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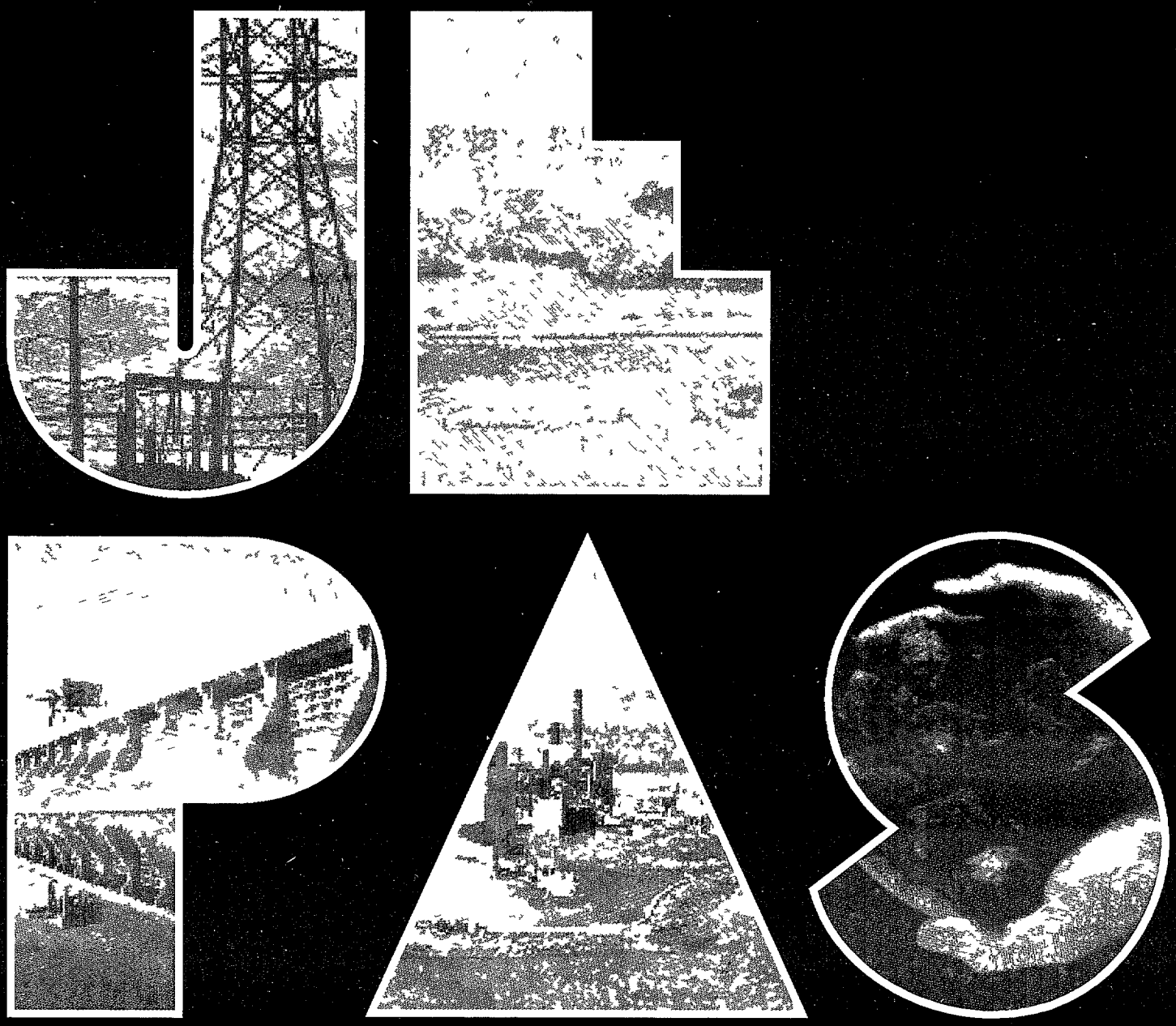
JOINT ELECTRIC POWER ALTERNATIVES STUDY

An Investment Program for Russia



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GLOSSARY OF TERMS

BCM	**Billion Cubic Meters**
bkWh	**Billion Kilowatt hour**
BTU	**British Thermal Unit** 1 BTU equal to 1,055 joules which is equivalent to 252 calories
CHP	**Combined Heat and Power Plant** Plants using coal or gas that supply heat in the form of hot water for the heating of buildings and steam for industrial use, and that generate electricity
CHP-CC	**Combined Heat and Power Combined Cycle Plant** A plant consisting of a combustion gas turbine coupled to a heat recovery steam generator and condensing turbine, with recovery of heat for distribution in the local heat grid
CPP	**Condensing Power Plant.** A plant generating electricity either from coal or from gas (with fuel oil backup capability) using condensing steam turbines
CPP-CC	**Gas Turbine Combined Cycle Power Plant** A plant producing electricity using a combustion gas turbine coupled to a heat recovery steam generator and condensing turbine
Equivalent Peak Load	a term used in the Russian power industry to represent the avrage annual utilization rate for one or more power plants
GW	**Million Kilowatts**
GWh	**Million Kilowatts hours**
HPP	**Hydroelectric Power Plant**
IPM©	**Integrated Planning Model,** least cost optimization model developed by ICF Resources
IPS	**Integrated Power System of Russia** refers to the system covering the following dispatch regions (Northwest, Center, North Caucasus, Middle Volga, Urals, Tyumen, Siberia and Far East

MBTU	1,000,000 BTU which is equivalent to 36 kgsf
MWh	**Megawatt hour,** equivalent to thousand Kilowatt hours
Nm^3	**Normal Cubic Meter**
NPP	**Nuclear Power Plant**
O & M	**Operation and Maintenance**
RAO EES Rossii	**RAO EES Rossii** refers to the Russian Joint Stock Holding Company for Electric Power and Electrification
RBMK-1000	A graphite moderated, pressure-tube, low enriched reactor rated 1,000 MW, designed for on-line refueling
sf	**Standard Fuel Unit (Coal Equivalent)** 1 kgsf equal to 7,000 kilocalories
SGU	**Steam Gas Unit** A Combined Cycle generating unit
tce	**Tons of Coal Equivalent**, equal to 0 7 Tons of Oil Equivalent which is the metric ton of oil equivalent, 10^7 kilocalories
tsf	**Ton Standard Fuel**, equal to 29 3 gigajoules which is the equivalent of 27 8 MBTU
TWh	**Billion Kilowatt hours**
UPS	**Unified Power System(s)** refers to the individual regional dispatch areas mentioned above, but it should be noted that Tyumen and Urals are dispatched as one region
VVER-440	A first-generation pressurized water reactor rated 440 MW
VVER-440/213	A second-generation pressurized water reactor rated 440 MW
VVER-1000	A second-generation pressurized water reactor rated 1,000 MW

INTRODUCTION

1 The goal of the Joint Energy Alternatives Study (JEAS) is to provide, on the basis of an objective assessment of Russia's energy alternatives, a time-phased investment program for the period 1995-2000 The program would be aimed at meeting future electricity demand in Russia reliably, economically, and consistent with environmental and safety standards When Prime Minister Chernomyrdin and Vice President Gore met in September 1993 to initiate the US-Russia Joint Commission on Economic and Technological Cooperation, they also agreed to undertake this Study As noted in the Study's Terms of Reference, major investments will be needed over the coming decades to overcome the Russian power sector's main problems, including an aging population of thermal generating plants, doubts about the safety of first generation nuclear plants, and inefficient patterns of electricity use The international community, including the leaders of the G7 group of countries, attaches great importance to working with Russia to solve these problems As the Russian economy is restructured and recovers, electricity demand growth will be met by a combination of investments in efficient end-use technology, modernization of existing generating plants, construction of state-of-the-art power plants, and upgrading and expansion of transmission and distribution systems to enhance the integrated national network At the same time, existing thermal and nuclear power plants will be upgraded to meet environmental and safety requirements or will be decommissioned

2 This Study also is intended to indicate how the investment program could be financed from domestic and international sources, what the international sources might be, and under what conditions they might be tapped Financing power sector development from Russia's federal budget has all but ended, while new financing mechanisms appropriate for a market economy have not yet developed The report describes fundamental conditions for investment and suggests measures to improve the investment climate for the power sector

3 Although the organizational and logistical elements between the U S and Russian sides took longer than envisaged to be put in place, highly productive technical working relationships have been established in all areas during the course of this Study Successful implementation of this collaborative effort is a major milestone in achieving the Joint Study objectives enunciated by the Russian and American governments These productive working relationships, which comprise mutually beneficial exchanges of concepts, data, analytical methods, and perceptions, represent the start of a process that will yield benefits for all parties with an interest in the development of the Russian electric power sector

4 Five separate working groups of Russian and US experts were assembled to develop the information needed to complete this evaluation Working Group 1 analyzed the potential for improving the efficiency of electricity end-use and prepared an evaluation of the economics of the range of demand-side investment options (Appendix D) Working Group 2 analyzed the costs of modernizing existing fossil thermal power plants and investing in new fossil-fired power plants (Appendix F) Working Group 3 evaluated the economics and feasibility of certain safety improvements to nuclear power plants, decommissioning, repowering, completion of partially-built nuclear plants, and construction of new, evolutionary nuclear power plants (Appendix G) Working Group 4 assessed the feasibility and economics of investments in transmission, power control, and hydroelectricity Their final reports are presented in Appendix H (transmission and power control) and Appendix I (hydroelectric options) Finally, Working Group 5 had the tasks of preparing economic and electricity demand scenarios (drawn from the new Russian energy strategy presented in Appendix A), addressing financing issues, and integrating the results of the work of the other working groups The work of Working Group 5 is presented in Appendices B and C (model results), Appendix E (institutional and regulatory issues related to improvements in energy efficiency), Appendix J (institutional and regulatory reform issues prerequisites for financing), Appendix K (finance), and Appendix L (environment and safety issues) Appendix K also includes a summary of those projects already identified by Russian and foreign institutions that might be candidates for funding by international lenders and investors

5 To respond to the questions considered in this Study, the joint team used two views of Russian economic performance and electricity demand, set forth in the Russian Energy Strategy, based on a set of assumptions regarding the pace and degree of success of measures to control inflation and reform the economy Time-phased investment requirements were estimated using two planning models Financing requirements were calculated from the total costs of the investments, and potential domestic and foreign sources of finance were identified All of the scenarios and financing requirements are based on assumptions regarding future developments that are subject to uncertainties, and the team has prepared an investment strategy that addresses the main elements of uncertainty As the future direction of reform and the rate of evolution to a market economy become clearer, it will be necessary to undertake periodic reevaluations of investment priorities The two economic models of the Russian electric power sector that were developed and tested as part of this Study will be available for future reevaluations

6 This report addresses four main topics 1) the costs and characteristics of investment options on both the supply and demand side, 2) investment requirements under different demand scenarios and assumptions, 3) conditions for capital mobilization and potential sources of financing, and 4) possible projects for international financing The first chapter of this report describes the macroeconomic situation in Russia, electricity demand projections, and the major issues that will govern requirements for investment in the

power sector Chapter 2 describes the power sector and its existing supply mix, and Chapter 3 presents the range of future demand and supply-side investment options Chapter 4 describes the modeling that was done and the major conclusions that can be drawn from the modeling results Chapter 5 outlines the sources of finance that may be available to meet the indicated investment requirements, and sets forth illustrations of how specific project financing might be arranged Finally, Chapter 6 summarizes the main conclusions and recommendations of the Study

7 Please note that all dollar amounts used in the text, unless otherwise noted, are in U S dollars Also, totals in tables may not add up due to rounding

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8 This Study was organized into joint Russian/American Working Groups and a Joint Steering Committee responsible for overall direction of the Study The Steering Committee included representatives of the following Russian government organizations

Ministry of Fuels and Energy
Ministry of Atomic Energy
Ministry of Economy

The Steering Committee included the following U S government organizations

Agency for International Development
Department of State
Department of Energy
Nuclear Regulatory Commission

In addition to the organizations represented on the Steering Committee, the following organizations contributed to the development of the JEAS

Working Group 1
Krzhizhanovsky Energy Power Institute (ENIN)
Burns and Roe Enterprises
Resource Management Associates
RCG/Hagler, Bailly, Inc

Working Group 2
TeploEnergoProekt
Burns and Roe Enterprises

Working Group 3
RosEnergoAtom
Institute of Nuclear Reactors (Kurchatov Institute)
AtomEnergoProekt
GydroPress
VNIIAES
Brookhaven National Laboratories
Raytheon Engineers and Contractors
NUS-Halliburton

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Working Group 4
EnergoSetProekt
Central Dispatch Center
GidroProekt (Hydroproject Design Institute of Moscow)
EnergoPromTechnica
High Voltage Direct Current Transmission Research Institute
Harza Engineering
Power Technologies, Inc
American Electric Power Energy Services
NRECA International
Burns and Roe Enterprises

Working Group 5
RAO EES Rossii
Institute for Energy Research, Russian Academy of Sciences (ERI)
ENIN
TeploEnergoProekt
Kurchatov Institute
EnergoSetProekt
Burns and Roe Enterprises
ICF Resources, Inc
RCG/Hagler Bailly, Inc

9 In addition, a number of independent consultants contributed to this work, and other US agencies participated as required for information policy coordination and project implementation

JOINT ELECTRIC POWER ALTERNATIVES STUDY: VIP SUMMARY

1 Following an agreement between Vice President Gore and Prime Minister Chernomyrdin in late 1993, the Russian Federation and the United States decided to undertake the Joint Electric Power Alternatives Study (JEPAS) The goal of the JEPAS was to provide a time-phased investment program for the period 1995-2000 on the basis of an objective assessment of Russia's electric power sector alternatives through the year 2010 A study objective was to find ways to meet future electricity demand in Russia in a reliable and economic manner, consistent with environmental and safety standards

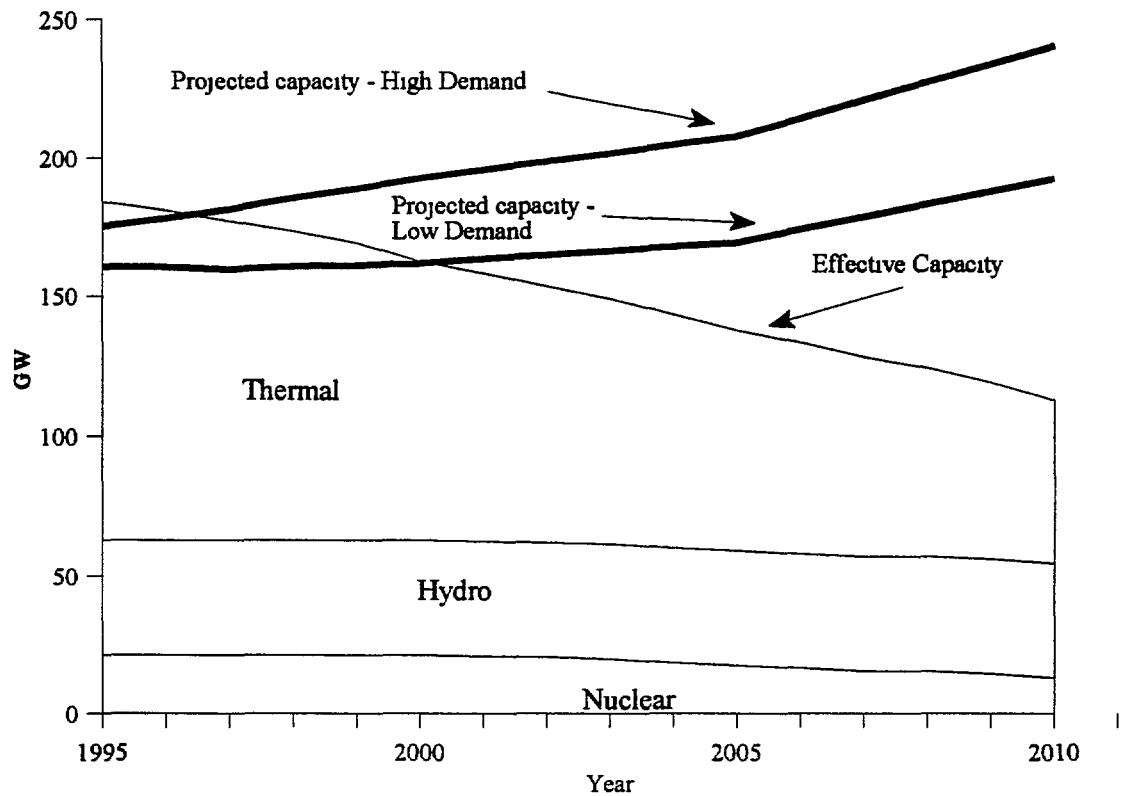
2 This Joint Study has identified the strategic directions for the Russian electric power sector's development, investment requirements, and opportunities for energy efficiency over the next fifteen years under two scenarios that differ in their assumptions about the timing and speed of Russia's economic recovery The Study addresses a broad range of issues affecting investment, such as the scope for more efficient advanced generation and end-use technologies, nuclear safety upgrades and decommissioning options, environmental standards, sources of financing, and energy policy impacts on investment choices This Study is expected to have a major influence on Russian power sector investment, including environment and safety considerations, and to provide a basis for follow-on actions by countries and institutions with an interest in Russia's economic future

3 The two scenarios considered in this Study were based on two views of Russian economic performance and electricity demand, set forth in the *Russian Energy Strategy (Main Directions)*, and on a set of assumptions regarding the pace and degree of success of measures to control inflation and reform the economy Investment and fuel requirements were estimated using two planning models Financing requirements were calculated from the total costs of the investments, and potential domestic and foreign sources of finance were identified All of the scenarios and financing requirements are based on assumptions about future developments of the Russia economy which are subject to uncertainties, and the team has prepared an investment strategy that addresses the main elements of uncertainty As the future direction of reform in Russia and its rate of evolution to a market economy become clearer, it will be necessary to undertake periodic re-evaluations of investment priorities

4 Russia currently has 215 Gigawatts (GW) of generation capacity, of which 201 GW are included in the Integrated Power System (IPS) Within the IPS, 80 GW (600 units) of fossil thermal plants and 8 GW of nuclear capacity will reach the end of their service life

by the year 2010 Figure 1 shows the possible evolution of the Integrated Power System's generating capacity according to the established schedule for power plant retirements This calculation did not take into account life extensions, rehabilitations or additions of new plants Superimposed on this plant retirement pattern are the two scenarios for electricity demand that form the basis of the two "Reference Cases" used in the Joint Study Russia as a whole remains comfortably in surplus for the next four to seven years, depending on demand growth However, the same is not true for the North Caucasus, Urals, Transbaikalia and a few other regions, which are already in deficit

Figure 1
Effective Capacity Reduction Dynamics for Russia's Power Plants



Note The effective capacity is determined by adjusting the actual installed capacity by an amount equal to the fraction of total capacity that is historically out of service due to routine maintenance or equipment failures The adjustment factor used in this study is 13 %

KEY STUDY FINDINGS

5 The JEPAS confirmed the importance of the further development of Russia's electric power sector in assuring its economic development and socio-economic stability during this period of transition The principal conclusions of the JEPAS are consistent with the importance given to the electric power sector in the *Russian Energy Strategy* The Study indicates the need for support from the international financial community during 1995 through 1997 for high-priority projects costing approximately $2-4 billion

6 The JEPAS analysis indicates the following ranking of priorities during the period 1995-2000 (1) improvements in the efficiency of electricity end-use, (2) nuclear safety upgrades, particularly for first-generation nuclear power reactors where approved by the regulator, (3) further development of the Integrated Power System through the expansion and strengthening of inter-regional and intra-regional transmission, particularly between surplus and deficit areas, and the modernizing of control/dispatch centers, (4) thermal plant modernization and rehabilitation using improved technology, with the consideration of life extension options, (5) completion of those nuclear power plants that are in advanced stages of construction, (6) construction of new gas-fired simple cycle and combined cycle plants, and (7) completion of detailed design for new-generation nuclear power plants to enable their certification by regulatory authorities

