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LEAST COST INVESTMENT PLAN KRASNODAR POWER GENERATION PROJECT

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DEFINITION OF TERMS USED IN THIS REPORT

CURRENCY

Dollars are U S Dollars as of Jan 1 1995
Current day Ruble costs have been converted at 4550 Rubles per U S Dollar

UNITS OF MEASURE

1 BTU (British Thermal Unit)	= 1055 Joules
1 Joule	= 0 239 Calories
1 Standard Cubic Meter of Natural Gas	= 38 0 Kilojoules
1 Ton	= 1000 Kilograms
1 Ton of Crude Oil	= 41 8 Gigajoules

TERMS

Capacity Factor (%) equals the yearly number of equivalent full load hours of operation divided by 8760 hours per year

Heat Rate (BTU/kWh) equals quantity of heat required to produce one kilowatt of electricity, or an equivalent amount district heat

CHAPTER 1
EXECUTIVE SUMMARY

The Krasnodar Krai region of southern Russia, which is part of the North Caucasus Unified Power System (UPS), has been experiencing electricity shortages and disruptions for the past few years A group of Russian companies composed of Kubanenergo, RAO EES Rossii, Gasprom and others (Project Owners) is planning the Krasnodar Power Generation Project This Project will address the region's need for additional power generation capacity by building one or more power generation facilities The World Bank has reviewed the Project Owners' plans and believes the project may be appropriate for Bank financing support The purpose of this study task (Task 1) is to assess the need for the proposed project and evaluate its economic merits Based on the results of this task, work will proceed on the preparation of detailed business plans and technical and environmental feasibility studies for appraisal by the World Bank

1.1 PROJECT JUSTIFICATION

The North Caucasus UPS has an acute electricity generation capacity deficit that is affecting the quality of supply The system has a combined installed capacity of 10,557 MW, including 2,180 MW of hydro and 8,337 MW of fossil capacity In the past, the North Caucasus region received substantial quantities of power from Russia's Center UPS (through Ukraine) and additional power directly from generating plants within Ukraine This interconnection became unreliable, and it is now no longer in operation While a recent drop in consumption has provided some respite, the projected power deficit is expected to reach approximately 2,000 MW by 2000, assuming that most of the aging existing capacity can be kept in operation

The region with the greatest power deficit within the North Caucasus is the Krasnodar Krai, which relies on imports from neighboring Energos for 60% of its electricity consumption Because the local utility, Kubanenergo, has equipment that is in general 20 to 40 years old, the deficit will deepen further as the aging units become less reliable and must ultimately be retired To address this deficit, Kubanenergo is planning to install up to 900 MW of combined cycle capacity at Krasnodar, a 300 MW combined cycle plant at Novorossiysk, and another 1,350 MW combined cycle plant at Mostovskoy

1.2 LEAST-COST PLAN

The purpose of Task 1 is to evaluate proposed projects as potential elements of a least-cost investment program to address the electricity needs of the North Caucasus UPS, with emphasis on the Krasnodar Krai The task involved a detailed assessment of the needs for electricity and district heating in the Krasnodar Krai, and an evaluation of the supply options available within the North Caucasus UPS and from neighboring power grids in Russia and Ukraine to determine the most economical plan to alleviate the North Caucasus' power shortage

1.3 SUMMARY OF RESULTS

The North Caucasus is in need of substantial generation capacity additions in the immediate future At this time, there is a program of Hydroelectric plant additions, totaling 160 MW, that is scheduled to bring capacity on line gradually between 1996 and 2000 In addition, a 500 kV transmission link with the Center UPS is scheduled to be completed in 1997 This will provide an additional 550 MW of firm capacity to the region There is also a current program to replace 159 MW of aging boiler equipment and 190 MW of combustion turbines at the Krasnodar TETS site with a 450 MW CHP/Combined cycle plant Even with these additions there is a pressing need for building new gas fired power plants

With regard to gas fired plants, the study has found that there is a need for the addition of approximately 900 MW of new thermal capacity in the North Caucasus in 1998, this is the earliest date that is considered feasible for commissioning new units The study has also determined the need for about 300 MW additional capacity in 1999, and for approximately 400 MW of capacity in 2000 This will be necessary to maintain a system reserve margin of 14 percent, which is considered to be the minimum for assuring reliable system operations These capacity additions would bring the total gas fired capacity additions for the North Caucasus UPS to 1600 MW during the next five years Figure 1- 1 illustrates the need to add capacity in the region as demand grows and retirements reduce the capacity available from existing units The data used in preparing Figure 1 -1 is presented in Table 1 - 1 The table indicates that a potential capacity shortage, ranging from 664 to 928 MW, will exist in the region through 1997 To eliminate the shortage, it will be necessary to extend the life of some of the units that have been scheduled to be retired through 1998 This is necessary because there is no practical possibility for adding new generating capacity before that year

Regarding the general location of the new capacity, it appears that Krasnodar Krai is the most likely area in the North Caucasus for substantial capacity additions because over 600 MW of existing capacity is scheduled to retire before 2000, and the region is already heavily dependent on other regions for power, a situation that impairs the reliability of electricity service and results in excessive transmission losses Of the three potential sites, only the Mostovskoy site is available for the addition of new capacity in 1998 and, it is initially limited to the addition of simple cycle gas turbines due to construction lead time The other two sites are expected to require an additional year or two of

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lead time because of the need for environmental studies to verify that they would be appropriate for building new power plants

While the Mostovskoy site offers the advantage of early development, it has a disadvantage, in that it is not located near the major load centers in the region The Krasnodar and Novorossiysk sites are located at major load centers, and they may also offer the opportunity for improved economic efficiency through their use as Combined Heat and Power Plants (CHP) Because work has already been started on a replacement of the oldest existing units at Krasnodar TETS, and because of its timing advantage, the next project for the addition of new capacity should be done at Mostovskoy However, recognizing the advantages of having plants located near load centers, it is likely that plant additions after 2000 could be most attractive at Novorossiysk, subject to further investigation of the advantages of that site

The following list gives a ranking of Combined Cycle options starting with the lowest cost alternative The cost of electric power production includes the cost of new transmission facilities and gas pipelines as required for each site Rankings have also been done for simple cycle plants, these appear in Chapter 5 (Production costs below are at 80% capacity factor)

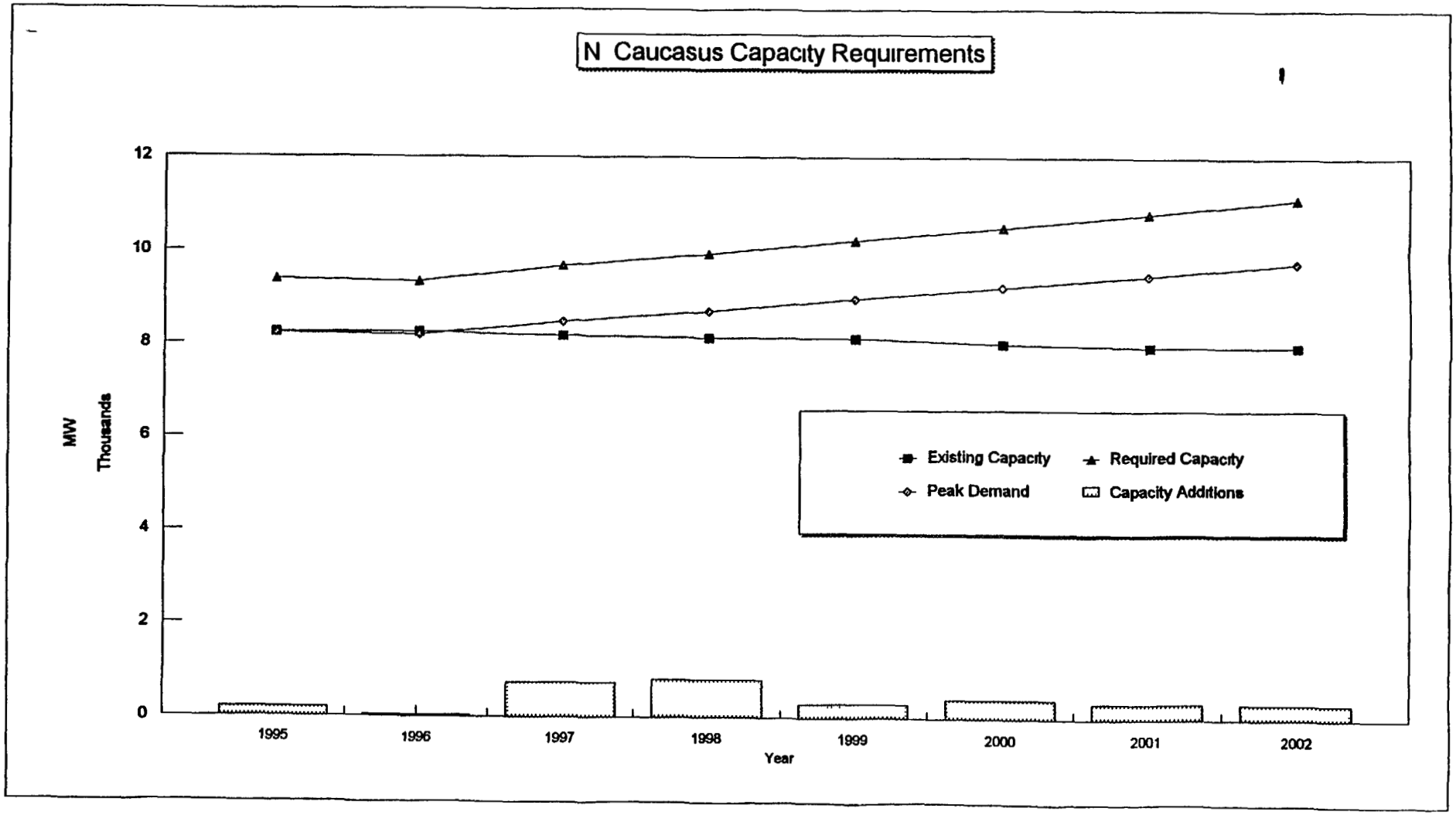
Site	Capacity	Production Cost, $/kWh
Krasnodar CC/CHP	450 MW	0236
Mostovskoy CC	900 MW	0318
Novorossiysk CC/CHP	450 MW	0320
Novorossiysk CC	450 MW	0320
Krasnodar CC	450 MW	0333
Mostovskoy CC	450 MW	0339

Considering all of the above factors the following is considered to be the best approach to meeting needs for immediate capacity additions while keeping the long term costs to a minimum

Mostovskoy - 600 MW Simple cycle addition for 1998-99 operation, with conversion to combined cycle operation in 1999 or 2000 based on construction scheduling and demand growth

Krasnodar - replacement of the two existing 95 MW simple cycle in 1997 and 1999, with conversion to combined cycle in 1999

Novorossiysk - 300 to 600 MW simple cycle for operation in 2001, with partial conversion to combined cycle if and when CHP operation is shown to economical


N Caucasus Capacity Requirements
MW
Thousands
12
10
8
6
4
2
0
1995
1996
1997
1998
1999
2000
2001
2002
Year
Existing Capacity
Required Capacity
Peak Demand
Capacity Additions

ESTIMATION OF REQUIRED CAPACITY NEEDS FOR NORTH CAUCASUS

Year	Existing Capacity MW	Peak Demand MW	Required Capacity MW	Committed Hydro Additions MW	Committed Trans Additions MW	Required Fossil Additions MW	Total Capacity Additions MW
1994	8562	8616*					
1995	8243	8220	9371	0	200	0	200
1996	8243	8180	9325	40	0	0	40
1997	8168	8475	9662	40	550	150**	740
1998	8130	8697	9915	40	0	765	805
1999	8130	8967	10222	40	0	268***	308
2000	8004	9212	10502	0	0	405	405
2001	7959	9471	10797	85	0	255	340
2002	7955	9753	11118	85	0	240	325
2003	7660	10018	11421	85	0	512	597
2004	7255	10293	11734	85	0	634	719
2005	7128	10588	12070	0	0	463	463

* Includes 110 MW of unserved demand
** 150 MW committed addition at Krasnodar TETS
*** Includes 250 MW committed additions at Krasnodar TETS

CHAPTER 2
CURRENT ELECTRIC SUPPLY SITUATION

The North Caucasus UPS is one of seven major regional power grids or Unified Power Systems within Russia It is currently connected with the Center UPS, which in turn is connected with the other UPS grids The North Caucasus UPS is also connected to the grids to the south in adjacent countries that were previously members of the USSR. In addition, there is a connection to the Ukrainian power grid, but this connection is currently not operational

In the past for economic and policy reasons, the North Caucasus relied on regions to the north and east for much of its power supply The North Caucasus is not well endowed with the natural resources used for power generation, and substantial amounts of inexpensive energy were available from large nuclear, fossil and hydroelectric generating stations in those regions The bulk of the power imported into the region flowed through what is now Ukraine Following the dissolution of the USSR, political and technical problems have developed that have caused the supply of power from Ukraine to become unreliable This has resulted in the current power shortage problem in the North Caucasus

2.1 ELECTRICITY SUPPLY

The North Caucasus's installed capacity was 10,557 MW at the end of 1994 This included 2,180 MW at the region's 88 hydroelectric generating units and 8,377 MW from its 73 fossil units Last year fossil fueled power production accounted for 82% of all electricity produced within the region, hydroelectric power accounted for 10%, and the balance was provided from imports

There is no nuclear generation capacity in the region. However, at one time nuclear power was planned for the North Caucasus Work was begun on two plants, one at a site near Rostov-on-Don and another at Mostovskoy in Krasnodar Krai. The work on the Rostov Plant site has proceeded, and the plant is now within 70 to 95% of completion (estimates of its status vary) Work at the Rostov site is currently suspended, however, while Minatom pursues approvals and funds to put the plant into operation. The Mostovskoy Nuclear Project was converted to a fossil plant shortly after the site was acquired due to public pressure Work at the site is now on hold pending the approval of funding This is the site of the Mostovskoy projects reviewed in this study

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The region has and continues to be a net importer of power from other regions Imports totaled 5,061 million kWh or 9% of total consumption in 1993, and 3,991 million kWh or 8% of total consumption in 1994 Historical data on generation capacity and power production for the North Caucasus region are shown in Table 2-1

Table 2-1
North Caucasus Capacity and Generation

Generation Source	Generation Mill kWh		Installed Capacity (MW)		Average Capacity Factor (percent)	
	1993	1994	1993	1994	1993	1994
Hydroelectric	6,872	5,065	2,180	2,180	36 0	26 5
Conventional Thermal	34,181	31,640	6,090	6,090	64 1	59 3
Combined Heat and Power	9,621	8,820	1,977	1,977	55 5	50 9
Imported Power	5,061	3,991				
Total	55,735	49,516	10,247	10,247	56 7	51 0

The region includes nine Energos or electric utility companies, all but one, Kalmenergo, generate power Their capacities and 1993 generating levels are shown in Table 2-2

Table 2-2
1993 Capacity and Generation by Energo

Utility	Total Capacity MW	Fossil Capacity MW	Hydro Capacity MW	1993 Production Mill. kWh
Kubanenergo	924	838	86	5,648
Stavropolenergo	4,215	3,750	465	22,502
Dagenergo	1,339	20	1,319	3,972
Grozenergo	489	489	0	2,016
Rostovenergo	3,174	2,970	204	16,077
Three others	106	0	106	477
Total	10,247	8,067	2,180	50,647

RETIREMENT PROGRAM

Approximately 4400 MW of thermal plant capacity are scheduled for retirement between the years 1995 and 2005 Table 2-3 presents the attrition of this capacity as a function of retirement date The projected retirement dates are based on a life of forty (40) years which includes life extension for each plant A large number of operating plants have already passed their projected retirement dates, and others are scheduled to retire in the next few years Because it is not possible to build replacement capacity for these units before 1998-9, it is apparent that a program for rehabilitation or life extension must be continued, if power shortages are to be averted (A detailed list of unit retirements is given in Appendix A.)

Table 2-3
Retirements by Year
(MW)

Retirement Date	Available Capacity	Rated Capacity
1995	319	735
1996	0	0
1997	75	95
1998	38	50
1999	0	0
2000	126	165
2001	45	60
2002	4	6
2003	295	314
2004	405	462
2005	127	150
Total	**1434**	**2037**

2.2 ELECTRICITY DEMAND

Electricity demand in Russia has been declining steadily since 1990 Table 2-4 shows recent annual consumption figures for the North Caucasus and the Krasnodar Krai

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Table 2-4
Recent Electricity Consumption*

	North Caucasus		Krasnodar Krai	
Year	Bill kWh	Index	Bill. kWh	Index
1990	63 2	1 00	17 5	1 00
1991	63 3	0 92	16 4	0 94
1992	58 5	0 93	15 3	0 93
1993	55 6	0 88	15	0 86
1994	50 4	0 80	13 5	0 77

* Total consumption (includes line losses and own usage)

The major factor affecting the decline has been decreasing industrial activity Electricity consumption by the industrial sector declined by 53% in Krasnodar Krai between 1990 and 1994, and only the residential sector had an increase in demand during that period The decline in demand is expected to level off during 1995, and demand is expected to begin growing at about 4 to 5% annually based on current projections of economic activity for Russia and the North Caucasus region in general (Details of the trends in past and projected electricity consumption are given in Appendix C)

With regard of peak load, there has also been a decline in recent years as industrial activity in the region slowed In 1990 the peak load for the North Caucasus was 10,375 MW, peak load declined to 8674 MW in 1993, and to 8506 MW in 1994 The peak for the current year to date is 8127 MW, this may represent the high for the year as historically the annual peaks have occurred in January, February or December

2.3 HEAT DEMAND

Heat demand has also been declining in North Caucasus and Krasnodar Krai since 1990 The rate of decline has been similar to that of electricity, with most of the decline occurring in the industrial sector Table 2-5 below illustrates the recent trend in heat consumption in North Caucasus and Krasnodar Krai

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Table 2-5
Recent Heat Annual Consumption *

	North Caucasus		Krasnodar Krai	
Year	Mill. Gcal	Index	Mill. Gcal	Index
1990	103	1 00	28	1 00
1991	98	0 95	27	0 96
1992	87	0 84	25	0 89
1993	84	0 82	23	0 82
1994	84	0 82	20	0 71

* Total consumption (includes distribution losses and own usage)

Heating needs are expected to continue to decline until 1996 and then to resume growing at about 3% per year through 2005 (Additional details on the recent trends and projections for heat consumption are included in Appendix C) Heat consumption has been declining somewhat more rapidly than electricity consumption and will continue for a slightly longer period The overall difference is about a 10% reduction in heating relative to electricity use While this is significant, it is not expected to have a major impact on the application of combined heat and power (CHP) electricity generation. For this reason the study has gone forward on the assumption that existing CHP capacity should be replaced in the case of unit retirements and that new base load capacity should take advantage of CHP opportunities in the selection of plant sites

In considering sites for the Krasnodar Power Project, two major district heat demand centers were identified the city of Krasnodar and the rapidly developing port city of Novorossiysk Krasnodar has a base heat demand of 380 Gcal/hr and a peak demand of 1,950 Gcal/hr, while Novorossiysk has a base demand of 120 Gcal/hr and a peak demand of 525 Gcal/hr Only these two locations are considered likely candidates for the installation of a major CHP plant While there are other cities in Krasnodar Krai that could use heat from CHP plants, they were not considered large enough to make effective use of the heat that would result from plants of the size under consideration (450 MW and up)

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2.4 CURRENT INTERREGIONAL TRANSMISSION CAPACITY

The current interregional capacity for transferring major quantities of power is two long 220 kV lines connecting the North Caucasus to the Center UPS About 500 MW of power can be delivered to the region, only 200 MW of this can be considered as firm. A 500 kV transmission reinforcement project is currently underway that will increase the transfer capacity to 900 MW, of which 750 will be firm capacity Further reinforcements are under consideration to make up for the loss of transmission capacity through Ukraine (Details regarding Transmission options are presented in Appendix B)

2.5 NEED FOR ELECTRIC GENERATING CAPACITY

As can be seen from the above discussion and Table 2-6 below Krasnodar Krai is highly dependent on other regions to provide its power needs This dependency is endangering electricity supply reliability in the region, it also results in unnecessary transmission losses The situation there is reported to be resulting in adverse economic and environmental impacts, since much of the existing capacity is old, inefficient, and difficult to maintain properly The demand for power in the region is not being met due to reliability problems and an overall shortage in capacity This situation will only worsen with growing demand If the system is to become reliable, there is a pressing need to provide new and replacement plants in Krasnodar Krai to meet current and projected power and heat demand levels

Table 2-6
Electricity generation Versus Consumption
Billion Kwh

	North Caucasus			Krasnodar Krai		
	Generation	Consumption	%	Generation	Consumption	%
1993	50 6	55 6	91	5 6	15 0	37
1994	45 5	50 4	90	5 9	13 5	44

CHAPTER 3
OPTIONS FOR HEAT AND POWER SUPPLY

Because the North Caucasus is deficient in generation capacity, investment in new facilities is required to meet the region's current and future electricity demand The need for additional capacity can be met through a combination of constructing new generation capacity, importing additional power from neighboring regions, and completing already-committed hydroelectric and nuclear projects Heat demand will be met through a combination of combined heat and power plants and single-purpose boiler plants

Within the North Caucasus region, the Krasnodar Krai has the greatest need for additional capacity All power generation technologies can be considered to meet this capacity requirement However, the results of the JEPAS study indicated that coal-fired power plants have high delivered fuel costs, and gas- and mazut-fired steam plants are not as efficient as (and therefore not competitive with) modern combustion turbine combined cycle plants

3.1 CANDIDATE PROJECTS FOR THE KRASNODAR KRAI

Kubanenergo has identified three future generation sites in Krasnodar Krai Mostovskoy, Krasnodar and Novorossiysk Because the Krasnodar and Novorossiysk plants can serve a significant district heating load, a combined heat and power plant has been considered for them At Mostovskoy, the heating requirements of the adjacent settlement will be met by the power plant, however, this is a small load The Mostovskoy plant is considered a power-only plant in this evaluation

