capacity developed a higher thermal rating, thus more net power. For the dual plant, net power increases to 2,360 MW, 2,820 MW for power only. However, adjusting these estimates to any average yearly continuous mode, equivalent numbers (smaller capacity continuously) are obtained: 2,000 MW for the dual plant, 2,390 MW for the power-only Alternative. Nuclear plants costs (dual Alternative) in 1974 dollars for the steam-cycle HTGR reactor type are reported in Table 82.

For the power-only Alternative, the turbine plant category will be $232 million, increasing total capital cost to $1,028 million. Operating and maintenance costs remain the same at $119.1 million annually. Average yearly net power increases to 2,390 MW, cooling water requirements to about 49,000 acre-feet a year.

Desalting Plant

Since costs were specified in 1974 dollars, no adjustment was necessary. A range of possible costs for pre-treatment was developed and the upper limit was selected for use. Desalting plant costs (exclusive of mineral recovery processes) in 1974 dollars are reported in Table 82.

Table 82. Estimated capital, operating and maintenance costs in 1974 dollars; power production and requirements; and water requirements by component for the Tularosa basin project, New Mexico

Cost Item	Capital Costs in 1974 Dollars (million $)	Operating and Maintenance Costs in 1974 Dollars (million $)	Electricity (MW)	Water (ac-ft)
Nuclear plant costs[a] (dual Alternative)				
Structure and site facilities	167.0			
Reactor plant equipment	308.0			
Turbine plant equipment	178.0			
Electric plant equipment	82.0			
Spares and contingency allocation	60.0			
Professional service	105.0			
Indirect construction costs	74.0			
Operation and maintenance (labor, fuel, etc.)		119.1		
Average yearly net power for sale			2,000	
Cooling water requirements (approximate)				16,000
Desalting plant costs[b]				
Construction and capital costs	300.0			
Pretreatment ($13.00/acre-foot)		5.0		
Operation and maintenance ($22.70/acre-foot)		8.8		
Average yearly continuous power requirement			129	
Project brine water (approximately)				21,000
Plant evaporation requirement (approximately)				6,500
Well-field costs				
Well construction (400 wells), including pumps, motors, and controls	30.0			
Collection system, including main canal, electrical distribution lines	68.0			
Replacement costs at 15 years	15.6			
Operating and maintenance (exclusive of electrical power)		0.438		
Electrical energy consumption (converted to an average yearly uniform linear increase for those between)				
2000			42.7	
2030			121.8	
Well-field costs (power only)[c]				
Well construction (40 wells), including pumps, motors, and controls	3.0			
Collection system (including main canal and electrical distribution lines)	6.1			

Table 82. Continued

Cost Item	Capital Costs in 1974 Dollars (million $)	Operating and Maintenance Costs in 1974 Dollars (million $)	Electricity (MW)	Water (ac-ft)
Replacement costs at 15 years	1.5			
Operating and maintenance (exclusive of electrical power)		0.034		
Electrical energy consumption (converted to an average yearly uniform linear increase for those between)				
2000			6.1	
2030			13.2	
Water delivery system (plant to reservoir) costs				
Concrete pipe ($300/foot for 10 miles)	15.900			
Pumps, including motors and controls ($868,500 each for 40 pumps)	34.700			
Replacement costs at 15 years	34.700			
Operation and maintenance (1%/year)		0.506		
Average yearly continuous power requirement			60.0	
Agricultural off-farm distribution system costs				
Construction and capital costs ($387,000/mile for 67 miles)	26.000			
Operation and maintenance (1%/year)		0.206		
Dam construction costs[d]				
Earthen dam	169.800			
Spillway	5.400			
Outlet works	9.400			
Excavation/preparation (25% of above)	46.200			
Operation and maintenance (1%/year)		0.231		
Mineral recovery costs				
Capital construction costs	109.0			
Operation and maintenance (labor, steam, and etc.)		27.3		
Average yearly continuous power requirement			152.0	
Water exportation costs				
Open conveyance channel (80 miles)	35.2			
Pumps, controls, and electrical distribution lines	34.8			
Replacement costs at 15 years	34.7			
Operation and maintenance (1%/year)		0.7		
Average yearly continuous power requirement			102.0	

[a]For the steam cycle HTGR reactor type adjusted for the 18 percent capacity expansion

[b]Exclusive of any mineral recovery processes

[c]For the power-only nuclear reactor Alternative

[d]For storage reservoir

Well Field

Costs were adjusted to 1974 dollars by examining recent indices for construction labor and material. An average adjustment factor of 1.25 was derived from weighing the major indices. On this basis, the proposed well field and collection system would cost about 25 percent more to construct in 1974 than in 1972. Since the 40-mile main canal was excluded from the cost estimates, a $230,000-per-mile figure from the Navajo Indian Irrigation Project (NIIP) was used. The characteristics of both open conveyance channels are similar enough that this dollar-per-mile figure is reasonable. Well-field costs in 1974 dollars are reported in Table 82.

For the power-only Alternative, the number of wells and collection system size can be reduced tremendously. A cooling water requirement of 49,000 acre-feet a year necessitates only 36 wells, plus four for contingency purposes. The large main canal is now reduced in size and shortened. Well-field costs in 1974 dollars for the power-only nuclear reactor Alternative are reported in Table 82.

Water Delivery System (Plant to Reservoir)

All costs developed for this component were specified in 1974 dollars. Water delivery costs in 1974 dollars are reported in Table 82.

Agricultural Distribution System (Off Farm)

Agricultural off-farm distribution system costs were specified in 1974 dollars. The cost per mile of the open channel conveyance system is higher than that of the well-field main canal because it must be capable of carrying greater amounts of water over certain periods of time and it includes controls and laterals as well as the central main canal. Agricultural off-farm distribution costs in 1974 dollars are reported in Table 82.

Reservoir

All costs developed for this component were specified in 1974 dollars. Actual distribution of the capital costs was used in the benefit-cost analysis, although only the totals are summarized here. Dam construction costs in 1974 dollars are reported in Table 82.

Mineral Recovery Process

These costs were developed and specified in 1974 dollars. The specific process analyzed in that section will be used in the benefit-cost analysis. Mineral recovery costs in 1974 dollars are reported in Table 82.

Potential Export Conveyance Systems

Although four Alternatives were discussed earlier, the Elephant Butte Alternative for delivery to the Rio Grande was considered most applicable for project analysis. Costs for the Elephant Butte export Alternative were also specified in 1974 dollars. Water exportation costs in 1974 dollars are reported in Table 82.

SUMMARY OF SOURCES OF BENEFITS

Direct benefits are potentially derived from four sources: sales of electrical power, water, minerals, and recreation. Each is described in detail.

Sale of Power

Power available for sale is reduced by the interal requirements of the proposed project. For example, in Alternative 1 for the base year 2000, these include 129.2 MW for the desalting plant, 42.7 MW for the well field, 60 MW for delivery of water to the reservoir, and 152 MW for mineral recovery. This reduction from the continuous 2,000 MW produced by the dual-nuclear plant leaves 1,616.1 MW for export sale and M & I use. It is assumed that initially local M & I can use 151 MW and the remaining 1,465.1 MW will be available for export. However, M & I use increases by 2.93 MW per year as local growth occurs. Thus where $P_{M\&I}$ is the price (\$/MW) at the busbar for local use and t denotes project year (t - 1, 2, ..., 30), yearly revenue (8,760 hrs/year) from local power sales can be expressed in dollars as $8{,}760 \cdot P_{M\&I}(151 + 2.93(t-1))$. Similarly, revenue per year from export sale can be expressed as

$$8{,}760 \cdot P_B(1{,}465.1 - 5.66(t-1))$$

where P_B is the busbar price (\$/MW) for exported power and 5.66 MW each year are removed from export sale to cover both M & I growth (2.93 MW/yr) and increased pumping effort as the water table drops (2.73 MW/yr). Revenues from power sales for other Alternatives are constructed similarly from estimates in the previous analysis of the three Alternatives.

For purposes of the B/C analysis, it was assumed that local M & I can pay a 10 percent greater price for power than that made available for export sale onto the grid. This differential approximates the savings in transportation costs over long distances but includes no adjustment in local distribution costs. Thus the assumption, $P_{M\&I} = 1.1P_B$ was used as an adjustment factor where P_B was determined by the alternative cost of electrical power from coal-fired generating plants, as explained below.