7 The Study's analysis also shows that during the period 2000-2005, it will be increasingly important to complete large under-construction hydroelectric plants, to construct clean coal generation plants, and to construct new-generation nuclear power plants A priority of Russia's long-term scientific and technological policy should be the development of new-generation design NP 500 and NP 1000 nuclear power plants and cleaner coal power units as well as developing the potential for their manufacturing, to provide for the commissioning by 2010 of new nuclear capacity and of environmentally-cleaner coal fired units

Energy Efficiency

8 The JEPAS analysis shows that energy efficiency should be given a high priority There is a large potential for energy efficiency improvements throughout the Russian economy Power consumption could be reduced by up to 29 billion kilowatt hours (bkWh) by the year 2000 and 112 bkWh per year by the year 2010, just by installing efficient end-use technologies

9 The energy efficiency savings noted above could be achieved at relatively low cost The average life cycle costs of the recommended energy efficiency measures is approximately one cent per kWh saved, and 90% of all measures recommended have life cycle costs of less than two cents per kWh saved Although the cost of replacing outdated equipment

with new equipment is high, the incremental cost caused by using energy-efficient equipment is relatively low and easily justified economically

10 In order to implement energy efficiency programs, additional investments of $2-3 billion will be required over the period up to 2000 depending on power demand levels, half of this amount will be needed in 1995-1997 It is equally important to undertake regulatory, institutional, legal and economic measures in order to develop and implement effective programs To be most successful, energy efficiency programs should be designed for unique local conditions In the near future, legislation on energy conservation should be passed Government support for energy efficiency should include tax and customs duties-based incentives, loans and accelerated depreciation

Thermal Power

11 The JEPAS modeling results indicate that 49 0 and 47 1 GW -- high demand and low demand, respectively -- of reconstructed thermal generating capacity (conventional power plants and combined heat and power plants) is needed through the year 2010 In both cases the bulk of the reconstructed capacity -- 40 1 and 41 5 GW, respectively -- would be installed after the year 2001

12 The JEPAS modeling results also indicate that 69 2 and 27 4 GW of new thermal generating capacity will be required to be installed through the year 2010 under high and low demand growth, respectively Under high demand growth, 19 2 GW would be installed through the year 2000, while 3 5 GW is required if demand growth is slower during the same period Given the lead time for the construction of new plants, these results indicate the need for an aggressive development and implementation program, particularly if demand rises quickly On a regional basis, near-term new plant capacity is needed in the North Caucasus, Urals, and Transbaikalia regions RAO EES Rossii, Kubanenergo and others are formulating plans to build modern gas-fired combined cycle units in the North Caucasus

13 The full rehabilitation of thermal plants that are scheduled to be retired will play a significant role in meeting future power need, however, the investment costs are significant Life extension provides an opportunity to reduce investment requirements during the period under consideration Therefore, plant-level evaluations of rehabilitation and life extension options are recommended for thermal power plants

14 New, more stringent environmental standards are being developed for thermal power plants These standards should allow for differentiation among new, existing and rehabilitated thermal plants Programs should be developed to 1) identify the best emission reduction technologies for each plant, 2) provide support for domestic

22

production of those technologies, and 3) employ continuous emission monitoring equipment to ensure compliance with emission limits

15 Advanced technologies such as gas turbine combined cycles and circulating fluid bed boilers should be given serious consideration to improve thermal efficiencies and environmental performance, and to take advantage of the availability of low-quality solid fuel Developing manufacturing capability for these advanced technologies, through joint ventures or other means, should be further encouraged

Nuclear Energy

16 The JEPAS has confirmed the important contribution nuclear power makes to the Russian electric power sector The JEPAS found that future investment in the power sector should include investments in nuclear power plant upgrades, plant completions, new evolutionary plant designs, and where appropriate, decommissioning of first-generation reactors

17 The JEPAS found that investments in nuclear power plant safety upgrades are competitive with investments in alternative power sources It is economic to continue the operation of most existing nuclear power plants with the completion of safety upgrades evaluated in this Study and where approved by the nuclear regulatory agency, Gosatomnadzor The implementation of such safety upgrades could encourage foreign investment in Russia's nuclear power sector In the initial study period, investments in safety upgrades of the existing nuclear power plants are considered as a priority whether demand growth is high or low

18 The JEPAS shows that, with the scheduled service life remaining, it is not economic to implement all of the safety upgrades evaluated in the Study for Kola 1 and 2 and Novorovonezh 3 and 4 (and Leningrad-1 if demand growth is low) The decommissioning of these units should be considered comprehensively, on the basis of local area conditions and on a site-specific basis

19 New nuclear capacity was found to be an economic supply option in some regions The completion and commissioning of Rostov 1 and Kalinin 3 have been identified as priorities for investment

20 The legislative basis required to support the safe development and operation of nuclear power in Russia should be completed as soon as possible

Hydro

21 Eight existing hydro power plants have been identified for rehabilitation to permit their continued operation after 2000 These plants' rehabilitation would cost approximately $900 million between 1995 and 2001 Detailed designs, cost estimates and financing plans should be prepared for hydro rehabilitation projects that are viable under regional least-cost plans The completion of six plants under construction and three new plants were also identified as potential investments at a cost of $4 8 billion

Transmission and Dispatch

22 Russia's transmission system needs to be modernized to provide for higher efficiency and the ability to transfer power among regions for the ultimate development of an electricity market Intra-regional and inter-regional transmission projects/programs have been identified for priority investment, two of which are described below

23 Two priority transmission projects are recommended in the North-West Region and for interties among the Middle Volga, Center and North Caucasus regions The North-West Region reinforcement projects, at an approximate cost of $775 million, consist of 330 kV and 750 kV lines complete with substations, and are designed to strengthen the supply to the nuclear plants The second priority project (four-500 kV lines at a cost of $430 million) has been planned and at present is in the implementation phase It will reinforce the internal systems of the Middle Volga and Center regions to enable increased transfers to the North Caucasus and Center regions

24 A detailed study is recommended to evaluate the construction of a high-voltage transmission line of 3-6 GW capacity between Siberia and Center regions

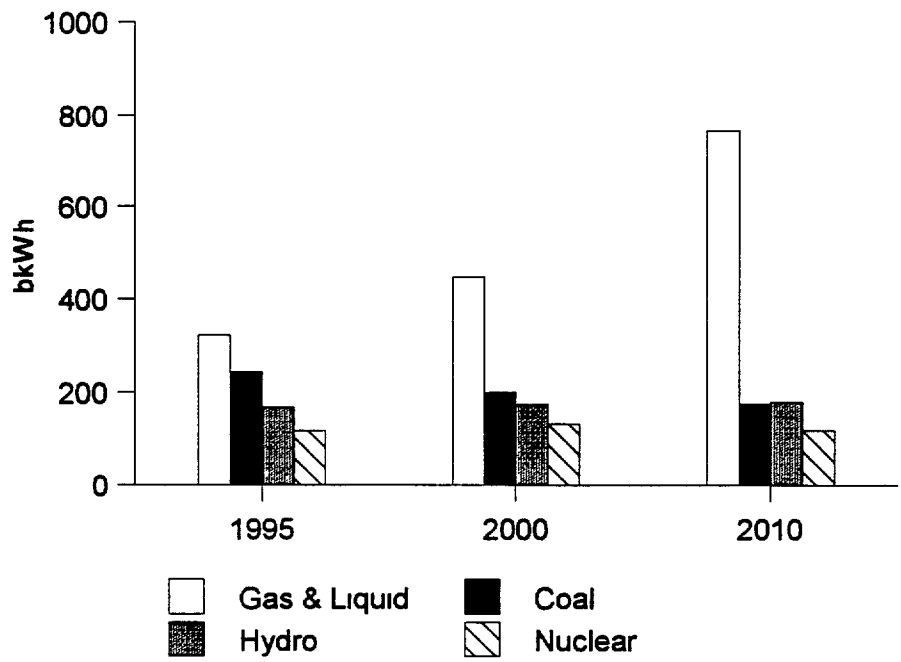
25 Some upgrades are urgently needed for the control, communications and dispatch systems of the Integrated Power System due to inadequate technology Two control and dispatch projects have been prioritized for early investment, namely the Central Dispatch Office and the North-West Dispatch Center for an aggregate cost of $80 million Such upgrades will accommodate similar upgrades in other regions of the IPS

Projected Electric Power Generation

26 The amount of electricity generated from natural gas is expected to rise significantly under both scenarios because generation from natural gas using combined cycle and simple cycle technologies is economically competitive in many regions of Russia Generation from hydroelectric sources is also expected to increase in both scenarios, but by a much smaller amount Nuclear generation is expected to increase in both scenarios until the year 2000, in the high demand scenario it will increase slightly after 2000, while in the low

demand scenario it will decline after 2000 Coal use will decline in both scenarios Figure 2 shows estimates of electricity generation by fuel source over the period of the study, as indicated by the U S model for the high demand scenario For the low demand scenario a similar trend is expected, but at a slower rate

Figure 2
Electricity Output by Fuel Type (High Demand)



RUSSIA'S PREFERRED INVESTMENT PROGRAM FOR THE POWER SECTOR

27 The Russian side recognizes the value and importance of the results of the Joint Study, and has developed a Preferred Investment Program based upon the JEPAS This program adapts the JEPAS results to take account of (1) constraints on the availability of investment capital over the next five years, (2) socio-economic policies with respect to employment in the fuel and energy complex, and (3) energy policy with respect to domestic and export uses of natural gas The Russian side anticipates that technology investments will be made along the lines indicated in Table 1, but that final decisions on

individual power sector projects will result from a blend of investor preferences and governmental incentives, including research and development

Table 1
Capacity Additions and Replacements for the IPS for the Preferred Investment Program (GW)

	1995-2000		2001-2005	
	HIGH DEMAND	LOW DEMAND	HIGH DEMAND	LOW DEMAND
ALL TYPES				
New units	13 - 14 9	1 5 - 2	10 - 12 9	9 3 - 11
Rehabilitations and Upgrades	17 - 17 6	7	27 - 27 6	18 7 - 19
Total Additions	30 - 32 5	8 5 - 9	37 - 40 5	28 - 30
Hydroelectric Plants Total	0 6	0 4	2 - 2 3	2 1 - 2 5
Nuclear Power Plants Total	2 0	1 0	2 7 - 3 3	0
Thermal Heat and Power Plants				
New Units	7 4	0 1 - 0 6	3 8 - 4 4	6 0
Rehabilitations and Upgrades	12 - 12 1	5 7	12 - 12 6	12 1 - 12 5
Total Additions	19 5	5 8 - 6 3	15 8 - 17 0	18 1 - 18 5
Conventional Thermal Plants				
New Units	4 9	0	2 - 2 9	1 2 - 2
Rehabilitations and Upgrades *	5 - 5 5	1 3	14 5 - 15 0	6 6 - 7
Total Additions	10 4	1 3	16 5 - 17 9	7 8 - 9

* including rehabilitation using simple-cycle gas turbines

Finance

28 The amount of financing required over the next five years could range from $12 to $34 billion , depending primarily on the demand for electricity Details of the investment

requirements are shown below in Table 2 Over this period, it is expected that the power sector will need to generate 70-75% of its financing requirements from internally-generated funds The tariff increases needed to cover the capital investment requirements over the study period are estimated to be less than 1 cent per kWh, although debt financing would decrease the tariff impact in the near term It is estimated that the power sector will be able to obtain up to approximately 25-30% of its capital requirements ($3-$10 billion) through external financing Table 3 provides details on the sources of financing for the electric power sector

Table 2
Investment Requirements Indicated by the JEPAS Findings
($ billion)

	High Demand	Low Demand
Generation		
1995 - 2000	21 - 26	9 - 10
2001 - 2005	25 - 32	14 - 20
Subtotal	46 - 58	23 - 30
Energy Efficiency		
1995 - 2000	3-4	2-3
2001 - 2005	5-11	3-8
Subtotal	8-15	5-11
Transmission		
1995 - 2000	2-3	1-3
2001 - 2005	5-5	3-5
Subtotal	7-8	4-8
All Requirements		
1995 - 2000	26-34	12-16
2001 - 2005	35-48	20-33
Total	61-81	32-40

Table 3
Expected Sources of Finance

SOURCES OF FINANCING	1995-1997	1998-2000	2001-2005	Average
% from Borrowed Funds	15%	20%	20%	19%
% Financed from Sales of Stock	10%	10%	15%	13%
% from Internally Generated Funds	75%	70%	65%	68%
Total	100%	100%	100%	100%

29 The role of the Russian Government in promoting financing for the power sector is important An improved state system for the regulation of natural monopolies, which provides for the setting of electricity and heat tariffs on both the federal and regional levels, as well as for setting appropriate legal and regulatory standards, is needed Government decisions on the sale of power sector enterprises, the use of those proceeds, and the future industry structure will influence the amount of funds available The willingness of the government to provide sovereign guarantees on foreign loans will affect the amount of foreign borrowing available, especially during the next three years Tax credits, accelerated depreciation, and lower tax rates are needed to implement the principle of self-financing in the power sector It is also recommended that the part of retained earnings which is directed into investment be made tax deductible, including the part which is collected through centralized investment funds

ACKNOWLEDGEMENTS

30 This Study was organized into joint Russian/American Working Groups and a Joint Steering Committee responsible for the Study's overall direction The Steering Committee included representatives of the following Russian Government organizations

Ministry of Fuels and Energy
Ministry of Atomic Energy
Ministry of Economy

The Steering Committee included the following U S Government organizations

Agency for International Development
Department of State
Department of Energy
Nuclear Regulatory Commission

31 In addition to the organizations represented on the Steering Committee, the following organizations contributed to the development of the JEPAS

Working Group 1
Krzhizhanovsky Energy Power Institute (ENIN)
Burns and Roe Enterprises
Resource Management Associates
RCG/Hagler Bailly, Inc

Working Group 2
TeploEnergoProekt
Burns and Roe Enterprises

Working Group 3
RosEnergoAtom
Institute of Nuclear Reactors (Kurchatov Institute)
AtomEnergoProekt
GydroPress
VNIIAES
Brookhaven National Laboratories
Raytheon Engineers and Contractors
NUS-Halliburton

Working Group 4
EnergoSetProekt
Central Dispatch Center
GidroProekt (Hydroproject Design Institute of Moscow)
EnergoPromTechnica
High Voltage Direct Current Transmission Research Institute
Harza Engineering
Power Technologies, Inc
American Electric Power Energy Services
NRECA International
Burns and Roe Enterprises

Working Group 5
RAO EES Rossii
Institute for Energy Research, Russian Academy of Sciences (ERI)
ENIN
TeploEnergoProekt
Kurchatov Institute
EnergoSetProekt
Burns and Roe Enterprises
ICF Resources, Inc
RCG/Hagler Bailly, Inc

32 In addition, a number of independent consultants contributed to this work, and other U S agencies participated as required for information, policy coordination and project implementation

EXECUTIVE SUMMARY

THE JEPAS

1 Following an agreement between Vice President Gore and Prime Minister Chernomyrdin in late 1993, the Russian Federation and the United States decided to undertake the Joint Electric Power Alternatives Study (JEPAS), whose terms of reference included the following

> The Russian electric power sector will require major investments over the coming decades The sector's main problems include the high proportion of thermal generating plants which are currently beyond their planned operational life spans, doubts about the safety of older nuclear plants, and highly inefficient patterns of electricity use In the present state of the Russian economy, federal budget financing of power sector development has all but ended while new financing mechanisms appropriate to a market economy have not yet developed
>
> The international community, including the leaders of the G-7 group, attaches great importance to joint efforts in helping to solve these problems Fundamental conditions of investment in this most important sector of the Russian economy should be identified on a priority basis

2 This Joint Study has identified investment requirements for the Russian electric power sector and opportunities for energy efficiency over the next fifteen years under two scenarios that differ in their assumptions about the timing and speed of Russia's economic recovery The Study addresses a broad range of issues affecting investment, such as the scope for new advanced, more efficient generation and end-use technologies, nuclear safety upgrades and decommissioning options, environmental standards, sources of financing, and energy policy impacts on investment choices This Study is expected to have a major influence on Russian power sector investment, including environment and safety considerations, and to provide a basis for follow-on actions by countries and institutions with an interest in Russia's economic future This executive summary sets out recommendations for consideration by Vice President Gore and Prime Minister Chernomyrdin

3 The two governments formed five joint working groups of experts to carry out the analytical work, supervised by an inter-governmental committee comprising concerned ministries and agencies The Study used two electric power integrated planning models that are complementary The Russian simulation model incorporates 1) detailed expert

knowledge of the entire Russian power system 2) screening analysis of the cost-effectiveness of supply and energy efficiency options, and 3) fuel supply constraints and environmental impacts The American integrated resource planning model uses least-cost optimization techniques to analyze the same set of issues as the Russian model The Joint Study uses the technical flexibility of the American model to study the sensitivity of answers to a wide range of economic uncertainties and policy questions Both sides in the Joint Study recognize that while the model results do not determine an investment plan for the Russian power sector, they are an important aid to its formulation

4 The data generated by the working groups were used in the two models to identify the mix of technologies that would be needed to meet Russia's electricity demand under two scenarios year-by-year through the year 2010

5 The two scenarios considered in this Study were based on two views of Russian economic performance and electricity demand, set forth in the *Russian Energy Strategy (Main Directions)*, and on a set of assumptions regarding the pace and degree of success of measures to control inflation and reform the economy Time-phased investment and fuel requirements were estimated using the two planning models Financing requirements were calculated from the total costs of the investments, and potential domestic and foreign sources of finance were identified All of the scenarios and financing requirements are based on assumptions about future developments of the Russian economy that are subject to uncertainties, and the team has prepared an investment strategy that addresses the main elements of uncertainty As the future direction of reform and the rate of evolution to a market economy become clearer, it will be necessary to undertake periodic re-evaluations of investment priorities

THE RUSSIAN ELECTRIC POWER SYSTEM

6 Russia's installed generating capacity in 1994 was 215 GW, of which 21% was hydroelectric (45 GW), 10% was nuclear (21 GW), and 69% was fossil-fired thermal (149 GW), including 73 GW of combined heat and power (CHP) stations Natural gas provides 65% of the fuel required by fossil thermal plants, coal provides 25% and residual fuel oil (mazut) provides 10% In 1990, Russia's per capita electricity consumption was 5,360 kWh, similar in magnitude to that of France (5,350 kWh) or Japan (6,140 kWh), but well below that of Canada and the United States

7 Industry's share of final electricity consumption in Russia dropped from 67% in 1980 to 56% in 1993 In the United States the comparable figure is 27%, in Japan 52%, and in Germany 42% In Russia, agriculture used 13% of electricity, transport used 10% and other sectors, including buildings, used 10% in 1993

8 The Integrated Power System (IPS) is composed of seven regional power systems the North-West, Center, Middle Volga, North Caucasus, Urals (including Tyumen), Siberia, and the Far East The first six of these are interconnected through a transmission network with lines rated at 330 kV and above The IPS spans 9,000 km west to east and six time zones (see Figure 1) The Russian electricity industry is made up of 51 large generators, 72 regional "AO Energos" that provide distribution, as well as electricity and heat production, and the transmission and dispatch operations This industry is currently in the process of being restructured and privatized to create a more efficient sector based on the principles of competition

9 Out of the existing generation capacity, 80 GW (600 units) of fossil thermal plants and 8 GW of nuclear capacity will reach the end of their service life by the year 2010 Figure 2 shows the possible evolution of all generating capacity according to the established schedule of power plant retirements This calculation did not take into account life extensions, rehabilitations or additions of new plants Superimposed on this plant retirement pattern are the two scenarios for electricity demand that form the basis of the Joint Study Russia as a whole remains comfortably in surplus for the next four to seven years, depending on demand growth However, the same is not true for the North Caucasus, Urals, Transbaikalia and a few other regions, which are already in deficit Figure 3 shows the pattern of capacity retirement on a regional basis