Site-specific costs were developed for a range of plant configurations The generation technologies considered are limited to combustion turbine applications, both simple cycle and combined cycle power plants for power only or combined heat and power plants Table 3-1 identifies the alternate plant configurations that are being considered as candidates to meet the future electric demand of the Krasnodar Krai

Plant Capacity Plant configurations are based on a 150 MW capacity combustion turbine This unit size represents an advanced design of high efficiency, and has demonstrated operating experience The typical combined cycle power block would have two combustion turbines (300 MW total) and one steam turbine generator (150 MW) for a total capacity of 450 MW Multiple

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blocks would be built to produce additional power Power plants from 300 MW to 1,350 MW are considered

Staged Construction. In developing an investment plan that reflects the timing of capacity needs, it may be desirable to build multiple blocks of power at the same site, but with blocks spaced more than one year apart Under this scenario, the first stage of construction would include higher costs to accommodate future plant expansion For example, the gas pipeline would be sized for the final capacity and a majority of the transmission lines, site roads and infrastructure would be built in the first stage

Table 3-1 includes alternates for staged construction As an example, Cases 5a and 5b represent a 900 MW plant built in two stages, while Case 6 represents the same 900 MW plant built at one time

3 1 1 Mostovskoy Project

Simple cycle combustion turbines and combined cycle power plants up to a capacity of 1,350 MW are considered for Mostovskoy The plants would be built at the site that is now under development by Kubanenergo A new gas pipeline and large transmission system investment are required for this project

The design of the gas pipeline for the Mostovskoy site is based on information provided by Kuban Gazprom for the 1,350 MW plant at an April 1995 meeting The design basis is as follows

Distance	60 km
Pressure	5 5 MPa
Size	one 400 mm diameter line for 300 MW (simple cycle) or 450 MW (combined cycle) one 500 mm diameter line for 600 MW (simple cycle) or 900 MW (combined cycle) one 700 mm diameter line for 1,350 MW (combined cycle)

The line is assumed to be routed underground

Kubanenergo discussed the need for two lines to the power plant, one for the primary fuel and one to supply backup fuel Because of the very high cost of the pipeline, this is not considered to be cost-effective The backup source of supply should be routed through the primary line

The transmission system interconnection work consists of the following projects

Table 3-1

PLANT CONFIGURATIONS

SITE/CASE #	DESCRIPTION
MOSTOVSKOY	
1	300 MW Simple Cycle
2a	300 MW Simple Cycle - First Stage
2b	300 MW Simple Cycle - Second Stage
3	600 MW Simple Cycle
4	450 MW Combined Cycle
5a	450 MW Combined Cycle - First Stage
5b	450 MW Combined Cycle - Second Stage
6	900 MW Combined Cycle
7a	450 MW Combined Cycle - First Stage
7b	450 MW Combined Cycle - Second Stage
7c	450 MW Combined Cycle - Third Stage
8	1350 MW Combined Cycle
KRASNODAR	
9	300 MW Simple Cycle
10	450 MW Combined Cycle /CHP
11a	450 MW Combined Cycle - First Stage/CHP
11b	450 MW Combined Cycle - Second Stage/CH
12	900 MW Combined Cycle /CHP
NOVOROSSIYSK	
13	300 MW Simple Cycle
14	450 MW Combined Cycle/CHP

1 Up to 600 MW 220 kV (250 km) from Kurgannaya to Zilposelok, including rerouting existing lines via the Krasnodar Plant

500 kV (44 km) reroute line Tzentralnaya - Zelenchukskaya via the Krasnodar Plant

2 Up to 900 MW add 220 kV (120 km) from the Krasnodar Plant to Cheremushki

3 Up to 1,350 MW add 500 kV (280 km) from the Krasnodar Plant to Krymskaya

3 1 2 Krasnodar Project

Simple cycle combustion turbines and combined cycle power plants operating in a combined heat and power mode up to a capacity of 900 MW are considered for the existing Krasnodar TETS site Based on information provided by Gazprom, 60 km of existing pipeline will need to be replaced to accomodate expansion of the power plant In addition a booster compressor will be required

The transmission system interconnection work consists of the following projects

1 Up to 450 MW 220 kV (25 km) from the Krasnodar Plant to Alipskaya

500 kV (180 km) from Krymskaya to the Krasnodar Plant to Tzentralnaya

2 Up to 900 MW add 220 kV (50 km) from the Krasnodar Plant to Vitamincombinat

3 1 3 Novorossiysk Project

Simple cycle combustion turbines and combined cycle power plants operating in a combined heat and power or condensing mode up to a capacity of 450 MW are considered for Novorossiysk A specific site has been identified by Kubanenergo but site studies have not been performed No cooling water is available at the site

The district heating system in Novorossiysk consists of local sytems around individual boilier houses A new CHP plant would include a district heating trunk pipeline (700 mm underground pipe, 10 km long) to connect to the centralized district heating system

The existing gas pipeline to Novorossiysk does not have adequate capacity and pressure to meet the requirements for this additional capacity Based on information provided by Gazprom, a new pipeline from the Kushevskoye underground storage reservoir to Krasnodar, and a new pipeline from Krasnodar to Novorossiysk will be required Of the total length of new pipeline required, 200 km will be assessed to the power plant

The transmission system interconnection work consists of the following projects

1 Up to 450 MW 220 kV (25 km) from the Krasnodar Plant to Alipskaya
500 kV (180 km) from Krymskaya to the Krasnodar Plant to Tzentralnaya

2 Up to 900 MW add 220 kV (50 km) from the Krasnodar Plant to Vitamincombinat

3.2 CANDIDATE PROJECT CAPITAL AND OPERATING COSTS

3 2 1 Power Plant Capital Costs

A summary of the capital costs for each power plant configuration is presented in Table 3-2 The cost estimates for the simple cycle and combined cycle power plants are based on plant design and site information learned in meetings with Kubanenergo and Rostov Teploelectroproject in April, as well as visits to the Mostovskoy and Krasnodar sites

In estimating the costs it has been assumed that the combustion turbines, heat recovery steam generators, steam turbines, and the distributed control systems will be procured under international competitive bidding which will allow both foreign and Russian suppliers For the purpose of this cost estimate U S prices were used Owner's costs and allowance for contingencies are included Taxes and duties are not included

It was assumed that a dry cooling tower would be required at the Mostovskoy and Novorossiysk site because of environmental and other considerations At Krasnodar the existing once-through cooling system was assumed, however, further investigations will be required

Previous cost estimates for the Krasnodar Power Generation Plant (Mostovskoy site) are based on 1991 costs in Rubles and have not been updated In order to develop current (1995) costs, an estimate was prepared based on U S costs, and the local Russian content was converted into equivalent U S dollars using factors established in the JEPAS Specifically, U S costs were converted to Russian costs at the rate of 70% for materials, 75% for metals, and 50% for equipment Taking into account current salaries and labor productivity, Russian labor costs were assumed to be 20% of U S costs

Table 3-2

NEW PLANT CAPITAL COSTS

SITE/CASE #	DESCRIPTION	LEAD TIME (months)	CAPITAL COSTS								TOTAL $/kW
			NON RUSSIAN (1995 US $/kW)			RUSSIAN (1995 US $/kW)					
			EQUIPMENT	INDIRECT	SUBTOTAL	EQUIPMENT	MATERIALS	LABOR	INDIRECT	SUBTOTAL	
MOSTOVSKOY											
1	300 MW Simple Cycle	24	192	44	236	19	32	7	73	131	367
2a	300 MW Simple Cycle - First Stage	24	192	48	240	19	40	8	73	140	380
2b	300 MW Simple Cycle - Second Stage	18	192	44	236	17	15	5	37	74	310
3	600 MW Simple Cycle	30	192	34	226	18	23	6	44	91	317
4	450 MW Combined Cycle	30	208	37	245	52	92	24	66	234	479
5a	450 MW Combined Cycle - First Stage	30	214	40	254	61	123	27	84	295	549
5b	450 MW Combined Cycle - Second Stage	24	202	27	229	41	35	19	27	122	351
6	900 MW Combined Cycle	42	208	34	242	51	77	23	53	204	446
7a	450 MW Combined Cycle First Stage	30	220	49	269	73	149	29	103	354	623
7b	450 MW Combined Cycle - Second Stage	24	202	27	229	41	35	19	27	122	351
7c	450 MW Combined Cycle - Third Stage	24	202	27	229	41	35	19	27	122	351
8	1350 MW Combined Cycle	48	208	32	240	50	71	22	47	190	430
KRASNODAR											
9	300 MW Simple Cycle	24	192	44	236	19	31	7	57	114	350
10	450 MW Combined Cycle /CHP	30	208	37	245	52	58	22	50	182	427
11a	450 MW Combined Cycle - First Stage/CHP	30	214	39	253	61	81	24	66	232	485
11b	450 MW Combined Cycle - Second Stage/CH	24	202	27	229	41	34	19	25	119	348
12	900 MW Combined Cycle /CHP	42	208	34	242	50	57	21	43	171	413
NOVOROSSIYSK											
13	300 MW Simple Cycle	24	192	44	236	19	28	7	65	119	355
14	450 MW Combined Cycle/CHP	30	208	37	245	52	92	24	66	234	479

NOTES.

1 All configurations use combustion turbines in simple cycle or combined cycle mode with natural gas as fuel Backup Fuel is #2 oil

ASSUMPTIONS.

1 International supplied equipment includes combustion turbines HRSGs, steam turbines and distributed control systemm
2 A dry cooling tower assumed at Mostovskoy and Novorossiysk & a once through cooling system assumed at Krasnodar
3 Owner's Costs included in Indirects A Contingency of 10% included in Indirects only
4 For CHP Plants costs are included only for work inside plant boundary in regard to industrial steam and district heating
5 To allow for front end engineering and environmental work add one year to the lead time for Krasnodar and two years for Novorossiysk plants (each configuration) to determine earliest commercial operation date

3 2 2 Power Plant Operating and Maintenance Costs

A summary of the plant operating and maintenance costs and plant performance characteristics is presented in Table 3-3 for Simple Cycle and Combined Cycle power plant configurations Performance characteristics and operating costs for the district heating configurations are presented in Table 3-4

For estimating the operating and maintenance costs, the number of plant operating and maintenance personnel (including administrative and supervisory personnel) was assumed to be twice the number of people used at similar plants in the United States This number is substantially below the current staffing levels in Russian power plants Details of the staffing plan will be developed in conjunction with Kubanenergo in Task 2 of this project The assumed staffing levels are as follows

Plant Capacity	*Number of Personnel*
300 MW simple cycle	70
600 MW simple cycle	100
450 MW combined cycle/CHP	120
900 MW combined cycle/CHP	170
1,350 MW combined cycle	220

3 2 3 Costs of Settlement at Mostovskoy and Novorossiysk (Social Costs)

Although a large settlement (about 5,000 people) is planned at Mostovskoy, the scope of this settlement goes beyond what The World Bank would consider financing as part of the project's cost The Bank has indicated than appropriate project costs would include housing for the families of power plant personnel and directly related support facilities for them (e g , school, medical, recreation) Any other facilities, such as retail stores and housing for the families working in these other facilities, would need to be financed outside of the project

The subsidized housing provided to plant personnel is considered a fringe benefit that is related to the salaries paid to the personnel The total investment required for the settlement costs for the plant personnel, support personnel, and facilities is amortized over 25 years to develop an annual charge for social costs This annual charge is included in the fixed O&M budget

Sufficient housing has already been constructed at Mostovskoy to accommodate the families of the maximum level of 220 plant personnel as well as families of the support personnel Since the

Table 3-3

NEW PLANT PERFORMANCE CHARACTERISTICS AND OPERATING COSTS

SITE/CASE #	DESCRIPTION	STATION AUX LOAD (MW) (1)	NET CAPACITY (MW) (2)		NET HEAT RATE (LHV) (2)		OUTAGE RATES (%)		O & M COSTS		
			Full Load	Min Load	Full Load	Min Load	Forced	Planned	Fixed ($/kW/yr)		Variable ($/MWh
									Labor & Mat	ocial Costs (3)	
MOSTOVSKOY											
1	300 MW Simple Cycle	1 8	300	75	10 634	15 952	4	6 9	5 38	0 00	0 07
2a	300 MW Simple Cycle First Stage	1 8	300	75	10 634	15 952	4	6 9	5 38	0 00	0 07
2b	300 MW Simple Cycle - Second Stage	3 2	600	150	10,634	15,952	4	6 9	5 38	0 00	0 07
3	600 MW Simple Cycle	3 2	600	150	10,634	15,952	4	6 9	5 38	0 00	0 07
4	450 MW Combined Cycle	8 5	443	111	7,004	9,806	4 6	6 9	7 80	0 00	0 29
5a	450 MW Combined Cycle First Stage	8 5	443	111	7 004	9 806	4 6	6 9	7 80	0 00	0 29
5b	450 MW Combined Cycle - Second Stag	17	886	221 5	7 004	9,806	4 6	6 9	7 24	0 00	0 29
6	900 MW Combined Cycle	17	886	221 5	7 004	9 806	4 6	6 9	7 24	0 00	0 29
7a	450 MW Combined Cycle First Stage	8 5	443	111	7,004	9,806	4 6	6 9	7 80	0 00	0 29
7b	450 MW Combined Cycle Second Stag	17	886	221 5	7,004	9,806	4 6	6 9	7 24	0 00	0 29
7c	450 MW Combined Cycle Third Stage	25 5	1330	332 5	7,004	9,806	4 6	6 9	6 82	0 00	0 29
8	1350 MW Combined Cycle	25 5	1330	332 5	7,004	9 806	4 6	6 9	6 82	0 00	0 29
KRASNODAR (4)											
9	300 MW Simple Cycle	1 8	300	75	10,634	15,952	4	6 9	5 38	0 00	0 07
10	450 MW Combined Cycle	7	450	112 5	6,892	9,649	4 6	6 9	7 68	0 00	0 29
11a	450 MW Combined Cycle - First Stage	7	450	112 5	6,892	9,649	4 6	6 9	7 68	0 00	0 29
11b	450 MW Combined Cycle Second Stag	14	900	225	6 892	9 649	4 6	6 9	7 13	0 00	0 29
12	900 MW Combined Cycle	14	900	225	6,892	9,649	4 6	6 9	7 13	0 00	0 29
OVOROSSISYK (4)											
13	300 MW Simple Cycle	1 8	300	75	10,634	15,952	4	6 9	5 38	1 78	0 07
14	450 MW Combined Cycle	8 5	443	111	7,004	9,806	4 6	6 9	7 80	1 58	0 29

NOTES.

(1) Aux load is at full load
(2) Iso Ambient conditions Fuel natural gas Units kJ/kWh
(3) Social Costs remain constant and are amortized over 25 years
(4) Net MW and Net Heat Rate are for combined cycle plants with no district heating Performance data with district heating are being provided separately
(5) These numbers are approximate and are to be considered for the duration until the next stage is built

Table 3-4

NEW PLANT PERFORMANCE CHARACTERISTICS AND OPERATING COSTS

(Combined Cycle with District Heating)

DESCRIPTION		NET CAPACITY (MW) (1)		NET HEAT RATE (LHV) (1,4)		O & M COSTS		
		Full Load	Min Load	Full Load	Min Load	Fixed ($/kW/yr)		Variable ($/MWh)
						Labor & Mat	Social Costs (2)	
KRASNODAR (3) 450 MW Combined Cycle	winter	389	369	5 233	5 174	8 45	0 00	0 32
	spring/fall	409	307	5 855	5 840			
	summer	428	236	6,420	6,905			
900 MW Combined Cycle	winter	778	738	5,233	5,174	8 45	0 00	0 32
	spring/fall	818	614	5,855	5,840			
	summer	856	472	6,420	6,905			
NOVOROSSIYSK (3) 450 MW Combined Cycle	winter	384	364	5 307	5 247	8 45	1 58	0 32
	spring/fall	403	304	5 942	5 926			
	summer	421	232	6,517	7,008			

NOTES.

(1) Performance parameters are based upon the combustion turbine operating under iso ambient conditions, Fuel natural gas Units kJ/kWh
(2) Social Costs remain constant and are amortized over 25 years
(3) Net MW and Net Heat Rate are for combined cycle plants with district heating
(4) The maximum district heating water supply temperature from the unit is 120 deg C

economic analysis does not consider costs already incurred, the social costs for Mostovskoy are assumed to be zero

It is assumed that no additional social costs are required for the Krasnodar TETS plant since housing for plant operators already exists, and any new hires will be local people

It is assumed that at Novorossiysk, housing and related facilities will be required for one-half of the plant personnel, with the balance of the staff hired locally

3 2 4 Gas Pipeline, District Heating and Transmission Line Costs

A summary of the gas pipeline capital costs is presented in Table 3-5, while the capital costs of the transmission system interconnections are presented in Table 3-6 Transmission system losses are also identified in Table 3-6

The cost of the gas pipeline is based on the design description provided in Section 3 1 1 A current Russian cost for this pipeline is not available An estimate was prepared based on U S costs It is assumed all of the pipeline construction would be done with Russian materials and labor The Russian costs were converted into equivalent U S dollars using the factors described above for the power plant (Section 3 2 1)

It is recognized that the cost of gas pipelines will be paid by Gazprom, and included in the price charged to the project for gas However, the costs of installing gas pipelines will be different for each site, and these differences must considered in the economic analysis of the project The gas pipeline to Novorossiysk would be installed in conjunction with the replacement of the existing pipeline serving Novorossiysk A gas pipeline sized to meet both the city requirements and power plant was assumed, with the power plant project assessed a cost in proportion to its requirements

The new CHP plant at Krasnodar will connect with the existing district heating network and no costs for district heating pipelines are included The new CHP plant at Novorossiysk includes a 10 km pipeline to connect to the district heating system This new pipeline is estimated to cost $5 88 million based on estimates provided by RAO EES Rossii

The new CHP plants may avoid the need to install new single purpose heat only boilers to replace aging boiler plants The analysis of plant alternatives considers the cost of heat only boilers A heat only boiler plant consisting of multiple boilers with a total capacity of 1,000 Gcal/hr is estimated to cost $43 million

Transmission system upgrades and additions needed to integrate power plants at either Mostovskoy, Krasnodar or Novorossiysk into the regional power system assume that existing ties to Ukraine are available, and that the first stage of the interregional tie between the Center region

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Table 3-5

CAPITAL COSTS
GAS LINE FOR NEW PLANTS

SITE/CASE #	DESCRIPTION	CAPITAL COSTS RUSSIAN (1995 US $ x1000)			
		MATERIALS	LABOR	INDIRECT	TOTAL
MOSTOVSKOY					
1	300 MW Simple Cycle	14 630	7 405	2 420	24 455
2a	300 MW Simple Cycle - First Stage	22 990	7 695	3 420	34 105
2b	300 MW Simple Cycle - Second Stage	0	0	0	0
3	600 MW Simple Cycle	22 990	7 695	3 420	34 105
4	450 MW Combined Cycle	14 630	7,405	2,420	24 455
5a	450 MW Combined Cycle - First Stage	22 990	7 695	3,420	34 105
5b	450 MW Combined Cycle - Second Stag	0	0	0	0
6	900 MW Combined Cycle	22 990	7 695	3 420	34 105
7a	450 MW Combined Cycle - First Stage	26 410	7 845	3 790	38 045
7b	450 MW Combined Cycle - Second Stag	0	0	0	0
7c	450 MW Combined Cycle - Third Stage	0	0	0	0
8	1350 MW Combined Cycle	26 410	7 845	3 790	38 045
KRASNODAR					
9	300 MW Simple Cycle	29 175	10 180	4,150	43,505
10	450 MW Combined Cycle/CHP	29 175	10,180	4,150	43 505
11a	450 MW Combined Cycle/CHP - 1st Stag	29 175	10 180	4 150	43 505
11b	450 MW Combined Cycle/CHP - 2nd Sta	0	0	0	0
12	450 MW Combined Cycle/CHP	44 550	10 785	5 900	61 235
NOVOROSSIYSK					
13	300 MW Simple Cycle	47 523	8 715	6 030	62 268
14	450 MW Combined Cycle/CHP	47 523	8 715	6 030	62 268

ASSUMPTIONS.