Determining a reasonable estimate of the marginal benefit of additional generating capacity in the year 2000 is difficult since price projections vary drastically. Current busbar price per MWH is approximately \$3, but this figure does not reflect the current cost of providing additional energy. Coal-fired generating plants under construction and expected to go on-line by 1980 in the Southwest will be producing electricity at prices in excess of \$10 per MWH. This alternative cost of power is also highly sensitive to the interest or discount rate. Relatively-complete cost data for a proposed coal-fired generating station were used as the basis for determining the future busbar price of electricity. A cost description of this plant and a hypothetical (larger) 800 MW coal-fired plant is presented in Table 83.

The following calculations are based on estimates of costs for a proposed generating station to go on-line in 1980. This unit will be a coal-fired steam generating station with a capacity of 500 MW.

Capital costs in 1974 dollars are estimated at \$573 per kilowatt. This includes investment in stack gas desulfurization systems. Annual capital costs per unit of capacity and per unit of net generation are based on a 30-year amortization at interest rates of five, six, eight, and 10 percent. The assumed availability factor is 80 percent for units under 600 MW.

Operations and maintenance costs are estimated after Arthur D. Little Co. (ADL's) report (1973), Long Island Light Company (LILCO) in 1973. Their figures had to be de-escalated from levelized values for the period 1981-1990. The result is \$1.42 per megawatt-hour in 1974 prices.

Fuel costs assume heating value of coal is 9,000 BTU per pound; net heat rate of 10,800 BTU/KWHR (high due to lower system efficiency with stack gas desulfurization); and nine-month generation with coal mine owned by parent utility. Fuel costs at $2.70/MW are based on these assumptions.

Total busbar costs presented in Table 84 are based on these four interest rates.

Busbar costs presented in Table 85 are based on a larger 800 MW unit and capital costs used by ADL in the LILCO study.

Since the B/C analysis incorporates five, six, eight, and 10 percent as possible discount rates, the above analysis allows the use of the appropriate busbar cost for each of these rates for the alternative cost of power. The smaller of the two plants is used for the B/C analysis.

Sale of Water

In the Alternatives analyzed, water has three possible uses. Local agriculture may in Alternative 1 use up to 396,000 acre-feet initially, at a maximum value of $50/acre-foot. This use, however, decreases as local M & I needs increase, since a value of up to $100/acre-foot has been projected for associated industrial projects such as coal gasification. These dollar prices of water are used in the B/C analysis. In Alternative 1, M & I initially uses 54,500 acre-feet and increases its share at the expense of agriculture by 1,362 acre-feet/year. The third potential use is export to the Rio Grande, which is projected to become acutely water short before the year 2000. Since most additional water available to the Rio Grande would be used for M & I, a value of $90 per acre-foot was chosen for this Alternative. About 399,500 acre-feet would initially be available for export, with a slight reduction over time to meet local M & I requirements. Also in Alternative 3, 30,000 acre-feet must be allocated to support current levels of agriculture.

Sale of Minerals

The proposed mineral by-product recovery process will produce magnesium, potash, and sodium sulfate at a commercially-acceptable cost. Chlorine gas could be produced also but sale prices would only cover transport costs from the site (Office of Saline Water, 1971). Table 86 presents quantities and current prices in 1974 dollars. No substantial relative price trends have been

Table 83. Estimates of costs associated with a proposed Southwestern generating station and a hypothetical 800 megawatt coal-fired plant

Interest rate	Proposed 500 MW unit	Hypothetical MW unit
(percent)	- -(dollars per megawatt)- -	
5	5.32	4.85
6	5.94	5.42
8	7.26	6.62
10	8.67	7.91

Table 84. Estimated capital, operation and maintenance, and fuel busbar costs at selected interest rates for a typical 500 megawatt coal-fired plant

Interest rate*	Capital cost	Operation and Maintenance cost	Fuel cost	Total busbar cost
(percent)	- - - - - -(dollars per megawatt)- - - -			
5	5.32	1.42	2.70	9.44
6	5.94	1.42	2.70	10.06
8	7.26	1.42	2.70	11.38
10	8.67	1.42	2.70	12.79

*Based on a 30-year amortization

Table 85. Estimated capital, operation and maintenance, and fuel busbar costs used by Arthur D. Little in the Long Island Light Co. study for an 800 megawatt plant at selected interest rates

Interest rate*	Capital cost**	Operation and maintenance cost	Fuel cost	Total busbar cost
	- - - - -	(dollars per megawatt)	- - - - -	
5	4.85	1.42	2.70	8.97
6	5.42	1.42	2.70	9.54
8	6.62	1.42	2.70	10.74
10	7.91	1.42	2.70	12.03

* Based on a 30 year amortization.
** Availability factor for plants 800 megawatts or larger is assumed to be 75 percent.

Table 86. Proposed mineral by-product recovery process quantities and current prices for magnesium, potash, and sodium sulfate for the Tularosa basin project, New Mexico

Mineral	Quantity	Price*	Revenue
	(tons)	(dollars/ton)	(000 $)
Magnesium	73,600	790	58,200
Potash	1,800	40	72
Sodium Sulfate	255,000	37	9,400
Total revenue			67,672

* Prices in 1974 dollars
Source: Office of Saline Water, *Research and Development Progress Report No. 6357*, U. S. Department of the Interior, U. S. Government Printing Office, January 1971.

noted for these products and the quantities should be acceptable given current demand projections. Thus, annual benefits from sale of recovered mineral products would be in excess of $67 million.

Recreation

Projected visitor days of 1,873,152 per year were obtained from the recreation study of the proposed dam and storage reservoir. At the current approved value of $2 per visitor day for water-based recreation, benefits are more than $3.7 million. This may be a severe underestimate based on the previous discussion of measurement of benefits. The sensitivity of results will be examined in a later section, when various values are tested. However, substitution of a more reasonable estimate ($14 million) based on willingness to pay failed to affect the results of the overall B/C analysis.

BENEFIT-COST ANALYSIS

The following notation will be used in describing the B/C analysis:

Let j = 1, 2, 3, 4, = source of benefits;

i = 1, 2, ..., 8 = cost component;

t = 1, 2, ..., 30 = project year;

B_{jt} = annual benefit from the jth source in year t;

K_i = total capital outlay for cost component i;

C_i = construction time in years for cost component i;

R_i = replacement cost for component i;

I_k = replacement interval in years for component i;

O_i = annual operating cost of component i;

and r = discount rate.

The present value of benefits can then be defined as the discounted sum over the 30-year project life from the four sources of benefits

$$B_0 = \sum_{j=1}^{4} \sum_{t=1}^{30} (1 + r)^{-t} B_{jt}.$$

Discounting is based on the initial year prior to operation, project year 0. Construction costs are also revalued upward to the last year of construction prior to operation. This, we have as a present value of capital outlays

$$K_0 = \sum_{i=1}^{8} \sum_{t=0}^{C_i - 1} (1 + r)^t K_i/C_i$$

where each of the eight cost components is revalued over its construction period, C_i, to the initial period. Replacement costs are discounted to the initial period from the replacement year, I_i, giving as a present value

$$R_0 = \sum_{i=1}^{8} (1 + r)^{-I_i} R_i$$

and operating costs are discounted as

$$O_0 = \sum_{i=1}^{8} \sum_{t=1}^{30} (1 + r)^{-t} O_i.$$

As explained earlier, net benefits should be used as the criterion for project selection. These may be calculated as

$$NB = B_0 - K_0 - R_0 - O_0.$$

For convenience and as an indication of the percentage of current costs covered by future net benefits, the traditional benefit-cost ratio is calculated as

$$B/C = (B_0 - O_0)/(K_0 + R_0).$$

Tables 87, 88, 89 present cost components for Alternatives 1, 2, and 3 consistent with the above notation. Similarly, Table 90 presents sources of benefits for Alternatives 1, 2, and 3 where in some instances B_{jt} is defined as a function of time, t. Table 91 presents prices or values used in the benefits formulation for power and water under different discount rates, r.