Figure 1
Russian Electric Power System by Region

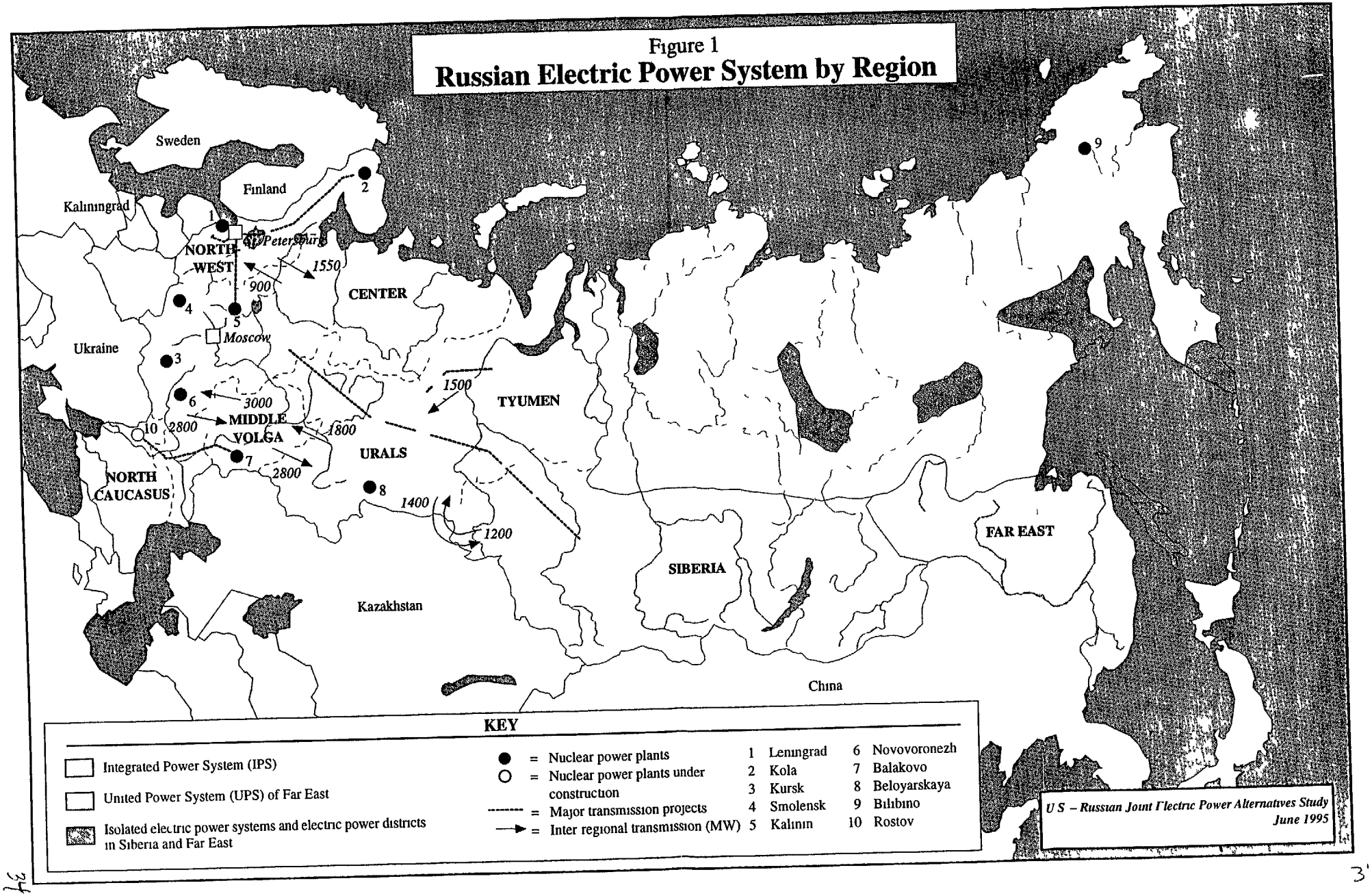


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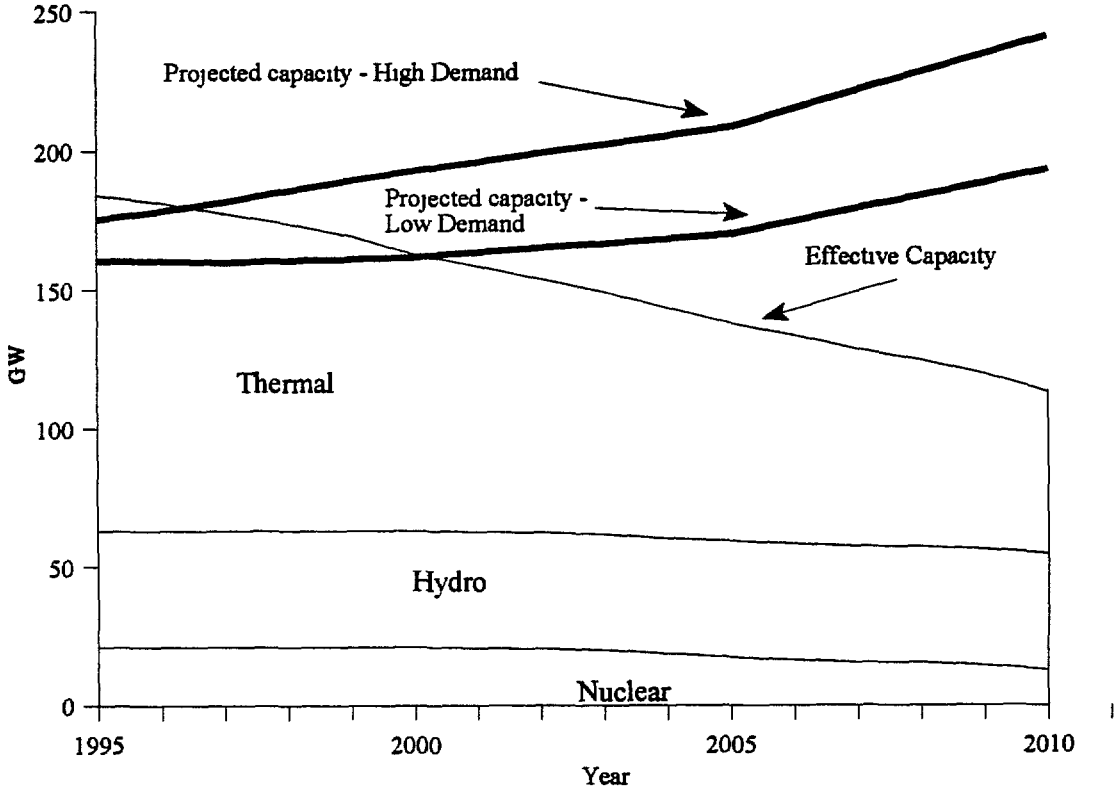
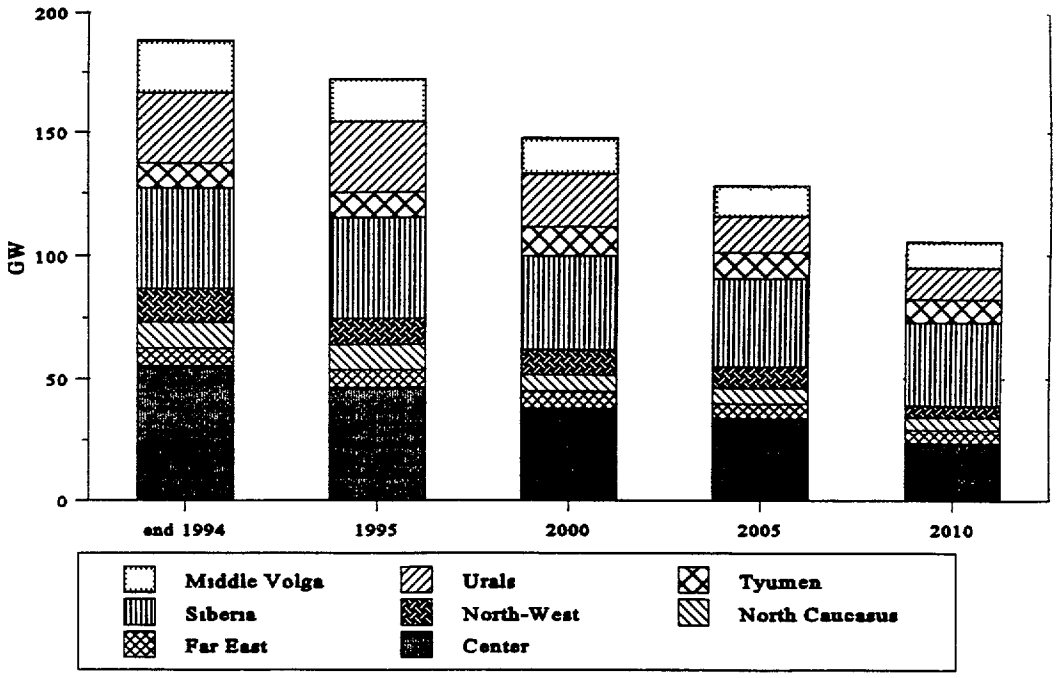
Figure 2
Effective Capacity Reduction Dynamics for Russia's Power Plants



Note The effective capacity is determined by adjusting the actual installed capacity by an amount equal to the fraction of total capacity that is historically out of service due to routine maintenance or equipment failures The adjustment factor used in this study is 13 %

Figure 3
Available Electric Generating Capacity by Region* (1994-2010)



Note *Available capacity reflects currently installed capacity and its decline resulting from scheduled retirement The figure shown for end-1994 does not include capacity in isolated systems, but does include nuclear generating capacity to be removed from service for safety upgrades

ELECTRICITY DEMAND AND RUSSIA'S OPTIONS TO MEET DEMAND

10 The high reputation of Russia's electric power industry is built on providing a reliable supply to meet the needs of the economy This dictates the need to project and ensure investments in generation, transmission and energy efficiency that will be sufficient to meet future demand in a reliable, safe and environmentally sound manner Under-investment could leave the country unable to meet all demand, while over-investment would be a misuse of scarce financial resources whose cost would be borne by users Variations in the timing and shape of Russia's recovery from economic depression and dislocation must be taken into account in estimating investment needs, and this Study has used two electricity demand scenarios taken from the *Russian Energy Strategy*, which was adopted in 1994 These demand scenarios have embedded in them no cost/low cost energy efficiency measures as well as energy conservation resulting from structural changes in the Russian economy

- ***Demand Scenario A (High Demand)*** is based on an official Russian economic forecast that assumes a quick turnaround, with recovery starting in 1997 and GDP reaching its 1990 level by the year 2004

- ***Demand Scenario B (Low Demand)*** is based on an official Russian economic forecast that assumes recovery might not start until 2000, and that by 2010 the GDP would only have reached just over 70% of its 1990 level

- ***Fuel and electricity prices*** are assumed in the Study to rise to levels needed to cover production costs and provide a return to investors An analysis of the impact of domestic prices at world levels was also conducted

11 The JEPAS Working Groups developed options and their costs for potential future developments in energy efficiency, thermal power, nuclear power and hydro power generation, transmission and dispatch Major options considered in the Study are as follows

- **Energy Efficiency** - Working Group 1
  - New, more efficient electricity-using technologies (lighting, motors, etc) and their likely implementation schedule

- **Fossil Thermal Generation** - Working Group 2
  - Rehabilitation and modernization, including combined cycle and advanced combustion technologies
  - Life extension
  - Construction of new coal and gas power plants
  - Fuel switching (re-powering) and modernization
  - Emission control technologies

- **Nuclear Power Generation** - Working Group 3
  - Safety upgrades to first-generation reactors (RBMK and VVER 440-230) to allow them to operate until the end of their service lives
  - Russian and U S decommissioning practices for first-generation reactors
  - Re-powering of the Rostov 1 reactor as a fossil-fired unit
  - Completion of the Kalinin 3 unit

- Safety upgrades to operating VVER 440/213 and 1000 reactors
- Construction of new-generation NP-500 reactors

▸ **Hydroelectric Generation** - Working Group 4

- Completion of on-going rehabilitation at four plants
- Rehabilitation of four additional plants
- Completion of six plants now under construction
- Construction of three new plants

▸ **Transmission, Dispatch and Control** - Working Group 4

- Reinforcement of existing inter-regional connections
- Improvement of system network control within regions
- Improvement of distribution network to reduce losses

KEY STUDY FINDINGS

12 The JEPAS confirmed the importance of the further development of Russia's electric power sector in assuring its economic development and socio-economic stability during this period of transition The principal conclusions of the JEPAS are consistent with the importance given to the electric power sector in the *Russian Energy Strategy* The Study indicates that it would be important for Russia to undertake certain high-priority projects on a time-phased basis over the next 10-15 years to maximize the effectiveness of its power sector and energy efficiency investment decisions The amount of financing required over the next ten years could range from $32 to $81 billion, depending on the demand for electricity The Study also indicates the need for support from the international financial community during 1995 through 1997 for high-priority projects costing approximately $2-4 billion

13 The JEPAS analysis indicates the following ranking of priorities during the period 1995-2000 1) improvements in the efficiency of electricity end-use 2) nuclear safety upgrades, particularly for first-generation nuclear power reactors where approved by the regulator 3) further development of the Integrated Power System through the expansion and strengthening of inter-regional and intra-regional transmission, particularly between surplus and deficit areas, and the modernizing of control/dispatch centers, 4) fossil thermal plant modernization and rehabilitation using improved technology, with the consideration of life extension options, 5) completion of those nuclear power plants that are in advanced stages of construction, 6) construction of new gas-fired simple cycle and combined cycle

plants, and 7) completion of the detailed design for new generation nuclear power plants to enable their certification by regulatory authorities

14 The Study's analysis also shows that during the period 2000-2005, it will be increasingly important to complete large under-construction hydroelectric plants, to construct clean coal generation plants, and to construct new-generation nuclear power plants A priority of Russia's long-term scientific and technological policy should be the development of new-generation design NP 500 and NP 1000 nuclear power plants and cleaner coal power units as well as developing the potential for their manufacturing, to provide for the commissioning by 2010 of new nuclear capacity and of environmentally-cleaner coal fired units

Energy Efficiency

15 The JEPAS analysis shows that energy efficiency should be given a high priority There is a large potential for energy efficiency improvements throughout the Russian economy Power consumption could be reduced by up to 29 billion kilowatt-hours (bkWh) by the year 2000 and 112 bkWh per year by the year 2010, just by installing efficient end-use technologies (see Table 1) In all sectors of the Russian economy, a significant portion of the savings potential is associated with lighting and motors improvements The changes in the demand for and use of electricity will vary in different service areas of the AO Energos, depending upon the effect of economic restructuring on local economic activities To be most successful, energy efficiency programs must be designed for these unique local conditions

16 The energy efficiency savings noted above could be achieved at relatively low cost The average life cycle costs of energy saved by the measures recommended in this study is approximately one U S cent per kWh Although the cost of replacing of outdated equipment with new equipment is high, the incremental cost caused by using new energy-efficient equipment is relatively low and easily justified economically (see Table 2)

Table 1
Annual Electricity Savings and Total Incremental Cost for the Year 2010
(from Measures Screened at 4 ¢/kWh and Less)

Sector	Savings bkWh		Incremental Capital Cost ($ million)	
	High Demand	Low Demand	High Demand	Low Demand
Industrial	61 1	37 5	6,382	3,950
Residential	15 1	11 7	3 278	2,545
Transportation	5 1	4 8	146	139
Agriculture	11 3	8 8	232	182
Service	19 5	15 1	2 223	1,726
Total	112 0	78 0	12,262	8 542

1 "Incremental cost" is the difference in cost between replacement with energy-efficient equipment versus replacement in kind
2 The above numbers do not include energy savings resulting from low-cost/no-cost measures, and from structural changes in the Russian economy

Table 2
Costs of Illustrative Demand-Side Measures

Description of Measure	Sector	Cost[1] (¢/kWh)	Savings in 2010 Under High Demand
Adjustable Speed Drive Motors >135 horsepower	Industrial	2 05	10 4 bkWh
Compact Fluorescent Bulbs	Residential	3 02	9 7 bkWh
Recuperative Braking	Transport	1 17	1 5 bkWh
Mercury Lamps & Fixtures	Agriculture	- 0 56[2]	2 3 bkWh
Adjustable Speed Drive Water Pumps	Service	1 94	3 9 bkWh

Note 1 The costs presented for the illustrative measures are the total incremental costs of the measures divided by their cumulative energy savings
2 A negative value indicates that use of the energy efficiency technology will reduce costs in addition to saving energy

17 At present, there are some barriers to the installation of efficient technologies Energy-efficient equipment is not always available in Russia There is a considerable shortage of financing available for energy efficiency

18 Priority should be given to investments to develop the capability for mass producing energy-efficient motors and new lighting technologies (such as compact fluorescent bulbs and metal halide lights), as well as implementing new manufacturing methods (i e , process changes) for oil and chemical plants using high-quality catalysts Demonstration projects for energy-efficient technologies should be established and assistance provided for carrying out energy audits Investments should also be made to set up information and training programs in the area of energy savings

19 Regulatory, institutional and economic measures must be undertaken before energy efficiency programs can be implemented In the near future, the Law on Energy Conservation must be passed Government support for energy efficiency should include tax and customs duties-based incentives and loans and accelerated depreciation

Supply Alternatives

20 The JEPAS Working Groups identified and screened an array of investment options including 1) energy efficiency improvements in the industrial, residential, transportation, agriculture, and services sectors, 2) thermal power plant modernization, conversion, fuel switching, life extension, and new plant completions, 3) the completion, safety upgrade, and/or decommissioning of nuclear plants, 4) the rehabilitation, modernization and expansion of existing hydro plants and the construction of new hydro plants, and 5) transmission and dispatch projects Table 3 provides illustrative capital costs for selected generation capacity additions

Table 3
Illustrative Resource Costs Used in JEPAS Modeling

	1995	2000	2010
	Capital Costs $/kW	Capital Costs $/kW	Capital Costs $/kW
New Plants			
Pulverized Coal	942	1,083	1 486
Combined Cycle	682	782	988
Hydro	924 to 1 590	1,146 to 1 972	1 737 to 2 989
Nuclear	1 144	1,281	1 970
Modernizations			
CPP (Oil/Gas)	552	623	787
CPP (Coal)	552	661	938
CHP (Oil/Gas)	455	545	747
CHP (Coal)	619	776	1,121
All costs are expressed in January 1994 U S dollars			

Thermal Power

21 Some 79 GW of existing thermal plant capacity, which is evenly divided between CPP and CHP units, will reach the end of its service life by the year 2010 This retiring capacity represents 40% of the current total electric generating capacity within Russia More than 54 GW of this capacity is located in three regions -- the Center, the Urals and Siberia Approximately 39 GW of the retiring capacity will have reached the end of its life by the year 2000 and more than 13 GW of this total has already reached its maximum design life

22 The modeling results indicate that new and reconstructed thermal power plants would account for 75-80% of the total generating capacity to be installed

23 Under high demand growth, about 28 GW of Russia's generating capacity would be installed through the year 2000, while 9 GW would be required if demand growth is slower during the same period Given the lead times for the construction of new plants and the reconstruction of existing capacities, these results dictate the urgent need for an aggressive development program Near-term new plant capacity is needed in the North Caucasus, Urals and Transbaikalia

24 The North Caucasus is an example of a region with significant near-term need for additional power generation capacity This need has resulted from the retirement of older thermal units and from the loss of power supplied via Ukraine At the North Caucasus sub-regional level, the Krasnodar Krai (Kubanenergo) has the largest self-generating capacity deficiency in the region Cognizant of this need, RAO EES Rossii, Kubanenergo and others have formulated plans to build modern gas-fired combined cycle units in the Kubanenergo system The modeling results support this approach Such a project would also serve as a major demonstration of this highly efficient and environmentally sound technology, and as a blueprint for replication in other parts of Russia

25 The rehabilitation of thermal plants that are scheduled to be retired will play a significant role in meeting future power needs, however, the investment costs are significant Life extension provides an opportunity to reduce investment requirements Therefore, plant-level evaluations of rehabilitation and life extension options are recommended for thermal power plants