1 Contingency included in Indirects
2 A 60 km gas line considered at Mostovskoy Gas line sized for 5 5 MPa
3 A 200 km gas line is included for Novorossiysk Cost shown represents project share of 700 mm line sized to meet the City requirements and the power plant A compressor is included in material costs
4 A new 60 km gas line and booster compressor will be required for Krasnodar for projects which increase current gas consumption

Table 3-6

TRANSMISSION COSTS AND TRANSMISSION SYSTEM LOSSES

Options		Capital Cost Million US$	Transmission Loss MW
GT 300 M	2x150MW - Gas Turbines - Mostovskoy	84	-4 8
GT 600 M	4x150MW - Gas Turbines - Mostovskoy	86 3	-1 9
CC 450 M	1x450MW - Combined Cycle - Mostovskoy	84	-3 8
CC 900 M	2x450MW - Combined Cycle - Mostovskoy	105	10 5
CC 1350 M	3x450MW - Combined Cycle - Mostovskoy	192	24 5
GT 300 K	2x150MW - Gas Turbines - Krasnodar	89	-8 7
CC 450 K	1x450MW - Combined Cycle -Krasnodar	89	-8 5
CC 900 K	2x450MW - Combined Cycle -Krasnodar	99	-3 9
HP 450 K	1x450MW - CHP - Krasnodar	89	-8 5
HP 900 K	2x450MW - CHP - Krasnodar	99	-3 9
GT 300 N	2x150MW - Gas Turbines -Novorossiysk	19 5	-11 3
CC 450 N	1x450MW - Combined Cycle - Novorossiysk	23	-12 7
HP 450 N	1x450MW - CHP - Novorossiysk	23	-12 7
600 N	4x150MW Novorossiysk	28	-12 7
750 N	750MW Novorossiysk	123	-12 4
900 N	2x450MW Novorossiysk	127	-8 6
1050 N	1050MW Novorossiysk	130	-6 0
1200 N	1200MW Novorossiysk	200	-4 0
1350 N	3x450MW Novorossiysk	200	-3 0

and North Caucasus (three 500 kV lines from Balakovskaya Nuclear Plant to the Rostovskaya Nuclear Plant) is available

Transmission line costs are assumed to consist of 63% materials, 25% labor, and 12% right of way

3.3 OTHER POWER PROJECTS

The IPM© model considers all power generation technologies fossil, nuclear and hydroelectric Capital costs provided in the JEPAS study for fossil plant options were reviewed and updated Table 3-7 identifies the capital costs for fossil plants used in this study

A portion of the future electric power demand in the North Caucasus will be met by hydroelectric plants that are already committed The following hydroelectric plant were considered

Zaramagskaya	340 MW	4 x 85 MW units	First unit operation in 2001
Zelentchukskaya	160 MW	4 x 40 MW units	First unit operation in 1996
Aushigerskaya	40 MW		Indefinite

The Rostov Nuclear Power Plant is partially constructed and the option exists to complete at least the first unit of this plant The cost used in the JEPAS study of approximately $100/kW to complete construction is not considered sufficient Taking into consideration possible deterioration and the potential for safety upgrades, an estimate of $300/kW is assumed as the cost to complete the first unit of the Rostov Nuclear Power Plant

3.4 INTERREGIONAL TRANSMISSION PROJECTS

The maximum transfer capability from the Center Region to the North Caucasus is 1,700 MW, including 1,340 MW going through Ukraine This capability reduces significantly to 1,200 MW as a result of the first contingency when an intra-Ukrainian or inter-regional 500 kV line is out of service

3 4 1 Middle Volga - Center - North Caucasus Project

A transmission reinforcement program consisting of four complementary 500 kV transmission additions with a total length of 975 km has been considered in the JEPAS study The first stage consists of 360 km of 500 kV lines, related substation upgrading, and conversion of the Balakovskaya Nuclear Plant to Trubnaya 500 kV line from 220 kV to the rated 500 kV Russian

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Table 3-7

COST DATA FOR NEW UN-SITED GENERATING TECHNOLOGIES

	Gross Capacity Rating (MW)	Foreign Cost 1994 US $/kW			Russian Cost 1994 US $/kW				
		Equipment	Indirect	Subtotal	Equipment	Materials	Labor	Indirect	Subtotal
CLEAN COAL TECHNOLOGIES									
Pulverized Coal Supercritical	300	107	11	118	270	303	29	60	662
	500	94	9	103	239	268	26	53	586
Atmospheric Fluidized Bed (AFB)	300	332	33	365	150	377	35	56	618
NATURAL GAS TECHNOLOGIES									
Combined Cycle (1)	360	216	32	248	16	106	5	19	146
	450	216	32	248	16	106	5	19	146
Combustion Turbine (2)	40	315	47	362	23	133	7	24	187
	70	239	36	275	19	108	6	20	153
	125	192	29	221	15	87	5	16	123
COMBINED HEAT & POWER (CHP) (COGENERATION UNITS)									
Combined Cycle (3)	330	197	30	227	46	135	6	28	215
	260	197	30	227	46	135	6	28	215
	27	437	66	503	56	119	8	27	210
Combined Cycle (4)	330	0	0	0	134	114	5	38	291
	260	0	0	0	134	114	5	38	291
	27	0	0	0	198	183	10	59	450
Pulverized Coal / Steam	180	121	12	133	351	394	38	78	861
AFB / Steam	180	375	37	412	195	490	46	73	804

(1) Costs reflect Foreign supply of gas turbine HRSG and steam turbine equipment
(2) The 40 MW Combustion Turbine is an Aeroderivative model and the 70 MW & 125 MW Combustion Turbines are Heavy Duty models
(3) Costs reflect Foreign supply of gas turbine and HRSG and Russian supply of cogeneration steam turbine
(4) Costs reflect Russian supply of all plant equipment

experts assume this stage will be completed within two years, irrespective of the Krasnodar project

The second stage of the project consists of 615 km of 500 kV lines and related substation upgrading

The costs associated with the construction of the first stage of the Middle Volga - Center - North Caucasus project are considered to be committed costs and are not included in this economic analysis

3 4 2 Volgograd-North Caucasus and Southern Center-North Caucasus Projects

Additional transmission projects that could increase the power transfer capability to the North Caucasus were considered as follows

- Volgograd - N Caucasus (540 km of 500 kV line from Frolovo via Shahty to the Rostov nuclear power plant, 84 km of 220 kV line and related substation upgrading)
- Southern Center - N Caucasus (525 km of 500 kV line from the Novovoronezskaya nuclear power plant to Shahty and related substation upgrading)

3.5 COMPARISON OF GENERATION PROJECT SITES

All three of the sites proposed for the addition of generation capacity in the Krasnodar Krai have certain unique advantages They differ principally in terms of three items transmission access, proximity to gas supply lines, and the need for infrastructural improvements to support the future plant operating staff and their families The costs of these items have been included in the overall estimates of capital and operating costs of each of the options under consideration The costs vary with both plant capacity and technology type, as well as with the specific location of the sites

In general, transmission costs have the most impact, plants located near load centers that are remote from existing plants and replacement plants benefit from having low transmission capital cost impacts and potentially high savings in transmission losses This is the situation for both the Novorossiysk and Krasnodar sites, while the Mostovskoy site is adversely affected by being remote from load centers Gas line costs are also a major factor as explained in Section 3 1, and vary for each site Social costs are only a factor at Novorossiysk Housing for plant staff has

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already been constructed at Mostovskoy, and the existing housing in the city of Krasnodar is considered to be adequate to accommodate the plant staff and their families

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CHAPTER 4
METHODOLOGY

4.1 OVERVIEW OF THE LEAST-COST INVESTMENT PLAN

The least-cost investment plan analysis builds upon the efforts already undertaken for the North Caucasus region under the JEPAS The assumptions were reviewed closely with World Bank staff, enabling a set of normative least-cost plans to be developed for the North Caucasus region, focusing on Krasnodar Krai Among the assumptions under review were 1) the load forecast for both electricity and heat, 2) the expected evolution of the shape of the load duration curve, 3) broadening the options to include simple cycle gas turbines, 4) the potential for supply from other regions (including Ukraine), 5) the feasible start dates for new plants, 6) the cost estimates for new investments, and 7) the fuel cost assumptions

Building on work undertaken for the JEPAS, a new power demand forecast was developed for the 1995-2020 period for the North Caucasus Assessments of the structure of demand were undertaken to determine the expected changes in demand characteristics (e g , the impact of decreasing base load demand due to industry closings and increases in peak demand due to growth in the household and service sector markets) The impact of inter-fuel substitution (such as the replacement of cooking loads serviced by gas with electric stoves) and energy efficiency investments have also been addressed The demand management aspects build on analytical work undertaken by Russian consultants The results from the more detailed analysis of the Krasnodar Krai have been used to update the demand forecast for the North Caucasus region

The study reviewed the status of the existing assets in the Krasnodar system, focusing on the age and reliability of existing plants, and the likely timetable for decommissioning or replacing these plants The transmission and distribution systems have been assessed to determine the impact on project costs, based on an assessment of current and forecast loss levels The comparison of specific alternative electricity generation sites has been made using spreadsheets to identify the most appropriate choices for the Krasnodar Krai

The study assessed the available investment options for meeting future demand This encompassed the candidate plants that have been previously assessed by others, including plants at Mostovskoy, Krasnodar TETS, and Novorossiysk The relative merits of combined cycle and simple cycle plants were reviewed to determine the optimal mix of plants and the staging of investments, given the need

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for combined heat and power Alternative sites were assessed to evaluate the benefits of a combined approach to meeting both power and heat demand

The study also reviewed the existing and planned generation and transmission system in the North Caucasus region to determine the potential for supplying demand in the Krasnodar Krai from elsewhere in Russia and Ukraine

The result is an investment plan for the Krasnodar Krai regional power system, based on a thorough analysis of the trade-offs among alternative generating types and location, and transmission options evaluated over the period 1995-2020

4.2 THE PLANNING MODELS

4 2 1 Linear Program Model

A core element of the least-cost planning effort is the IPM© integrated planning model, which was applied to characterize the Russian UPS as part of the JEPAS

The IPM© is a least-cost planning model that uses a linear programming algorithm to select investment options and to dispatch generating resources to meet overall electricity demand and energy requirements A graphical overview of the model inputs and outputs is shown in Figure 4-1

Figure 4-1
IPM© Features

INPUTS	IPM© Operations	OUTPUTS
Existing Units	Multi-Year Simulation	Capacity Additions
Fuel Price Projections	Multi-Regional Simulation	Purchases
New Resources Supply-Side Renewables Demand-Side	Least-Cost Optimization	Transmission Additions
Fuel Use Constraints		Fuel Use
Transmission Limits		Capacity Factors
Hourly Consumption		Life Cycle Costs
		Marginal Costs

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Utility generating options are characterized in terms of their capital costs, operating and maintenance costs, fuel costs, heat rates, reliability, and lead times The amount and scheduling of available powerfrom outside the North Caucasus grid and its costs are evaluated as possible bulk power purchase options, either for economy or for firm power purchases

Least-cost investment options are selected by the model based

- the cost and performance characteristics of available options
- forecasts of customer hourly consumption of electricity
- reserve margin requirements

The most efficient use of the existing and new resources available is optimized given

- the resource mix
- unit operating characteristics (including heat rate, forced outage rates, full and minimum load unit ratings)
- operation, maintenance, and fuel costs

The model is dynamic, that is, it develops a least-cost capacity plan for the entire forecast period at once Decisions are made on the basis of minimizing the net present value of capital plus operating costs over the full planning horizon

IPM© also incorporates seasonal factors into the optimization process Seasonality is critical to realistic modeling, particularly with regard to the availability of reservoir and run-of-river hydro resources, the cost and operation of pumped storage plants, and the seasonal operation of combined heat and power units

4 2 2 Screening Model

The evaluation of generation alternatives in a least-cost plan requires the consideration of numerous possible combinations of fuels, technologies, and sizes of generation units In practice, the number of choices can usually be reduced somewhat because of restrictions imposed by fuel availability, system size and load characteristics, however, there can still be a very large number of alternatives to be considered in the analysis The number of possibilities can be reduced by comparing the

economic performance of each resource at different levels of utilization This is done by a type of model known as a "screening" model

A screening model typically does not use specific information about system load It calculates the economic performance of each possible generation option over its full load range By comparing the relative performance of various options at specific ranges of utilization, the most likely options can be identified for in-depth consideration by a dynamic model

The basic methodology used in the screening analysis involves the computation of the levelized costs of capital and operating expenses The levelized approach allows for the consideration of factors such as increases in operating costs, construction time, and the cost of capital, in addition to present-day capital and operating cost levels In this study, the screening analysis was also applied to determine the critical levels of seasonal district heating utilization for choosing between CHP and combined cycle applications at each site

The screening model used in this study calculates the levelized fixed and variable operating costs in terms of $/kW-year and $/kWh, respectively These costs are then combined for specific load factors to give production costs in terms of $/kWh The model also includes credits for district heating in CHP units, both in terms of net savings of fuel and the avoided capital costs for heat-only boilers

4 2 3 Base Case and Change Cases

The following assumptions will be included in the base case of the IPM© modeling work

A One demand scenario (the Base demand) will be considered based on current indications that the Russian economy has begun to rebound

B The model will assume that the Rostov 1 nuclear power plant will not be completed

C The Mostovskoy plant site will be treated as an option for development, not as a committed project

D The model will assume that power will not be available from Ukraine, or from other regions of Russia via Ukrainian transmission lines

E Political turmoil in Chechnia will not have a lasting effect on the North Caucasus transmission grid

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F The transmission capacity linking the North Caucasus to the Center UPS will be increased to 900 MW during 1997 Of that capacity, 750 MW will be committed as "firm capacity "

G Existing plants will be retired after 40 years

In addition to the base case evaluations, change case model runs will be conducted based on the following changes in the model's base assumptions

A An additional 500 MW of transmission capacity (450 MW of firm capacity) from the Center UPS will be added to the grid

B A further addition of 500 MW of transmission capacity (450 MW of firm capacity) from the Center UPS will be added to the grid

C The transmission tie to Ukraine with a capacity of 1,400 MW will be re-established, with a firm capacity commitment of 700 MW

D The Rostov 1 nuclear power plant will be commissioned at the end of 1999 with a net capacity of 1,000 MW

E Energy demand will grow at a slower rate due to weak level of economic recovery (the low demand)

4.3 SUMMARY OF DATA AND ASSUMPTIONS

IPM© was recently used to model the entire Russian Unified Power System for the JEPAS The multi-regional structure and plant aggregation categories developed for that study were retained for the Krasnodar project, since they offer an appropriate balance between minimizing execution time and computer resources on the one hand, and maintain sufficient detail to capture the key regional generation and transmission characteristics of Russia

4 3 1 Regions

The North Caucasus is one of Russia's seven Unified Power Systems, it was not disaggregated for the Krasnodar analysis However, additional detail was developed for the North Caucasus, and selected inputs were refined based on new data from RAO EES Rossii, other contractors working on the Krasnodar project, and other sources

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4 3 2 Generation Capacity

Refined data on the costs and performance characteristics of new generating units were developed Recent data on the capacity mix and retirement schedule for the North Caucasus were compiled for this study The capacity mix and retirement schedules for the rest of Russia used in the IPM model are those from the JEPAS

4 3 3 Transmission

In modeling transmission links, a 360 MW link between the Center region and the North Caucasus is assumed to be in operation, of which 200 MW is treated as firm, reliable capacity for meeting peak demand The link increases to 900 MW in 1997, of which 750 MW will be reliable for meeting peak demand requirements

Intra-regional transmission is not explicitly modeled, but is implicitly treated as unbounded Transmission losses are explicitly modeled, this study assumes 5% losses on inter-regional transmission Intra-regional losses for transmission and distribution combined are 11% The transmission losses associated with alternative capacity options were developed for the Krasnodar project

4 3 4 Financial and Economic Assumptions

Natural gas price forecasts for the North Caucasus (shown in Table 4-1) were provided by the World Bank, and are based on the assumption that gas prices are regulated and allow for full recovery of costs plus a return on investment For other regions, delivered natural gas prices were calculated based on city-gate price differentials derived from the July 1993 Hagler Bailly report *Principles of Natural Gas Pricing in Russia* Gas prices increase at the rate of 2% per year starting in 2005, reflecting diminished production from the Urengoy field, which will be offset by higher-priced production in the Yamal Peninsula and other sources

Table 4-1
Natural Gas Prices
(January 1995 U.S $/thousand m^3, delivered)

Year	North Caucasus	Center	North West	Middle Volga	Urals	Tyumen	Siberia
1995	$40	$33	$34	$30	$27	$21	$34
1996	$43	$36	$38	$33	$30	$24	$38
1997	$47	$40	$41	$37	$34	$28	$42
1998-2005	$52	$45	$46	$42	$39	$33	$46
2010	$57	$50	$51	$46	$43	$36	$51

The coal price forecasts were used in the JEPAS fuel price sensitivity change case Forecasts for high-grade bituminous and lignite coal in the North Caucasus are shown in Table 4-2 For comparative purposes, high-grade bituminous prices for other connected regions are shown in Table 4-3

Table 4-2
North Caucasus Coal Prices
(January 1995 U S $/tce, delivered)

Year	High-Grade Bituminous	Lignite
1995	$41	$40
2000	$44	$48
2005	$48	$58
2010	$53	$69

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Table 4-3
High-Grade Bituminous Coal Prices
(January 1995 U S $/tce, delivered)

Year	North Caucasus	Center	North West	Middle Volga	Urals	Tyumen	Siberia
1995	$41	$35	$38	$30	$26	$26	$13
2000	$44	$41	$45	$35	$30	$32	$17
2005	$48	$47	$53	$41	$35	$41	$22
2010	$53	$54	$63	$48	$40	$51	$29

Calculation of Real Escalation Rates Real escalation of capital costs was taken into account in this analysis The Russian component of the cost estimates was assumed to escalate over time in real terms to approach current Western levels by 2010 As listed in Table 4-4, the escalation factors used for this analysis were developed in the JEPAS

Table 4-4
Escalation Factors
(Russian Costs Relative to U S Costs)

Year	Material	Equipment	Labor
1994/1995	0 70	0 50	0 10
2000	0 85	0 60	0 30
2010	0 90	0 90	0 60

The methodology for applying these escalation factors consisted of the following

- The Russian equipment, labor, and material capital cost components were escalated by applying the factors in Table 4-4
- Indirect costs were escalated using a weighted average of the material, equipment, and labor escalation rates The weights used in this calculation were the capital costs in January 1995 U S dollars
- Owner costs were escalated using a weighted average of equipment, labor, material

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and indirect escalation rates

- Contingency costs were escalated using a weighted average of equipment, labor, material, indirect, and owner costs

- Fixed operation and maintenance costs were escalated using a weighted average of labor and material escalation rates, with a 30% weight for labor and a 70% weight for materials

- Variable operation and maintenance costs were escalated at the same rate as materials

Other key financial and economic assumptions are listed in Table 4-5

Table 4-5
Other Key Financial and Economic Assumptions

Real discount rate	15%
Economic growth	5% per year
Physical lifetimes	
Thermal plants	40 years
Hydroelectric plants	50 years

Cost of Unserved Energy The cost of unserved demand is evaluated using a proxy generation option that is based on the assumption that emergency diesel generators will be used to produce power when customers are denied service from the grid This is generally what occurs during shortages when industrial and larger commercial enterprises must operate in regions are curtailed The fixed charge used for this power source is $133/kW-year and the variable cost is $0 0669/kWh This is based on the following assumptions

Capital cost	500 $/kW
Maintenance Costs	26 $/kW - year
Heat rate	14,240 kJ/kWh
Diesel Fuel Cost	142 $/ton

Residential demand is not included in computing the cost of unserved energy This is because of the policy of Russian utility companies to give priority to residential customers during shortage periods

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4.4 DEMAND PROJECTIONS

Demand projections for electricity and heat consumption in the North Caucasus and Krasnodar Krai were developed by the Center for Energy Efficiency (CENEf) in Moscow A complete text of CENEf's findings are presented in Appendix C CENEf evaluated historical data and projections on economic conditions and electricity supply, and developed detailed projections for consumption through 2020 The projections for electricity and heat demand for the North Caucasus UPS are shown in Figures 4-2 and 4-3 and Table 4-6

The base projections have been calculated on the assumption that growth in the region well average just under 5% during the study period The high projection is based on the assumed economic growth rate of 8%, and the low scenario is based on the assumed growth rate of 2%

Using the consumption figures and historical records of hourly demand, projected hourly demand curves for electricity were developed for each year through 2020 These demand curves were incorporated into the linear program model, where they are used to project capacity requirements through 2020 The annual peak demand electrical projections for the North Caucasus UPS are shown in Figure 4 - 4 and Table 4 - 6

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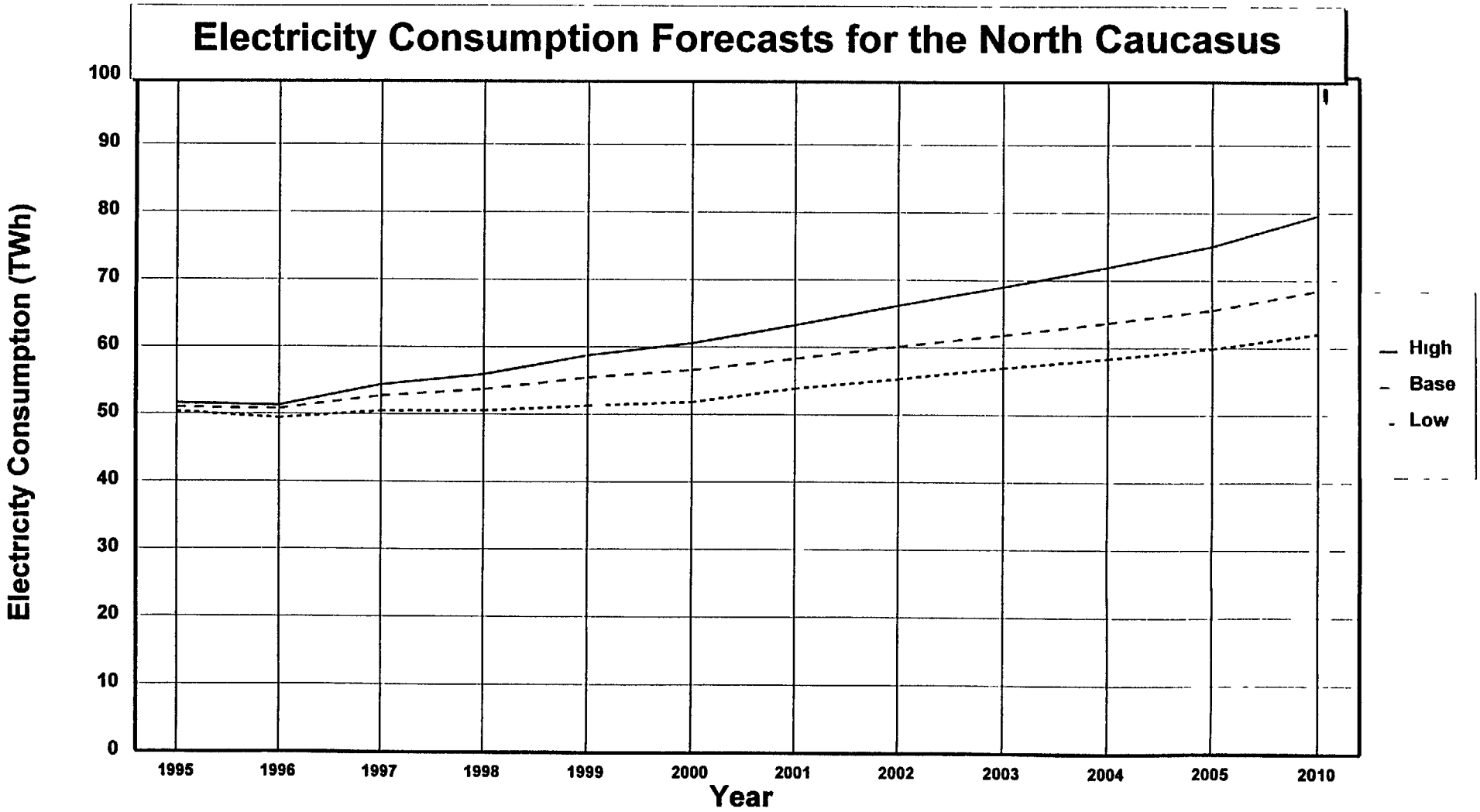
Krasnodar Power Generation Project