Table 92 presents results of the benefit-cost analysis for the three Alternatives. Net benefits are negative in Alternatives 1 and 3 for all discount rates used in the analysis, indicating that with current technology the proposed nuclear-desalting-agricultural complex

Table 87. Capital outlays, construction time, replacement costs and interval, and annual operation costs for the cost components of the benefit-cost analysis for Alternative 1, Tularosa basin project, New Mexico

Cost component ($i=1,\ldots,8$)		Total capital outlay costs (K_i)	Construction time (C_i)	Replacement costs (R_i)	Replacement interval (I_i)	Annual Operating costs (O_i)
		(million dollars)	(years)	(million dollars)	(years)	(million dollars)
Nuclear plant	1	974.0	5	0	-	119.1
Desalting plant	2	300.0	5	0	-	13.8
Well field	3	98.0	5	15.6	15	0.4
Water delivery (plant to reservoir)	4	50.6	2	34.7	15	0.5
Agricultural distribution system	5	26.0	5	0	-	0.3
Reservoir	6	230.8	8	0	-	2.3
Mineral recovery	7	109.3	5	0	-	27.3
Water export canal	8					

Table 88. Capital outlays, construction time, replacement costs and interval, and annual operation costs for the cost components of the benefit-cost analysis for Alternative 2, Tularosa basin project, New Mexico

Cost component ($i=1,\ldots,8$)		Total capital outlay costs (k_i)	Construction time (C_i)	Replacement costs (R_i)	Replacement interval (I_i)	Annual operating costs (O_i)
		(million dollars)	(years)	(million dollars)	(years)	(million dollars)
Nuclear plant	1	1,028.0	5	0	-	119.10
Desalting plant	2					
Well field	3	9.1	5	1.5	15	0.03
Water delivery (plant to reservoir)	4					
Agricultural distribution system	5					
Reservoir	6					
Mineral recovery	7					
Water export canal	8					

Table 89. Capital outlays, construction time, replacement costs and interval, and annual operation costs for the cost components of the benefit-cost analysis for Alternative 3. Tularosa basin project, New Mexico

Cost component (i=1,...,8)		Total capital outlay costs (K_i)	Construction time (C_i)	Replacement costs (R_i)	Replacement interval (I_i)	Annual operating costs (O_i)
		(million dollars)	(years)	(million dollars)	(years)	(million dollars)
Nuclear plant	1	974.0	5	0.0	-	119.10
Desalting plant	2	300.0	5	0.0	-	13.80
Well-field	3	98.0	5	15.6	15	0.44
Water delivery (plant to reservoir)	4					
Agricultural distribution system	5					
Reservoir	6					
Mineral recovery	7	109.3	5	0.0	-	27.30
Water export canal	8	70.0	5	34.7	15	0.70

Table 90. Sources of benefits for the benefit-cost analysis for Alternatives 1, 2, and 3, Tularosa basin project, New Mexico

Source of benefits (j=1,2,3,4)	(j)	Amount of benefits (t=1,2,..., 30=project year) (B_{jt})
Alternative 1		
Power	1	$8760\ [P_B(1465.1) \quad +P_{M\&I}(151+2.93(t-1))]$*
Water	2	$V_{AG}[396{,}000-1362(t-1)]+V_{M\&I}[54{,}500+1362(t-1)]$**
Minerals	3	67,672,000
Recreation	4	3,746,300
Alternative 2		
Power	1	$8760\cdot[P_B(2341.9-2.135(t-1))+P_{M\&I}(48+1.9(t-1))]$
Alternative 3		
Power	1	$8760\cdot[P_B(1659.1-5.21(t-1))+P_{M\&I}(67+2.48(t-1))]$
Water	2	$V_{AG}30{,}000+V_{M\&I}(25{,}000+931(t-1))+V_{EX}(399{,}500-931(t-1))$***
Minerals	3	67,672,000

* P_B = price of electricity per megawatt hour at busbar for export.

$P_{M\&I}$ = price of electricity per megawatt hour in local municipal and industrial use.

** V_{AG} = value of water in local agricultural use.

$V_{M\&I}$ = value of water in local municipal and industrial use.

*** V_{EX} = value of water exported to Rio Grande.

Table 91. Prices/values used in the benefits formulation for power and water under different discount rates, Tularosa basin project, New Mexico

Discount rate (r)	Price of export power (P_B)	Price of power to local M & I ($P_{M\&I}$)	Value of water in agriculture (V_{AG})	Value of water in local M & I ($V_{M\&I}$)	Value of water for export (V_{EX})
	($/MW)	($/MW)	($/ac-ft)	($/ac-ft)	($/ac-ft)
5	9.44	10.38	50	100	90
6	10.06	11.07	50	100	90
8	11.38	12.52	50	100	90
10	12.79	14.07	50	100	90

Table 92. Results of the benefit-cost analysis for Alternatives 1, 2, and 3, for the Tularosa basin project, New Mexico

Discount rate	Net Benefits $B_0-K_0-R_0-O_0$	Benefit-cost Ratio $(B_0-O_0)/(K_0+R_0)$	Total Benefits (B_0)	Capital costs (K_0)	Oper & maint costs (O_0)	Replacement costs (R_0)
	-(millions of dollars)-					
Alternative 1--Nuclear reactor, Desalting, Agriculture						
5	-986.570	0.508	3,536.890	1,982.557	2,516.707	24.195
6	-1,012.340	0.505	3,286.279	2,024.122	2,253.508	20.989
8	-1,076.415	0.494	2,892.703	2,110.203	1,843.058	15.857
10	-1,137.528	0.486	2,618.195	2,200.356	1,543.325	12.042
Alternative 2--Nuclear reactor only*						
5	57.723	1.050	3,035.906	1,146.125	1,831.336	0.722
6	84.421	1.072	2,894.105	1,169.245	1,639.814	0.626
8	110.042	1.090	2,668.506	1,216.850	1,341.141	0.473
10	132.817	1.105	2,522.529	1,266.318	1,123.034	0.359
Alternative 3--Nuclear reactor, Desalting, Water export						
5	-382.527	0.779	3,824.740	1,702.890	2,480.182	24.195
6	-424.824	0.758	3,552.004	1,735.036	2,220.803	20.989
8	-509.777	0.719	3,123.617	1,801.227	1,816.310	15.857
10	-578.612	0.693	2,824.366	1,870.009	1,520.927	12.042

*Note: The benefits of electricity production are determined by the opportunity cost of using a coal-fired plant. As a result, the discount rate increases as the value of electricity increases. Thus in Alternative 2, the value of electricity increases faster with the discount rate than with the cost of electricity production, since nuclear power production is less capital intensive in this example than are coal-fired electricity generation plants.

and the nuclear-desalting-export scheme are infeasible. However, Alternative 2 which includes only power production and uses brine for cooling, is feasible, producing net benefits of \$57 to \$132 million in 1974 dollars in the project base year, depending on the discount rate chosen.

Before further discussion of these results, cost estimates associated with the proposed project are examined in more detail.

POSSIBLE COSTS EXCLUDED FROM THE FEASIBILITY STUDY

In Alternative 2 (power-only Alternative), the busbar electricity prices assumed from the coal-fired generating plant are more than adequate to cover all costs for the nuclear power plant, as detailed in the analysis. Incidentally, busbar prices of \$9.26, \$9.77, \$10.88, and \$12.14 per MWH at the interest rates of five, six, eight, and 10 percent respectively allow this Alternative to just break-even. However, these prices will fall short of recovering costs associated with a nuclear power plant if they have been underestimated or if certain classes of costs have been omitted.

Nuclear Costs

Direct capital costs for the two steam-cycle HTGR reactors were broken into six categories.[17] The initial acquisition and preparation of a suitable piece of land was excluded from the analysis. This can be variable, depending on specific areas of a region and its associated terrain characteristics. It was not possible to specify these costs adequately. However, a range can be constructed by examining several recent studies. Land purchases and preparation have ranged from less than 0.5 percent to 2.7 percent of the direct capital costs. Thus, it can be assumed that additional expenditures would range from \$4 to \$22 million. Costs of Tularosa basin land are relatively low, with site preparation probably requiring no more effort than similar projects on the drawing board. Therefore, the land acquisition and preparation costs should be toward the lower end of the range, from \$4 to \$10 million. These additional direct capital expenditures would increase busbar prices about two to three percent on the average (20 to 39 cents per MWH, depending on the interest rate chosen for the analysis).