26 Russia is on the verge of promulgating environmental emission standards The present institutional framework for monitoring and enforcement is still evolving New, more stringent environmental standards are being developed for thermal power plants These standards should allow for differentiation among new, existing and rehabilitated thermal plants Programs should be developed to 1) identify the best emission reduction technologies for each plant and 2) provide support for the domestic production of those technologies For coal-fired plants, technologies such as low-NO_x burners, fabric filters for particulate collection, flue gas desulfurization and circulating fluid bed boilers should all be considered Continuous emission monitoring equipment should be employed to ensure compliance with emission limits

27 Advanced technologies such as gas turbine combined cycles and circulating fluid bed boilers should be given serious consideration to improve thermal efficiencies and environmental performance, and to take advantage of the availability of low-quality solid fuel Developing manufacturing capability for these advanced technologies, through joint ventures or other means, should be further encouraged

Nuclear Energy

28 The *Russian Energy Strategy* emphasizes the importance of nuclear power in Russia's economic development under the new conditions Nuclear power plays a significant role in the country's development The JEPAS has confirmed the important contribution that nuclear power makes to the Russian power sector The Study found that future investment in the power sector should include investments in nuclear power plant upgrades, plant completions, evolutionary plant designs, and where appropriate, decommissioning

13

29 The JEPAS found that investments in nuclear power plant safety upgrades are competitive with investments in alternative energy sources It is economic to continue the operation of most existing nuclear power plants with the completion of safety upgrades evaluated in this Study and where approved by regulatory authority The implementation of such safety upgrades could encourage foreign investment in Russia's nuclear power sector In the initial study period, investments in safety upgrades of the existing nuclear power plants are considered as a priority whether demand growth is high or low

30 The JEPAS shows that, with the scheduled service life remaining, it is not economic to implement all of the safety upgrades evaluated in the Study for Kola 1 and 2 and Novorovonezh 3 and 4 (and Leningrad-1 if demand growth is low) The decommissioning of these units should be considered comprehensively, on the basis of local area conditions and on a site-specific basis

31 The completion and commissioning of Rostov 1, Kursk 5, Kalinin 3, and Balakovo 5 and 6 should be considered in the context of regional least-cost plans and following their full safety review Rostov 1 and Kalinin 3 have been identified as priorities for investment

32 New nuclear capacity was found to be an economic supply option in some regions The design of the NP-500 and NP-1000 evolutionary reactors, which will be the basis for the future development of the nuclear energy sector, should be developed to a sufficient level of detail so as to permit their certification by the regulatory body

33 Legislation required to support the safe development and operation of nuclear power in Russia should be completed as soon as possible

34 While the JEPAS estimated the cost of nuclear power plant safety upgrades, it did not quantify the safety significance of each of these upgrade measures There are, however, existing studies conducted both in Russia and internationally that have assessed the safety significance of many of these upgrades It may be useful to conduct a new study, combining the results of the above work, to look at the question of how to maximize the safety benefit of investments in safety upgrades within the limitations of the available financing, and to assess the level of safety improvement derived from implementing each measure

Hydro

35 Eight existing hydro power plants have been identified as eligible for rehabilitation to permit their continued operation after 2000 These plants' rehabilitation would cost approximately $900 million between 1995 and 2001 Detailed designs, cost estimates and financing plans should be prepared for hydro rehabilitation projects that are viable under

regional least-cost plans The completion of six plants under construction and three new plants were also identified as potential investments at a cost of $4 8 billion

Transmission and Dispatch

36 Russia's transmission system needs to be modernized to provide for higher efficiency and the ability to transfer power among regions for the ultimate development of an electricity market Intra-regional and inter-regional transmission projects/programs have been identified for priority investment, two of which are described below

37 Two priority transmission projects are recommended in the North-West Region and for interties among the Middle Volga, Center and North Caucasus regions The North-West Region reinforcement projects, at an approximate cost of $775 million, consist of 330 kV and 750 kV lines complete with substations, and are designed to strengthen the supply to the nuclear plants The second priority project (four-500 kV lines at a cost of $430 million) has been planned and at present is in the implementation phase It will reinforce the internal systems of the Middle Volga and Center regions to enable increased transfers to the North Caucasus and Center regions

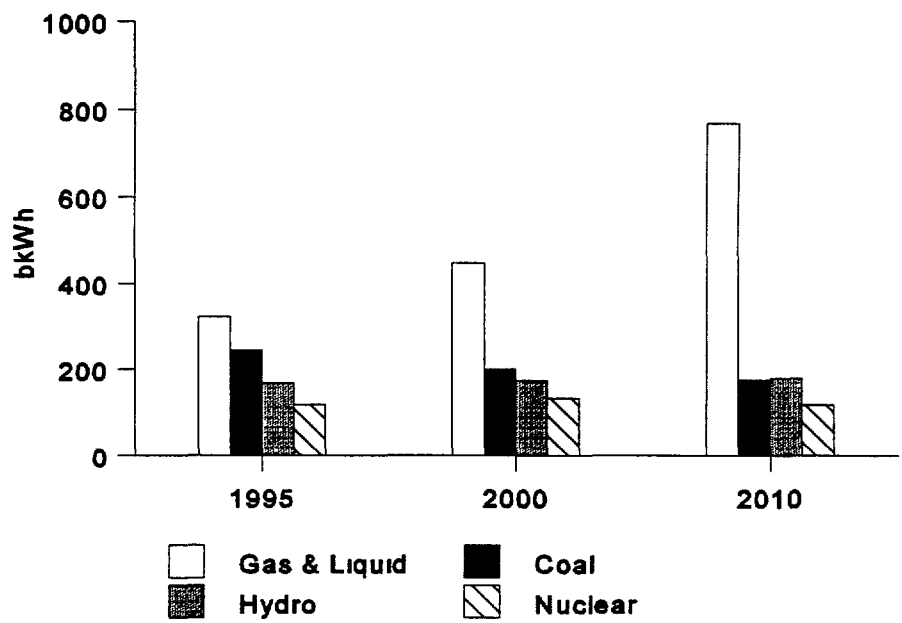
38 A detailed study is recommended to evaluate the construction of a high-voltage transmission line of 3-6 GW capacity between Siberia and Center regions

39 Some upgrades are urgently needed for the control, communications and dispatch systems of the Integrated Power System due to inadequate technology Two control and dispatch projects have been prioritized for early investment, namely the Central Dispatch Office and the North-West Dispatch Center for an aggregate cost of $80 million Such upgrades will accommodate similar upgrades in other regions of the IPS

Projected Electric Power Generation

40 The amount of electricity generated from natural gas is expected to rise significantly under both scenarios because generation from natural gas using combined cycle and simple cycle technologies is economically competitive in many regions of Russia Generation from hydroelectric sources is also expected to increase in both scenarios, but by a much smaller amount Nuclear generation is expected to increase in both scenarios until the year 2000, in the high demand scenario it will increase slightly after 2000, while in the low demand scenario it will decline after 2000 Coal use will decline in both scenarios Figure 4 shows estimates of electricity generation by fuel source over the period of the study, as indicated by the U S model for the high demand scenario For the low demand scenario a similar trend is expected, but at a slower rate

Figure 4
Electricity Output by Fuel Type (High Demand)



RUSSIA'S PREFERRED INVESTMENT PROGRAM FOR THE POWER SECTOR

41 The Russian side recognizes the value and importance of the results of the Joint Study, and has developed a Preferred Investment Program based upon the JEPAS This program adapts the JEPAS results to take account of (1) constraints on the availability of investment capital over the next five years, (2) socio-economic policies with respect to employment in the fuel and energy complex, and (3) energy policy with respect to domestic and export uses of natural gas The Russian side anticipates that technology investments will be made along the lines indicated in Table 4, but that final decisions on individual power sector projects will result from a blend of investor preferences and governmental incentives, including research and development

46

Table 4
Capacity Additions and Replacements for the IPS for the Preferred Investment Program (GW)

	1995-2000		2001-2005	
	HIGH DEMAND	LOW DEMAND	HIGH DEMAND	LOW DEMAND
ALL TYPES				
New units	13 - 14 9	1 5 - 2	10 - 12 9	9 3 - 11
Rehabilitations and Upgrades	17 - 17 6	7	27 - 27 6	18 7 - 19
Total Additions	30 - 32 5	8 5 - 9	37 - 40 5	28 - 30
Hydroelectric Plants Total	0 6	0 4	2 - 2 3	2 1 - 2 5
Nuclear Power Plants Total	2 0	1 0	2 7 - 3 3	0
Thermal Heat and Power Plants				
New Units	7 4	0 1 - 0 6	3 8 - 4 4	6 0
Rehabilitations and Upgrades	12 - 12 1	5 7	12 - 12 6	12 1 - 12 5
Total Additions	19 5	5 8 - 6 3	15 8 - 17 0	18 1 - 18 5
Conventional Thermal Plants				
New Units	4 9	0	2 - 2 9	1 2 - 2
Rehabilitations and Upgrades *	5 - 5 5	1 3	14 5 - 15 0	6 6 - 7
Total Additions	10 4	1 3	16 5 - 17 9	7 8 - 9

* including rehabilitation using simple-cycle gas turbines

Finance

42 It is difficult for lenders to assess the creditworthiness of potential borrowers in Russia's electric power industry A legal and regulatory system for the new industry structure is not yet in place The non-payments problem remains (for some companies 45% of billings are unpaid), although there are mechanisms such as bills of exchange and barter to overcome short-term difficulties At present there is no long-term lending in rubles, and short-term annual rates are measured in hundreds of percent Punitive taxes, inflation, and the inability of the industry to cover its costs in revenues are some of the

problems faced by the sector Despite the uncertainties of the current situation, the power sector needs to mobilize funds for operations and investment The sector does not generate significant amounts of foreign exchange, and so it is more difficult to attract foreign lending and investment than is the case for the oil and gas sectors

43 The amount of financing required over the next ten years could range from $32 to $81 billion, depending primarily on the demand for electricity Over this period, it is expected that the power sector will need to generate 65-75% of its financing requirements ($21-$61 billion) from internally-generated funds The sector will need to ensure that tariffs are set at levels that cover operating costs and the costs of its capital investment program The tariff increases needed to cover the capital investment requirements over the study period are estimated to be less than 1 cent per kilowatt-hour, no matter how the program is financed, although financing with debt would decrease the tariff impact in the near term

44 It is estimated that the power sector will be able to borrow up to approximately 20-30% of its capital requirements ($6-$24 billion) Total borrowing will be limited for several reasons 1) the creditworthiness of power sector enterprises will take time to establish and will be greatly influenced by the general economic and business climate in Russia, 2) medium- and long-term domestic capital is not available in Russia and will take years to develop, and 3) foreign sources of borrowing, while extremely important as gap financing over the short term, will be limited in the long term because of the large domestic content in power sector investments and the foreign exchange risk inherent in repaying dollar-denominated debt with domestic revenues

45 Project financing and innovative financing mechanisms could speed up the process at which debt could be made available, but will still take time to structure and negotiate These mechanisms include independent power projects, sales of generating assets, leasing, energy savings contracts, and barter and counter-trade

46 The role of the Russian Government in developing financing for the power sector is important Government decisions on the sale of power sector enterprises, the use of the proceeds, and the future industry structure will influence the amount of funds available and which entities (private/public, generation/transmission/distribution) will have access to markets and financing The willingness of the government to provide sovereign guarantees on foreign loans will affect the amount of foreign borrowing available, especially during the next three years Tax policies for power sector enterprises will influence the amount of internally-generated funds available for the investment program Tax credits, accelerated depreciation and lower tax rates would improve the power sector's ability to become financially independent Direct subsidies or credits from the government may be required to provide financing for nuclear unit safety upgrades and energy efficiency improvements

FINAL RECOMMENDATIONS AND CONCLUSIONS

47 To realize potential energy savings of 29 bkWh by the year 2000 and up to 112 bkWh by 2010, market-oriented incentives should be introduced to improve end-use efficiencies The development of energy service companies and joint ventures should be encouraged These would provide equipment, energy management techniques and financing for energy efficiency improvement

48 Where approved by the regulatory authority, economically justified program safety upgrades of RBMKs (9,000 - 11,000 MW) and of first-generation VVER nuclear power reactors (880 MW) should be implemented This is estimated to require $1 0 billion between 1995 and 2000 Russian Government financial support and, to the extent possible, support from international financial institutions will be needed to undertake these upgrades

49 A major goal for RAO EES Rossii and the AO Energos should be the rehabilitation and modernization of older thermal plants so as to extend their operating lives and to improve their environmental and operational performance Approximately 79 GW fall into this category, of which about 39 GW will require modernization by the year 2000 Plant-level evaluations should be undertaken to determine rehabilitation requirements and the extent to which life extension at lower capital cost may be possible In addition, Russia should place high priority in its technological and investment policy for the power sector on using simple cycle and combined cycle gas turbines (4,000 - 18,000 MW by 2000, 38,000 to 83,000 MW by 2010) and on developing the domestic capability for their manufacturing, including joint ventures with Western partners

50 Further detailed study, including project identification, of the electricity and fuel supply situation in the North Caucasus, Urals, and TransBaikalia should be given high priority This work should take into account specific factors at the local level and apply least-cost utility planning tools It is estimated that 24,000 - 36,000 MW of new capacity will be required in these regions, as well as the strengthening and expansion of transmission interties Further feasibility studies are needed for the western and eastern extension of transmission between Siberian hydro capacity and demand centers in European Russia and TransBaikalia In addition, the issues in electricity interconnection among the CIS republics and other neighboring countries should be investigated, including the potential for electricity trade with China, Central Europe and other countries

51 The investment requirements for energy generation capacity replacements and additions, efficiency, and transmission improvements are listed in Table 5

Table 5
Investment Requirements Indicated by the JEPAS Findings
($ billion)

	High Demand	Low Demand
Generation		
1995 - 2000	21 - 26	9 - 10
2001 - 2005	25 - 32	14 - 20
Subtotal	46 - 58	23 - 30
Energy Efficiency		
1995 - 2000	3-4	2-3
2001 - 2005	5-11	3-8
Subtotal	8-15	5-11
Transmission		
1995 - 2000	2-3	1-3
2001 - 2005	5-5	3-5
Subtotal	7-8	4-8
All Requirements		
1995 - 2000	26-34	12-16
2001 - 2005	35-48	20-33
Total	61-81	32-40

52 Regional investment requirements under high and low demand are shown in Figures 5 and 6

53 Russian Federation Government support is needed to ensure the further development of the power sector under conditions of widening economic reforms and to create conditions conducive to attracting financing and capital investment An improved state system of regulating natural monopolies, which includes state regulation of electricity and heat rates at both the federal and regional levels, as well as an appropriate legal and standards infrastructure are needed Economic and commercial mechanisms are needed to implement the principle of self-financing in the power sector This would increase internal cash generation by power entities and improve the efficiency of allocation of these funds through depreciation and retained earnings of operating entities As a transition measure to a new regulatory system, a mechanism should be established to facilitate the rational

allocation of power sector investment funds between the federal and regional levels, and to create incentives to attract funds into the power sector from both domestic and foreign sources on both an equity and debt basis

54 It is also recommended that the part of retained earnings which is directed into investment be made tax deductible, including the part collected through centralized investment funds

55 Economic stimuli should be created to attract investment into the power sector by establishing government guarantees at both the federal and regional levels, and permitting reasonable levels of return on investment As an interim measure, funds should be generated at the federal level to finance modernization and rehabilitation, and a mechanism should be developed to allocate these funds between the federal and regional levels

Figure 5
Indicated Power Sector Investment by Region from 1995-2000 for Higher and Lower Demand ($billion)

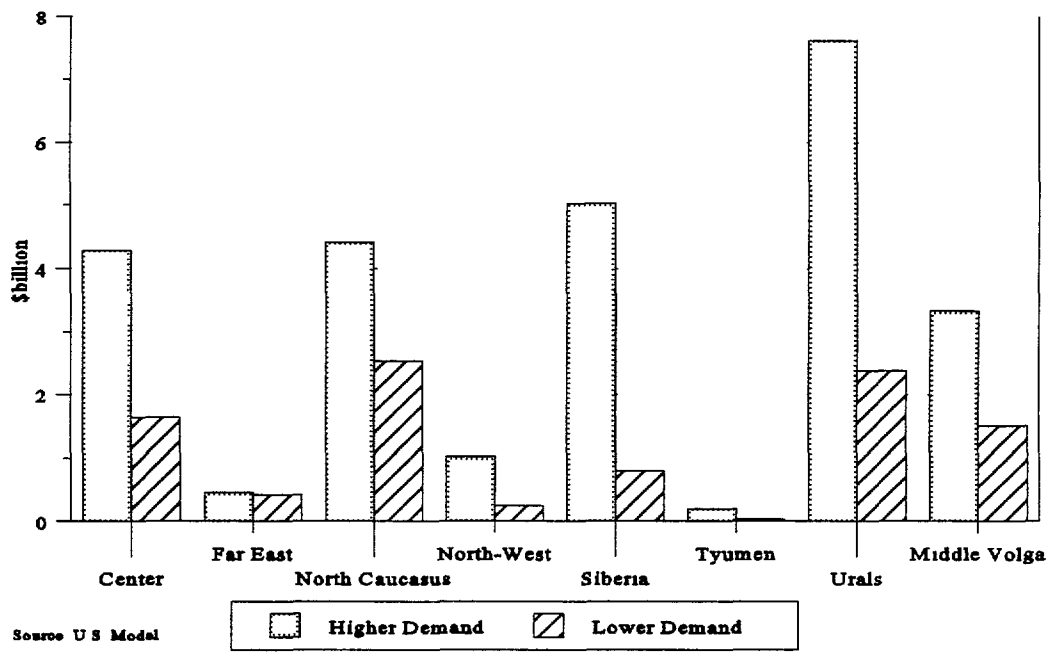


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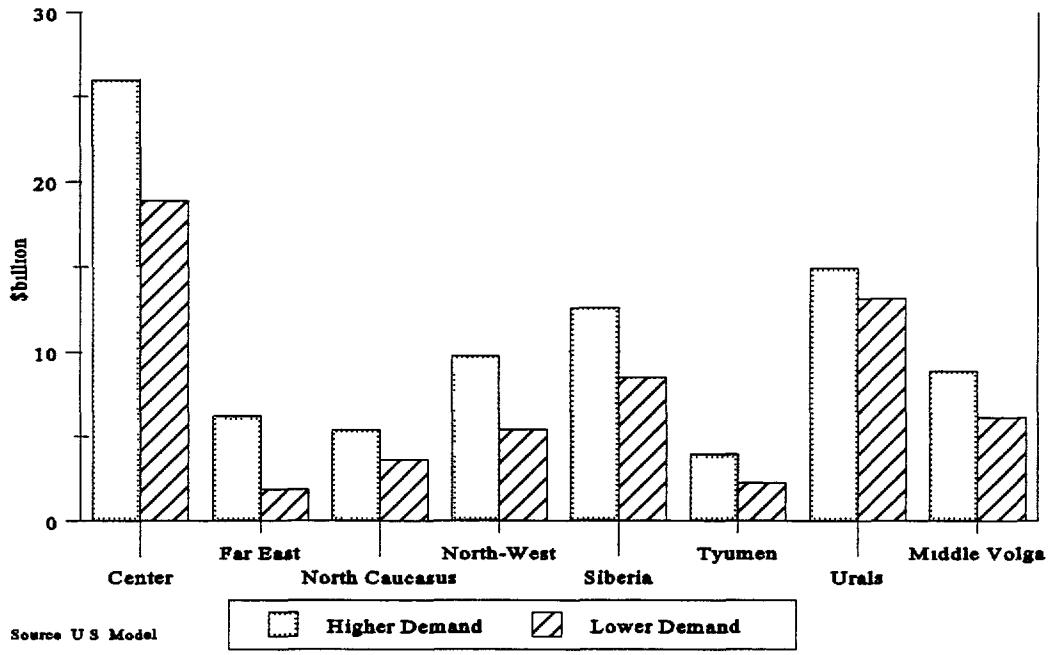
Figure 6
Indicated Power Sector Investment by Region from 2000-2010 for Higher and Lower Demand ($billion)