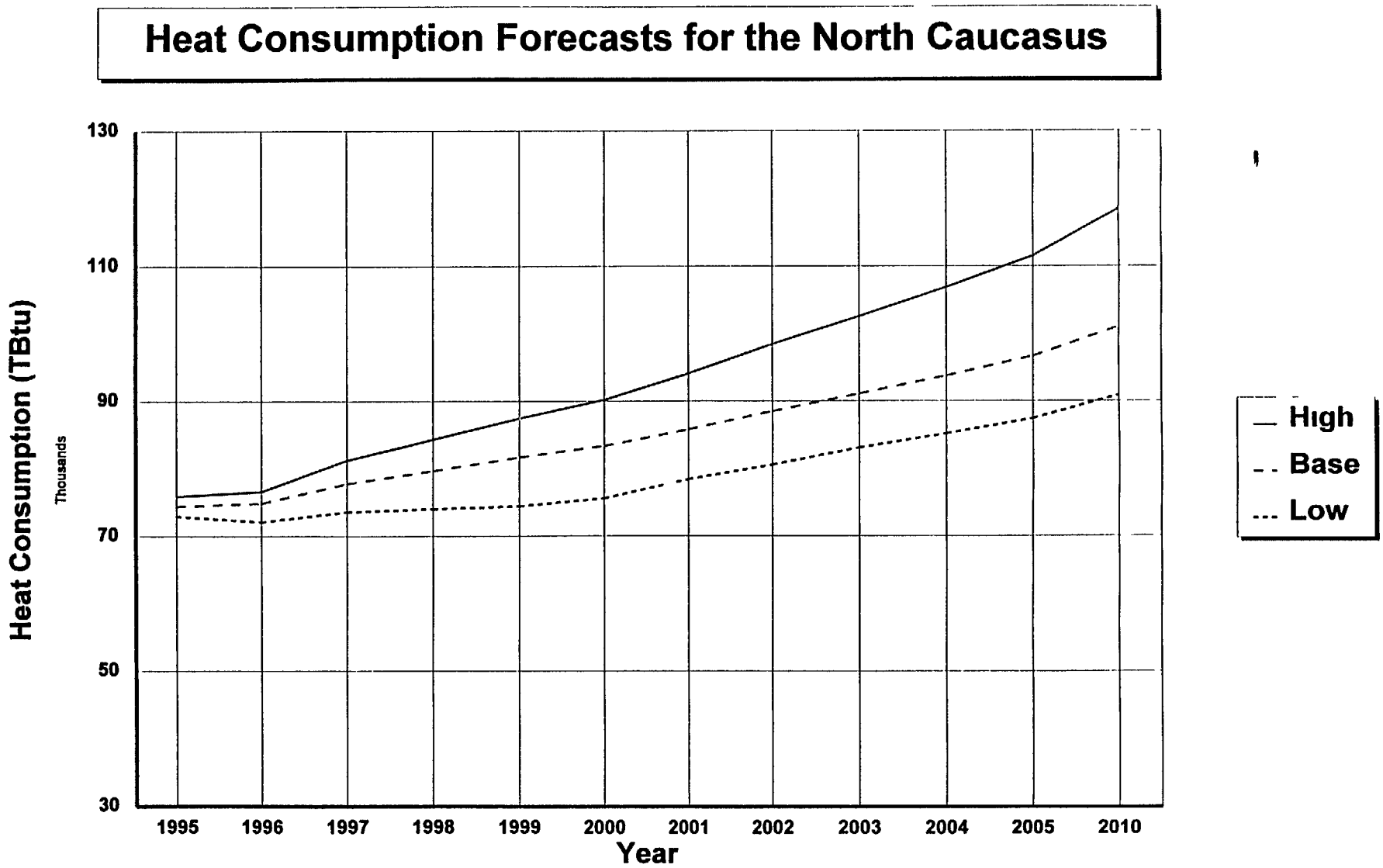
Table 4-6

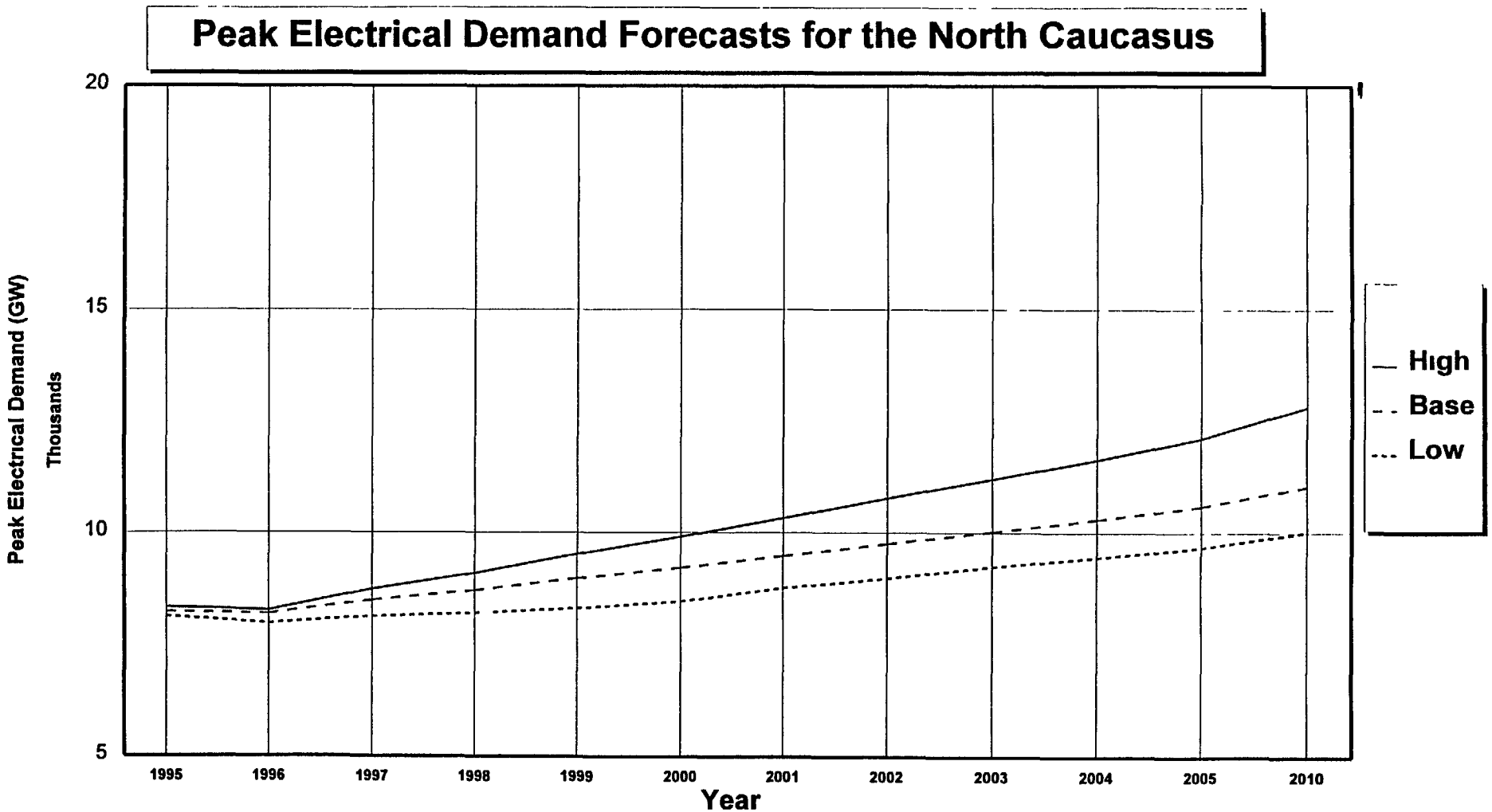
Forecasts of Heat Electricity Consumption, and Peak Electrical Demand in the North Caucasus

	Heat Demand (TBtu)			Electric Energy (GWh)			Peak Demand (GW)		
	High	Base	Low	High	Base	Low	High	Base	Low
1995	75,891	74,415	72,939	51,622	51,002	50,383	8,320	8,220	8,120
1996	76,653	74,891	72,137	51,309	50,807	49,444	8,256	8,180	7,960
1997	81,250	77,765	73,595	54,420	52,752	50,517	8,728	8,475	8,117
1998	84,367	79,713	74,057	55,975	53,723	50,579	9,083	8,697	8,189
1999	87,516	81,681	74,465	58,776	55,474	51,328	9,515	8,967	8,300
2000	90,237	83,381	75,625	60,589	56,607	51,884	9,907	9,212	8,448
2001	94,128	85,813	78,432	63,303	58,303	53,877	10,322	9,471	8,755
2002	98,482	88,534	80,600	66,251	60,146	55,318	10,773	9,753	8,976
2003	102,605	91,111	83,119	69,044	61,891	57,006	11,197	10,018	9,234
2004	106,900	93,795	85,191	71,955	63,711	58,405	11,637	10,293	9,444
2005	111,545	96,699	87,425	75,075	65,661	59,899	12,109	10,588	9,669
2010	118,533	101,066	90,926	79,637	68,512	62,071	12,818	11,031	10,015

Figure 4-2


Electricity Consumption Forecasts for the North Caucasus
Electricity Consumption (TWh)
100
90
80
70
60
50
40
30
20
10
0
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2010
Year
High
Base
Low


Heat Consumption Forecasts for the North Caucasus
Heat Consumption (TBtu)
Thousands
130
110
90
70
50
30
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2010
Year
High
Base
Low


Peak Electrical Demand Forecasts for the North Caucasus
Peak Electrical Demand (GW)
Thousands
20
15
10
5
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2010
Year
High
Base
Low

CHAPTER 5
RESULTS

The objective of this study task has been to assess the need for the Krasnodar Power Generation Project, and evaluate the economic merits of the proposed sites, and to prepare a ranking of options that fit within definition of a least cost plan The results of this task indicate that the development of natural gas fired plants in Krasnodar Krai, using high-efficiency combustion turbines, are an economical and necessary step in improving the power supply situation in the local area and in the North Caucasus as a whole

5.1 INITIAL SCREENING ANALYSIS - COMPARISON OF MERITS OF SITES

As mentioned in Section 3 5, all three of the sites proposed for the addition of generation capacity in the Krasnodar Krai have certain unique advantages They differ principally in terms of three items transmission access, proximity to gas supply lines and the need for infrastructural improvements to support the future plant operating staff and their families In addition they differ in base heat rate and the extent of base load district heating demand The static screening analysis was used to identify the overall impacts on the likely production costs for the three technologies when used at each of the three sites The relative impacts of the factors are explained below (Spreadsheets showing the detailed results of the static screening analyses for each of the sites are included in Appendix D)

5.2 NON-PLANT COST IMPACTS

TRANSMISSION COSTS

Of the factors not related directly to the technology, transmission had the greatest relative impact on production costs The impacts varied from zero in the case of a replacement CHP unit for the Krasnodar TETS site to 0 0048 $/kWh for a 450 MW plant at Mostovskoy Among options for green field plants the Novorossiysk site has an advantage over the other sites for capacities up to 600 MW, after that its transmission costs are similar to those of the Krasnodar site, with costs varying from 0 0036 to 0 0055 $/kWh The Mostovskoy site, because of its distance from existing load centers, is only competitive at capacities of 900 MW and above in terms of transmission costs

GAS LINE COSTS

Gas line costs are a major factor which affect all sites The Mostovskoy site is not currently served with natural gas, a lateral of approximately 60 km to an existing gas trunk line will be needed to supply the plant The cost of the lateral will be from $24 to 38 million depending on plant size The cities of Krasnodar and Novorossiysk are currently served by gas lines, however, any significant increase in the needs for natural gas at either location will also require major capital investments for improving gas delivery The only exception is the case of the 450 MW replacement plant at Krasnodar TETS, where gas is already supplied to the site A 450 MW expansion of the Krasnodar TETS site would require gas pipeline improvement costs of $44 million, and a 900 MW expansion would require $61 million. At Novorossiysk, which is the greatest distance from the major gas trunk lines, extensive improvements for expanding the capacity of the existing gas supply pipeline would be required at costs ranging from $62 to 76 million, depending on the size of the plant

The impact of gas pipeline investments on the cost of production for the Mostovskoy site will range from 0 0009 to 0 0043 $/kWh depending on the ultimate plant size, the impact at Krasnodar will range from zero to 0 0078 $/kWh, while the impact at Novorossiysk will vary from 0 0026 to about 0 0108 $/kWh

SOCIAL COSTS

Social costs only have an impact at Novorossiysk, since housing for the plant staff has already been constructed at Mostovskoy and the existing housing in the city of Krasnodar is considered to be adequate to accommodate the plant staff and their families The impact at Novorossiysk was on the order of 0 0003 $/kWh for all plant sizes

5.3 CHP IMPACT ON HEAT RATES

The opportunity to improve overall economic performance through the utilization of plant waste heat for district heating provides a distinct advantage to plants in or very near urban areas The dual use of energy inputs that CHP units accomplish allow those plants to operate at effective heat rates that are substantially below comparable plants which do not make use of waste heat from the steam power cycle

Both Krasnodar and Novorossiysk have district heating markets, and can take advantage of CHP plants Mostovskoy is not an urban area and is not able to make use of the plant waste heat In cases where CHP can be used, its heat rate advantage amounts to an average year-round savings of approximately 0 0008 $/kWh. In cases where a CHP plant is matched to meet a year-round base load heat demand the savings advantage can increase to approximately 0 0010 $/kWh The high level of district heating use in Krasnodar makes it an attractive site for up to 1350 MW of CHP/Combined

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Cycle capacity However, much of the demand for district heating in Krasnodar is already served, and energy conservation measures may limit or even reverse demand growth there In Novorossiysk where the base demand is much lower, 120 Gcal/h versus 380 Gcal/h at Krasnodar, a CHP plant of up to 300 MW may prove cost effective when combined with base load power generation

5.4 RANKING OF NEW PLANT OPTIONS

When the factors discussed above are compiled for each plant type at each site a strong indication of the best site options for plant specific sizes results This is easily illustrated in the comparisons of siting advantages shown in Figure 5-1 for simple cycle and combined cycle plants These values are calculated on a technology by technology basis because changing capacity factors over time make comparisons between plants with different technologies difficult to evaluate without the use of a dynamic modeling tool such as IPM©

The static screening results are also shown in Table 5-1 These tables indicate the relative advantages of each of the sites for various combinations of Simple Cycle and Combined Cycle options (Detailed spreadsheets showing the complete static screening analyses are presented in Appendix D) The static screening does not present a final answer on the least cost plant options but it was used in selecting candidate options for life cycle evaluation by the IPM© This is needed to assess the cost performance of the options in response to varying load conditions over their life time

Table 5-1
Cost of Generation for Various Sites
Costs in $/kWh

Simple Cycle @ 40% Capacity Factor			
Size, MW	**Krasnodar**	**Mostovskoy**	**Novorossiysk**
300	0 0607	0 0580	0 0519
600	0 0494	0 0474	0 0469
900	0 0487	0 0476	0 0511
Combined Cycle @ 80% Capacity Factor			
Size, MW	**Krasnodar**	**Mostovskoy**	**Novorossiysk**
450	0 0333	0 0339	0 0320
900	0 0306	0 0318	0 0336
1350	N/A	0 0320	N/A

A second time related factor that must be considered in selecting least cost options is the probable completion time of each of the plant options Because there is a severe shortage of power in the region, economic losses are accumulating as a result of power curtailments The sooner this situation is resolved the sooner the region will recover economically This places a premium on plant options that can be brought on line quickly

5.5 REPLACEMENT PROJECTS

Replacement power projects offer substantial advantages over greenfield plants in cases where the construction of the replacement plant can occur while the existing units remain on line The reasons include savings in land and infrastructure costs, the existence of the necessary transmission and fuel supply lines, and the absence of social costs that could result if workers at the existing sites were to become unemployed or have to move This is the situation at the Krasnodar TETS site The plant is currently scheduled to have a total capacity of 350 MW replaced over the period of 1997 to 1999 with a 450 MW Combined Cycle Plant The replacement of that capacity with a state of the art CHP/Combined Cycle plant will provide a more economical option than any of the other plants considered in this study

As the Krasnodar TETS plant is the only thermal site of any magnitude within Krasnodar Krai, it is the only candidate for replacement power All other sites are considered to be greenfield sites It is assumed that up to 450 MW additional capacity can be added adjacent to the Krasnodar TETS plant when 300 MW of the older CHP units are retired in 2003

5.6 STATIC SCREENING OF OPTIONS

COMBINED CYCLE OPTIONS

Combined cycle options fall into two categories with and without district heating The study has determined that CHP plants will offer advantages in cases where the annual district heat demand, that which is not already served by a CHP installation, is equal to approximately 60 percent of the annual heat generation capacity of the unit to be added This condition is satisfied for a capacity equivalent to two 450 MW installations at Krasnodar (presumably one as a replacement of the existing units that are about to be retired and the second a new unit) At Novorossiysk, a single unit of 450 MW will exceed the current base load heat demand, so it would take full advantage of the CHP fuel savings opportunity for perhaps 8 to 10 years (see Figures 5 2 and 5 3) Once the CHP opportunities are satisfied, conventional Combined Cycle units will provide least cost options where base load capacity is needed The following list gives a rank order of Combined Cycle options starting with the lowest cost alternative (Production costs are at 80% capacity factor)

Site	Capacity	Production Cost, $/kWh
Krasnodar CC/CHP	450 MW	0236
Mostovskoy CC	900 MW	0318
Novorossiysk CC/CHP	450 MW	0320
Novorossiysk CC	450 MW	0320
Krasnodar CC	450 MW	0333
Mostovskoy CC	450 MW	0339

SIMPLE CYCLE OPTIONS

The ranking of simple cycle options is more straight forward that for the Combined Cycle options There are no similar plants scheduled for near term retirement, and there is no CHP alternative for this technology The following list gives a rank order of 300 MW and 600 MW Combined Cycle options starting with the lowest cost alternative (Production costs are at 40% capacity factor)

Site	Capacity	Production Cost, $/kWh
Novorossiysk	600 MW	0 0469
Mostovskoy	600 MW	0 0474
Krasnodar	600 MW	0 0494
Novorossiysk	300 MW	0 0519
Mostovskoy	300 MW	0 0580
Krasnodar	300 MW	0 0607

With the ranking information above decisions can be made based on the overall need for capacity in the region as to where to add plants and in what order

5.7 RESULTS OF THE BASE CASE

Because the model was constrained not to select new fossil capacity prior to 1998 due to construction lead time concerns, it did not elect to indicate the addition of fossil fueled units until that year However, once the addition of new fossil plants was available, the model immediately called for the addition of 765 MW of fossil fueled capacity in 1998 The model also calls for the addition of 268 MW in 1999, and for 405 MW of additional capacity in 2000 The need for capacity additions is expected to continue, at about 400 MW per year, from 2001 to 2005 due to retirements that will occur during those years as well as growth in demand

The attached Table 5-2 indicates the annual needs to add new capacity as demand grows and retirements reduce the capacity available from existing units The table also shows that it will not be possible to eliminate capacity shortages until 1998 This is because there is no practical possibility for adding thermal new generating capacity before that year

Regarding the general location of the new capacity, it appears that Krasnodar Krai is the most likely area in the North Caucasus for major capacity additions because over 600 MW of existing capacity is scheduled to retire before 2005 and the region is already heavily dependent on other regions for power

5.8 SELECTION OF PREFERRED SITES IN KRASNODAR KRAI

Of the three potential sites, only the Mostovskoy site is available for the addition of new capacity in 1998 and, it is limited to the addition of simple cycle gas turbines due to construction lead time concerns The other two sites are expected to require an additional year or two of lead time because of the need for environmental studies to verify that they would be appropriate for building new power plants

While the Mostovskoy site offers the advantage of early development, it has a disadvantage, in that it is not located near the major load centers in the region The Krasnodar and Novorossiysk sites are located at major load centers, which reduces transmission costs, and they offer the opportunity for improved economic efficiency through their use as Combined Heat and Power Plants Because of these advantages it is possible that plant additions after 2000 may be more attractive at those two sites

Considering all of the above factors the following is considered to be the best approach to meeting needs for immediate capacity additions while keeping the long term costs to a minimum

Mostovskoy - 600 MW Simple cycle addition for 1998-99 operation, with conversion to combined cycle operation in 1999 or 2000 based on construction scheduling and demand growth

Krasnodar - replacement of the two existing 95 MW simple cycle in 1998 and 2000, with conversion to combined cycle in 1999 and 2000

Novorossiysk - 300 to 600 MW simple cycle for operation in 2001, with partial conversion to combined cycle if and when CHP operation is shown to economical

This will bring the capacity in the Kubanenergo RPS up to 2366 MW, this would amount to approximately 22% of the total capacity in the North Caucasus IPS which compares favorably with Kubanenergo's average share of 27% of overall electricity consumption, given that the region does not have substantial hydro resources

Below is the recommended sequence for capacity additions for Krasnodar Krai

Table 5-3
Recommended Capacity Additions for Krasnodar Krai

Year	Capacity Addition	Technology	Location
1997	150 MW	Simple Cycle	Krasnodar
1998	300 MW	Simple Cycle	Mostovskoy
1999	150 MW	Simple Cycle	Krasnodar
	150 MW	Steam Cycle Add-on	Krasnodar
	450 MW	Combined Cycle	Mostovskoy
2000	150 MW	Steam Cycle Add-on	Mostovskoy
	300 MW	Simple Cycle	Novorossiysk
2001	300 MW	Simple Cycle	Novorossiysk or Mostovskoy
TOTAL	1950 MW		