A set of important expenditures (fixed charges) was not considered in Chapter IV. Although public ownership and operation of the proposed complex is an inherent assumption, some of these expenditures are important if private ownership and operation of the nuclear power generating facilities is to be considered. Therefore, these effects will be discussed briefly.

This set of expenditures includes taxes, insurance (except liability, which was in the operation and maintenance category), depreciation, interest, and return of investment. Not all of these expenditures are one-time expenses, but rather recur every year. They are part of the everyday costs of doing business whether they are operating, maintenance, or capital expenditures. If excluded, any analysis to assess economic feasibility will overstate the net benefits.

When the project is viewed in the public context, not all of the expenditures are applicable. Some forms of taxes and return on investment are not considered in a cost estimate for a public utility. However, depreciation, interest, and some taxes are expenses borne by public utilities. The interest on money borrowed (capital requirements) and depreciation (capital recovery) are implicit in any standard benefit-cost procedure. This is done by specifying all final cost and benefit calculations in present value terms.

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[17] See Chapter IV on nuclear power alternatives for a more complete discussion of the categories.

Because of the nature of benefit-cost procedures, depreciation is assumed to be straight-lined. Where recovery is permitted at a faster rate, costs are understated. Within the private context, this is usually the case. However, most studies dealing with public expenditures use a uniform continuous depreciation or capital recovery rate. Therefore, no additional expenditures or costs can be attributed to this component of the expenditure set.

Taxes are paid by public utilities. By ignoring this component, costs are understated measurably. Information in Federal Power Commission reports indicates that taxes represent around five percent of the total operating and maintenance expenditures of public utilities. This additional expense raises busbar prices by 2.5 to 4.2 percent, according to the interest rate chosen for analysis, and the portion of total costs attributable to annual operating and maintenance expenditures. This represents an increase of 23 to 53 cents per MWH, depending on the interest rate.

If the project is viewed in a private context, corporate taxes and returns on investment must be included within the annaul operating and maintenance expenditures. Of these, returns on investment represents a sizable addition to a project of this nature. Initial capital outlays, even if not entirely financed by equity, are enormous and make even a small return (in percentage terms) to investment a measurable addition to expense. Today, returns to investment are from six to 18 percent. Along with the additional tax expenditures, this translates into an 11 to 34 percent increase in busbar electricity prices. Actual dollar increases per MWH are between \$1.03 and \$4.18, depending on the interest rate and percent increase.

A close examination of public utilities shows that many of them pass a certain percentage of their revenue to the controlling agency, especially in most municipalities. By manipulating accounting categories, these released revenues could be stated as a rate of return on total investment. By so doing, from three to 15 percent of total operating and maintenance expenses is added. This results in a \$4.3 to \$19.7 million increase in that category of costs, and a 29 cent to \$1.17 increase in busbar electricity prices.

Table 93 presents the initial assumed busbar electricity prices applied to the power-only Alternative (Alternative 2) when its associated capital and operating and maintenance expenditures are increased by the lower range of incremental cost additions (0.5 percent for land acquisition and preparation, five percent for taxes, and three percent for pass-through revenue to municipalities). The benefit-cost ratio is now less than one for the interest rates of five and six percent, with net benefits being negative. For the Alternative to just break-even with these increased costs, prices of \$9.82, \$10.21, \$11.30, and \$12.59 per MWH at the interest rates of five, six, eight, and 10 percent, respectively, are needed (higher for the first two and lower for the second two).

Table 93. Results of benefit-cost analysis for Alternative 2 (Nuclear reactor only) with optimistic assumptions and no recreation or associated facilities

Discount Rate	Net Benefits	B/C Ratio	Total Benefits	Capital Cost	O&M Cost	Replacement Cost
			(million \$)			
Alternative 2-- Nuclear Reactor Only						
5%	-81.544	0.974	3035.906	1151.650	1965.078	0.722
6%	-38.091	0.987	2896.985	1174.882	1759.568	0.626
8%	18.009	1.007	2680.282	1222.717	1439.083	0.473
10%	44.698	1.018	2522.529	1272.423	1205.048	0.359

These results show no large difference from Alternative I where these additional costs were excluded (break-even prices of $9.26, $9.77, $10.88, and $12.14 per MWH).

In recent nuclear energy cost studies, the actual cost per installed capacity has averaged much higher than those developed for this study (around $400 per KWH). This can be attributed partially to the use of 1975 dollars in the recent studies, but other reasons may play much larger roles. These include realized downtime being greater than originally assumed, increased maintenance costs to meet more stringent safety requirements, and operating at less than capacity due to many factors. Any or all of the above reasons would raise costs above those used in the previous B/C analysis. Consequently, the assumed busbar prices will fall far short of recovering costs, resulting in negative benefits and an infeasible economic situation.

Up to this point, only costs associated with nuclear power production in the dual-plant complex have been considered. Other project components play a much larger role in water costs.

The cost of water is governed by more than the power production costs just discussed (internal power usage implies electrical equivalent to that usage times the cost or price per unit). All costs contained within the fixed charge set included in the above power costs are applicable to the other project components although in varying degrees. Interest on borrowed money and depreciation are implicit within the B/C analysis for all project components and need not be considered further, except possibly in the context of non-uniform distribution of construction costs and non-linear depreciation rates. The addition of taxes, insurance, etc., excluded from the cost estimates because of potential variances from unspecified structural assumptions, would increase the operating and maintenance expenditures appreciably and further decrease net benefits to the project. An estimate of these costs is beyond the scope of this initial study and of small consequence in overall impact on the preliminary economic feasibility. Since net benefits were negative in two of the three Alternatives, there was no point in trying to quantify these specific costs.

The analysis of feasibility by components shows that all project pieces contribute in some way to the cost of water in a dual-plant concept. Costs of the desalination plant were based on recent estimates from studies similar to the proposed Tularosa basin energy-water complex. These studies used the engineering approach in developing and computing cost estimates, therefore significant direct costs are not excluded.

Water Delivery Costs

However, the same may not be said for some of the other project components. Cost estimates for transportation-delivery system from plant to reservoir have not included installation and housing of the 10 pump stations (four pumps to each), controls, and an electrical transmission system to the stations. Costs of similar pumping stations being developed and installed for the Navajo Indian Irrigation Project have ranged between 14 and 27 percent of the total. This implies that the capital expenditure for the plant-to-reservoir delivery system may increase by as much as $5 million.

The same costs were excluded from the pumping stations in the export system. Therefore, total costs for that component may also be increased by as much as $5 million.

Recreation Costs

Although recreational benefits are counted within the analysis, the necessary facilities in addition to the reservoir are not included in the costs. Although these costs may be small, their exclusion attributes a higher net benefit to recreation. Also, if the delivery system and storage reservoir are assigned exclusively against recreation, the estimated revenue will not cover these costs.

Land Costs

All land costs have been excluded from the initial cost estimates, thereby eliminating a potentially large expenditure. Situation of the project on public lands reduces this potential dollar amount. Right-of-ways, access facilities, and that portion of the proposed project not on public land will have to be acquired through outright purchase or other means. These expenditures will add to the overall cost of the project and increase both electricity and water prices. This argument of course ignores the scrap value of the land on completion of the project period.

Other Costs

Most of the data for the initial cost estimates in this study depend almost exclusively on secondary sources. Where simplifying assumptions were made, they were generally conservative in nature; that is costs would tend to err on the high side if the assumptions proved to be untrue. However, where the assumptions were not conservative in nature, the opposite would be the case.

Costs in the last two years have far exceeded most estimates. Whether this is a short-term phenomenon or will become a long-run trend remains to be seen. If it is not just a short-term situation, most of the costs in real terms that have been developed for this project may be expected to increase somewhat.

Because of the capital intensive nature of the proposed project, any economic analysis is far more sensitive to initial capital requirements than it is to either the benefit or recurring cost streams. Small changes in either of the latter will not provide the same impact as small changes in initial capital requirements. Therefore, underestimates of replacement expenses, operating and maintenance expenditures, or other recurring costs will not be as noticeable as underestimates of capital requirements. A systematic review of these expenditures is not indicated due to the lesser impacts and the negative net benefits in Alternatives 1 and 3.