Source U S Model

56 In the nuclear power sector, an economic mechanism should be developed that increases internally generated funds through tariffs without damaging the competitiveness of nuclear energy in the energy market A portion of these internally generated funds would be centralized in a national reserve which would finance priority safety upgrades, plant completions, decommissioning, and new nuclear power plant construction Opportunities should be created to attract loans into the nuclear sector with corresponding government guarantees The possibility to convert the nuclear sector into stock companies should be studied as well as the corresponding issue of guarantees for potential domestic and foreign investors

57 On the basis of further changes and definition of the ownership structure, the restructuring of the power sector should proceed to set up a competitive environment and to improve rate setting in electric energy markets

58 A legal and tax infrastructure conducive to investment by independent power producers should be created

59 It is necessary to develop a comprehensive program for the public sale of government-held power sector stock at an acceptable value Funds from these sales should be used for reinvestment to provide needed investment capital for the power sector

CHAPTER 1
MACROECONOMIC AND ELECTRICITY DEMAND SCENARIOS

1.1 ENERGY POLICY SITUATION AND KEY ISSUES FOR INVESTORS IN THE RUSSIAN POWER INDUSTRY

1 The *Russian Energy Strategy* (Appendix A), which was approved by the Russian Federation Government in December 1994, considered several scenarios for electricity consumption in Russia The two scenarios representing the highest and lowest consumption levels (Scenarios A and B, respectively) were used in the Joint-Study to examine a range of possibilities for electricity demand Given the numerous uncertainties that exist in present-day Russia, these are not to be considered as forecasts Rather, they represent possible paths of economic development and electricity consumption The macroeconomic assumptions used to develop the scenarios and the resulting electricity consumption are described in Sections 1 2 through 1 5

2 The *Energy Strategy* sets forth policies to improve the efficiency with which Russia's energy resources are used and to realize the considerable industrial potential of its fuel and energy complex One of its main objectives is to raise the standard of living and to stimulate the economic recovery of the country Other important strategy objectives include the reduction of environmental impacts and the costs of the material inputs, labor, and natural resources needed to ensure a reliable energy supply for consumers

3 The *Strategy's* highest energy policy priority is in the area of energy conservation The government holds the view that the most efficient way to meet domestic demand and to increase fuel and energy exports would be to implement a phased program to reverse wasteful practices and tap the country's enormous energy efficiency potential Wasteful consumption accounts for up to 40-45% of Russia's current energy demand and for 35-40% of its electricity consumption A pricing policy would be the most effective means of achieving the energy efficiency objectives Nevertheless, the escalation of domestic fuel prices to reflect world prices would have to be supplemented with special incentives for energy efficiency and a package of administrative measures and institutional initiatives to overcome barriers to investments in efficient technology Energy efficiency programs at the national and local levels will be needed to realize a substantial share of the energy efficiency potential It is estimated that energy conservation measures could curb overall

54

energy demand by 10-15% by the year 2000, and by 25-40% beyond the year 2000, and that a 1% savings in energy demand would result in a 0 35-0 40% increase in GDP

4 While promoting the use of all energy resources, the *Energy Strategy* emphasizes the primacy of natural gas, which accounts for 50% of all primary energy sources produced in Russia The government intends to stabilize and then increase oil production and to restructure the oil refining industry entirely Russia's coal industry, which needs to be restructured and rebuilt, will retain its prominent role in the energy supply system, particularly in the Eastern regions Expanding fuel and energy exports are also important objectives of the *Energy Strategy*, which envisages significant oil exports and growing natural gas exports to foreign countries and former Soviet republics, and to the European as well as Asian markets

5 The *Energy Strategy* describes the electric power sector as the core of the Russian fuel and energy complex Interfuel competition in the power sector is expected to improve the overall efficiency of energy supply and end-use Modeling conducted to support the *Strategy* projects a moderate growth in hydro generation, a flat or modest growth of nuclear generation, and the upgrading of existing thermal plants with advanced combustion and combined-cycle units

6 Effective pricing, a key component of the *Energy Strategy*, is expected to play an important role in areas other than end-use energy efficiency The *Strategy* calls for the liberalization of prices for most fuels while maintaining monopoly price regulation at both the federal and regional levels for gas, electric power, and district heating Effective pricing policies would ensure that domestic market prices gradually move from the utility self-financing or full-cost price levels that were reached in 1994 to world market prices Any change to real competition in electricity generation markets would change how prices are set, but would nevertheless be expected to lead to prices that reflect marginal costs of supply Potential inequities between existing capacity (largely depreciated from historical investment costs) and new capacity (priced to reflect current market conditions) would need to be addressed

1.2 MACROECONOMIC SCENARIO ASSUMPTIONS

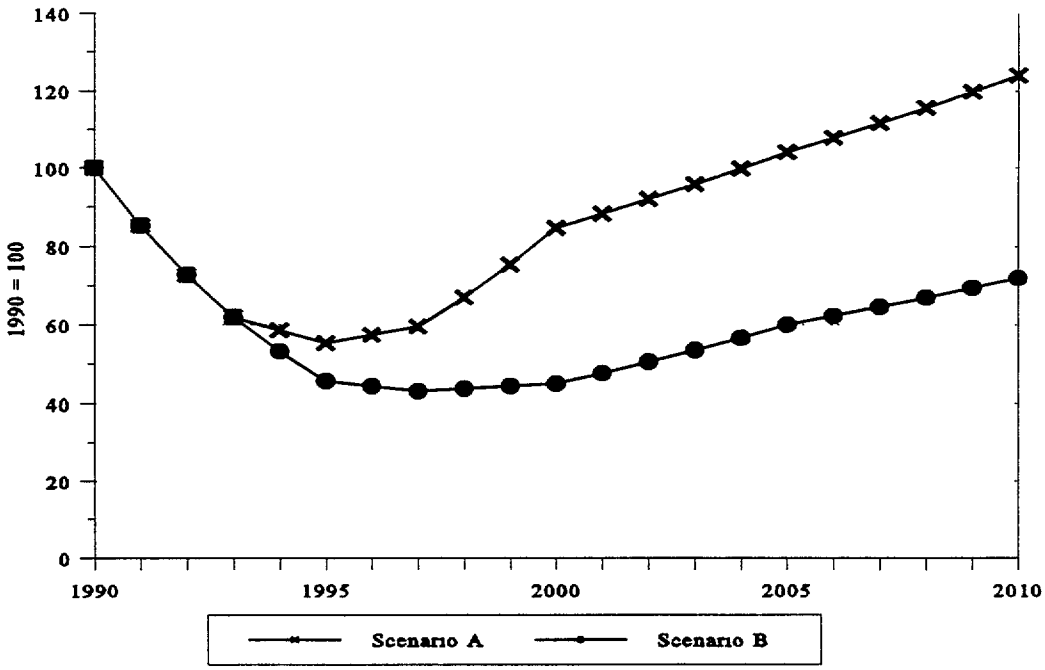
7 Although the absolute levels of Russian GDP are the subject of debate, there is general agreement that GDP growth slowed in the late 1980s and fell 2% in 1990 According to Russian Ministry of Economy estimates, GDP fell 13% in 1991, 18% in 1992, 13% in 1993, and 15% in 1994 In 1994, GDP was at 52 7% of 1990 levels

8 The current uncertainties regarding Russia's economic turnaround and the strength of this recovery are demonstrated in the GDP projections under Scenarios A and B (Figure

1-1) Scenario A represents a quicker turnaround in economic growth and then higher growth rates than Scenario B This scenario reflects a halting of the decline in GDP by 1996, with recovery following in 1997 By 2004, GDP is projected to be back at 1990 levels, and then grow by 3 5 to 4 5% per year to 2010 Scenario A illustrates an optimistic version of reform of the Russian economy For the power sector, this scenario would reflect intensive energy conservation, the rapid growth of energy resources, and a conservative investment policy

9 Scenario B assumes that macroeconomic activities continue to fall through 1998, stagnate through 2000, and recover gradually thereafter Under this scenario, by 2010 GDP will recover to just over 70% of 1990 levels Scenario B reflects an unfavorable development of the Russian economy, demonstrated by the absence of effective anti-inflation policies, sluggish investment processes due to massive capital flight from the country, a continued fall in industrial production, and a continuous increase in the energy intensity of the economy

Figure 1-1
Projected Trends in GDP



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1.3 ELECTRICITY DEMAND: STRUCTURE AND TRENDS

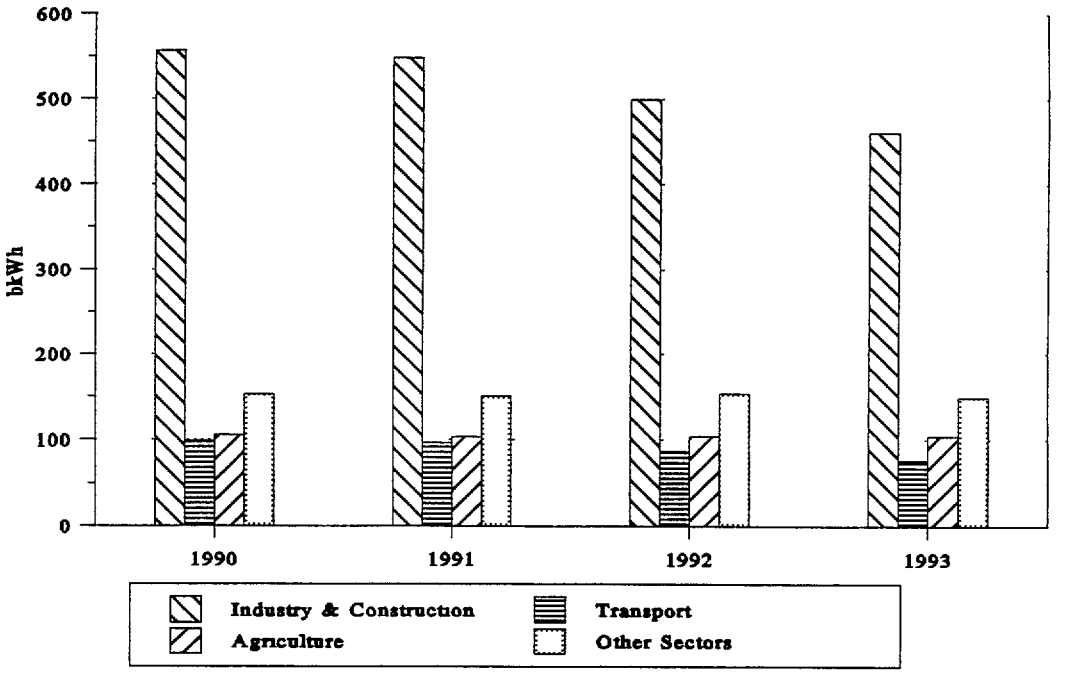
10 While electricity consumption levels fell very slightly in 1991, it was not until 1992 that they fell noticeably This decline in electricity consumption (-6%), however, was slight compared to the drop in GDP (-18%) Electricity consumption continued to decline in 1993 (falling another 5 5%) and 1994 (-8 5%), but it again failed to match declines in GDP of 13% and 15%, respectively While 1994 GDP was 52 7% of 1990 levels, electricity consumption was at 80% of 1990 levels These trends suggest a rapidly increasing electricity intensity (as measured by electricity consumption per unit of GDP) of the economy [1]

11 The lack of response of electricity consumption to macroeconomic activity is linked to government pricing policies and the rapidly growing non-payment problem Electricity prices remained controlled, with insufficient adjustments for inflation, until the second half of 1992 By this time, real electricity prices were lower than in 1990 Starting in the second half of 1992, electricity prices kept pace with inflation, and in 1993 and 1994 they rose faster than inflation However, it appears as if increased prices have had little effect on consumption decisions, as a growing number of consumers (particularly in industry) simply stopped paying their electricity bills In 1994, for example, almost 45% of revenues owed to the electricity sector were not paid This non-payment problem makes it impossible to establish any sort of demand elasticity for the period 1990-1994

12 Final electricity consumption patterns (not including in-plant use, distribution losses, or exports) for the period 1990 to 1993 are shown in Figure 1-2 The sectors showing the largest drops in electricity consumption during this period were industry (including construction activities) and transport (which in Russia is based heavily on electrified rail) Even with this recent decline, the industrial sector still plays a major role in electricity consumption Including construction activities, this sector accounted for 58% of final electricity consumption in Russia in 1993, compared to 61% in 1990

[1] The GDP figures used here are from the Ministry of Economy and are considered "official' figures Many specialists both in Russia and abroad have voiced opinions that this official series does not capture many economic activities which were not reported Hence, it is difficult to provide an accurate figure for the pace at which electricity intensity is increasing

Figure 1-2
Final Electricity Consumption, Russia (bkWh)



13 It is difficult to analyze the dynamics of Russia's sectoral electricity consumption in recent years because of inconsistencies among data sources Within industry, the largest consumers have been nonferrous metals (which accounted for approximately 20% of industrial electricity consumption in the early 1990s), followed by manufacturing and ferrous metals The dominance of heavy industry in electricity consumption, coupled with the lack of management of electricity use within industry and the lack of economic mechanisms (prices and bills) to change consumption patterns, has led to high electricity intensities If the government pursues radical reforms that result in a restructuring of industrial activities, it is likely that industrial electricity consumption would fall substantially before rebounding The social consequences of such radical reform efforts, however, prevent this possibility

14 On the other hand, certain sectors of the economy can be said to be "under electrified " The commercial and residential sectors have traditionally played very minor roles in final electricity consumption However, the commercial sector's electricity consumption should grow with the addition of stores and other service-sector activities In the residential sector, the expansion of electricity use will be closely linked with new home construction and the subsequent increase in the stock of appliances

58

15 There is also some potential for increased electricity use in the existing housing stock Although most Russian homes have refrigerators, there are fewer automatic washing machines or advanced consumer electronics than in other industrial countries Because many people resort to using electric space heaters when the district heating system has not been turned on or is not working properly, an improvement in heat delivery or building insulation could moderate an absolute increase in electricity use in the existing housing stock Electricity prices to the residential sector have been held artificially low, in line with the government's social policies, and it is unclear to what extent higher prices in the future might dampen potential increases in this sector's electricity consumption

16 A comparison of per capita electricity consumption for Russia and several OECD (Organization for Economic Cooperation and Development) countries shows that in 1990 Russia (5,360 kWh per capita) lagged significantly behind Canada and the United States, but was very similar in its magnitude of consumption to Japan (6,140 kWh), Germany (6,020 kWh), and France (5,350 kWh) [2] Perhaps the most striking element of this comparison is the role the industrial sector plays in consumption patterns In most OECD countries, the residential/commercial sectors play a more important role in consumption patterns than the industrial sector But in Russia, the industrial sector has the dominant role In fact, per capita electricity consumption in Russia's industrial sector was close to U S levels

17 When electricity consumption is compared per unit of economic output (GDP), the Russian economy appears to have been three to four times more electricity intensive than the United States, Japan, and most European members of the OECD GDP estimates for Russia are incomplete, these figures provide only an estimate of the electricity intensity dynamics However, the differences are considerable, especially in comparisons of industrial sector electricity consumption Given that per capita electricity consumption in the industrial sector of Russia was similar to that of the United States in 1990, and that per capita GDP varied significantly between these two countries, the Russian economy has been extremely electricity intensive in light of its economic output An underlying aspect in comparisons of electricity intensity is that Russia has high electricity consumption in industries producing goods with little (or declining) market value

1.4 PROJECTIONS OF ELECTRICITY DEMAND

18 Figure 1-3 shows the two scenarios for electricity demand Electricity consumption in Scenario A falls less and recovers at a faster pace than under Scenario B In Scenario A, electricity consumption begins a moderate climb after 1995, nearly reaching 1990 consumption levels by 2005 After this, consumption grows at an annual average rate of

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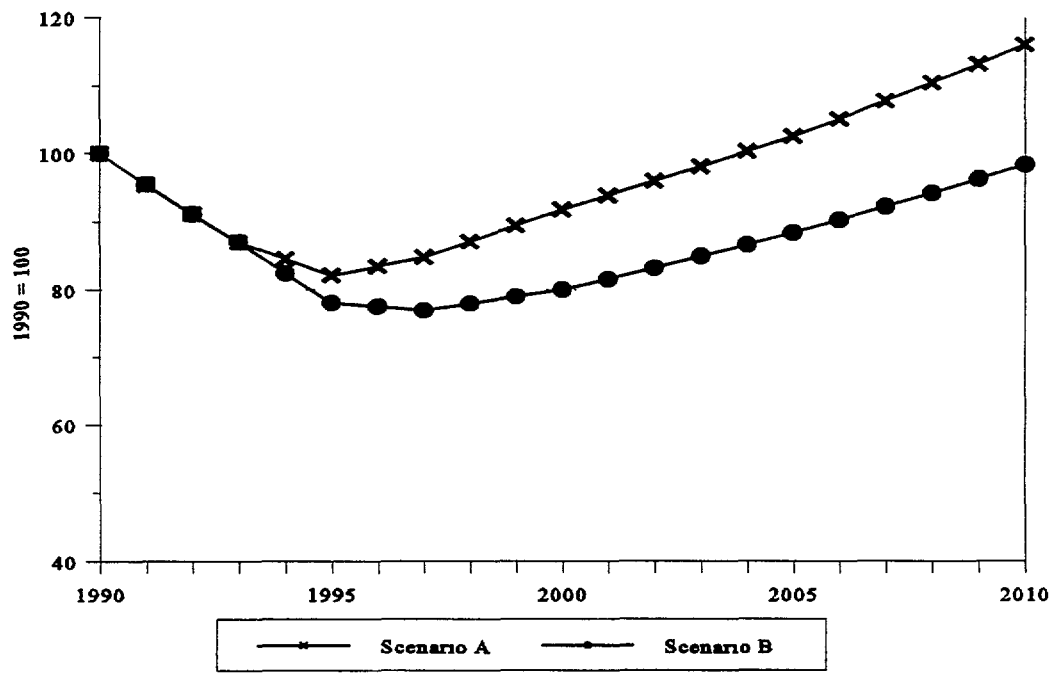
2 These figures are not corrected for climatic conditions

2 5%, and by the year 2010, it is 19% above 1990 levels Scenario B shows a deeper and longer decline in electricity consumption In this scenario, consumption does not begin to rise again until 1998 It is not until after the year 2000 that growth rates average 2%, and by the year 2010, electricity consumption just reaches 1990 levels

19 The opportunities for electricity conservation measures appear to be substantial The electricity demand estimates embody energy conservation measures in the two scenarios Scenario A, with higher macroeconomic growth rates (and higher prices and investment levels), embodies more energy conservation than does Scenario B