5 9 CHANGE CASE RESULTS

Five change cases were evaluated to determine the potential impacts of possible changes in the economic climate or electricity supply situation in Russia These are discussed below

Low Growth Scenario - A change case was developed using the low growth demand projection shown in Section 4 4, to assess the impact of a slow recovery of economic activity in Russia This case showed a sharp drop in the need for additional capacity in the North Caucasus throughout the study period, with the need for added fossil capacity additions between 1998 and 2000 declining from 2098 to 1213 MW, when compared to the Base Case The low growth scenario also indicated that the near term capacity shortage would be eased, although it would not go away This was due to peak demand declining to 7860 MW in 1996, and not returning to the 1994 level until 2001 The average requirement for capacity additions 1998 and 2002 be approximately 250 MW per year Current indications of economic activity, based on the first half of this year, are strong, and the possibility of the low growth scenario coming about seem unlikely at this time

500 MW Transmission Reinforcement - This change case evaluated the impact of adding an additional 500 MW of firm capacity from the Center UPS The addition of a substantial amount of firm capacity being provided through further development of the Center-North Caucasus transmission link would decrease the need for adding capacity by 500 MW This project is currently under consideration, but the capital and operating costs have not been determined While such a project might lead to lower initial costs, it is likely that over the long run that costs associated with high transmission costs and reduced system reliability would out weigh the initial savings Further study of this option is needed to determine if it would be cost effective

1000 MW Transmission Reinforcement - This change case evaluated the impact of adding an additional 1000 MW of firm capacity from the Center and Mid-Volga UPS's This project is essentially the same as the previous case, except for its magnitude It would reduce the capacity addition needs by 1000 MW over the study period The same concerns exist regarding transmission losses and reliability There is also a question as to whether ample sources of low cost power will be available from the Center and Mid-Volga UPS's to satisfy this added demand Further study is also needed for this option

Reestablishment of Transmission via Ukraine - Prior to the break-up of the USSR, and for some time thereafter, power that was generated at nuclear plants in the Center UPS was transmitted to the North Caucasus via the Ukraine grid This practice was discontinued due to frequency control and reliability problems within the Ukraine transmission system While the possibility exists to reestablish this link, there are serious technical and political problems in the way It is highly unlikely that transmission via Ukraine could be restored prior to 1999, but if it reestablished in that year it would eliminate the need to provide fossil capacity additions during 1999 and 2000

Rostov 1 - The work on the Rostov nuclear plant is currently suspended due to public concern about its safety and lack of funds Minatom is endeavoring to get approvals to complete the plant, and may succeed in doing so by as early as 2000 While this would result in eliminating the need for fossil capacity additions from 2000 to 2003, it does not displace need for added capacity in the near term

All of the change cases result in a reduction of capacity needs relative to the base case However, only the Low Growth case results in eliminating the need for 765 MW in 1998 Since all of the cases are speculative, it seems prudent to go forward based on the study's basic assumptions Otherwise valuable time will be lost in addressing the need to eliminate the severe power shortage in the region, due to the long lead times involved in power generation project execution A summary of the change case impacts is shown in Table 5-4

5.10 Qualifications Regarding Assumptions

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Mostovskoy's Timing Advantage - It should be noted that while Mostovskoy is not the lowest cost plant for either combined cycle or simple cycle options, it is reasonably close in terms of life costs to the other options When this is considered in light of the fact that it can be brought online to relieve the current power shortage in the region one to two years earlier than the alternatives, Mostovskoy can be regarded at the least cost option

Novorossiysk Plant Site - Although a potential site for a power plant in Novorosssiysk has been identified, no site investigations have been performed An assessment of the district heating system in Novorossiysk, and the use of a new power plant as a source for a centralized district heating system needs to be evaluated Investigation of sources of water supply, waste water disposal and potential environmental impacts need to addressed in a detailed feasibility study In view of the above, it is considered that a new plant at Novorossiysk could not be constructed before the year 2000

Small Scale Plants Not Evaluated - Small scale plants (75 to 200 MW) at locations such as Sochi, Temyruk and elsewhere were not considered in this study Because of the pressing need for large scale additions of generating capacity in the region the study focused on plants of 300 MW and larger There are however sites, primarily at the extreme ends of the grid, that may be good choices for small scale plants that would substantially improve local power reliability and reduce line losses It may be worth to identify and evaluate these options in a more comprehensive study of the region's needs for power generation

CHP Requirements - This study has made certain assumptions regarding the demand for district heat These assumptions yield favorable indications of potential cost savings for the CHP/Combined cycle plants that could be installed in Krasnodar and Novorossiysk There is considerable speculation those assumptions regarding the continuing need for levels district comparable to current day levels It is the opinion of some experts who have studied the district heating practices in Russia that considerable savings could be obtained through conservation and efficiency improvement measures Before commitments are made for adding CHP capacity in the region a detailed evaluation of the potential for reducing district heating needs through demand side management programs should be undertaken

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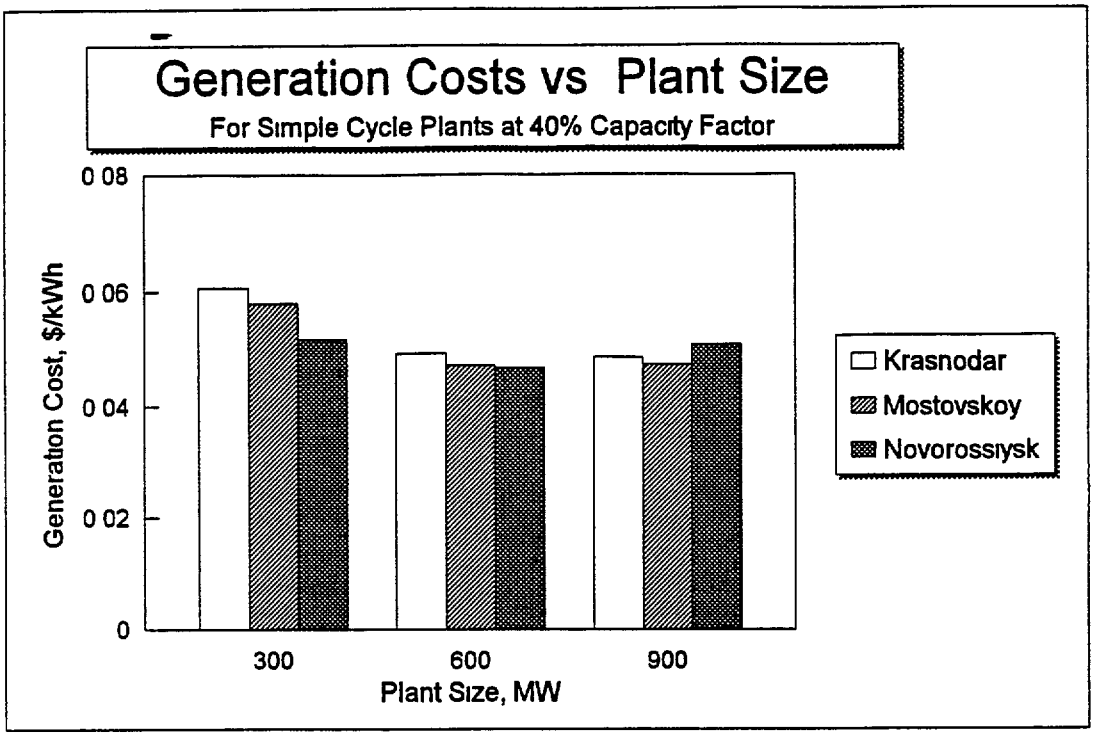
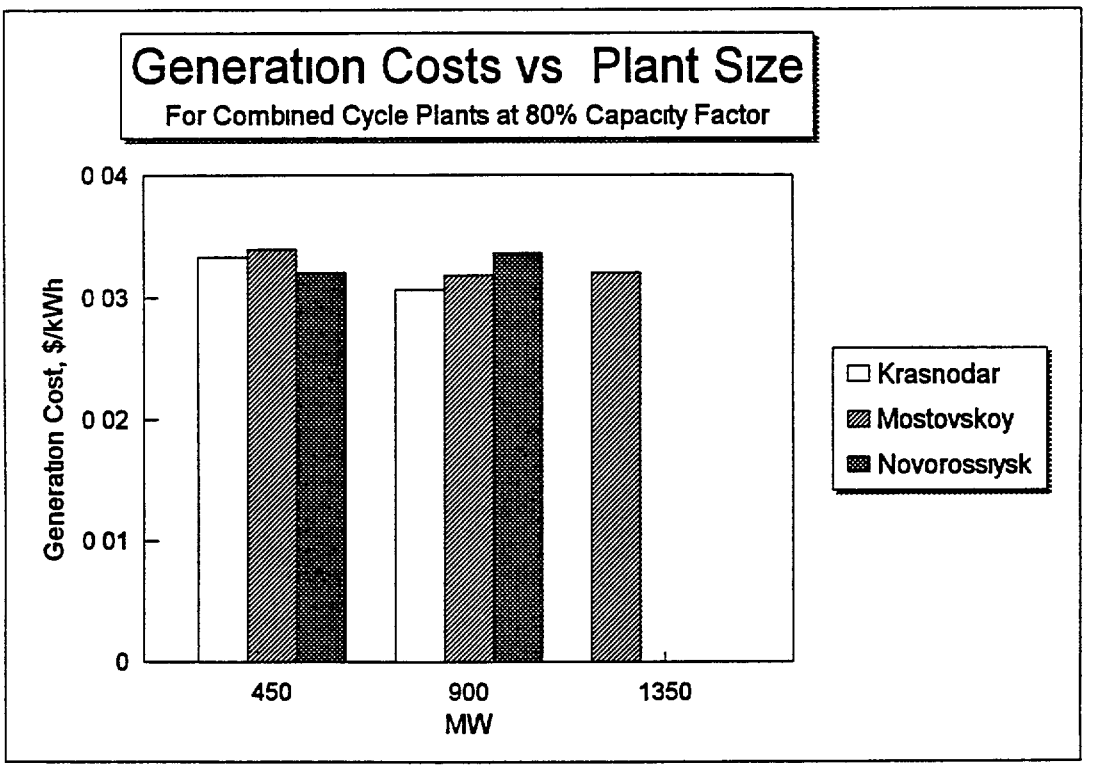
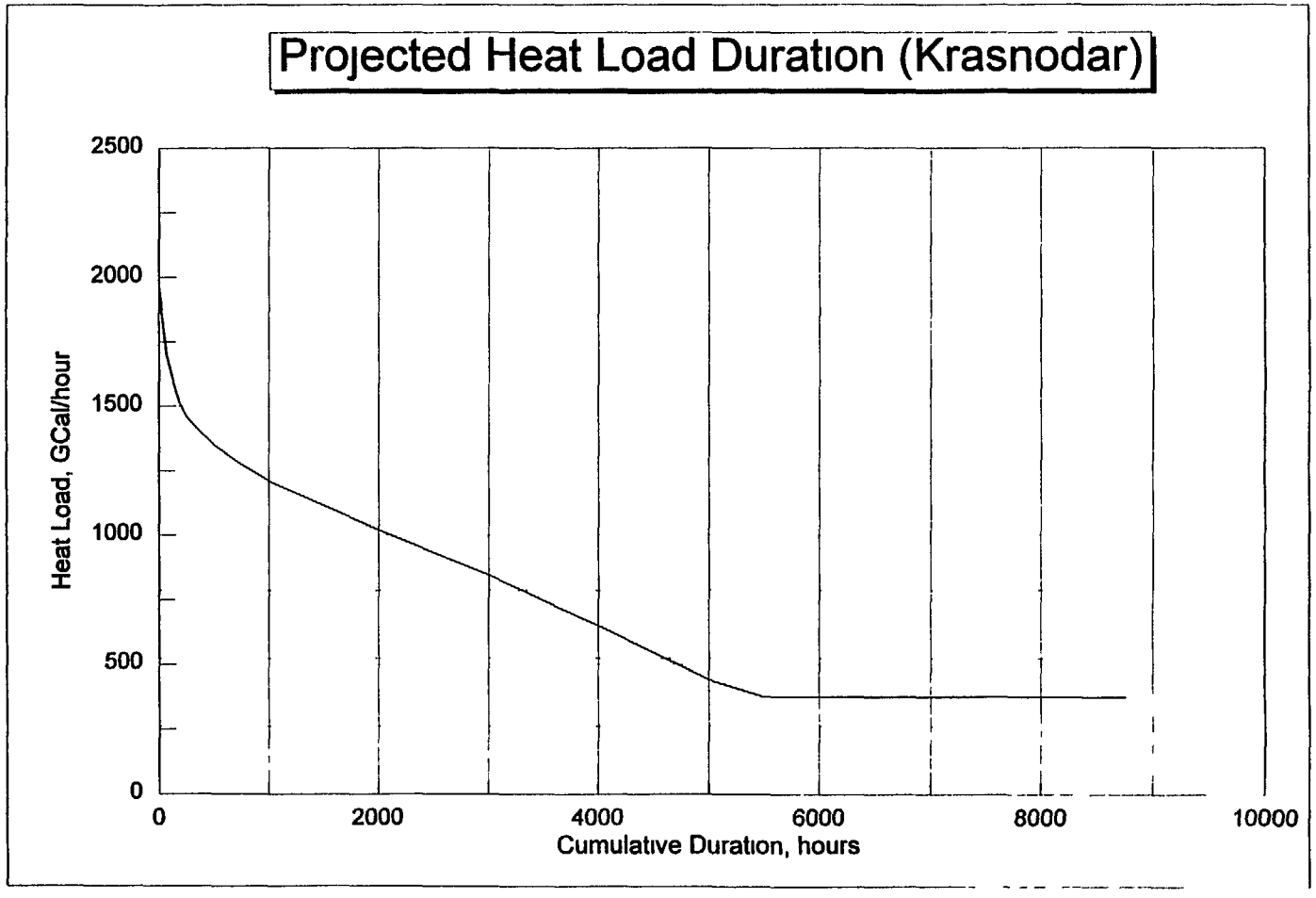
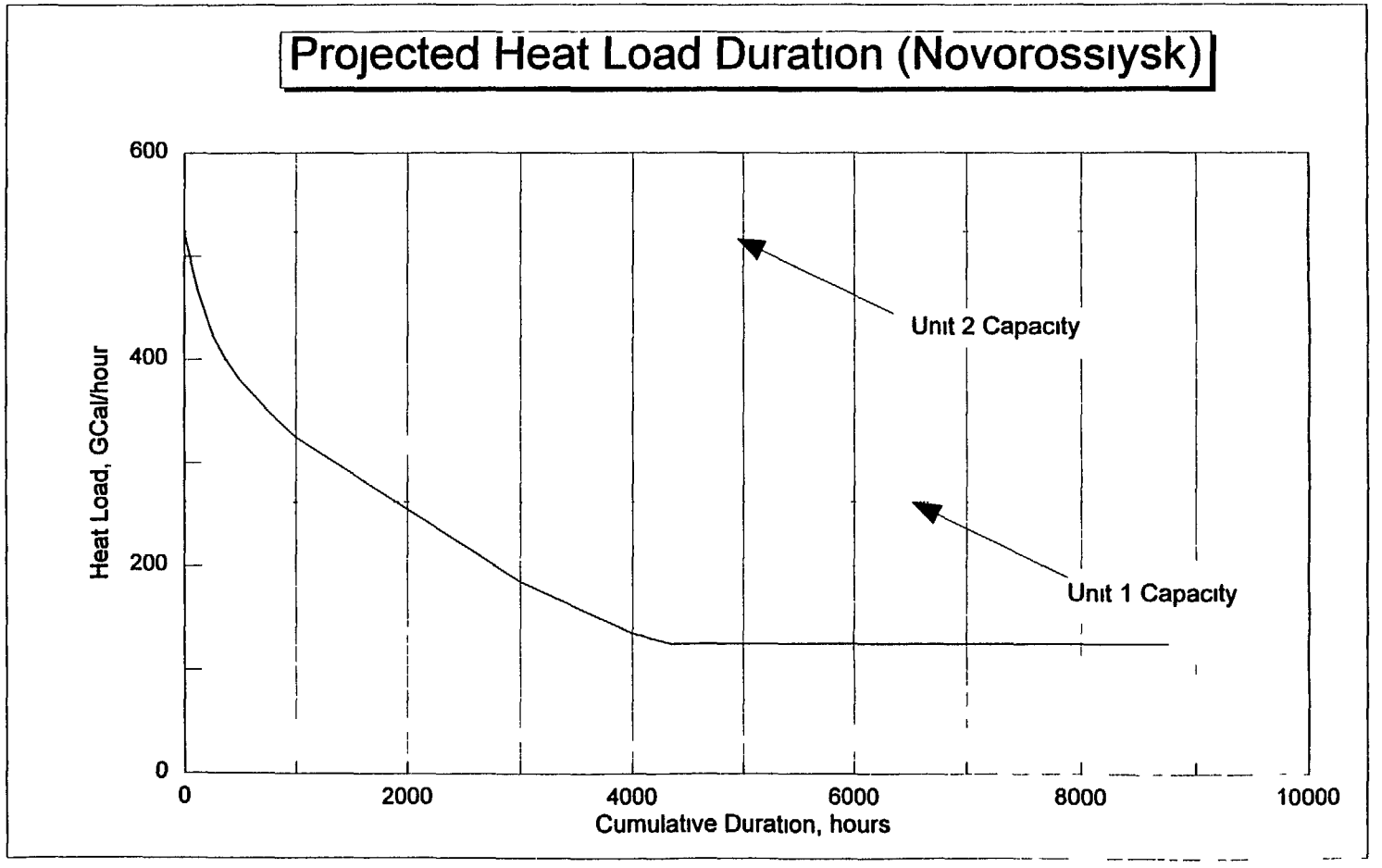

Generation Costs vs Plant Size
For Simple Cycle Plants at 40% Capacity Factor
0 08
0 06
0 04
0 02
0
Generation Cost, $/kWh
300
600
900
Plant Size, MW
Krasnodar
Mostovskoy
Novorossiysk


Generation Costs vs Plant Size
For Combined Cycle Plants at 80% Capacity Factor
0 04
0 03
0 02
0 01
0
Generation Cost, $/kWh
450
900
1350
MW
Krasnodar
Mostovskoy
Novorossiysk


Projected Heat Load Duration (Krasnodar)
Heat Load, GCal/hour
2500
2000
1500
1000
500
0
0
2000
4000
6000
8000
10000
Cumulative Duration, hours

53


Projected Heat Load Duration (Novorossiysk)
600
400
200
0
Heat Load, GCal/hour
0
2000
4000
6000
8000
10000
Cumulative Duration, hours
Unit 2 Capacity
Unit 1 Capacity

ESTIMATION OF REQUIRED CAPACITY NEEDS FOR NORTH CAUCASUS - BASE CASE

Year	Capacity Retirements MW	Existing Capacity MW	Peak Demand MW	Required Capacity MW	Hydro Additions MW	Trans. Additions MW	Projected Capacity MW	Fossil Additions MW	Potential Shortage MW
1994		8562	8616*						
1995	319	8243	8220	9371	0	200	8443	0	928
1996	0	8243	8180	9325	40	0	8483	0	842
1997	75	8168	8475	9662	40	550	9148	150	514
1998	38	8130	8697	9915	40	0	9915	765	0
1999	0	8130	8967	10222	40	0	10222	268	0
2000	126	8004	9212	10502	0	0	10502	405	0
2001	45	7959	9471	10797	85	0	10797	255	0
2002	4	7955	9753	11118	85	0	11118	240	0
2003	295	7660	10018	11421	85	0	11421	512	0
2004	405	7255	10293	11734	85	0	11734	634	0
2005	127	7128	10588	12070	0	0	12070	463	0

* Includes 110 MW of unserved demand

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Base and Change Case Results
Fossil Capacity Additions

CASE	Description	1998 Capacity Additions			1999 Capacity Additions			2000 Capacity Additions			2001-2 Capacity Additions			'98-'02 Fossil
		Hydro	Fossil	Total	Hydro	Fossil	Total	Hydro	Fossil	Total	Hydro	Fossil	Total	Total
REF	Base Case	40	765	805	40	268	308	0	405	405	85	495	580	2098
LRF	Low Demand Scenario	40	185	225	40	87	127	0	295	295	85	481	566	1213
CC1	500 MW Firm Transmission in '99	40	765	805	40	0	40	0	173	173	85	495	580	1598
CC2	1000 MW Firm Transmission in '99	40	765	805	40	0	40	0	0	0	85	169	254	1099
CC3	700 capacity Firm via UKR in '1999	40	765	805	40	0	40	0	0	0	85	468	553	1398
CC4	Rostov 1 on Line in 2000	40	765	805	40	268	308	0	0	0	85	0	85	1198

25-Jul-95

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APPENDIX A

LIST OF PLANTS AND RETIREMENT SCHEDULE

The following pages show installed units and the assumed retirement schedule for fossil fueled generating capacity in the North Caucasus

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Fossil Plants in North Caucasus

	CAPACITY Rated MW	CAPACITY Avail MW
UPS TOTAL THERMAL CAPACITY	**8377**	**6597**
UPS TOTAL HYDRO CAPACITY	**2180**	**1969**
UPS TOTAL CAPACITY	**10557**	**8566**