Another aspect of the cost question concerns the overall desalting component of the proposed Tularosa basin energy-water complex.

Desalting Costs

True costs of desalting may have been somewhat masked in the previous discussion which concerned preliminary economic feasibility for the project as a whole in terms of B/C analysis. Even though the initial Tularosa proposal involved a dual-plant complex where power and water were considered joint inseparable products, a power-only Alternative has already been examined briefly. If power production is the first and primary function of the dual-plant concept and the desalination process is an additional component of the project, assessing real desalting costs is much easier.

For the power-only portion (Alternative 2) of the dual-plant concept, two steam-cycle high-temperature gas-cooled HTGR nuclear reactors and a well field capable of supplying 49,000 acre-feet of water are the only components necessary. The steam-cycle HTGR reactors with a capacity of delivering 2,390 MW busbar load continuous electrical power were priced at $1,028 million. Forty wells and a small collection system at $9.1 million will deliver the 49,000 acre-feet of cooling water to the reactors. Operating and maintenance expenditures will average slightly over $119 million for the nuclear reactors, and $34,000 for the well field each year. Power drain (or requirements) associated with the well field is estimated at six MW in the year 2000, increasing to 14.3 MW by 2030. All costs and design criteria are accepted as is from the previous chapters where more detailed discussion of each component is found. No attempt is made to account for missing costs (land for the complex, installation of pumps, etc.) or to examine the impact of technological advances.

Adding the desalination portion to the dual-plant concept causes additional expenditures. The most obvious, of course, is the desalting plant. Others include the enlarged well field, power requirements for the well field and desalting plant, and transportation-delivery expenses.

Actual capital expenditures for the two steam-cycle HTGR nuclear reactors will be reduced (cost savings), when steam at 260° F and 35 psia is delivered to the desalination plant, and back-pressure turbines are substituted for the condensing turbines and cooling towers. In the present analysis, this is \$54 million--the difference between \$1,028 million for the power-only configuration and \$974 million for the dual plant.

There is, of course, a negative aspect to the cost savings aspect from substituting back-pressure turbines. Substantial net power loss occurs. When the nuclear reactors are producing for power only, there is a 2,390 MW yearly continuous capacity. Only 2,000 MW are available when the 260° F 35 psia steam is transferred to the desalination process, a loss of 390 MW.

In addition to this pure loss of 390 MW, internal power requirements are met from the 2,000 MW capacity. With power-only being produced, as contrasted with the joint power-water production, well-field needs were only six to 14.1 MW. The additional wells necessary to ensure pumpage of 500,000 acre-feet per year (49,000 for power-only Alternative) will require 42.7 to 121.8 MW, an increase of 36.7 to 114.7 MW.

The MSF desalination process requires high amounts of electricity in addition to the large inputs of steam. Processing 385,000 acre-feet of water each year requires 129 MW of continuous power to operate the large number of pumps. Thus, if the project were to comprise only the three components--nuclear reactors, well field, and desalination plant--internal power directly chargeable to the desalting process in the configuration is about 556 MW in the year 2000, increasing to 632 MW by 2030. The total comprises the 390 MW pure loss, 129 MW desalting requirement, and 36.7 to 114.7 MW well-field drain. Of the 2,390 MW electrical capacity for power only, the extraction and subsequent desalting of enough water to produce 500,000 acre-feet utilizes 23.2 to 26.5 percent of that power production.

Although potential users could take delivery at the dual-plant complex and furnish their own storage and transportation, it is highly unlikely that this would happen in a project of this magnitude. Also, in a public water project most potential components are included within the overall scope. If the transportation and delivery systems are considered an inherent part of any large-scale desalting project, these power requirements must be added to the MW requirements.

Mineral recovery is <u>not</u> an inherent part of the desalination process. It is a by-product of the reject brine. Therefore, power requirements for any mineral recovery processes to obtain saleable products from the reject brine will not be charged to desalting itself. Mineral recovery can be considered a joint product with the desalted water since without the desalination, there would be no mineral production.

Capital expenditures that can be charged directly to desalination involve the extraction and processing of the saline water. The cost savings of \$54 million from elimination of back-pressure turbines has already been discussed. Net additions to cost, however, are larger. Probably the most obvious additional capital outlay is the desalination plant component of the complex estimated at \$300 million.

Net additions to well-field costs include the increased number of pumps and controls, a more extensive transmission system (electrical distribution to pumps), and a much larger collection system. These have been estimated to be about \$89 million (\$98 million less the \$9.1 million required for power only), with replacement costs increasing to \$15.6 million from \$1.5 million, a difference of \$14.1 million.

Capital chargeable to the extraction and production phases of the desalination process is \$335 million initially (\$300 million plus \$89 million minus the \$54 million savings), and \$14.1 million at the 15-year point. However, if transportation and delivery are assumed to be an inherent part of the process, an additional \$50.6 million for initial capital, plus \$34.7 million for replacement at the 15-year point must be added to the above figures. If a storage facility is also to be a part of the desalination process, an additional \$230.8 million is applicable.

Annual operating and maintenance expenditures attributable to the extraction process are \$404,000 (\$438,000 less \$34,000). In the desalination process, pretreatment will run \$5 million, which added to \$8.8 million for operation and maintenance totals \$13.8 million. Transportation, delivery and storage, operating and maintenance charges, if included, would amount to \$2.3 million for the reservoir and dam, plus \$0.5 million for the delivery system.

Table 94 summarizes the costs chargeable to the overall desalting process of water to be used within the Tularosa basin. Export costs could be substituted for the transportation and delivery costs. In most export alternatives, overall costs will be somewhat less due to the exclusion of the reservoir. Only within-basin water use is shown in Table 94. Extraction, production, and transportation-delivery components are defined independently to allow comparisons.

ANALYSIS OF FEASIBILITY BY COMPONENT

In any analysis of the preliminary economic feasibility, the individual components are examined to determine their net contribution to the overall project if inseparable joint products are not present. This was partially done in the B/C analysis of the three Alternatives. However, the separate components of water, power, minerals, and recreation were not always analyzed independently but could have easily been included in the proposed project. There may be some question about minerals and recreation, but they should be considered for informational purposes, if not analytical, even if the dual-plant concept were visualized as a joint and inseparable project. Possibly more important than insisting upon separable products to ensure the assessment of component contri-

Table 94. Real desalting costs chargeable to the overall desalting process, Tularosa basin energy-water complex, New Mexico

Type	Capital Costs	Replacement Costs	Operating & Maintenance Costs	Power
	- - - - -	- -(million \$)-	- - - - - - -	(MWH)
Extraction				
(well field)	89	14.1	.404	36.7 to 114.7
Production				
(Nuclear Facility)	-54*			390 (loss)
(Desalting Plant)	300		13.8	129
	335	14.1	14.204	556 to 634
Transportation-Storage				
(Plant to Reservoir System)	50.6	34.7	.506	60
(Reservoir)	230.8		2.3	

*Negative numbers indicate savings.

Note: The benefit side of the equation has been ignored here. Recreational benefits are, however, utilized in the overall analysis. Mineral recovery costs and revenues are also included in the overall analysis. Component additions and subsequent B/C results are examined in another section of this chapter.

butions from an economic standpoint, is the consideration of technological improvements in one component or another and alternative energy sources for the dual concept.

Several points should be made about the subsequent examination of the project components. First, although there are many possible combinations of components, only the most reasonable are utilized. Second, all costs, internal water and power requirements, and design characteristics of the individual components are as specified previously. Third, instead of pre-specifying the price of water, it is allowed to seek its own level, with the only requirement being that the project break-even. Fourth, all potential water users will be treated as a single class, thus allowing product water to be sold at the same price to all users. Fifth, the electricity busbar prices originally assumed are to be used ($9.44, $10.06, $11.38, and $12.79 per MWH at five, six, eight, and 10 percent interest rates, respectively).