Figure 1-3
Projected Trends in Electricity Demand



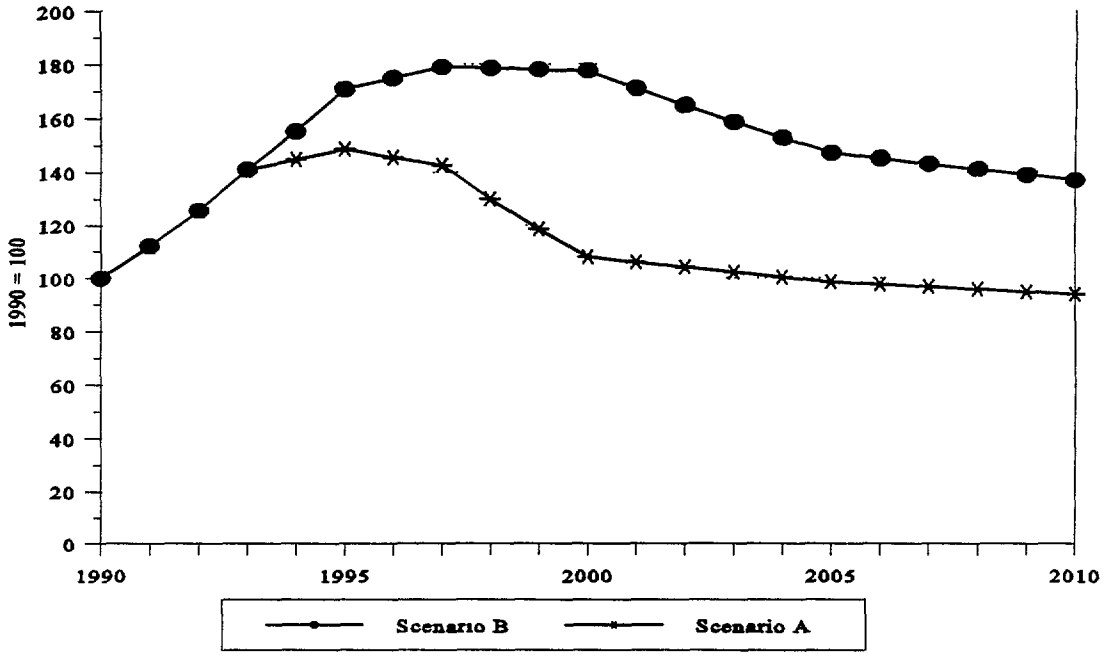
Note

Base year for the two demand scenarios is 1993

20 Therefore, as shown in Figure 1-4, there is a rapid decline in electricity intensity after 1995 in Scenario A, where electricity intensity peaks at about 50% above 1990 levels By the year 2010, it shows the Russian economy as less electricity intensive than in 1990 This pattern of electricity intensity is similar in nature to the experiences of East European countries, where electricity intensity increased rapidly after reforms were implemented, but also rapidly fell after several years of reform efforts Scenario B, on the other hand, shows a much higher and longer rate of increase in electricity intensity, which peaks at 80% over

1990 levels in the year 2000 After this point, electricity intensity gradually declines, but is still 37% above 1990 levels in 2010

Figure 1-4
Projected Trends in Electricity Intensity



21 Table 1-1 shows the projections for total centralized heat demand for the two scenarios (as given in the *Russian Energy Strategy*, as well as the share of this heat demand that is to be met by the power system

Table 1-1
Projected Requirements for Heat from Centralized Sources and the Power Sector
(Million Gigacalories)

	1993	1995	2000	2010
Scenario A				
Total Requirements for Centralized Heat	1 950	1,880	1 950	2 050
Of Which Heat Supplied by the Power Sector	940	890	905	1 010
Scenario B				
Total Requirements for Centralized Heat	1,950	1 850	1,870	1 900
Of Which, Heat Supplied by the Power Sector	940	880	855	905

1.5 ELECTRICITY DEMAND BY REGION

22 Russia's Integrated Power System is composed of seven regional power systems, six of which are inter-connected through a transmission network with intertie lines rated at 330 kV and above The power systems were developed as relatively independent grid systems, with little exchange of power among them The strongest interconnection was formerly between the Center system and the North-West and South systems The South system used to be a part of the Unified Power System of the former Soviet Union, but now comprises the power system of Ukraine Three power systems -- Center, Urals, and Siberia -- together accounted for 75% of Russia's electricity consumption in 1991 The Center is the largest electricity-consuming region in Russia, accounting for 28% of electricity consumption, followed by the Urals system (26%) and Siberia (22%)

23 The structure of electricity consumption in the Integrated Power System is shown in Table 1-2 There are some variations in consumption patterns among these systems The Siberian and Urals systems have the highest relative levels of industrial consumption (70 0% and 65 1%, respectively), while the North Caucasus system has the lowest (45 5%)

Table 1-2
Structure of Final Electricity Consumption, Russia and Regional Power Systems in 1991

	Industry	Agriculture	Transport	Commercial/ Service	Residential
Russia as a whole	61 1%	7 8%	10 8%	10 9%	9 5%
North-West	59 4%	6 2%	4 9%	18 9%	10 6%
Center	54 0%	9 4%	10 2%	15 0%	11 4%
Middle Volga	57 0%	10 3%	13 4%	9 3%	10 0%
North Caucasus	45 5%	15 4%	7 6%	14 8%	16 7%
Urals*	65 1%	6 7%	12 9%	8 0%	7 3%
Siberia (1990)	70 0%	6 6%	9 3%	6 7%	7 3%
Far East	n a	n a	n a	n a	n a

* Includes Tyumen Power System
n a - not available

24 There are only slight variations in per capita levels of electricity consumption in the residential sector across the Integrated Power System, ranging from a low of 480 kWh per capita in the North-West system, to 550 kWh in the Center, and to 650 kWh per capita in the Urals system

25 The two scenarios both suggest slight shifts in regional consumption patterns In Scenario A (Table 1-3), the North-West power system increases from 6 7% to 7 1% of the Integrated Power System total, and the Far East increases from 3 0% to 3 2%, while there is a decrease in the share of Siberia (19 9% to 19 4%) Under Scenario B (Table 1-3), the largest power-consuming region, the Center, declines slightly from 28 9% of the Integrated Power System's consumption in 1990 to 28 3% in 2010, there is also a very slight decline in the Middle Volga (10 1% to 9 8%), and slight increases in Siberia (19 9% to 20 8%) and the Far East (3 0% to 3 2%)

Table 1-3
Equivalent Full Load Hours and Load Maximum

	Equivalent Full Load Hours	Load Maximum, GW				
		1993	1995	2000	2005	2010
Scenario A						
Integrated Power System	6 118	138 7	138 3	155 1	173 4	201 7
North-West	5 900	9 6	9 8	11	12 5	14 9
Center	5,900	42 2	41 6	46 8	52 2	59 8
Middle Volga	6 200	14 4	13 8	15 3	16 9	19 7
North Caucasus	5 800	9 1	9 1	10 2	11 6	13 8
Urals	6 400	31 3	24 2	27 8	30 9	35 9
Tyumen Power System*	6,500	n/a**	7 6	8 6	9 5	11 1
Siberia	6 450	26 6	27 2	29 3	32 6	37 2
Far East***	5,300	5 5	5 0	6 0	7 2	9 2
Scenario B						
Integrated Power System	6 502	138 7	123 9	126 8	140 2	159 8
North-West	6 200	9 6	8 9	9	10	11 3
Center	6 200	42 2	37 4	38 2	42	47 4
Middle Volga	6 400	14 4	12 8	13 0	14 3	15 9
North Caucasus	6 200	9 1	8 1	8 2	9	10 3
Urals	6 800	31 3	21 8	22 3	24 7	28 8
Tyumen Power System*	7,000	n/a**	6 7	7	7 9	9 1
Siberia	7 000	26 6	16 5	24 4	27 1	30 9
Far East**	5 500	5 5	4 5	4 6	5 2	6

* Part of the Urals regional power system
** 1993 data for Tyumen are included in the Urals data
*** The system is isolated from the IPS and it has its own load maximum

26 Per capita electricity consumption in the Urals system is close to the average levels in the United States In 1991, its per capita electricity consumption was 9,650 kWh,[3] while that of the United States (1990) was 11,400 kWh Industrial electricity consumption the Urals (again, measured per capita) was almost twice the U S level

[3] This data set has not been adjusted to OECD format while it does not include the in-plant use of electricity or line losses it does include electricity use in the fuel sector and for pipeline transport

27 Industrial electricity use is quite concentrated in the Urals, Center, and Siberia power systems (over 75% of industrial electricity use among the power systems) Almost 40% of electricity use by the metallurgical industry in the Integrated Power System is consumed within the Siberian system, followed by the Urals (37%) The Center region accounts for 45% of the Integrated System's electricity use in the machinery industry (followed by the Urals system, with 23%) Of the major electricity-consuming industrial branches, only the chemical industry is distributed rather evenly across regions (Center 27%, Middle Volga 22%, Siberia 21%, and Urals 19%)

28 The changes forthcoming in electricity consumption patterns in all of Russia and in the power systems will influence electric load patterns Scenario A envisages greater shifts in the structure of electricity consumption, with a smaller share of industrial and a greater share of residential consumption Therefore, the load duration curve for this scenario is less "dense" for all of the power systems, with the number of equivalent peak load hours down from 6,502 to 6,118 hours/year for the Integrated Power System In Scenario B, on the other hand, there are no further changes in electricity consumption structure, and the number of equivalent peak load hours is taken at today's levels (6,502 hours/year) which is, nevertheless, considerably lower than the 1990 levels

29 Because six of the seven Russian power systems work as parts of the Integrated Power System, they have a common load curve and load peak Usually, it takes place at approximately 6 p m Moscow time in late February The yearly load maximum for the Far East power system, which works separately from the Integrated Power System, takes place at approximately the same hour local time Table 1-3 shows the values for load maximum and its duration that were used in the calculations for the Integrated Power System and the regional power systems within it

CHAPTER 2
ELECTRICITY SUPPLY

2.1 THE ELECTRIC POWER SECTOR OF RUSSIA

2 1 1 Background on the Power Sector and its Structure

1 Russia's power sector is based on a range of diverse technologies and fuels Fossil-fired plants provide the bulk of electricity capacity and generation, followed by hydroelectric and nuclear plants Cogeneration plants comprise almost 50% of fossil-fired capacity, the secondary heat and hot water from these plants are sent through extensive distribution systems to industrial, commercial, and residential consumers

2 Almost all of Russia's power plants were managed centrally, approximately 10 GW of capacity (less than 5% of total capacity) were held outside of the main power sector ministries or organizations These power plants, which are located primarily at large industrial facilities, are powered almost exclusively by fossil fuels

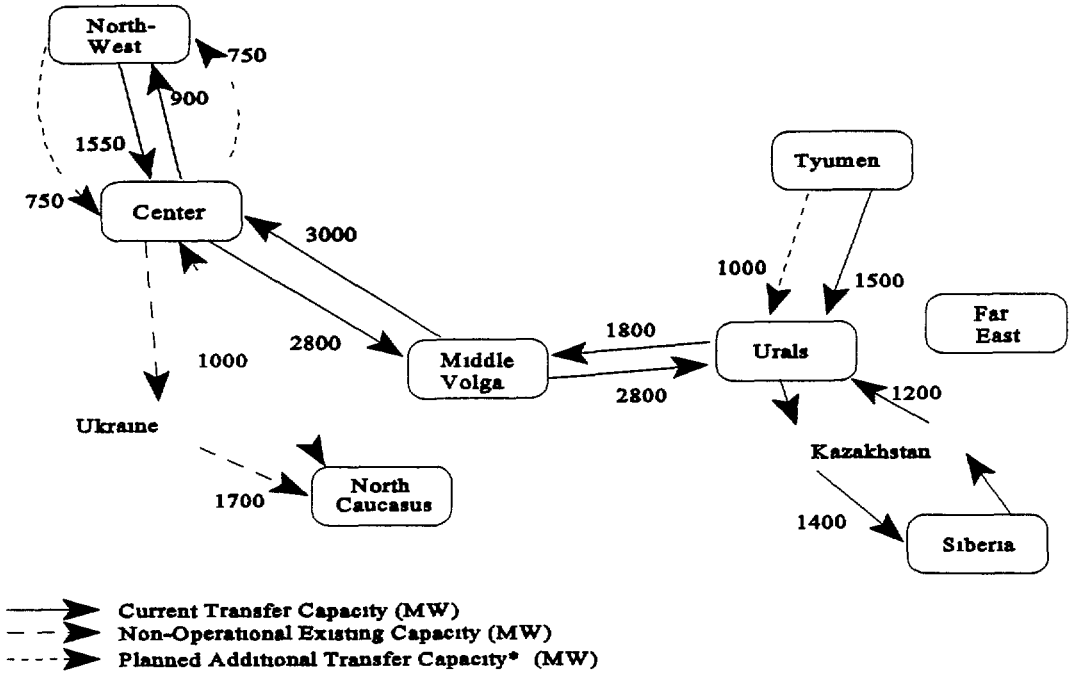
3 The Integrated Power System (IPS) of Russia represents a subset of Russia's capacity, not all of the country's power plants and regions are integrated into the IPS The Integrated Power System consists of six large unified regional power systems (North-West, Center, Middle Volga, North Caucasus, Urals (including Tyumen), and Siberia) plus the Far East, which is only weakly linked (see Figure 2-1) There are 65 local electricity administrations that operate in conjunction with the Integrated Power System, and 7 local electricity administrations are located in remote regions (such as Kamchatka, Magadan, and Sakhalin) that are not connected to the IPS

4 A series of steps have been taken to bring the power sector in line with the market reforms taking place in the rest of the economy The changes in the ownership and structure of the power sector were formulated in three presidential decrees

- Decree #922 (August 14, 1992) "On Particulars of Transforming State Enterprises, Associations, and Organizations of the Energy Sector into Joint-Stock Companies"

- Decree #923 (August 15, 1992) "On the Organization of Management of Electric Power Sector of the Russian Federation Under Conditions of Privatization"

Figure 2-1
Power Transmission Capacity Among IPS Regions in Russia



Note *Includes planned and work under construction to be operational by 2000

- Decree #1334 (November 5, 1992) "On the Implementation of the Electric Power Sector Decree #922 "

5 During the second half of 1992, the Russian State Property Committee created a new Russian joint stock company "RAO EES Rossii" as a holding organization for certain power sector enterprises, and the assets of the Integrated Power System were split between RAO EES Rossii and other administrative units RAO EES Rossii was assigned direct responsibility for transmission lines of 330 kV and higher, substations and dispatch centers, fossil-fired power stations over 1,000 MW capacity, and hydroelectric power plants greater than 300 MW RAO EES Rossii holds 46 fossil-fired plants and 37 hydroelectric plants These plants represent just over 40% of Russia's fossil-fired capacity, and 60% of its hydroelectric capacity The remaining capacity and distribution lines are owned by joint stock companies formed on the basis of local electricity administrations (now called AO Energos) RAO EES Rossii holds a financial stake in the AO Energos as well (at least 49%), although the actual share varies among the AO Energos RAO EES Rossii also owns 100% of various research and design institutes and a trust that in turn

owns 49% of the nation's electric power construction and machine building enterprises RAO EES Rossii's largest shareholder is the Government of the Russian Federation, which by statute must retain at least a 49% interest in RAO EES Rossii for a three-year period ending in 1995

6 It has been decided that further reform of the power sector is needed introduce competition and improve the industry's efficiency A uniquely Russian approach is being developed in which a wholesale power market is an essential component of the final structure The basic approach is in many respects similar to the electricity industry in the United Kingdom The key policy features include

- A national wholesale market based on competitive biddings
- Unbundling the ownership of generation and transmission, with privatization of RAO EES Rossii's thermal and hydro generation
- Direct access by large customers to the wholesale market
- Efficient, system-wide dispatch of generation
- An efficient system of national and regional regulation to preserve competition, regulate monopoly activities, and protect electricity consumers
- Encouragement of independent private power producers

7 During the second half of 1992, Rosenergoatom was set up under the Ministry of Atomic Energy to manage the operation of commercial nuclear reactors Under Rosenergoatom's management are 16 2 GW of nuclear capacity, while the 4 GW Leningrad Nuclear Plant operates directly under the Ministry of Atomic Energy

8 While generation from nuclear power holds a relatively small share of total generation in Russia (about 11%), nuclear plants play an important role in electricity production in the North-West, Center, and Middle Volga power systems (32%, 21%, and 14% of generation, respectively)

2.1 2 Economic Regulation

9 Economic regulatory authorities (Federal and Regional Energy Commissions) control electricity tariffs Safety, health, and environmental regulatory authorities have guidelines and regulations that affect the technology choice, timing and cost of new plant upgrades and rehabilitation

10 The legal framework for the power sector is taking shape as the government manages the transition of the sector to a market orientation At the federal level, the Federal Energy Commission (FEC) has authority over all wholesale power tariffs As a result of a March 1, 1995 Presidential Decree, the FEC is being transformed into an independent regulatory

body with full-time commissioners and paid staff Because the Government of Russia owns most of RAO EES Rossii's shares, the Ministry of Fuels and Power also represents the government's interests as a shareholder At the regional level, each regional government has established a Regional Energy Commission (REC) to set the level of tariffs to electricity consumers District heat prices and billing are controlled by municipal housing authorities Wholesale prices for power plants that belong to AO Energos and retail prices are set by the RECs The FEC determines the wholesale tariffs for power plants that are 100% owned by RAO EES Rossii Electricity tariffs are set to reflect the full cost of production, including environmental and investment costs, and to allow for a reasonable return RAO EES Rossii does not earn any profits per se Rather, it charges a "user's fee" to cover transmission costs, the operation of dispatch, salaries of workers, and network development Residential tariffs are currently set below cost, which results in higher tariffs for industrial customers

11 The Ministry of Atomic Energy has direct responsibility for the development of nuclear power plants The operation and maintenance of these plants is the responsibility of Rosenergoatom GosAtomNadzor, (Federal Nuclear and Radiation Safety Authority), is responsible for overseeing the licensing and safety practices for the construction and operation of nuclear power plants

12 The Government Property Committee is responsible for the property management (and hence privatization) of all but the nuclear power plants The Anti-Monopoly Committee has the legal authority to prevent the abuses of monopoly power There is not yet any institution with the regulatory authority to ensure reliable financial information and transparency, although a major source of investment risk in Russia is the absence of a regulatory authority to protect the interests of investors

2 1 3 Environment and Safety

Air Quality

13 The basis for the Russian environmental protection regime is the Law on Environmental Protection, which went into force in March 1992 This law replaced the previous law On Protection of Nature in the RSFSR, which had been effect in the Soviet Union since 27 October 1990 The new law is comprehensive, relatively strict, and oriented toward a market economy It lays out the principles that guide environmental protection in Russia and delineates the division of responsibilities among the Supreme Soviet of the Russian Federation, the Russian Government, state organs, the republics and autonomous administrations, and local governments It also makes provisions for the following 1) emissions standards for air pollution, water pollution, and solid waste disposal, 2) a permit system, 3) pollution fees for the use of natural resources or for the emissions of pollutants, and 4) an Environmental Fund A very distinctive element of

Russian environmental efforts is that pollution fees are the principal source of revenues for activities to promote environmental quality

14 While Russia has made enormous strides in developing a regulatory structure for environmental protection, its impact is severely limited by enforcement problems, in large part because Russian environmental law does not set a clear procedure for enforcing certain standards To complicate matters further, there is no clear delineation of the spheres of authority of government agencies in relation to economic entities, and in many instances there is conflicting jurisdictional authority between ministries, which often results in inaction

Nuclear Safety

15 Russia is implementing measures to enhance engineering and operational safety at its nuclear power stations RBMK and first-generation VVER reactors were designed and built before Russia promulgated its current safety standards The areas of weakness include inadequate instrumentation and control systems, lack of emergency power, insufficient fire protection and fire fighting systems, inadequate operator training facilities, and lack of containment (These are discussed in greater detail in Appendix G) Since 1990, much work has been done to improve the situation at first-generation plants considered to represent the highest risk One issue studied is how the first-generation plant upgrades compare with other supply- and demand-side alternatives Safety upgrade alternatives considered in this Study were proposed by Russian design engineers and include measures prepared for the International Users' Group (published by WANO[1]) as well as additional containment measures These measures will bring safety levels closer to safety levels in reactors currently operating in the west

2 1 4 The Power Sector's Financial Situation

16 The present financial situation of the Russian power sector is difficult Overall economic conditions in the country have had an adverse effect on utilities' operations, leaving them without sufficient working capital or investment funds There are three major financial pressures on power sector enterprises non-payments by customers, excessive taxation, and inflation

Non-Payment Crisis

17 Due to the economic downturn and lack of adequate enforcement mechanisms, non-payment for electricity has reached nearly 50% of total billing Uncollected electricity bills amounted to 15 trillion rubles as of year-end 1994 Because accounts receivable are not