PLANT	UNIT #	FUEL	I O Year		
KUBANENERGO					
Armavirskaja CHP	1	gas	1959	2	2
	2	gas	1958	6	5
Total for the plant				8	7
Krasnodarskaja CHP	1	gas	1954	25	19
	2	oil	1955	20	15
	3	gas	1957	22	17
	4	gas	1959	50	38
	5	gas	1961	42	32
	6	gas	1963	145	138
	7	gas	1963	150	143
	8	gas	1964	150	143
	9	gas	1966	160	152
gas turbine	10	gas	1970	75	75
gas turbine	11	gas	1975	0	0
Total for the plant				839	772
CHP of Maikopsky CKK	1	gas	1964	6	4
	2	gas	1964	6	4
Total for the plant				12	8
CHP of Krasnodarsky X	1		1964	12	12
	2		1989	12	12
Total for the plant				24	24
CHP of Kropotkinski X	1	gas	1959	6	2
	2	gas	1960	4	1
Total for the plant				10	3
Sugar Plants' CHP	51	gas	1970	158	0
Block-plants	51	gas	1976	14	6
Total for the RPS				**1065**	**820**

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STAVROPOLENERGO					
Stavropolskaja TPP	1	gas	1975	300	267
	2	gas	1975	300	267
	3	gas	1976	300	267
	4	gas	1976	300	267
	5	gas	1978	300	267
	6	gas	1979	300	267
	7	gas	1981	300	267
	8	gas	1983	300	267
Total for the plant				2400	2136
Nevinnomysskaja TPP	1	gas	1960	25	19
	2	gas	1960	25	19
	3	gas	1961	60	45
	4	gas	1968	50	34
	5	gas	1973	100	85
	6	gas	1964	150	127
	7	gas	1964	150	127
	8	gas	1965	150	127
	9	gas	1966	150	127
	10	gas	1967	150	127
	11	gas	1970	160	136
	12	gas	1972	170	144
Total for the plant				1340	1117
Kislovodskaja CHP	2	gas	1958	4	0
	3	gas	1981	0	0
Replacement	4		1993	6	6
Total for the plant				10	6
Isobilnensky Sugar CHP	1	gas	1968	6	0
	2	gas	1968	6	0
Total for the plant				12	0
Stavropolskaja Geo TPP	1		1993	0	0
Total for the RPS				**3762**	**3259**
SEVKAVKAZENERGO					
Total for the RPS				0	0

GROZENERGO

CHP-4 Grozenergo	1	gas	1962	6	0
	2	gas	1962	6	0
Total for the plant				12	0
CHP-2 Grozenergo	1	gas	1953	25	17
	2	gas	1964	25	17
	3	gas	1957	20	14
	4	gas	1955	30	21
	5	gas	1958	50	34
	6	gas	1958	107	73
	7	-	1960	60	41
Total for the plant				317	217
CHP-3 Grozenergo	1	gas	1966	50	0
	2	gas	1967	50	0
Total for the plant				100	0
CHP-1 Grozenergo	3	gas	1974	9	0
	4	gas	1974	5	0
	6	gas	1976	8	0
	7	gas	1951	20	0
	8	gas	1980	12	0
	9	gas	1983	6	0
Total for the plant				60	0
Total for the RPS				**489**	**217**

DAGENERGO

Machatchkalinskaja CHP	3	gas	1982	6	6
Dagestanskaja CHP					
Replacement	1		1992	6	5
Replacement	2		1993	6	5
Replacement	3		1993	6	6
Total for the plant				18	16
Kajspijskaja CHP	2	gas	1973	6	6
	5	gas	1958	8	8
Total for the plant				14	14
Total for the RPS				**40**	**36**

KABARDINO-BALKARENERGO

CHP Nartkala	1		1977	12	3
	2		1977	4	1
Total for the plant				16	4
CHP of the Nalchik	51	gas	1962	6	4
Total for the RPS				**22**	**8**

ROSTOVENERGO

Novocherkassky TPP-1	1	coal	1968	267	206
	2	coal	1966	267	206
	3	coal	1967	277	214
	4	coal	1968	277	214
	5	coal	1969	290	224
	6	coal	1970	290	224
	7	coal	1971	290	224
	8	coal	1972	287	222
Total for the plant				2245	1734
Nesvetay TPP	5	coal	1954	105	86
Kamenskaja CHP	1	coal	1944	10	6
	7	coal	1971	12	6
	8	coal	1984	12	7
Total for the plant				34	19
Volgodonsky CHP - 1	1	oil	1960	6	5
Rostovskaja CHP-2	1	oil	1974	80	68
	2	oil	1974	80	69
Total for the plant				160	137
Volgodonsky CHP - 2	1	gas	1977	60	38
	2	gas	1979	110	69
	3	gas	1980	110	69
	4	gas	1989	140	88
Total for the plant				420	264
Rosselmash CHP	51		1931	6	6
Total for the RPS				**2985**	**2251**

KARACHAI-CHERKESSKENERGO

Erken-Shahar CHP	1	gas	1963	7	7
	2	gas	1963	7	7
Total for the plant				14	14
Total for the RPS				**14**	**14**

KALMYKENERGO

CPP in Elista	1		1995	0	0
Total for the RPS				**0**	**0**

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NORTH CAUCASUS UNIT RETIREMENT SCHEDULE FOR THERMAL UNITS

PLANT NAME	Unit Size	Fuel Type	Unit #	Year in Service	Year of Retirement
Krasnodar CHPP	95	gas	10	1970	1995
GrozEnergo CHPP-2	107	gas	6	1958	1995
GrozEnergo CHPP-2	30	gas	4	1955	1995
GrozEnergo CHPP-2	60	gas	7	1960	1995
GrozEnergo CHPP-2	25	gas	2	1964	1995
GrozEnergo CHPP-2	50	gas	5	1958	1995
GrozEnergo CHPP-1	8	gas	6	1976	2016
GrozEnergo CHPP-1	12	gas	8	1980	2020
GrozEnergo CHPP-1	6	gas	9	1983	2023
Caspian CHPP	8	gas	5	1958	1995
Kislovodsk CHPP	4	gas	2	1958	1995
Kropotkin	6	gas	1	1959	1995
GrozEnergo CHPP-3	50	gas	1	1966	1995
GrozEnergo CHPP-2	20	gas	3	1957	1995
Nesvetai SDPS	105	coal	5	1954	1995
GrozEnergo CHPP-2	25	gas	1	1953	1995
Armavir CHPP	6	gas	2	1958	1995
GrozEnergo CHPP-1	20	gas	7	1951	1995
GrozEnergo CHPP-4	6	gas	2	1962	1995
Kropotkin	4	gas	2	1960	1995
GrozEnergo CHPP-1	9	gas	3	1974	1995
GrozEnergo CHPP-1	5	gas	4	1974	1995
GrozEnergo CHPP-4	6	gas	1	1962	1995
Armavir CHPP	2	gas	1	1959	1995
Rostselmash Enterprise CHPP	6	gas	51	1931	1995
Kamenskaya CHPP	10	coal	1	1944	1995
GrozEnergo CHPP-3	50	gas	2	1967	1995
Subtotal	735				
Krasnodar CHPP	95	gas	11	1975	1997
Krasnodar CHPP	50	gas	4	1959	1998
Krasnodar CHPP	20	gas	2	1955	2000
Krasnodar CHPP	25	gas	1	1954	2000
Krasnodar CHPP	22	gas	3	1957	2000
Nevinnomysskaya SDPS	25	gas	1	1960	2000

Volgodon CHPP	6	gas	1	1960	2000
Nevinnomysskaya SDPS	25	gas	2	1960	2000
Krasnodar CHPP	42	gas	5	1961	2000
Subtotal	165				
Nevinnomysskaya SDPS	60	gas	3	1961	2001
Nalchik GMZ CHPP	6	gas	51	1962	2002
Krasnodar CHPP	150	gas	6	1963	2003
Krasnodar CHPP	150	gas	7	1963	2003
Erken-Shakar CHPP	7	gas	2	1963	2003
Erken-Shakar CHPP	7	gas	1	1963	2003
Subtotal	314				
Nevinnomysskaya SDPS	150	gas	6	1964	2004
MainopYSKK CHPP	6	gas	2	1964	2004
Krasnodar CHPP	150	gas	8	1964	2004
MainopYSKK CHPP	6	gas	1	1964	2004
Nevinnomysskaya SDPS	150	gas	7	1964	2004
Subtotal	462				
Nevinnomysskaya SDPS	150	gas	8	1965	2005
Total through 2005	**2037**				

UNIT RETIREMENT SCHEDULE - AFTER 2005

PLANT NAME	Unit Size	Fuel Type	Unit #	Year in Service	Year of Retirement
Krasnodar CHPP	160	gas	9	1966	2006
Nevinnomysskaya SDPS	150	gas	9	1966	2006
Novocherkasskaya SDPS	267	coal	2	1966	2006
Novocherkasskaya SDPS	277	coal	3	1967	2007
Nevinnomysskaya SDPS	150	gas	10	1967	2007
Novocherkasskaya SDPS	267	coal	1	1968	2008
Nevinnomysskaya SDPS	50	gas	4	1968	2008
Novocherkasskaya SDPS	277	coal	4	1968	2008
Isolinen s z CHPP	6	gas	2	1968	2008
Isolinen s z CHPP	6	gas	1	1968	2008
Novocherkasskaya SDPS	290	coal	5	1969	2009
Sugar Refineries CHPP	158	gas	51	1970	2010
Nevinnomysskaya SDPS	160	gas	11	1970	2010

North Caucasus Retirement Schedule

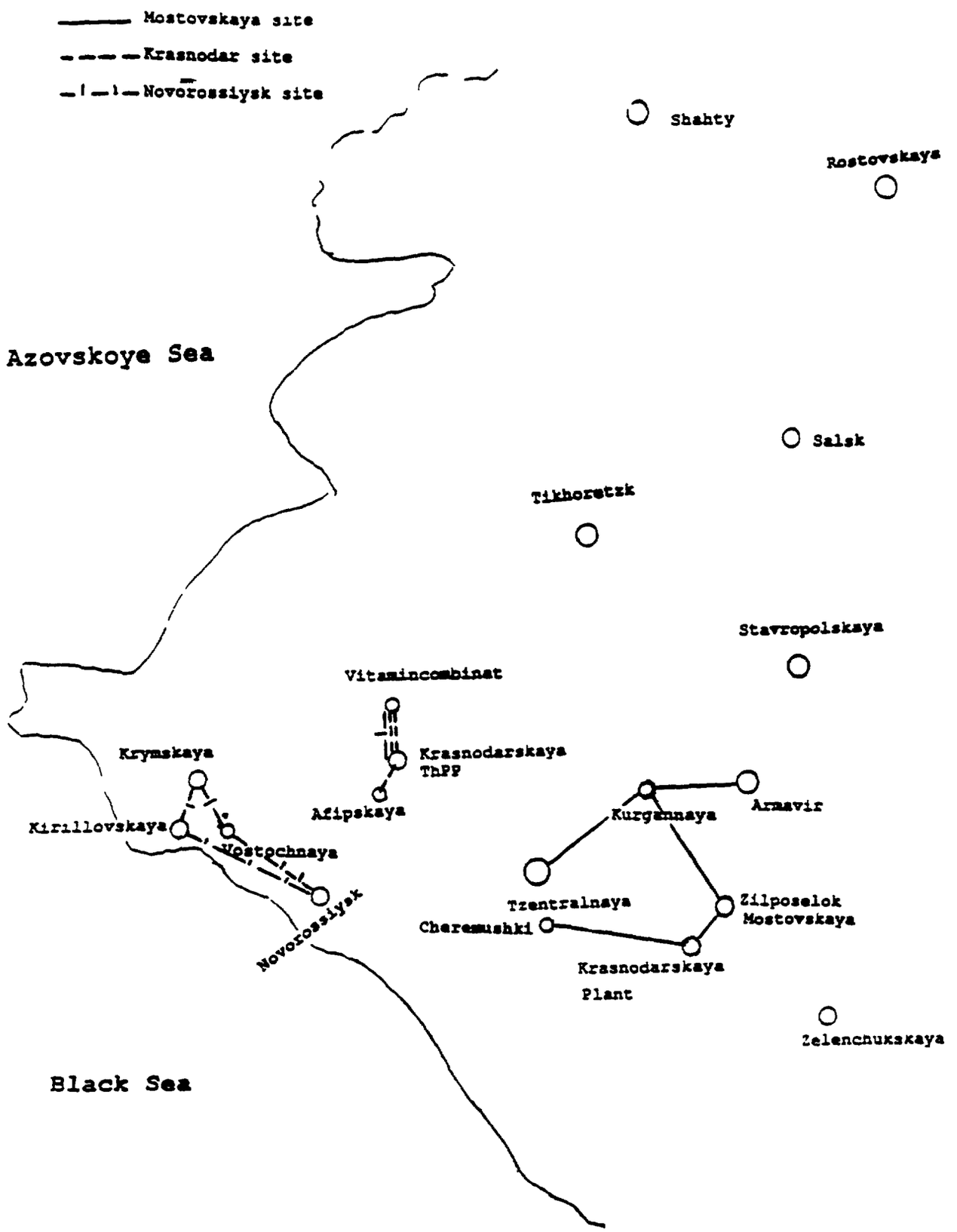
Novocherkasskaya SDPS	290	coal	6	1970	2010
Kamenskaya CHPP	12	coal	7	1971	2011
Novocherkasskaya SDPS	290	coal	7	1971	2011
Nevinnomysskaya SDPS	170	gas	12	1972	2012
Novocherkasskaya SDPS	287	coal	8	1972	2012
Nevinnomysskaya SDPS	100	gas	5	1973	2013
Caspian CHPP	6	gas	2	1973	2013
Rostov CHPP-2	80	gas	2	1974	2014
Rostov CHPP-2	80	gas	1	1974	2014
Stavropol SDPS	300	gas	2	1975	2015
Stavropol SDPS	300	gas	1	1975	2015
BLOCKSTATION	14	gas	51	1976	2016
Krasnodar Enterprise CHPP	12	gas	1	1976	2016
Stavropol SDPS	300	gas	4	1976	2016
Stavropol SDPS	300	gas	3	1976	2016
Nartkala CHPP	12	gas	1	1977	2017
Volgodon Plant CHPP	60	gas	1	1977	2017
Nartkala CHPP	4	gas	2	1977	2017
Stavropol SDPS	300	gas	5	1978	2018
Stavropol SDPS	300	gas	6	1979	2019
Volgodon Plant CHPP	110	gas	2	1979	2019
Volgodon Plant CHPP	110	gas	3	1980	2020
Kislovodsk CHPP	6	gas	3	1981	2021
Stavropol SDPS	300	gas	7	1981	2021
Makhachkala CHPP	6	gas	3	1982	2022
Stavropol SDPS	300	gas	8	1983	2023
Kamenskaya CHPP	12	coal	8	1984	2024
Volgodon Plant CHPP	140	gas	4	1989	2029
Krasnodar Enterprise CHPP	12	gas	2	1989	2029
Dagestan CHPP	6	gas	1	1992	2032
Kislovodsk CHPP	6	gas	4	1993	2033
Dagestan CHPP	6	gas	3	1993	2033
Dagestan CHPP	6	gas	2	1993	2033
Total from 2006	**6455**				

APPENDIX B

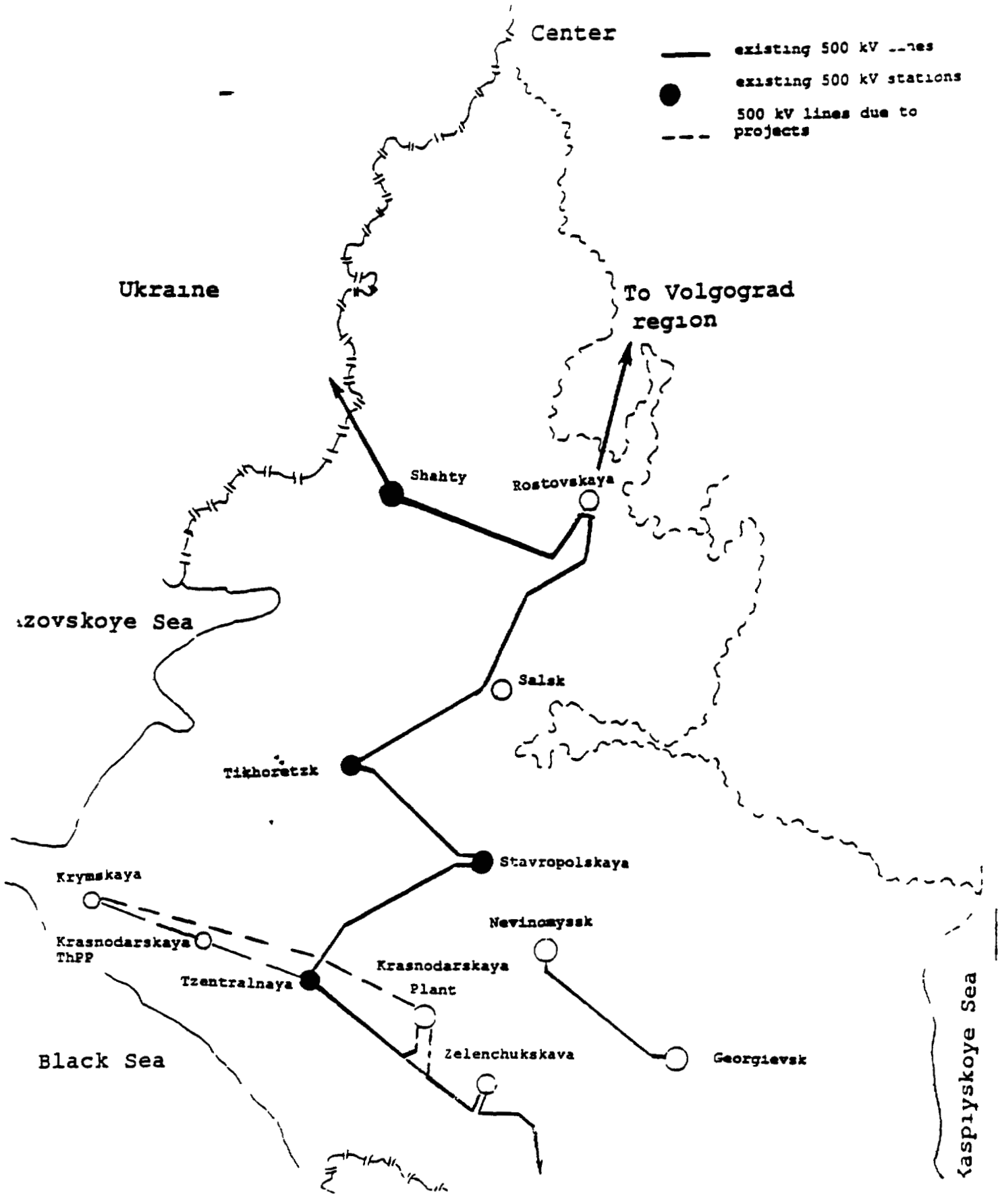
TRANSMISSION DIAGRAMS AND MAPS

The following pages include two maps showing the 220 kV and 500 kV transmission reinforcements considered in this study, and five diagrams illustrating interregional transmission options

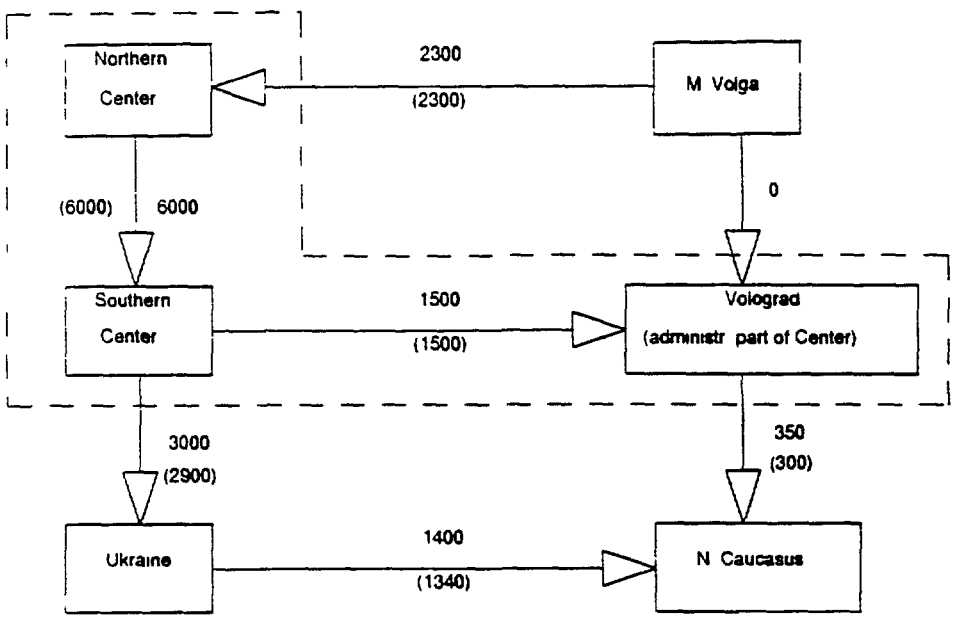
220 kV TRANSMISSION REINFORCEMENT



EXISTING 500 kV NETWORK OF NORTH CAUCASUS WITH REINFORCEMENT DUE TO PROJECTS



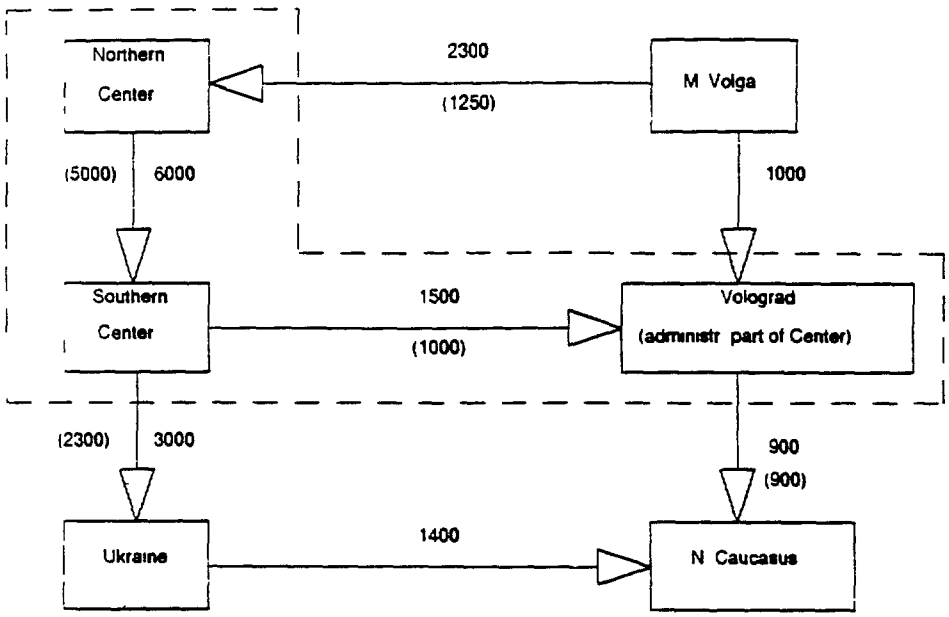
MAXIMUM TRANSFER CAPABILITIES
EXISTING SITUATION