The first project component to be examined comprises two nuclear power reactors, a well field and a desalting plant. Power production has already been treated as a separate component. Only the costs associated with the two steam-cycle HTGR reactors, 400 well-water-production field, and 500 mgd desalting plant are used here. Net power available for sale to the export or local M & I market is 1,828 MW in the year 2000, decreasing to 1,766 MW in 2030, due to increased pumpage requirements. Product water available to the complex after the internal requirements are met (21,000 acre-feet of reject brine, 6,500 acre-feet for holding pond evaporation, and 16,000 acre-feet for cooling requirements) is 456,500 acre-feet. Capital outlays, replacement costs, and operating and maintenance expenditures can be found in Table 87. Water prices presented in Table 95 are necessary to just recover all costs as delineated (project break-even).

If we maintain the three-component basic configuration of water available only at the dual-plant complex but add the mineral recovery process, increases occur in both costs and benefits. Capital expenditures are increased by $109.3 million, operating and maintenance expenditures by $27.3 million. Net power production available for outside sale is reduced by 152 MW, leaving

Table 95. Break-even water prices at selected interest rates for basic and enlarged project configurations

Interest Rate	Basic Configuration[a]	Enlarged Configurations-Basic Plus: Mineral[b]	Water[c]	Mineral-Water[d]	Export Water[e]	Mineral-Export[f]
(percent)	(dollars per acre-foot)					
5	183	138	205	159	217	173
6	191	149	215	173	228	187
8	212	177	240	204	254	223
10	238	212	269	247	281	256

[a]Composed of two nuclear power reactors, well-field, and desalting plants

[b]Basic configuration plus mineral recovery process

[c]Basic configuration plus plant to reservoir delivery system and storage reservoir

[d]Basic configuration plus mineral recovery process, plant to reservoir delivery system and storage reservoir

[e]Basic configuration plus water export delivery system (storage facilities not included)

[f]Basic configuration plus mineral recovery and water export delivery system (storage facilities not included)

1,676.1 MW in the year 2000 and 1,594.1 MW in 2030. Water available for sale remains at 456,500 acre-feet. There are, however, substantial benefits from the sale of minerals, $67.7 million. Table 95 presents the water prices necessary for this enlarged configuration to just break-even.

The addition of mineral recovery to the basic dual-plant configuration allows the product water to be sold at a substantially lower price (at six percent, $149 per acre-foot as opposed to $191 per acre-foot). These are the lowest rates that will allow full recovery of project costs no matter what configuration is assumed with all capital, replacement, and operating and maintenance expenditures as initially specified.

The extraction and subsequent production of usable water has been inherent in the two above project configurations. For the next three proposed project configurations, transportation and storage of the product water is introduced. Purchases of water are still to be made at one price, but may take place at sites other than the dual-plant complex. It is still likely, however, that in two of the three proposed project configurations some of the purchased water will come directly from the complex. No distinction is made when allowing the water price to seek a break-even level and all water is sold at the same price whether it comes from the complex, delivery system, or storage facility.

If mineral recovery is eliminated from the previous configuration, the three-component (nuclear reactors, well field, and desalting plant) basic configuration remains. By adding the plant to reservoir delivery system and the storage reservoir, a configuration equivalent to the entire initial project--less mineral recovery and off-farm agricultural distribution system--is portrayed. Capital expenditures of $50.6 and $230.8 million, replacement expenditures of $34.7 million, and operating and maintenance expenses of $506 thousand and $2.3 million for the delivery and storage facilities respectively must be included. In addition, a power requirement of 60 MW for the delivery system must be subtracted from net capacity available for sale. Water will be purchased from both the reservoir and dual-plant complex, depending upon the season. Water available for sale would be reduced to 449,500 acre-feet. The reservoir does add benefits estimated at $3.7 million in recreational visitor days. Far more costs have been added to the system than benefits, and these are reflected in the break-even water prices in Table 95.

By including mineral recovery in the above configuration (extraction, production, and delivery and storage of water for use within the basin), water costs can be reduced. Since mineral recovery is not possible without desalting, and the originally estimated costs and revenues produced a large net benefit for this component, it could be argued that minerals are an inseparable joint product and should always be included within the analysis. However, it is not always included to allow consistent assessment of component contributions. Mineral recovery costs, power requirements, and revenues remain as given before, and the break-even price of water is lower (Table 95).

If water is exported out of the basin, delivery costs become $70 million, an increase of $19.4 million over the in-basin delivery system. Replacement costs remain the same at $34.7 million, while operating and maintenance expenditures are increased by about $200 thousand. Power requirements of this system have been estimated at 102 MW, 42 more than the in-basin transfer. Storage facilities are no longer required and capital expenditures are lowered significantly. More water is made available for sale, 5,000 acre-feet, but the annual $3.7 million recreational benefit is lost. The overall effect is to lower break-even prices of water somewhat as shown in the last two columns of Table 95. The first set of figures is without the mineral recovery component, and the second set includes it.

OTHER TECHNOLOGICAL ALTERNATIVES

In previous chapters, where each major project component was examined in some detail, advanced technologies were mentioned as possibilities for the future. Some appear more likely than others, but, even more important, some may have significant effects on real costs, and consequently affect the results of any economic feasibility analysis. Because of this potential impact on project costs, these more likely technologies should be reviewed in terms of their probable economic consequences. A major premise of this study was to design and cost all components in 1974 technologies and dollars. But in view of the large negative benefits obtained in the benefit-cost analysis, partially attributable to the high initial expenditures, the introduction of cost-reducing technologies may be the only approach to obtain realistic prices of the product water.

Nuclear capital costs may be reduced by the introduction and operational availability of the direct-cycle HTGR process. Although cost comparisons are few, several recent studies have indicated that an eight to 12 percent direct capital cost savings could be possible. In terms of this project, this means that the same capacity plant could be constructed for about $100 million less. Savings in operating and maintenance expenditures have not been identified per se, but would be measurable. In addition, with a direct-cycle HTGR reactor no cooling water would be required, thus freeing 16,000 acre-feet for other productive use and sale.

Probably more important in any proposed desalting schema is an improvement in its technology as far as potential effects on costs of production are concerned. This statement is meant to apply only to the proposed project with all of its underlying assumptions. An examination of various scale possibilities, as well as alternative desalting processes available today may in fact lead to another conclusion. As discussed briefly in Chapter IV on desalination processes, vertical tube extraction (VTE) appears theoretically to be capable of significantly reducing capital and operating and maintenance expenditures for a project of this size. If this is true, it would have a dramatic impact on any assessment of desalting feasibility. Although no real data for a project of this scale utilizing the VTE process exists, it may not be overly optimistic to assume that real costs could be reduced by 25 to 30 percent. Also, with the increased efficiency purported for the VTE process, some additional water may be made available, as well as a reduction in overall operating and maintenance expenses and internal electrical power requirements.

Drilling and pumpage costs could be reduced with the introduction of some of the new drilling technologies now being laboratory tested. As pump efficiency is improved, some reductions in costs may be possible, but the practical demonstrated technologies have in some instances approached their calculated maximum.

Most costs for the delivery and storage systems stand little chance of being reduced through the introduction of major technological advances. The only foreseeable real improvement would be finding substantial overestimates of the dam cost or the possible use of much lower priced pumps to perform equivalent work use of ordinary pump material, as opposed to the stainless steel presently assumed to be required for example.

The opposite of costs is benefits, and there are several categories of possible increases through new technologies and/or improvements to the benefit stream such as improved irrigation efficiencies and introduction of higher-valued agricultural crops. Other improvements to the benefit stream could come from one of two sources: higher-revenue streams caused by increased prices, or additional minerals being recovered and profitably marketed. The latter includes sale of chlorine gas (Cl_2), which is now assumed to be sold at a price sufficient only to recover the transportation cost, or the recovery and subsequent sale of some of the trace minerals and metals previously mentioned in the chapters on desalting processes and on potential mineral markets (barium, sodium, hydroxide, etc.) Higher revenue streams may be possible by increased real demand and higher prices for the major recovered minerals (magnesium, sodium, sulfate and potash). Also, the $2.00 Congressional Unit on recreational visitor days may be increased, or the dollar values attributable to the recreational experience in recent studies could be used. The estimates range from $5 to $17 per visitor day.