1 World Association of Nuclear Operators

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indexed for inflation, the real value of accounts receivable declines over time This crisis requires utilities to put all their cash into working capital, including cash from that part of the electricity tariff designated for investment purposes Even this does not insulate utilities from critical shortages of funds In 1994, the Russian power sector supplied electricity valued at 24 6 trillion rubles ($12 4 billion), but was paid only 10 3 trillion rubles ($5 3 billion) and owed its suppliers 8 2 trillion rubles ($4 1 billion) Of this, only 1 7 trillion rubles ($0 9 billion) were available for investment in power sector capital

18 The Government of Russia and RAO EES Rossii fully understand the payments crisis and the need for the power sector to generate sufficient cash flow, not only to cover its operating expenses but also for investment Actions they have taken include increasing the non-cash component of payments (e g , direct debiting from bank accounts) and implementing a variety of penalty, incentive and customer credit programs

Taxes and Accounting Rules

19 Russian power sector enterprises pay 23% value-added tax on their revenues After deducting costs and expenses, their tax obligation (income tax, royalties, other taxes and payments to the budget, local taxes) on net income is about 50% Such a fiscal burden leaves no funds for investment

20 Further, utilities in Russia suffer from double taxation imposed by the Ministry of Finance through its accounting rules Russian accounting standards do not allow for the consolidated reporting of financial statements for taxation purposes In the regulated industries in Russia, taxes are included in tariffs Obviously, eliminating double taxation would reduce tariffs for end users, consistent with the government's goals

21 Revaluation of fixed assets to reflect current market conditions and increases in depreciation allowances are priorities for improving utilities' reinvestment capabilities

The Fight Against Inflation

22 The government has taken aggressive steps to control and reduce inflation The major negative impact of inflation is recognized in its effect on enterprises' access to short-term credit and the virtual elimination of long-term credit

2 1 5 Factors Affecting the Power Sector's Future Development

Electric Generating Capacity Requirements

23 The Russian power sector is undergoing radical change, and it is necessary to explore reliable and efficient ways of restructuring it It is very important to evaluate the external

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and internal factors that affect power sector development in Russia so that the most rational options for restructuring can be selected The most important factors are as follows

- In the past few years there has been a decline in electricity and heat consumption This trend is expected to be followed by "wave-like" patterns of rising and falling electricity and heat consumption

- In the transition of the Russian economy towards a market basis, relative costs are changing dramatically In this new environment, traditional notions about power plant cost competitiveness in different regions of Russia may not be valid

- The environmental requirements and expenses associated with the use of natural resources (e g , land, water) and environmental protection have risen dramatically and continue to rise The most difficult environmental challenge for the power sector is to meet emission standards

- There is a rapidly growing number of thermal generating units that have reached the end of their service life and should either be decommissioned or upgraded

- Although the service lives of RBMK and first-generation VVER reactors have not expired, these units do not meet the current safety requirements Consequently, there is an urgent need to upgrade these units or decommission them early

2.2 THERMAL PLANTS

2 2 1 Installed Capacity

24 The 135,700 MW of thermal power plants in Russia's IPS vary widely in their station configuration, power block size, fuel type, thermal cycle, age, etc As much as 79,000 MW (58%) of this capacity will reach the end of its design life by the year 2010 The existing installed capacity of thermal power plants in Russia is distributed geographically from the northwestern part of the country (St Petersburg) to the far eastern region The plants fire a range of fuels including natural gas, mazut and a variety of coals, frequently depending on the fuel available in the region

25 Table 2-1 presents an inventory of existing thermal power plants by the type of fuel fired The majority of these boilers are fired by natural gas alone, or with either mazut or

high-grade bituminous coal as a backup fuel Where both natural gas and mazut are indicated as the fuel types, about 92% of the heat input (annual basis) is from natural gas, while the remaining 8% is from mazut Where high-grade bituminous coal is used as a backup to natural gas, about 80% of the heat is generated by firing natural gas, while 20% comes from coal (primarily during the winter months) Coal firing is possible because the boilers were originally designed to fire coal but were subsequently converted to gas firing

26 The remaining installed existing capacity is fired by coal (whose quality varies from low-grade lignite to high-grade bituminous, depending on the location of the power plant) Approximately 46% of the existing units are of the condensing power plant (CPP) type, while the remaining units are of the combined heat and power plant (CHP) type

Table 2-1
Total Existing Capacity of Thermal Plants by Fuel Type

Fuel	Total Existing Capacity (MW)	Total Existing Capacity (%)
Natural Gas	1,070	0 8
Natural Gas/Mazut	77,662	57 2
Natural Gas/High-Quality Bituminous	9 956	7 3
High-Quality Bituminous	5 567	4 1
Low-Quality Bituminous	10,684	7 9
High-Quality Lignite	13 107	9 7
Low-Quality Lignite	17 661	13 0
Total	135 707	100 0

27 Table 2-2 presents the same inventory as a function of unit type The existing plants utilize steam boilers to generate power, although some new committed plants will utilize gas turbines in the more efficient combined cycle configuration

Table 2-2
Total Existing Capacity of Thermal Plants by Unit Type

Unit Type	Total Existing Capacity (MW)	Total Existing Capacity (%)
CPP	63,006	46 4
CHP	72,701	53 6
Total	135,707	100 0

28 Table 2-3 presents an inventory of the existing thermal power plants by region More than 67% of these plants are located in three regions -- Center, Urals, and Siberia -- which are the major regions of power production and consumption within Russia

Table 2-3
Total Existing Capacity of Thermal Plants by Region

Region	Total Existing Capacity (MW)	Total Existing Capacity (%)
North-West	6 585	4 9
Center	41 326	30 5
Middle Volga	13,483	9 9
Urals	28,278	20 8
Tyumen	9,690	7 1
North Caucasus	8 329	6 1
Siberia	22,299	16 5
Far East	5,717	4 2
Total	135 707	100 0

29 Tables 2-4 and 2-5 present full-load net plant heat rates for the existing plants as a function of fuel fired for both CPP and CHP plants The heat rates for CPPs are presented as a function of both fuel fired and unit size, since size has a significant impact on heat rate, and include CPP units as large as 1,200 MW Net plant heat rates for CHP units are given for all operating seasons since there is a significant seasonal variation Because the

CHP units are relatively small, size is not a significant criterion For more detailed information, refer to Appendix F

Table 2-4
Estimated Net Plant Heat Rates for Existing Thermal Plants
(Condensing Power Plants Only)

	Full Load Net Plant Heat Rate (Btu/kWh)	
Fuel Fired	**Natural Gas/Mazut**	**Coal**
Large Units (≥ 300 MW)	8,600 - 9,000	9,100 - 9,700
Medium Units (150-299 MW)	8 800 - 9 200	9 300 - 10 000
Small Units (< 150 MW)	9,400 - 9,700	10 300 - 10 800

Table 2-5
Estimated Net Plant Heat Rates for Existing Thermal Plants
(Combined Heat and Power Plants Only)

	Full Load Net Plant Heat Rate (Btu/kWh)	
Fuel Fired	**Natural Gas/Mazut**	**Coal**
Winter	5,000 - 5 200	5 700 - 6,100
Spring/Fall	5 900 - 6,100	6,800 - 7,300
Summer	6,800 - 7 000	7 700 - 8,300

30 Table 2-6 presents estimated operating costs for these existing plants as a function of fuel fired and unit size for both the CPP and CHP plants Operating costs were estimated in accordance with Electric Power Research Institute's (EPRI) Technical Assessment Guide (TAG) procedures, as described in Chapter 3, and include both the fixed and variable components Costs are presented in 1994 dollars For more detailed information, refer to Appendix F

Table 2-6
Estimated Operating Costs for Existing Thermal Plants
(Excluding Fuel)

	Fixed Operating Costs $/kW/yr	Variable Operating Costs $/MWh
Natural Gas/Mazut-Fired Units		
Large CPPs (≥ 300 MW)	5 10 - 13 10	0 65 - 0 85
Medium CPPs (150-299 MW)	12 50 - 15 80	0 95 - 1 00
Small CPPs (< 150 MW)	17 80	1 20
CHPs	33 00	1 25 - 1 50
Coal-Fired Units		
Large CPPs (≥ 300 MW)	8 85 - 14 75	1 35 - 1 40
Medium CPPs (150-299 MW)	16 05 - 16 70	1 50 - 1 60
Small CPPs (< 150 MW)	20 45	1 90
CHPs	37 60	5 15

2 2 2 Reliability and Availability

31 Forced and planned outage rates for the existing thermal plants were estimated and are presented in Appendix F and Table 2-7 The estimates were based on a computerized database of thermal power plant availability produced by the North American Electric Reliability Council (NERC) Availability statistics were compiled for both coal- and gas-fired units of varying thermal capacities and varying years of service These were applied to specific Russian unit types with similar characteristics

Table 2-7
Estimated Plant Outage Rates for Existing Thermal Plants

Unit Type	Forced Outage Rate (%)	Planned Outage Rate (%)
Older Units (to be retired by 2010)		
Large CPPs (≥ 300 MW)	11 0 - 18 1	12 2 - 17 9
Medium CPPs (150-299 MW)	9 8 - 14 0	12 2 - 13 0
Small CPPs (< 150 MW)	9 0 - 9 3	11 0 - 11 8
CHPs	9 0 - 9 3	11 0 - 11 8
Newer Units (not subject to retirement by 2010)		
Large CPPs (≥ 300 MW)	9 0 - 9 5	12 2 - 13 5
Medium CPPs (150-299 MW)	6 3 - 12 8	12 2 - 13 0
Small CPPs (< 150 MW)	6 0 - 6 8	10 5 - 11 8
CHPs	6 0 - 6 8	10 5 - 11 8

2.2 3 Retirement Program

32 Approximately 79,000 MW of thermal plant capacity are scheduled for retirement between the years 1994 and 2010 Table 2-8 presents the distribution of this capacity as a function of retirement date by region The total distribution of capacity to be retired is fairly uniform over the 15-year period, excluding a large number of plants that have already passed their projected retirement date and are described as 1994 retirements Based on this distribution, it is apparent that a program for rehabilitation or life extension must be established as soon as possible because almost 17% of the boilers have already passed their projected retirement date More than 68% of the retiring capacity is located in the Center, Urals, and Siberia regions As previously mentioned, these are the three major power production regions in Russia

Table 2-8
Capacity of Thermal Plants Subject to Retirement by Region (MW)

Retirement Date	1	2	3	4	5	6	7	8	Total Cap
1994	387	2 828	1 137	4,015	39	1,910	2 907	113	13,336
1995-1998	318	3 154	2 257	4,692	40	1 607	2 011	215	14 294
1999-2002	1,142	5,564	1,854	3,742	231	1,161	3,045	669	17 410
2003-2006	885	5 025	1 671	5 984	1,260	1 148	1 256	811	18 040
2007-2010	1 750	6 752	2 108	1 565	1,062	607	1 637	344	15 825
Region Total	4 482	23,323	9,027	19,998	2,632	6,435	10,856	2 152	78 905
% of Total Thermal Retiring Capacity	5 7	29 6	11 4	25 3	3 3	8 2	13 8	2 7	100 0
% of Total Existing Thermal Capacity to be Retired	68 1	56 4	67 0	70 7	27 2	77 3	48 7	37 6	58 1

Key
1 = North-West
2 = Center
3 = Middle Volga
4 = Urals
5 = Tyumen
6 = North Caucasus
7 = Siberia
8 = Far East

33 Table 2-9 presents the distribution of the retiring capacity as a function of retirement date by fuel type Nearly 65% of the retiring capacity is currently provided by natural gas-fired units, with the remaining capacity provided by coal-fired units

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Table 2-9
Capacity of Thermal Plants Subject to Retirement by Fuel Type (MW)

Retirement Date	NG	NG/M	NG/BH	BH	BL	LH	LL	Total Cap
1994	300	4 337	907	1,935	3,504	470	1 883	13 336
1995-1998	150	6,962	1,051	1,132	2,259	1 443	1,297	14,294
1999-2002	0	10,831	1 401	1 900	10	1,734	1,534	17 410
2003-2006	0	10,623	1,075	0	2,982	650	2,710	18 040
2007-2010	0	11 298	1 935	0	385	711	1 496	15 825
Total	450	44,051	6 369	4 967	9 140	5 008	8,920	78 905
% of Total Thermal Retiring Capacity	0 6	55 8	8 1	6 3	11 6	6 3	11 3	100 0

Key NG = natural gas; M = mazut; BH = high-quality bituminous; BL = low-quality bituminous; LH = high-quality lignite; LL = low-quality lignite

34 Table 2-10 presents the distribution of plant capacity subject to retirement by unit type About 50% of the 79,000 MW capacity that will reach the end of its design life by 2010 is in combined heat and power plants, with the remaining 50% in condensing power plants The number of CHP units/boilers scheduled for retirement will be greater than that of CPPs due to their smaller unit capacity

Table 2-10
Capacity of Thermal Plants Subject to Retirement by Unit Type (MW)

Retirement Date	CHP	CPP	Total Cap	% of Total
1994	6,108	7,228	13,336	16 9
1995-1998	7,793	6,501	14,294	18 1
1999-2002	10,222	7,188	17 410	22 1
2003-2006	11,671	6,369	18,040	22 8
2007-2010	4 057	11 768	15 825	20 1
Total	39 851	39,054	78 905	100 0
% of Total Retiring Cap	50 5	49 5	100 0	

2 2 4 Fuel Resources

Coal Supply

35 The Russian coal industry is characterized by low productivity and an inability to operate without subsidies, even though market pricing has been allowed since July 1993 The industry continues to receive subsidies for labor, capital, operating, and social costs that total about 2% of Russia's GDP Recent studies have indicated that the short-run demand for coal will likely continue to decline, and that many operating mines are not viable under expected demand and forecasts of rail prices to transport coal

36 Two scenarios were developed for total coal production, which are given as percents of 1993 production In the high scenario, total production would decline to 88% of 1993 production by 2000, then grow to 106% of 1993 production by 2010 In the low scenario, production would decline to 82% of 1993 levels by 2000, but recover to only 98% by 2010 In 1993, domestic production (including stock build-up) was 212 mt of steam coal

37 These coal production figures were used to roughly estimate Russia's coal-fired electricity generation from 1995 to 2010 These estimates do not consider improvements in the efficiency of coal use Table 2-11 shows the estimated coal-fired electricity generation that corresponds to the production figures given in the *Russian Energy Strategy*

Table 2-11
Coal-Fired Electricity Generation (bkWh)

Scenario	1990	1992	1995	2000	2005	2010
High	350	307	302	302	333	364
Low	350	307	285	285	310	336

Coal Pricing

38 The long-run costs of coal production in each basin were estimated in September 1994 to evaluate which coals and coal regions are likely to be viable in 2010, and are thus likely to supply the electricity sector as it is rebuilt Because incentives that were created under the Soviet system and persist today can distort investment and production decisions, market conditions were assumed when developing these cost estimates The estimates are thus based on the geological and quality characteristics of the coals, as described in Russian data, and not on current operating or investment practices

39 Estimated unit costs for coal vary significantly by region In Siberia (both North Siberia and East Siberia) coal costs were estimated to be lowest By contrast, coal in the Far East was estimated to be among the most costly

40 On the basis of geology, two basins provide outstanding opportunities to produce significant volumes of low-cost coal Kuzbass and Kansk-Achinsk When used locally, these coals have relatively low production costs and compare favorably to commercial (i e , unsubsidized) operations in other countries

41 At least one coal was identified for each basin on the basis of quality characteristics (energy, ash, sulfur, moisture content, and volatility) Where coal quality varies in a basin, multiple coals were identified to clarify whether one type of supply would offer cost and operating advantages over others Transportation rates were also estimated on the basis of U S costs for hauls of varying lengths Special attention was given to identifying each of the coals to be used in the modernized plants costed in this study and to provide a delivered cost for each coal and each market called for in the Joint Electric Power Alternatives Study (JEPAS)

42 In the JEPAS reference cases, fuel prices were assumed to be based on Energy Research Institute (ERI) calculations of the "full cost of production basis " This means that the cost includes all production costs (without subsidies), and that transport carriers are priced at full cost

Natural Gas Supply

43 The *Russian Energy Strategy* presents two scenarios for natural gas production in Russia through 2010 These scenarios are shown in Table 2-12

Table 2-12
Scenarios for Natural Gas Production (1990-2010, bcm)

Scenario	1990	1993	1995	2000	2010
High	640	618	630	740	860
Low	640	618	615	660	740

44 Of the 120 billion cubic meter (bcm) increase in production between 1993 and 2010 that is envisaged in the low scenario, only 25 bcm are expected to reflect increased exports The remainder represents increased domestic consumption and is expected to be available for the power sector In fact, the constraint on domestic natural gas supply is not considered to be the size of the resource base, which is vast in Russia in terms of both proven and estimated reserves Rather, price is the main constraint Accordingly, the analysis of using natural gas for power generation in Russia was based on its price projections

Natural Gas Pricing

45 The Energy Research Institute prepared two scenarios of natural gas prices, one based on the full costs of production and the other reflecting world natural gas price levels (Table 2-13) The latter levels were based on the International Energy Agency's European import prices from the *1993 World Energy Outlook* Prices were adjusted to reflect transport costs in both scenarios

Table 2-13
Price Scenarios for Natural Gas (1994 $/tce)

Region	Full Cost 1996-2000	World 1995	Full Cost 2001-2005	World 2000	Full Cost 2006-2010	World 2010
Moscow	43	47	65	71	75	88
North-West	45	48	67	72	77	90
North Caucasus	47	49	74	76	81	93
Volga	40	45	62	66	70	84
Urals	36	42	54	61	64	78
North Tyumen	16	23	32	40	40	51
North Siberia	35	40	52	59	62	74
East Siberia	46	42	60	68	72	84
Khabarovsk	70	60	90	93	100	107
Far East	-	-	-	-	-	-

2 2 5 Environmental Issues

46 Russia has strict environmental standards, but they are often ignored in practice Most existing generating capacity was built before current emissions standards were enacted, although new standards will be applicable when plants are modernized Older plants produce most emissions in Russia In 1992, thermal power plants operated by the Ministry of Fuel and Energy produced 20% of all emissions from stationary sources in Russia The most common pollutants are sulfur dioxide, nitrous oxide, carbon dioxide, and ash Because of reduced electricity output and the use of more efficient emissions control technology, emissions in 1992 were slightly less than the 7 05 million tonnes produced in 1991 However, only half of the thermal power plants stayed within the limits set forth in their emissions permits Table 2-14 shows SO_2, NO_2, and ash emissions for 1990, 1991 and 1992

Table 2-14
Primary Air Pollutant Emissions from Power Generation in Russia
(million of tonnes)

Pollutant	1990	1991	1992
Ash	n/a	n/a	2
Sulfur Dioxide	3 18	3 06	2 7
Nitrogen Oxides	1 61	1 64	1 4

Source FBIS *State Report on the State of the Environment in the Russian Federation in 1991* JPRS-TEN-93-001-L 7 January 1993, and *the State Report on the State of the Environment in the Russian Federation in 1992* JPRS-TEN 94-0005 25 February 1994

47 Working Group 2 discussed emission limits for new units This Group 2 explained that although final standards for emissions had not yet been adopted, it was probable that such standards would be in place when the rehabilitation program was initiated Working Group 2 indicated that, based on available information, the emission standards for utility-size coal-fired boilers are as shown in Table 2-15

Table 2-15
Existing Russian Emission Standards

Pollutant	(mg/Nm^3)
Particulates	150
NO_x	240
SO_2	400

48 In developing rehabilitation proposals for the various categories of thermal plants, Working Group 2 assumed that the rehabilitation of existing facilities would require the application of appropriate emission control technologies For each category of boilers, Working Group 2 selected the most suitable Western emission control equipment, based on efficiency requirements and plant site limitations, and developed both investment and operating cost requirements to achieve the required emission limit

49 Subsequent to this program, in December 1994, the Russian Ministry of Nature approved draft emission standards for new thermal plants Unfortunately, these standards are not the same as the existing standards Draft standards are summarized in Table 2-16

Table 2-16
Draft Standards of Atmospheric Emissions
New and Reconstructed Boilers
(Boilers Larger than 300 MW)