Ptotal to NC<1750 MW
First Contingency Limit 1200 MW

Note: Actual flows at peak load are shown in brackets

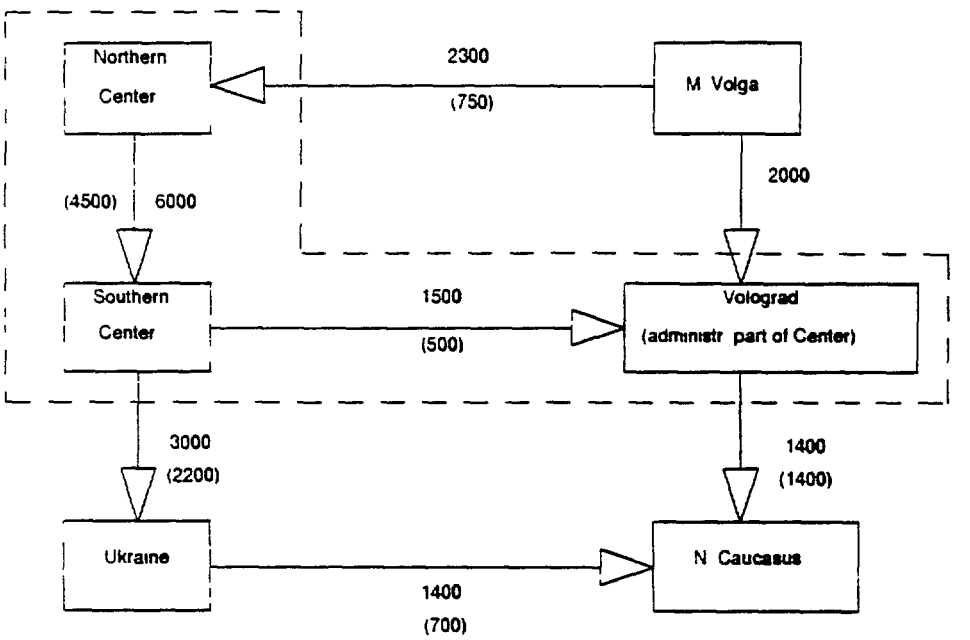
MAXIMUM TRANSFER CAPABILITIES
Middle Volga-Center-N. Caucasus Reinforcement (first stage)



Ptotal to NC < 2300 MW
First Contingency Limit=1500 MW

Note: Actual flows at peak load are shown in brackets

MAXIMUM TRANSFER CAPABILITIES
Middle Volga-Center-North Caucasus Reinforcement (second stage)

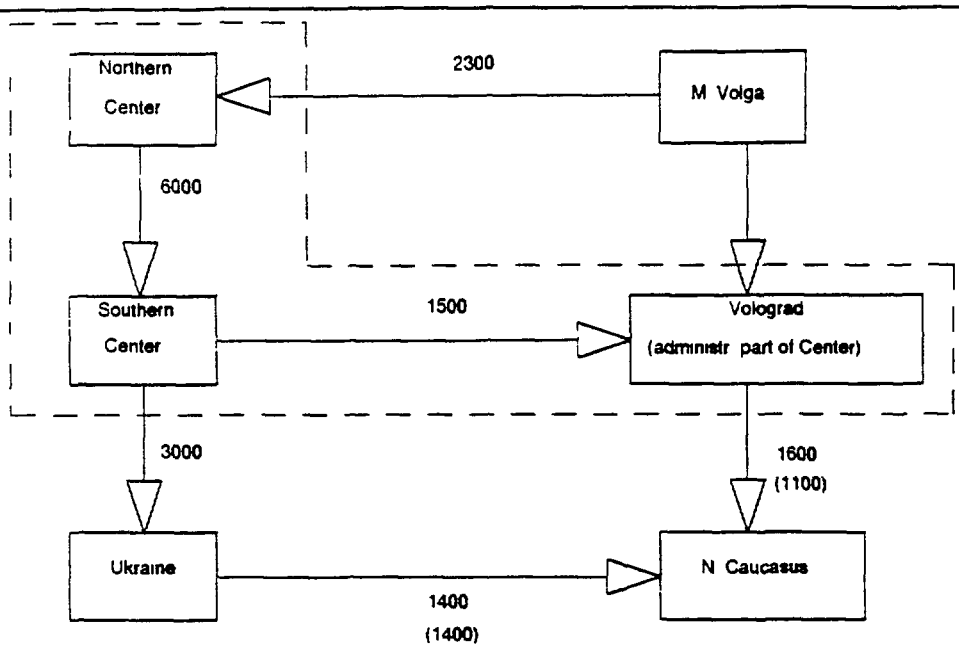


Ptotal to NC < 2800 MW
First Contingency Limit 1750 MW

Note: Actual Flows at Peak Load are shown in brackets

MAXIMUM TRANSFER CAPABILITIES

olgograd-N.Caucasus Reinforcement Complementary to the first stage of iddle Volga-Center-N. Caucasus Reinforcement

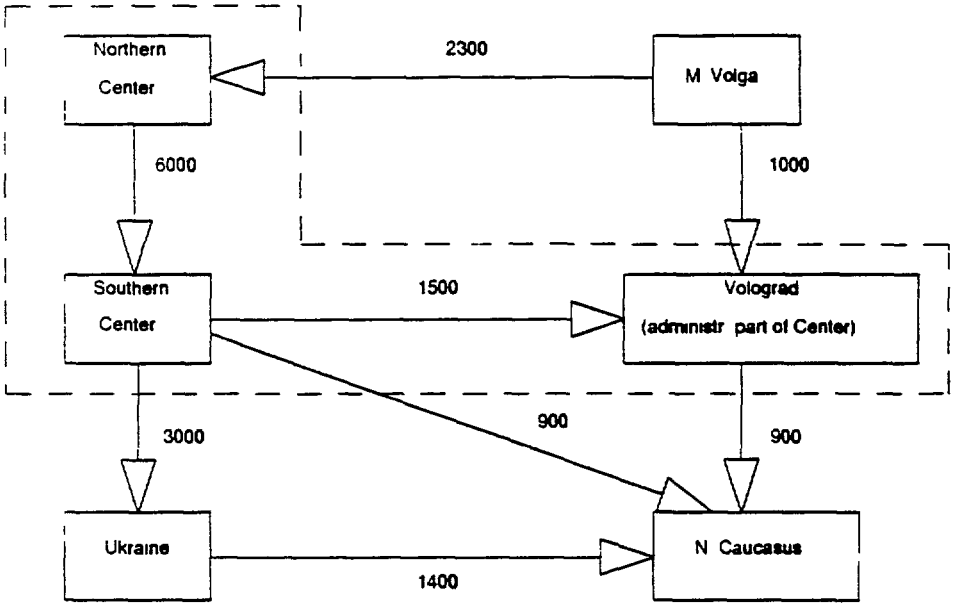


f ties with Ukraine are available: Ptotal to NC<2500MW
irst Contingency Limit = 2000MW

f ties with Ukraine are unavailable: Ptotal to NC<1600MW

MAXIMUM TRANSFER CAPABILITIES

Souther Center-N.Caucasus Reinforcement complementary to the first stage of Middle Volga-Center-N.Caucasus Reinforcement



Ties with Ukraine are available: Ptotal to NC<2700MW
First Contingency Limit=2000MW
Ties with Ukraine are unavailable:Ptotal to NC<1500MW

APPENDIX C

ELECTRICITY AND HEAT DEMAND PROJECTIONS FOR KRASNODAR KRAI NORTH CAUCASUS

The report prepared by the Center for Energy Efficiency (CENEf) Moscow, and dated July 21, 1995, is attached under separate cover

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APPENDIX D

STATIC SCREENING OF ALTERNATIVE GENERATION OPTIONS FOR KRASNODAR KRAI

The attached spreadsheets present the detailed computations of generation costs for the various power generation options considered in this study

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KRASNODAR POWER PROJECT

STATIC SCREENING OF ALTERNATIVE GENERATION OPTIONS

HAGLER BAILLY CONSULTING INC 10 05 AM 24-Jul-95

GENERATION OPTIONS		
A	GT 300 K	2x150MW - Gas Turbines - Krasnodar
B	GT 600 K	4x150MW - Gas Turbines - Krasnodar
C	CC 450 K	1x450MW - Combined Cycle - Krasnodar
D	CC 900 K	2x450MW - Combined Cycle - Krasnodar
E	HP 450 K	1x450MW - CHP - Krasnodar
F	HP 900 K	2x450MW - CHP - Krasnodar
DISCOUNT RATE	%	15 00%
LEVELIZING PERIOD	YEARS	25

COMPUTATION OF EFFECTIVE CAPACITY

PARAMETER	UNITS	GT 300 K	GT 600 K	CC 450 K	CC 900 K	HP 450 K	HP 900 K
NOMINAL CAPACITY	MW	300	600	450	900	450	900
NET RATED CAPACITY	MW	300	600	450	900	400	800
CHP CAPACITY	GCAL/H	0	0	0	0	250	448
FORCED OUTAGE RATE	%	4 00%	4 00%	4 60%	4 60%	4 60%	4 60%
PLANNED MAINTENANCE	DAYS	25	25	25	25	25	25
AVAILABILITY	%	**89 15%**	**89 15%**	**88 55%**	**88 55%**	**88 55%**	**88 55%**
TRANSMISSION LOSS	MW	8 70	-7 00	-8 50	-3 90	0 00	-8 50
EFFECTIVE RATING	MW	**276 15**	**542**	**407**	**801**	**354**	**717**

COMPUTATION OF ANNUAL CAPITAL COSTS

PARAMETER	UNITS	GT 300 K	GT 600 K	CC 450 K	CC 900 K	HP 450 K	HP 900 K
PLANT COST ON G R C	$/KW	350	307	427	413	429	415
CHP CAPACITY COST	$1000/Gcal-H	0	0	0	0	43	43
TOTAL PLANT COST	M$	**105**	**184**	**192**	**372**	**193**	**374**
CHP PIPING COST	M$	**0**	**0**	**0**	**0**	**0**	**0**
CHP CAPITAL COST CREDIT	M$	**0**	**0**	**0**	**0**	**11**	**19**
GAS PIPELINE COST	M$	44	61	44	61	0	44
TRANSMISSION COST	M$	89	92	89	99	0	89
ADJUSTED PROJECT COST	M$	**238**	**337**	**325**	**532**	**182**	**487**
COMPUTATION OF PROJECT VALUE AT TIME OF COMMISSIONING							
YEAR FROM START	PERCENT OF CAPITAL COST INCURRED						
FIRST YEAR OF OPERATION	0	0 00	0	0	0	0	0
LAST YEAR OF CONSTRUCTION	1	70 00	70	40	40	40	40
YEAR BEFORE	2	30 00	30	45	30	45	30
YEAR BEFORE	3	0 00	0	15	20	15	20
YEAR BEFORE	4	0 00	0	0	10	0	10
YEAR BEFORE	5	0 00	0	0	0	0	0
TOTAL (MUST ADD TO 100)		**100 00**	**100**	**100**	**100**	**100**	**100**
FUTURE VALUE MULTIPLIER		**1 1206**	**1 1206**	**1 1966**	**1 2457**	**1 1966**	**1 2457**
FUTURE VALUE	M$	**266 71**	**378**	**389**	**662**	**218**	**607**
EFFECTIVE CAPITAL COST	$/KW	**965 81**	**697**	**956**	**827**	**616**	**847**
DEPRECIATION	YEARS	30 00	30	35	35	35	35
CAPITAL RECOVERY FACTOR		**0 1523**	**0 1523**	**0 1511**	**0 1511**	**0 1511**	**0 1511**
CAPITAL COST	$/KW year	**147 09**	**106**	**144**	**125**	**93**	**128**

COMPUTATION OF OPERATION AND MAINTENANCE (O&M) EXPENSES

PARAMETER	UNITS	GT 300 K	GT 600 K	CC 450 K	CC 900 K	HP 450 K	HP 900 K
VARIABLE O&M	$/MWH	0 07000	0 07000	0 29000	0 29000	0 32000	0 32000
TRANSMISSION LOSS	$/KWH	-0 00057	-0 00023	-0 00024	-0 00006	0 000	0 000
FIXED ANNUAL PLANT O&M	$/KW	5 38000	5 38000	7 68000	7 13000	8 45000	8 45000
SOCIAL COST (FIXED)	$/KW	0 00	0 00	0 00	0 00	0 00	0 00
TOTAL FIXED COST	$/KW	**5 38**	**5 38**	**7 68**	**7 13**	**8 45**	**8 45**
EFFECTIVE FIXED COST	$/KW	**5 84**	**5 96**	**8 49**	**8 01**	**10 74**	**10 61**
CHP O&M CREDIT	M$/Year	**0 00**	**0 00**	**0 00**	**0 00**	**0 86**	**1 54**
HEAT TO DIST SYSTEM	Gcal/KWH	**0**	**0**	**0**	**0**	**706**	**624**

COMPUTATION OF LEVELIZED FUEL COST

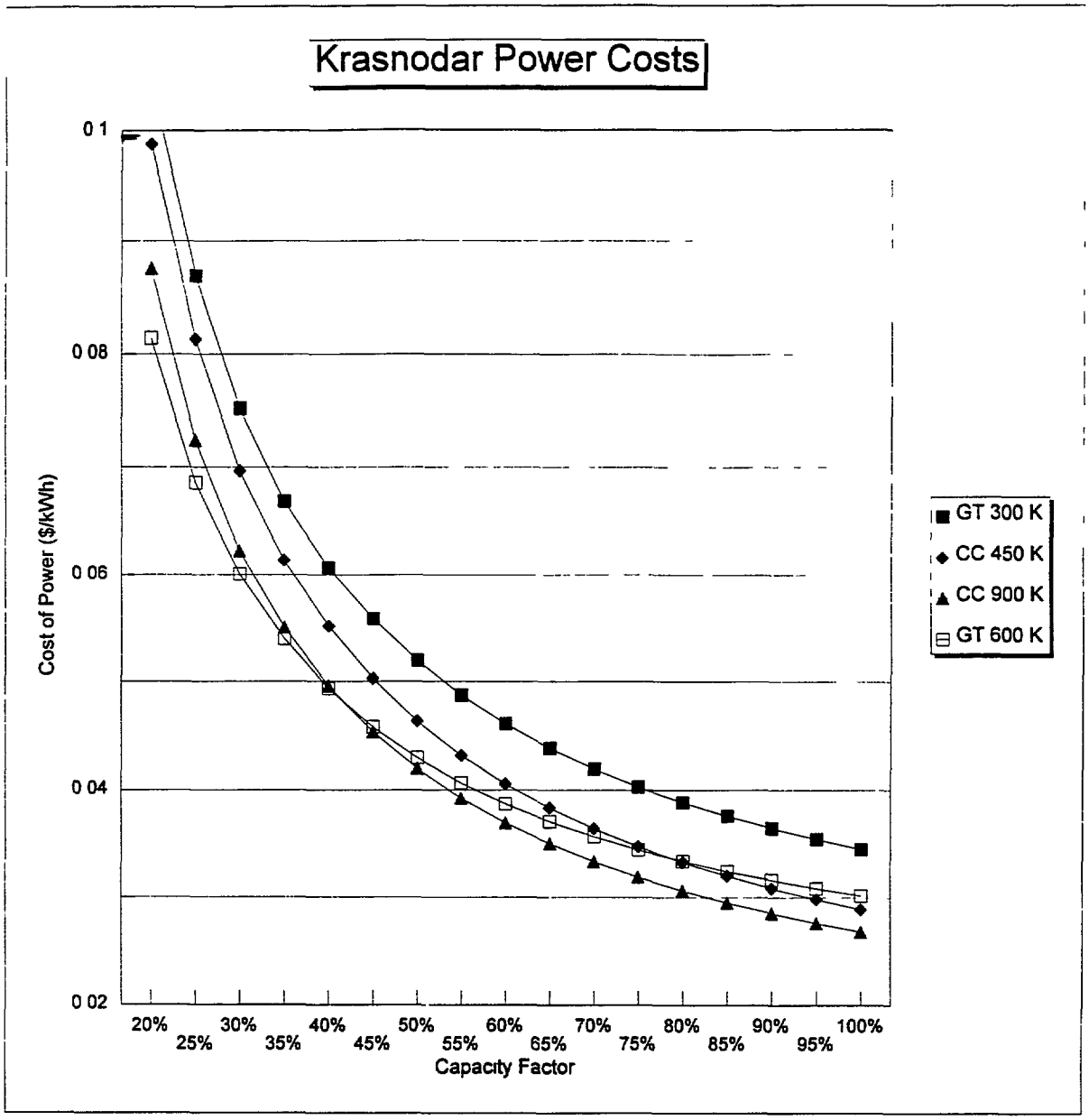
		GT 300 K	GT 600 K	CC 450 K	CC 900 K	HP 450 K	HP 900 K
FUEL TYPE		GAS	GAS	GAS	GAS	GAS	GAS
BASE PRICE	$/M BTU	1 40	1 40	1 40	1 40	1 40	1 40
ANNUAL ESCALATION	%	3 00%	3 00%	3 00%	3 00%	3 00%	3 00%
PRESENT VALUE FACTOR		6 46	6 46	6 46	6 46	6 46	6 46
LEVELIZING RATE	%	11 65%	11 65%	11 65%	11 65%	11 65%	11 65%
P V F + ESCALATION		8 04	8 04	8 04	8 04	8 04	8 04
LEVELIZING FACTOR		1 24	1 24	1 24	1 24	1 24	1 24
LEVELIZED PRICE	$/M BTU	1 741	1 741	1 741	1 741	1 741	1 741
HEATRATE	BTU/KWH	10080	10080	6561	6561	5269	5269
LEVELIZED FUEL COST	$/KWH	0 0175	0 0175	0 0114	0 0114	0 0084	0 0085

SUMMARY OF FIXED AND VARIABLE OPERATING EXPENSES WITH LEVELIZED FUEL

		GT 300 K	GT 600 K	CC 450 K	CC 900 K	HP 450 K	HP 900 K
FIXED	$/KW year	152 94	112	153	133	104	139
VARIABLE	$/KWH	0 0170	0 0174	0 0115	0 0117	0 0088	0 0088

LEVELIZED COST PER KWH PRODUCED

CAPACITY FACTOR	Hours/year	GT 300 K	GT 600 K	CC 450 K	CC 900 K	HP 450 K	HP 900 K
0%	0	NA	NA	NA	NA	NA	NA
5%	438	0 3662	0 2735	0 3607	0 3153	0 2458	0 3252
10%	876	0 1916	0 1454	0 1861	0 1635	0 1273	0 1670
15%	1314	0 1334	0 1027	0 1279	0 1129	0 0878	0 1143
20%	1752	0 1043	0 0814	0 0988	0 0876	0 0680	0 0879
25%	2190	0 0869	0 0686	0 0813	0 0724	0 0562	0 0721
30%	2628	0 0752	0 0601	0 0697	0 0623	0 0483	0 0616
35%	3066	0 0669	0 0540	0 0614	0 0550	0 0426	0 0540
40%	3504	0 0607	0 0494	0 0551	0 0496	0 0384	0 0484
45%	3942	0 0558	0 0458	0 0503	0 0454	0 0351	0 0440
50%	4380	0 0520	0 0430	0 0464	0 0420	0 0325	0 0405
55%	4818	0 0488	0 0407	0 0432	0 0393	0 0303	0 0376
60%	5256	0 0461	0 0387	0 0406	0 0370	0 0285	0 0352
65%	5694	0 0439	0 0371	0 0383	0 0350	0 0270	0 0332
70%	6132	0 0420	0 0357	0 0364	0 0333	0 0257	0 0314
75%	6570	0 0403	0 0345	0 0348	0 0319	0 0246	0 0299
80%	7008	0 0389	0 0334	0 0333	0 0306	0 0236	0 0286
85%	7446	0 0376	0 0324	0 0320	0 0295	0 0227	0 0275
90%	7884	0 0364	0 0316	0 0309	0 0285	0 0219	0 0264
95%	8322	0 0354	0 0309	0 0299	0 0276	0 0212	0 0255
100%	8760	0 0345	0 0302	0 0289	0 0268	0 0206	0 0247


Krasnodar Power Costs
0 1
0 08
0 06
0 04
0 02
Cost of Power ($/kWh)
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%
Capacity Factor
GT 300 K
CC 450 K
CC 900 K
GT 600 K

KRASNODAR POWER PROJECT

STATIC SCREENING OF ALTERNATIVE GENERATION OPTIONS

HAGLER BAILLY CONSULTING INC 10 05 AM 24-Jul-95

GENERATION OPTIONS		
A	GT 300 M	2x150MW - Gas Turbines - Mostovskoy
B	GT 600 M	4x150MW - Gas Turbines - Mostovskoy
C	CC 450 M	1x450MW - Combined Cycle - Mostovskoy
D	CC 900 M	2x450MW - Combined Cycle - Mostovskoy
E	CC 1350 M	3x450MW - Combined Cycle - Mostovskoy
F		