The chapter on potential irrigated agriculture mentions the distinct possibility of improving the value of water or the amount agricultural users would be able to pay by switching from more-water intensive and lower-valued crops to less-water intensive and higher-valued crops. Although this possible range of improvement (far beyond the initial scope of this study) was not analyzed, some plausible estimates have been made by reviewing cropping patterns in other parts of the country, consumptive irrigation requirements, and projected real prices of agricultural products. Values of about $60 to $80 an acre-foot were obtained in these estimates.

Improved irrigation efficiencies would certainly raise the value of water in agriculture. However, improved efficiency in this area of the country often implies an increase in capital expenditure to either improve the present irrigation system or purchase expensive pipe and controls for trickle or subsurface irrigation. The most recent proven irrigation methods have been employed in the initial agricultural analysis. Increased efficiency of any sizable degree is therefore unlikely. However, if the real price of water does increase substantially of its own accord, more capital intensive irrigation, as well as increased efficiencies, will occur in and of themselves to conserve and better utilize this precious resource.

To ascertain roughly the sensitivity of the earlier B/C analysis, several of the above cost decreases or benefit increases will be substituted in the data base where applicable. Since it is not intended to allow power to subsidize water production appreciably, no change will be hypothesized for the nuclear power component. Desalting capital costs, however, will be decreased by 25 percent (due to the use of the VTE process), with the associated operating and maintenance expenditures reduced by 15 percent. Lower priced pumps will also be used cutting capital costs by 40 percent, with an associated decrease of 10 percent in power requirements. Also, the mid-point of the estimated range of agricultural payments for water when some crop switching takes place is inserted in the benefit stream ($70 an acre-foot). Recreational benefits are increased from a daily rate of $2 to $7. Tables 87 through 91 contain the initial costs and benefits for Alternatives 1 and 3.

Capital costs for the desalting plant are now $225 million, with associated operating and maintenance expenditures of $11.7 million and a power requirement of 116 MW. In Alternative 1, the delivery system capital expenditures are decreased to $36.7 million, with replacement at 15 years being $20.8 million and operating and maintenance expenditures of $367 thousand. Power requirements for the delivery system were decreased to 54 MW. In Alternative 3, export transportation capital costs were decreased to $56 million, replacement costs to $20.8 million, operating and maintenance expenditures to $560 thousand, and associated power requirements to 92 MW. Recreational benefits in Alternative 1 were increased to $13.1 million, while the price of water purchased by agriculture was increased to $70 (formerly $50). In Alternative 3, the price of export water was raised to $125 to account for this increased agricultural value and potential increase in municipal and industrial water value. In both Alternatives 1 and 3, the price of water to local M & I users was increased to $120. Application of these assumptions result in the values presented in Table 96. Net benefits for Alternatives 1 and 3 are still negative.

Even this set of somewhat optimistic assumptions leaves the overall project far from economic feasibility. Other sets were constructed, run through the benefit-cost analysis, and results

Table 96. Results of benefit-cost analysis with improved technology, Alternatives 1 and 3, optimistic assumptions, Tularosa basin energy-water complex, New Mexico

Discount Rate	Net Benefits	B/C Ratio	Total Benefits	Capital Cost	O&M Cost	Replacement Cost
	- - - - - - - -	- - - - - - - -	- - (million $)- -	- - - - - - - -	- - - - - - - -	- - - - - - - -
Alternative 1--Nuclear Reactor-Desalting-Agriculture						
5%	-536.570	0.718	3848.652	1885.425	2482.288	17.509
6%	-594.391	0.694	3568.735	1925.249	2222.689	15.189
8%	-704.628	0.651	3132.447	2007.748	1817.852	11.1475
10%	-810.662	0.615	2814.455	2094.185	1522.218	8.714
Alternative 3--Nuclear Reactor-Desalting-Water Export						
5%	-230.382	0.858	3864.310	1604.534	2472.650	17.509
6%	-283.978	0.828	3579.965	1634.696	2214.058	15.189
8%	-382.439	0.776	3136.631	1696.802	1810.793	11.475
10%	-473.016	0.733	2813.343	1761.338	1516.308	8.714

subsequently examined. Some improvement in both net benefits and the B/C ratio did occur. However, in all cases the results still fall far short of reaching the point of just breaking-even (net benefits of zero).

The only positive result of special interest from the above analysis was in the area of recreational benefits. A $5 to $17 per-visitor-day range is probably more realistic and representative of actual recreational benefits than the suggested Congressionally imposed $2 estimate. When the higher dollar-per-visitor day ($7) was used, recreation was able to pay for itself. This means that all costs and required power inputs associated with delivering water to the storage reservoir is more than adequately covered by the $13.1 million annual recreational benefit. Table 97 summarizes the results when the delivery system and reservoir costs are dropped from the analysis (and hence the recreational benefits). However, by contrasting these results with those of Alternative 1 in Table 92, net benefits are lower (higher negative amount), leading to the conclusion that recreation priced at $7 a visitor day adds net benefits to the overall project. This was obtained even though the 7,000 acre-feet of water from reduction in reservoir evaporation and conveyance losses was not added to net water sales.

Solar power and solar desalting are additional alternatives not explored in this study. Although the economics are currently discouraging, higher levels of funded research may rapidly lower costs. Solar distillation using glass-covered stills is estimated to cost $3/1,000 gallons or more than $900/acre-foot. Estimates of solar thermal power production using central receivers range from $22/MWH for base load supply to more than $70/MWH for peak load supply. Combined systems for distillation and power production have been proposed and lower costs somewhat.

The saline water resource of the Tularosa basin could also be used to produce hydrogen through electrolysis. Recent technical improvements may reduce costs of hydrogen produced from water to levels comparable to imported natural gas. Clearly solar, geothermal, or nuclear power could provide the necessary energy resource in the Tularosa basin, perhaps resulting in gas piped north in the Rocky Mountain states as a substitute for dwindling natural gas or for direct use in coal gasification plants.

Finally, if the hot, dry rock geothermal experiments currently underway at Los Alamos Scientific Laboratory prove successful, and suitable well sites can be found near the Tularosa basin, this source of low-cost energy could produce desalted water at $84/acre-foot. However, this estimate should be qualified, since hot, dry rock geothermal energy is presently an unproven resource.

Table 97. Results of benefit-cost analysis with improved technology for Alternative 1, optimistic assumptions and no recreation or associated facilities, Tularosa basin energy-water complex, New Mexico

Discount Rate	Net Benefits	B/C Ratio	Total Benefits	Capital Cost	O&M Cost	Replacement Cost
	- - - - - - - -	- - - - - - - -	- - (million $)-	- - - - - - - -	- - - - - - - -	- - - - - - - -
Alternative 1--Nuclear Reactor-Desalting-Agriculture						
5%	-580.811	0.687	3715.636	1847.808	2441.136	7.504
6%	-626.130	0.669	3453.667	1887.448	2185.840	6.509
8%	-716.846	0.637	3045.367	1969.580	1787.715	4.918
10%	-808.543	0.607	2747.824	2055.650	1496.982	3.735

CHAPTER XII

CONCLUSIONS

In the preceding chapter possible alternatives for construction of an energy-water complex in the Tularosa basin of New Mexico were evaluated according to the criterion of economic efficiency. The results in discounted net values used to assess the feasibility of the project were essentially negative; that is, values were less than zero for full-scale development. Modifications of the original concept improve the potential but do not justify further consideration of desalting large quantities of saline water in the Tularosa basin at the present time. The results of the preliminary feasibility study are summarized as follows:

> The complete energy-water complex, Alternative 1, appears infeasible for two primary reasons. First, current desalting technology is capital intensive and too costly to allow feasibility for any reasonable projection of water values even when waste heat from power production was available, in fact, feasibility would require an increase in water values to $221 per acre-foot for all uses at a six percent discount rate. Second, capital costs and power drawdowns for storing water for agriculture are prohibitive in relation to the potential value of the water. In Alternative 3, where water is exported to the Rio Grande, value needs to be $187 per acre-foot to achieve feasibility. This value approaches minimum system cost of $149 per acre-foot for producing desalted water, not including transportation costs. Projected local uses cannot justify production of desalted water at this cost. Desalting, even in conjunction with a dual nuclear plant and mineral recovery from reject brine, is not economically feasible with current technology on the scale proposed for the Tularosa basin. But nuclear power production using brine water for cooling, Alternative 2, may be feasible and the possibility of constructing a nuclear energy park in the Tularosa basin may merit investigation. This decision would depend essentially on environmental risks not considered in the preliminary analysis.