DISCOUNT RATE	%	15 00%
LEVELIZING PERIOD	YEARS	25

COMPUTATION OF EFFECTIVE CAPACITY

PARAMETER	UNITS	GT 300 M	GT 600 M	CC 450 M	CC 900 M	CC 1350 M
NOMINAL CAPACITY	MW	300	600	450	900	1350
NET RATED CAPACITY	MW	300	600	443	886	1330
CHP CAPACITY	GCAL/H	0	0	0	0	0
FORCED OUTAGE RATE	%	4 00%	4 00%	4 60%	4 60%	4 60%
PLANNED MAINTENANCE	DAYS	25	25	25	25	25
AVAILABILITY	%	89 15%	89 15%	88 55%	88 55%	88 55%
TRANSMISSION LOSS	MW	-4 80	-1 90	-3 80	10 50	24 50
EFFECTIVE RATING	MW	272	537	396	774	1153

COMPUTATION OF ANNUAL CAPITAL COSTS

PARAMETER	UNITS	GT 300 M	GT 600 M	CC 450 M	CC 900 M	CC 1350 M
PLANT COST ON G R C	$/KW	367 00	317 00	479 00	446 00	430 00
CHP CAPACITY COST	$1000/GCAL-H	0 00	0 00	0 00	0 00	0 00
TOTAL PLANT COST	M$	110 10	190 20	215 55	401 40	580 50
CHP PIPING COST	M$	0 00	0 00	0 00	0 00	0 00
CHP CAPITAL COST CREDIT	M$	0 00	0 00	0 00	0 00	0 00
GAS PIPELINE COST	M$	24 00	34 00	24 00	34 00	38 00
TRANSMISSION COST	M$	84 00	86 30	84 00	105 00	192 00
ADJUSTED PROJECT COST	M$	218 10	310 50	323 55	540 40	810 50

COMPUTATION OF PROJECT VALUE AT TIME OF COMMISSIONING

YEAR FROM START		PERCENT OF CAPITAL COST INCURRED				
FIRST YEAR OF OPERATION	0	0	0	0	0	0
LAST YEAR OF CONSTRUCTION	1	70	70	40	40	40
YEAR BEFORE	2	30	30	45	30	30
YEAR BEFORE	3	0	0	15	20	20
YEAR BEFORE	4	0	0	0	10	10
YEAR BEFORE	5	0	0	0	0	0
TOTAL (MUST ADD TO 100)		100	100	100	100	100
FUTURE VALUE MULTIPLIER		1 1206	1 1206	1 1966	1 2457	1 2457
FUTURE VALUE	M$	244 41	347 96	387 17	673 16	1009 61
EFFECTIVE CAPITAL COST	$/KW	897 74	648 20	977 52	869 65	875 47
DEPRECIATION	YEARS	30 00	30 00	35 00	35 00	35 00
CAPITAL RECOVERY FACTOR		0 1523	0 1523	0 1511	0 1511	0 1511
CAPITAL COST	$/KW year	136 73	98 72	147 74	131.43	132 31

COMPUTATION OF OPERATION AND MAINTENANCE (O&M) EXPENSES

PARAMETER	UNITS	GT 300 M	GT 600 M	CC 450 M	CC 900 M	CC 1350 M
VARIABLE O&M	$/MWH	0 07000	0 07000	0 29000	0 29000	0 29000
TRANSMISSION LOSS	$/KWH	-0 00031	-0 00006	-0 00011	0 00015	0 00024
FIXED ANNUAL PLANT O&M	$/KW	5 38000	5 38000	7 80000	7 24000	6 82000
SOCIAL COST (FIXED)	$/KW	0 00000	0 00000	0 00000	0 00000	0 00000
TOTAL FIXED COST	$/KW	5 38000	5 38000	7 80000	7 24000	6 82000
EFFECTIVE FIXED COST	$/KW	5 92833	6 01337	8 86186	8 41796	7 98370
CHP O&M CREDIT	M$/Year	0 000	0 000	0 000	0 000	0 000
HEAT TO DIST SYSTEM	Gcal/KWH	0	0	0	0	0

COMPUTATION OF LEVELIZED FUEL COST

		GT 300 M	GT 600 M	CC 450 M	CC 900 M	CC 1350 M
FUEL TYPE		GAS	GAS	GAS	GAS	GAS
BASE PRICE	$/M BTU	1 40	1 40	1 40	1 40	1 40
ANNUAL ESCALATION	%	3 00%	3 00%	3 00%	3 00%	3 00%
PRESENT VALUE FACTOR		6 46	6 46	6 46	6 46	6 46
LEVELIZING RATE	%	11 65%	11 65%	11 65%	11 65%	11 65%
P V F + ESCALATION		8 04	8 04	8 04	8 04	8 04
LEVELIZING FACTOR		1 24	1 24	1 24	1 24	1 24
LEVELIZED PRICE	$/M BTU	1 741	1 741	1 741	1 741	1 741
HEATRATE	BTU/KWH	10080	10080	6561	6561	6561
LEVELIZED FUEL COST	$/KWH	0 0175	0 0175	0 0114	0 0114	0 0114

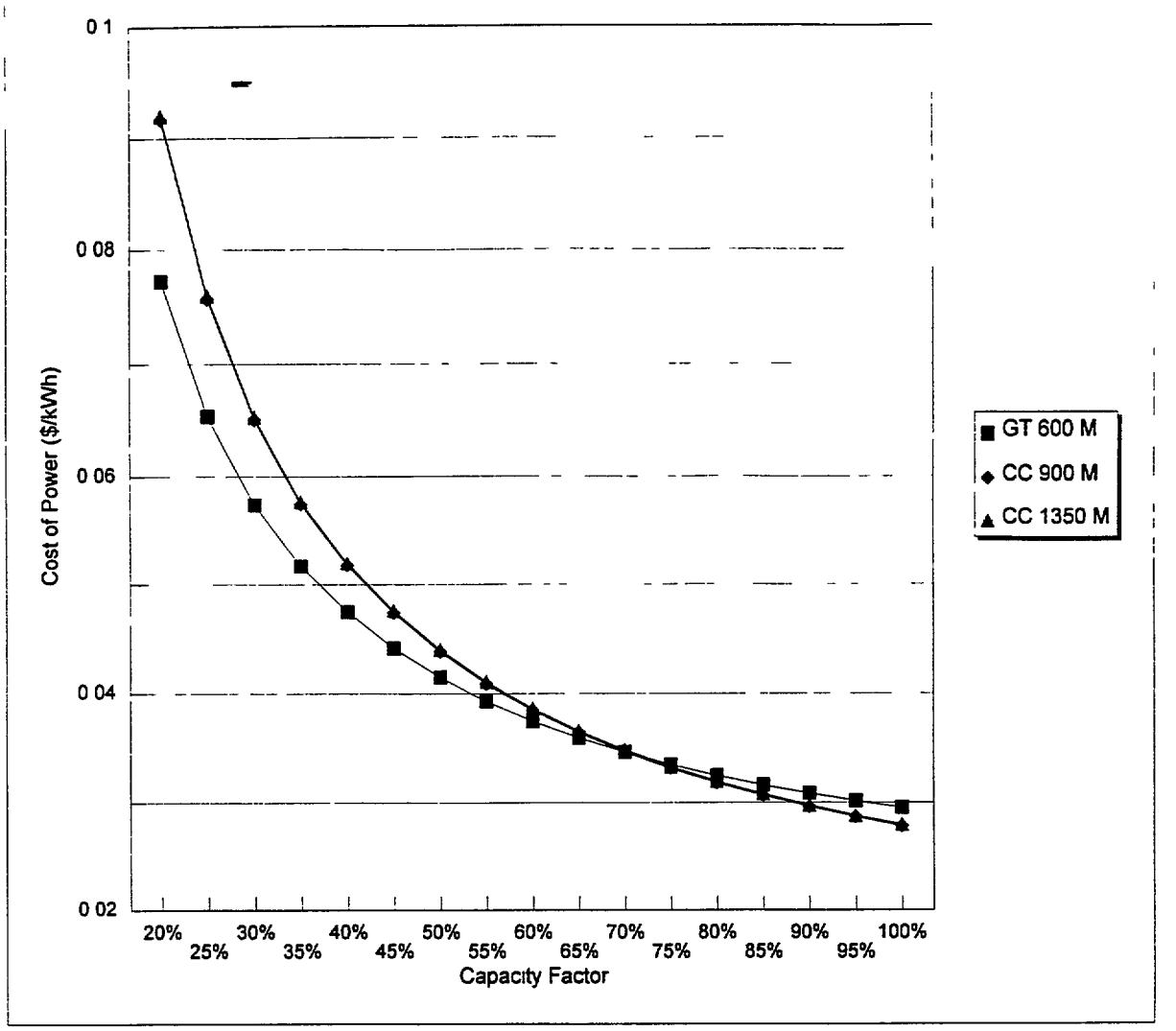
SUMMARY OF FIXED AND VARIABLE OPERATING EXPENSES WITH LEVELIZED FUEL

		GT 300 M	GT 600 M	CC 450 M	CC 900 M	CC 1350 M
FIXED	$/KW year	142 65	104 73	156 60	139 85	140 30
VARIABLE	$/KWH	0 0173	0 0176	0 0116	0 0119	0 0119

LEVELIZED COST PER KWH PRODUCED

CAPACITY FACTOR	Hours/year	GT 300 M	GT 600 M	CC 450 M	CC 900 M	CC 1350 M
0%	0	NA	NA	NA	NA	NA
5%	438	0 3430	0 2567	0 3691	0 3312	0 3323
10%	876	0 1801	0 1371	0 1904	0 1715	0 1721
15%	1314	0 1259	0 0973	0 1308	0 1183	0 1187
20%	1752	0 0987	0 0773	0 1010	0 0917	0 0920
25%	2190	0 0824	0 0654	0 0831	0 0757	0 0760
30%	2628	0 0716	0 0574	0 0712	0 0651	0 0653
35%	3066	0 0638	0 0517	0 0627	0 0575	0 0577
40%	3504	0 0580	0 0474	0 0563	0 0518	0 0520
45%	3942	0 0535	0 0441	0 0513	0 0473	0 0475
50%	4380	0 0499	0 0415	0 0474	0 0438	0 0440
55%	4818	0 0469	0 0393	0 0441	0 0409	0 0411
60%	5256	0 0444	0 0375	0 0414	0 0385	0 0386
65%	5694	0 0424	0 0359	0 0391	0 0364	0 0366
70%	6132	0 0406	0 0346	0 0371	0 0347	0 0348
75%	6570	0 0390	0 0335	0 0354	0 0332	0 0333
80%	7008	0 0377	0 0325	0 0339	0 0318	0 0320
85%	7446	0 0365	0 0316	0 0326	0 0306	0 0308
90%	7884	0 0354	0 0308	0 0315	0 0296	0 0297
95%	8322	0 0344	0 0301	0 0304	0 0287	0 0288
100%	8760	0 0336	0 0295	0 0295	0 0278	0 0280

Mostovskoy Power Costs



KRASNODAR POWER PROJECT

STATIC SCREENING OF ALTERNATIVE GENERATION OPTIONS

HAGLER BAILLY CONSULTING INC 10 05 AM

GENERATION OPTIONS		
A	GT 300 N	2x150MW - Gas Turbines - Novorossiysk
B	GT 600 N	4x150MW - Gas Turbines - Novorossiysk
C	CC 450 N	1x450MW - Combined Cycle - Novorossiysk
D	HP 450 N	1x450MW - CHP - Novorossiysk
E		
F		

DISCOUNT RATE	%	15 00%
LEVELIZING PERIOD	YEARS	25

COMPUTATION OF EFFECTIVE CAPACITY

PARAMETER	UNITS	GT 300 N	GT 600 N	CC 450 N	HP 450 N
NOMINAL CAPACITY	MW	300 00	600 00	450 00	450 00
NET RATED CAPACITY	MW	300 00	600 00	443 00	393 00
CHP CAPACITY	GCAL/H	0 00	0 00	0 00	172 50
FORCED OUTAGE RATE	%	4 00%	4 00%	4 60%	4 60%
PLANNED MAINTENANCE	DAYS	25 00	25 00	25 00	25 00
AVAILABILITY	%	**89 15%**	**89 15%**	**88 55%**	**88 55%**
TRANSMISSION LOSS	MW	-11 30	-12 70	-12 70	-12 20
EFFECTIVE RATING	MW	**278 75**	**547 60**	**404 98**	**360 20**

COMPUTATION OF ANNUAL CAPITAL COSTS

PARAMETER	UNITS	GT 300 N	GT 600 N	CC 450 N	HP 450 N
PLANT COST ON G R C	$/KW	355 00	312 00	479 00	481 00
CHP CAPACITY COST	$1000/GCAL-H	0 00	0 00	0 00	43 00
TOTAL PLANT COST	M$	**106 50**	**187 20**	**215 55**	**216 45**
CHP PIPING COST	M$	**0 00**	**0 00**	**0 00**	**5 88**
CHP CAPITAL COST CREDIT	M$	**0 00**	**0 00**	**0 00**	**7 42**
GAS PIPELINE COST	M$	62 00	76 00	62 00	62 00
TRANSMISSION COST	M$	19 50	28 00	23 00	23 00
ADJUSTED PROJECT COST	M$	**188 00**	**291 20**	**300 55**	**299 91**

COMPUTATION OF PROJECT VALUE AT TIME OF COMMISSIONING

YEAR FROM START		PERCENT OF C	PERCENT OF CAPITAL COST INCURRED		
FIRST YEAR OF OPERATION	0	0 00	0 00	0 00	0 00
LAST YEAR OF CONSTRUCTION	1	70 00	40 00	40 00	40 00
YEAR BEFORE	2	30 00	45 00	45 00	45 00
YEAR BEFORE	3	0 00	15 00	15 00	15 00
YEAR BEFORE	4	0 00	0 00	0 00	0 00
YEAR BEFORE	5	0 00	0 00	0 00	0 00
TOTAL (MUST ADD TO 100)		**100 00**	**100 00**	**100 00**	**100 00**
FUTURE VALUE MULTIPLIER		**1 1206**	**1 1966**	**1 1966**	**1 1966**
FUTURE VALUE	M$	**210 68**	**348 46**	**359 65**	**358 89**
EFFECTIVE CAPITAL COST	$/KW	**755 80**	**636 34**	**888 07**	**996 35**
DEPRECIATION	YEARS	30 00	30 00	35 00	35 00
CAPITAL RECOVERY FACTOR		**0 1523**	**0 1523**	**0 1511**	**0 1511**
CAPITAL COST	$/KW year	**115 11**	**96 91**	**134 22**	**150 58**

COMPUTATION OF OPERATION AND MAINTENANCE (O&M) EXPENSES

PARAMETER	UNITS	GT 300 N	GT 600 N	CC 450 N	HP 450 N
VARIABLE O&M	$/MWH	0 07000	0 07000	0 29000	0 32000
TRANSMISSION LOSS	$/KWH	-0 00074	-0 00042	-0 00037	-0 00030
FIXED ANNUAL PLANT O&M	$/KW	5 38000	5 38000	7 80000	8 45000
SOCIAL COST (FIXED)	$/KW	1 78000	1 27000	1 58000	1 58000
TOTAL FIXED COST	$/KW	**7 16**	**6 65**	**9 38**	**10 03**
EFFECTIVE FIXED COST	$/KW	**7 71**	**7 29**	**10 42**	**12 53**
CHP O&M CREDIT	M$/Year	**0 000**	**0 000**	**0 000**	**0 593**
HEAT TO DIST SYSTEM	Gcal/KWH	**0**	**0**	**0**	**479**

COMPUTATION OF LEVELIZED FUEL COST

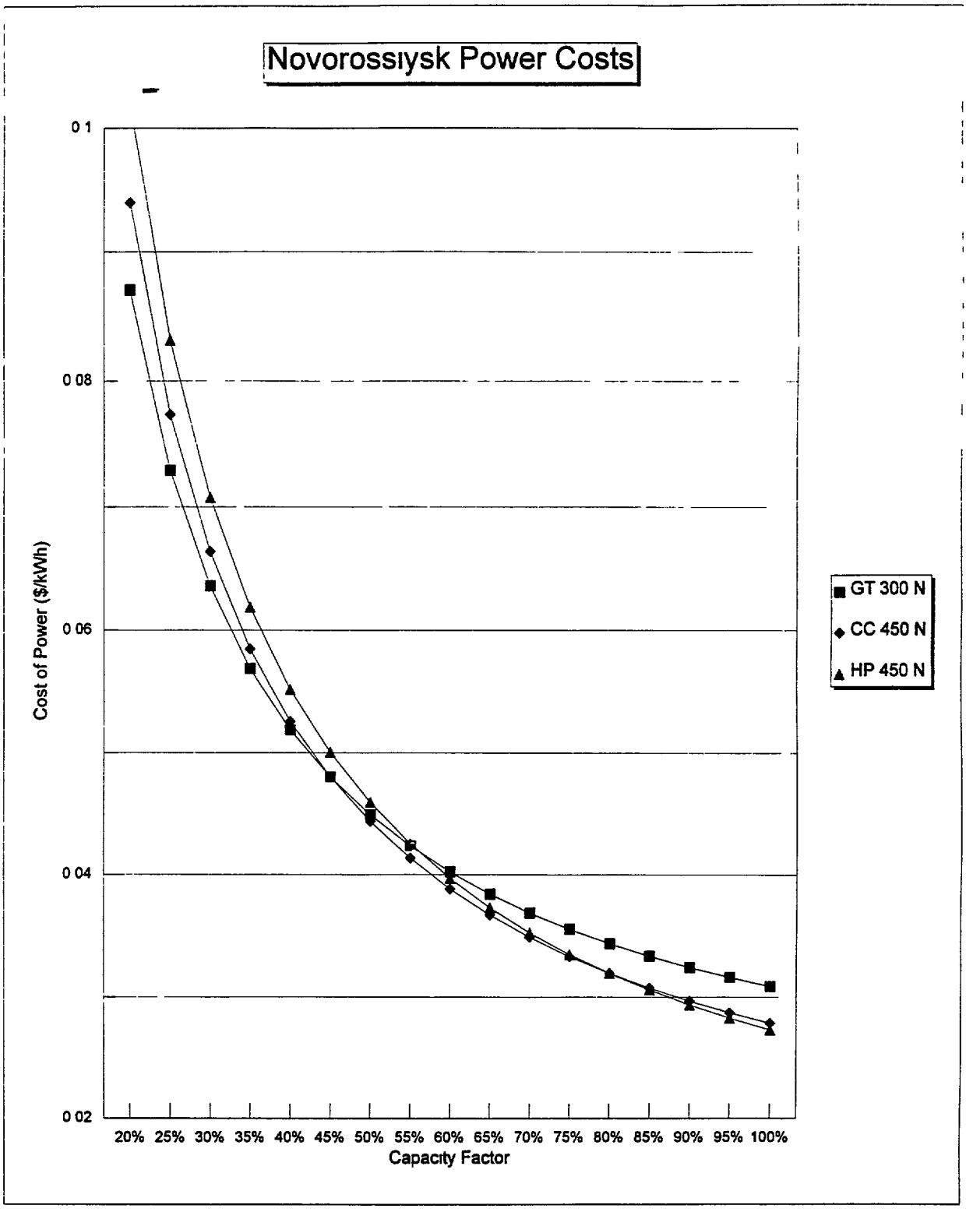
		GT 300 N	GT 600 N	CC 450 N	HP 450 N
FUEL TYPE		GAS	GAS	GAS	GAS
BASE PRICE	$/M BTU	1 40	1 40	1 40	1 40
ANNUAL ESCALATION	%	3 00%	3 00%	3 00%	3 00%
PRESENT VALUE FACTOR		6 46	6 46	6 46	6 46
LEVELIZING RATE	%	11 65%	11 65%	11 65%	11 65%
P V F + ESCALATION		8 04	8 04	8 04	8 04
LEVELIZING FACTOR		1 24	1 24	1 24	1 24
LEVELIZED PRICE	$/M BTU	1 741	1 741	1 741	1 741
HEATRATE	BTU/KWH	10080	10080	6561	5269
LEVELIZED FUEL COST	$/KWH	0 0175	0 0175	0 0114	0 0087

SUMMARY OF FIXED AND VARIABLE OPERATING EXPENSES WITH LEVELIZED FUEL

		GT 300 N	GT 600 N	CC 450 N	HP 450 N
FIXED	$/KW year	122 81	104 20	144 64	163 11
VARIABLE	$/KWH	0 0169	0 0172	0 0113	0 0087

LEVELIZED COST PER KWH PRODUCED

CAPACITY FACTOR	Hours/year	GT 300 N	GT 600 N	CC 450 N	HP 450 N
0%	0	NA	NA	NA	NA
5%	438	0 2973	0 2551	0 3416	0 3811
10%	876	0 1571	0 1362	0 1765	0 1949
15%	1314	0 1103	0 0965	0 1214	0 1328
20%	1752	0 0870	0 0767	0 0939	0 1018
25%	2190	0 0730	0 0648	0 0774	0 0832
30%	2628	0 0636	0 0569	0 0664	0 0708
35%	3066	0 0569	0 0512	0 0585	0 0619
40%	3504	0 0519	0 0469	0 0526	0 0552
45%	3942	0 0480	0 0436	0 0480	0 0501
50%	4380	0 0449	0 0410	0 0444	0 0459
55%	4818	0 0424	0 0388	0 0414	0 0425
60%	5256	0 0402	0 0370	0 0389	0 0397
65%	5694	0 0384	0 0355	0 0367	0 0373
70%	6132	0 0369	0 0342	0 0349	0 0353
75%	6570	0 0356	0 0331	0 0334	0 0335
80%	7008	0 0344	0 0321	0 0320	0 0320
85%	7446	0 0334	0 0312	0 0308	0 0306
90%	7884	0 0325	0 0304	0 0297	0 0294
95%	8322	0 0316	0 0297	0 0287	0 0283
100%	8760	0 0309	0 0291	0 0279	0 0273


Novorossiysk Power Costs
0 1
0 08
0 06
0 04
0 02
Cost of Power ($/kWh)
20% 25% 30% 35% 40% 45% 50% 55% 60% 65% 70% 75% 80% 85% 90% 95% 100%
Capacity Factor
GT 300 N
CC 450 N
HP 450 N