The remainder of this chapter presents a simplified economic analysis of the proposed desalting complex and summarizes briefly the overall conclusions and recommendations of this study.

SIMPLIFIED ECONOMIC ANALYSIS

This simplified economic analysis is based on a fixed-charge rate (FCR), which allows cross comparisons between the benefit-cost present-value approach used previously and the more common levelized fixed-cost approach. The fixed charge rate is a procedure normally used by the utility industry to translated unit capital costs to annual capital charges (ADL, 1974). (See also: The Aerospace Corp., 1975; USDI, 1971; IAEA, 1964; IAEA, 1972; IAEA, 1970; IAEC, 1968).

Table 98 presents an analysis of nuclear desalting at an FCR of 7.92 percent. This means that levelized fixed costs in each operating year are 7.92 percent of initial capital investment. Note that the cost per acre-foot of desalted water is $149, which corresponds to the "break-even" price in the discounted present value analysis for an interest rate of six percent. Thus, an interest rate of six percent in the present value analysis is equivalent to an FCR of 7.92 percent. Similarly, the high interest rate of 10 percent used in the discounting approach is equivalent to an FCR of 12.53 percent, and in both cases the cost of desalted water would be $212 per acre-foot.

Table 99 presents data on FCR's for selected private and municipal utilities as a function of important financial parameters. This table shows that the interest rates used in the discounted present value B/C analysis correspond to FCR's for municipal utilities, but that even the highest rate chosen, 10 percent, corresponds to an FCR of 12.53 percent, less than the lowest private FCR of 15.4 percent. Since the project as originally conceived was to be publicly developed, the range of implicit capital charges used in the analysis seems appropriate.

Table 98. Analysis of nuclear desalting using a fixed charge rate (FCR) of 7.92 percent, Tularosa basin energy-water complex, New Mexico

	Capital Outlays	Replacement Cost	Annual O & M Costs	Annual Power Costs @ $10/MWH
	-(million $)-			
Nuclear Plant	974.00		119.10	
Desalting Plant	300.00		13.80	11.30 (129 MW)
Well field	98.00	15.60 (15 yrs)	.44	7.71 (88 MW av)
Mineral Recovery	109.30		27.30	13.32 (152 MW)
Totals	1,481.30	15.60	160.64	32.33
Levelized Annual Costs	117.32	.62	160.64	32.33

	(million $)
Sum Levelized Annual Costs	310.91
less: power sales	175.20
mineral sales	67.70
Net Annual Costs	68.01
Cost/acre-feet ($68.01 x 10^6/455,000 acre-feet)	149.00/acre-foot

Table 99. Levelized fixed charge rates (FCR) for selected private and municipal utilities as a function of financial parameters

Financial Parameters	Private Utility									Municipal Utility			
	15.4	15.9	19.1	18.6	17.6	19.6	19.8	18.9	19.6	8.5	9.3	10.1	10.9
	-(interest rate)-												
Cost of Common Equity	10	10	12	12 →	→	→	→	→	→	N/A →	→	→	→
Cost of Preferred Equity	6	-	-	6 →	→	→	→	→	→	N/A →	→	→	→
Cost of Long-Term Debt (before taxes)	6	6	8	8 →	→	→	→	→	→	5	6	7	8
Percent of Common Equity	40	50		40 →	→	→	→	→	→	N/A →	→	→	→
Percent of Preferred Equity	10	-	-	10 →	→	→	→	→	→	N/A →	→	→	→
Percent of Long-Term Debt	50 →	→	→	→	→	→	→	→	→	100 →	→	→	→
Composite Corporate Tax Rate	40 →	→	→	→	→	→	50	40 →	→	0 →	→	→	→
Cost of Capital (after taxes)	6.4	6.8	8.4	8.0 →	→	→	7.6	8.0 →	→	5.6	6.0	7.0	8.0
Plant Operating Life Time	30 →	→	→	→	→	→	→	25	20	30 →	→	→	→
Local Taxes of Payments (percent of orig. inv.)	2 →	→	→	→	1	3	2 →	→	→	2 →	→	→	→

Source: *Solar Thermal Conversion Mission Analysis*, Volume I, Summary Report--Southwestern United States, The Aerospace Corporation, 1975.

Interpretation of the results in Table 98 is straightforward. The cost of desalted water shown here is at the plant and does not include expenses of storage, transportation, etc. This cost, compared to the value of the water over the potential range of uses ($50 per acre-foot for agriculture to $100 for municipal and industrial uses) shows the infeasibility of the desalting complex.

SUMMARY

Since the Executive Summary condensed the major research results of this study, the conclusions are stated briefly.

- DESALTING WATER IN THE TULAROSA BASIN ON THE PROPOSED SCALE OF 500,000 ACRE-FEET PER YEAR IS NOT ECONOMICALLY FEASIBLE.
- PRODUCTION OF NUCLEAR POWER USING BRACKISH WATER FOR COOLING APPEARS MARGINALLY FEASIBLE IF CUMULATIVE ENVIRONMENTAL COSTS AND RISKS ARE NOT TOO SEVERE.
- LAND FOR DEVELOPMENT OF AGRICULTURE, INDUSTRY, AND MUNICIPAL NEEDS IS NOT A LIMITATION, BUT ACQUISITION OF MORE SUITABLE LAND IN MILITARY USE WOULD PRESENT PROBLEMS.
- ANALYSIS OF THE MARKET POTENTIAL FOR ELECTRICITY PRODUCED IN THE TULAROSA BASIN SUGGESTS THAT 45,000 MW(E) WILL BE NEEDED FOR THE SOUTHWEST BY 1990, BUT IF THE PRICE INCREASES 3.5 PERCENT PER YEAR, ADDITIONAL REQUIREMENTS WILL BE LIMITED TO REPLACEMENT CAPACITY.
- THE FEASIBILITY OF MINERAL BY-PRODUCT SALES DEPENDS ON THE POTENTIAL RECOVERY OF CERTAIN MINERALS AND TRANSPORTATION COSTS TO MARKET, BUT EVEN SUBSTANTIAL SALES WOULD ONLY PARTIALLY OFFSET THE HIGH COST OF DESALTED WATER.
- EXPORTATION OF DESALTED WATER FROM THE TULAROSA BASIN IS ECONOMICALLY INFEASIBLE UNTIL THE PRICE OF WATER INCREASES BUT APPEARS A MORE LIKELY ALTERNATIVE THAN LOCAL USE FOR AGRICULTURE BECAUSE OF HIGHER-VALUED USES IN THE RIO GRANDE OR PECOS RIVER BASINS.
- THE ANALYSIS OF THE PROPOSED WELL FIELD WAS BASED ON AN OPTIMISTIC EVALUATION OF EXISTING VERY LIMITED HYDROLOGIC DATA: ACTUAL COST COULD BE SUBSTANTIALLY HIGHER AND OTHER SITES MAY PROVE TO BE MORE FAVORABLE.
- DATA ON GEOTHERMAL POTENTIAL OF THE TULAROSA BASIN ARE INSUFFICIENT TO EVALUATE THIS POTENTIAL SOURCE OF ENERGY FOR DESALTING WATER.

SUMMARY RECOMMENDATIONS

- AN EXTENSIVE PROGRAM OF HYDROLOGIC DATA COLLECTION, ANALYSIS, AND MODELING WILL BE REQUIRED FOR DETAILED EVALUATION AND DESIGN OF THE PROPOSED WELL FIELD.

- A similar program of data collection and analysis should be considered to assess the geothermal potential of the Tularosa basin.
- The comparibility of the proposed nuclear desalination complex or energy park with current military activities in the project area should be evaluated.
- Potential legal barriers to land acquisition should be investigated.
- Alternative desalination technologies and a nuclear center including dual-purpose facilities should be evaluated. High-value uses for variable quantities of desalted water may justify some dual-purpose capability.
- Alternative technologies, including solar and geothermal energy for the potential use of the saline water resources on the Tularosa basin should be explored.

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