	Emission Limit, mg/Nm³					
Fuel Fired	**Before 1 December 2000**			**After 1 January 2001**		
Natural Gas	NO_x	=	150	NO_x	=	125
Mazut	NO_x SO_2 Particulates	= = =	300 2000-3000 100-400	NO_x SO_2 Particulates	= = =	250 700 50-150
Lignite	NO_x SO_2 Particulates	= = =	370 2000-3000 100-400	NO_x SO_2 Particulates	= = =	300 700 50-150
Black Coal	NO_x SO_2 Particulates	= = =	540-700 2000-3000 100-400	NO_x SO_2 Particulates	= = =	390-570 700 50-150

50 These draft emission limits are, for the most part, less stringent than those used as the basis of this Study This is especially true for NO_x and SO_2 emission limits As a result, cost estimates reflecting the application of the more stringent limits are likely to be conservative

51 Still, the existing Russian thermal power generating units that are subject to retirement by the year 2010 cannot achieve these emission limits While the majority of boilers are equipped with some means of particulate collection (either electrostatic precipitators, mechanical collectors or wet scrubbers), the equipment is old and the design efficiencies may be lower than required to achieve the standards In recent years, some of the boiler combustion systems have been modified to reduce NO_x formation, but these modifications were usually insufficient to achieve the emission standard SO_2 control technologies have not been applied to any of the boilers and, as a result, SO_2 emissions remain uncontrolled Controls would be required to achieve the proposed 700 mg/Nm³ SO_2 emission standard

2 2 6 Planned Capacity Additions and Replacement

52 A program for constructing new condensing power (CPP) and combined heat and power (CHP) thermal units has been underway for the past several years, with planned commissioning dates beginning in 1994 While more detailed information is available in Appendix F, the following exhibits provide an adequate summary of the data Table 2-17 provides a breakdown by fuel type of the total capacity of new thermal power plants planned and under construction

Table 2-17
Total Committed Capacity of Thermal Plants by Fuel Type

Fuel	Total Committed Capacity (MW)	Total Committed Capacity (%)
Natural Gas/Mazut	1,594	9 9
Natural Gas	8,208	50 8
High-Quality Bituminous	3 205	19 8
Low-Quality Bituminous	930	5 8
High-Quality Lignite	590	3 7
Low-Quality Lignite	1 630	10 0
Total	16,157	100 0

53 It can be seen that some 16,000 MW have been planned (or committed) for construction About 60% of the planned capacity is to be fired with natural gas These units include combined cycle plants, gas turbines and gas-fired boilers The remaining units will be fired by a variety of solid fuels ranging from low-quality lignite to high-quality bituminous fuel

54 Table 2-18 presents a breakdown, by unit type, of the total capacity of new thermal power plants planned and under construction In addition to the power provided by CPP and CHP plants, 26% of the committed capacity will be provided by advanced gas turbine and combined cycle technologies

Table 2-18
Total Committed Capacity of Thermal Plants by Unit Type

Unit Type	Total Committed Capacity (MW)	Total Committed Capacity (%)
CPP	10,685	66 2
CHP	1,264	7 8
Gas Turbine	24	0 1
Combined Cycle	4,184	25 9
Total	16 157	100 0

55 Table 2-19 presents a breakdown of total committed capacity by region, with respect to unit type The distribution of new units varies significantly by region

- Siberia will be the site of the largest investment in new capacity (over 27%), with almost all new units firing solid fuel
- The Tyumen region will also be the site for major new investment (about 25%), but in this region all the new capacity will be fired by natural gas
- The North-West region will be the site of about 20% of the planned new capacity, with most of this capacity in natural gas-fired combined cycle, CHP installations
- These three regions account for almost 75% of the committed new fossil capacity

Table 2-19
Total Regional Committed Capacity of Thermal Plants by Unit Type (MW)

UNIT TYPE	1	2	3	4	5	6	7	8
CPP	630	1 260	0	930	4,000	0	3,865	0
CHP	0	0	310	0	0	0	614	340
Gas Turbine	0	0	0	24	0	0	0	0
Combined Cycle	2,700	0	0	0	0	1,484	0	0
Region Total	3,330	1 260	310	954	4 000	1,484	4 479	340
% of Total Cap	20 6	7 8	1 9	5 9	24 8	9 2	27 7	2 1

Key
1 = North-West
2 = Center
3 = Middle Volga
4 = Urals
5 = Tyumen
6 = North Caucasus
7 = Siberia
8 = Far East

56 Table 2-20 shows the annual investment (in millions of 1991 rubles) for committed thermal units by region through the year 1997 "Total Investment" refers to the total funds allocated for construction, while "Used Investment" refers to funds used as of January 1, 1994 Roughly 6,700 million rubles will be used to bring approximately 9,000 MW on line by 1997 Completion dates are not available for the remaining 7,000 MW of capacity Approximately 3,200 million rubles will be needed to bring the remaining capacity on line

Table 2-20
Annual Expenditure for Committed Units by Region
(mill rubles, 1991 year)

Region	Total Investment	Used Investment	1994	1995	1996	1997	1998+
1	3331 8	432 1	199 4	341 0	472 0	459 0	1428 3
2	292 4	237 1	9 5	24 3	25 0	6 0	---
3	161 0	82 4	36 6	16 0	13 0	13 0	0 0
4	472 4	61 5	36 9	64 0	67 0	56 0	187 0
5	2166 2	1183 1	53 5	123 0	175 0	197 5	434 2
6	1687 3	73 2	47 5	247 9	290 0	315 0	713 7
7	1328 3	670 9	73 6	142 5	82 0	71 9	287 4
8	364 6	127 4	16 8	30 8	32 0	33 0	124 6

Key
1 = North-West
2 = Center
3 = Middle Volga
4 = Urals
5 = Tyumen
6 = North Caucasus
7 = Siberia
8 = Far East

2.3 NUCLEAR ENERGY SECTOR

2 3 1 Overview of Installed Capacity

57 As of January 1994, there were nine nuclear power plants (NPPs) with 29 power units in Russia Their installed capacity was 21 GW, or 10% of the total installed capacity in the Russian power sector In 1993, Russian nuclear power plants produced some 118 billion kilowatt-hours (118 bkWh) of electric energy

58 Nuclear power is one of the major electricity sources in Russia In 1993, the share of nuclear electricity in total electricity generation was about 13% However, the importance of nuclear power greatly varies from region to region For example, in the regions with the most developed nuclear power (the North-West, Center and Middle Volga power systems), nuclear shares were 47 8%, 23 9% and 16 4%, respectively

59 Of the 29 operating units, there are

- pressurized light-water reactor units of the VVER type

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- channel-type graphite moderated reactor units of the RBMK and EGP types
- liquid metal-cooled fast neutron reactor unit of the BN type

60 The breakdown of total installed capacity by reactor type is given in Table 2-21

Table 2-21
Structure of the Russian Nuclear Power Sector, 1995

Reactor Type	Number of Units	Share in Total Capacity, %
RBMK-1000	11	51 8
VVER-1000	7	33 0
VVER-440	6	12 2
BN-600	1	2 8
EGP-6	4	0 2

61 The power reactors in commercial operation are of several types

- RBMK-1000, a graphite moderated, pressure-tube, low enriched reactor rated 1,000 MW, designed for on-line refueling (there are two generations of RBMK-1000 reactors that differ in some design features and physical parameters)

- VVER-440 (of the V-179 and V-230 modifications), a first-generation pressurized water reactor rated 440 MW

- VVER-440/213, a second-generation pressurized water reactor also rated 440 MW

- VVER-1000 (of the V-187, V-338, and V-320 modifications), a second-generation pressurized water reactor rated 1,000 MW

62 The liquid metal-cooled fast reactor (BN-600) is connected to the Ural grid The four small (12 5 MW) reactors of the water-cooled graphite-moderated channel type units (EGP-6) operate isolated from the grid in the far eastern portion of Russia In addition to these commissioned plants, the following are under construction

- Balakovo - units 5 and 6
- Kalinin - unit 3
- Rostov - units 1, 2 and 3
- Kursk - unit 5

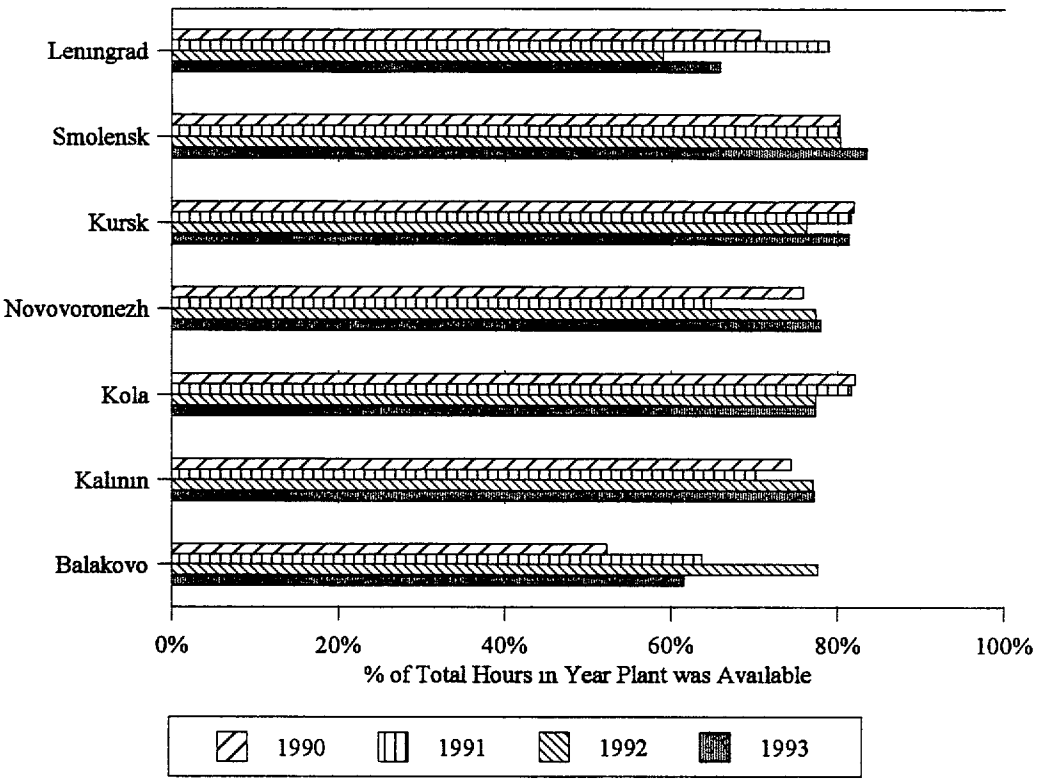
63 The characteristics of operating Russian NPPs are provided in Table 2-22

2 3 2 Historical Availability

64 Figure 2-2[2] provides top-level capacity factor data on NPPs for the years 1990 through 1993 The capacity factor is defined as the percent of time within a calendar year during which a nuclear unit is operating at its nominal power level

65 System-wide performance (average capacity factor) was 75 17% in 1990, 74 35% in 1991, 77 49% in 1992, and 75 90% in 1993 During this same period, the system wide-average number of emergency reactor trips per reactor unit was 1 39 in 1990, 1 04 in 1991, 1 29 in 1992, and 0 79 in 1993

Figure 2-2
Availability Over Time for Russian Nuclear Power Plants (1990-1993)



2 "Performance Indicators of Russian NPPs, 1993," Rosenergoatom, 1993

Table 2-22
Nuclear Power Plants in Russia (as of January 1, 1994)

No	Power Pool	Plant Name and Unit Number	Reactor Type	Capacity (gross) MW	Capacity (net) MW	Capacity Factor in 1993, %	Non fuel O&M Cost mills/kWh	Fuel Cost mills/kWh	Regulatory Requirement	Planned Shutdown Date
1	North West	Kola 1	VVER-440	440	414	56	4 36	3 2	Prior to OPB 73	2003
		Kola 2	VVER-440	440	414	61	4 36	3 2	Prior to OPB 73	2004
		Kola 3	VVER-440	440	414	71	4 36	3 2	OBP 73	2011
		Kola-4	VVER-440	440	414	79	4 36	3 2	OPB 73	2014
2	North West	Leningrad 1	RBMK 1000	1000	917	81	3 92	3 8	Prior to OPB 73	2003
		Leningrad 2	RBMK 1000	1000	917		3 92	3 8	Prior to OPB 73	2005
		Leningrad 3	RBMK 1000	1000	917	89	3 92	3 8	OPB 73	2009
		Leningrad-4	RBMK 1000	1000	917	84	3 92	3 8	OPB 73	2011
3	Center	Kalinin 1	VVER 1000	1000	905	59	5 03	3 2	OPB 73-OPB 82	2014
		Kalinin 2	VVER 1000	1000	905	70	5 03	3 2	OPB 73-OPB 82	2016
4	Center	Kursk 1	RBMK 1000	1000	893	57	3 92	3 7	Prior to OPB 73	2006
		Kursk 2	RBMK 1000	1000	893	57	3 92	3 7	Prior to OPB 73	2008
		Kursk 3	RBMK 1000	1000	893	70	3 92	3 7	OPB 73	2013
		Kursk-4	RBMK 1000	1000	893	71	3 92	3 7	OPB-73	2015
5	Center	Novovoronezh 1	VVER 213	210						shutdown in 1984
		Novovoronezh 2	VVER 365	365						shutdown in 1990
		Novovoronezh 3	VVER-440	417	367	51	6 16	3 7	Prior to OPB 73	2001
		Novovoronezh-4	VVER-440	417	367	74	6 16	3 7	Prior to OPB 73	2002
		Novovoronezh 5	VVER 1000	1000	881	72	6 26	3 2	OPB 73-OPB 82	2010
6	Center	Smolensk 1	RBMK 1000	1000	881	78	4 15	3 8	OPB 73	2012
		Smolensk 2	RBMK 1000	1000	881	82	4 15	3 8	OPB 73	2015
		Smolensk 3	RBMK 1000	1000	881	83	4 15	3 8	OPB 73-OPB 82	2020

No	Power Pool	Plant Name and Unit Number	Reactor Type	Capacity (gross) MW	Capacity (net) MW	Capacity Factor in 1993, %	Non fuel O&M Cost mills/kWh	Fuel Cost mills/kWh	Regulatory Requirement	Planned Shutdown Date
7	Middle Volga	Balakovo-1	VVER 1000	1000	900	40	4 36	3 2	OPB 82	2015
		Balakovo-2	VVER 1000	1000	900	45	4 36	3 2	OPB 82	2017
		Balakovo-3	VVER 1000	1000	900	54	4 36	3 2	OPB 82	2018
		Balakovo-4	VVER 1000	1000	900	65	4 36	3 2	OPB 82	2023
8*	Ural	Beloyarskaya 1	AMB 100	100						shutdown in 1980
		Beloyarskaya-2	AMB 160	160						shutdown in 1989
		Beloyarskaya 3	BN-600	600	570	80				2010
9*	Isolated pool	Bilibino-1	EGP-6	12		61			OPB 73	2004
		Bilibino-2	EGP-6	12		60			OPB-73	2004
		Bilibino-3	EGP-6	12		62			OPB 73	2005
		Bilibino-4	EGP-6	12		75			OPB 73	2006

* Not considered in JPNAS[3]

[3] Joint Parallel Nuclear Alternatives Study

2 3 3 Decommissioning

66 The Russian schedule for the decommissioning of nuclear power units prepared for the JEPAS is provided in Table 2-22

2 3 4 Nuclear Fuel Supply and Cost

67 There are several categories of nuclear materials available for fuel in Russia They include

- uranium in deposits
- natural and enriched uranium in stocks
- depleted uranium as a byproduct of the enrichment process
- uranium and plutonium from spent nuclear fuel
- plutonium and high-enriched uranium from nuclear weapons

68 In 1993, the quantity of uranium was assessed at about 720,000 tonnes of natural uranium in deposits and stocks [4] The annual consumption of uranium for electricity generation in Russia is about 4,000 tonnes/year Thus, at the present rate of consumption, Russia has resources for the foreseeable future It is clear that with the addition of other nuclear resources and less certain categories of uranium deposits, this number can become even greater Therefore, it is reasonable to assume that there is no fuel limitation in the foreseeable future for any reasonable development of nuclear power in Russia

2 3 5 Current Status of the Implementation of Safety Upgrades

69 The world community's concern regarding the safety of Russian NPPs' further operation, mainly NPPs with RBMK-1000 and first generation VVER-440 reactors, was an initial premise for the JEPAS and the JPNAS

70 Following the Chernobyl accident, additional measures for increasing the reliability and safety of Russian reactors were identified through additional safety analyses Some of these have been implemented, others are in the process of implementation Safety upgrades at operating nuclear units are made sequentially based on financial considerations and planned unit outages

71 Safety can be improved not only by equipment upgrades, but also by operational improvements Therefore, the Russian safety program includes measures aimed at

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4 *(Development of the Strategy of the Development of Nuclear Power in the Framework of the Long-Term Integrated State Fuel-Energy Program The Energy Strategy of Russia of the Russian Federation for the Period up to 2010* Phase Development of the Project of the Nuclear Power Strategy in Russia MINATOMENERGO RF TsNIIATOMInform No 378/0 Moscow, 1993 (In Russian)

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improving operation and maintenance, quality control, diagnostic methods, administrative controls, personnel qualifications and training, and periodic safety assessments

72 Among the organizational and technical measures, the most important was the introduction in 1990 of the special operating regime for units with the RBMK-1000 and first-generation VVER-440 reactors This regime includes expanded surveillance of the integrity of the primary circuit and an annual reassessment of safety for each unit, including a report to the Russian regulatory authorities Authorization for continued operation is based on this report

73 Specifically, the safety upgrades assessed in the Joint Study are based on

- A subset of the upgrades developed by the Russian engineers for the International Users Group (IUG) of Soviet Designed Reactors and published in a March 1994 report prepared for WANO that includes all the upgrades directly associated with reactor and plant safety

- The implementation of confinement/containment systems for RBMK and first generation VVER-440s

- Certain additional engineering studies from the current Russian program to identify upgrades not included in the two previous items

74 The safety upgrade programs that have been developed and implemented in Russian NPPs overlap those published in WANO reports Additional safety upgrades envisioned for the Russian program are as follows

- Upgrades to cope with "station blackout "
- Provisions to safely manage anticipated transients without scram (ATWS)
- Interactions between the plant and the grid (measures to protect the plant from transients or functional degradation on the grid)
- Additional safety upgrades that address common cause failures
- Environmental qualifications (assurance that the capability of safety-grade equipment and certain other systems and components function as required under accident conditions)
- Performance of a comprehensive set of accident analyses that will support current safety upgrade proposals and identify additional upgrades, if any
- Additional fire protection measures
- Addressing long-term cooling capabilities

2 3 6 Current Regulatory Environment[5]

GosAtomNadzor Responsibilities and Activities

75 GosAtomNadzor, as approved by statute from the President of the Russian Federation, is responsible for the following

- Participation with other state control authorities of the Russian Federation in determining and introducing a system of measures (legal, economic, organizational and technical) to promote nuclear and radiation safety
- Establishment of criteria, norms and procedures in the field of nuclear and radiation safety
- Supervision of government, military, private organizations and the citizenry to assure strict compliance with the laws of the Russian Federation regarding the production, handling and use of atomic energy, nuclear materials, radioactive materials and products based on them, in both civil and defense environments This includes development, production, testing, transportation, storage and elimination of nuclear weapons as well as the maintenance of codes and standards for nuclear and radiation safety
- Supervision over the organization, storage and inventory control of nuclear and radioactive materials, utilization and disposal of radioactive wastes and spent nuclear materials
- Supervision of physical protection for nuclear technologies, materials and non-proliferation Together with the Ministry of Foreign Affairs of the Russian Federation, supervision over the performance of pertinent international agreements
- Safety review of nuclear and radioactive products, production processes and technologies
- Licensing of activities listed in the Annex to the present Statute and preparation of proposals to improve the licensing procedures

5 The information in this section was extracted in part from *NUSAC News* (G-24 Nuclear Safety Assistance Coordination) January 1995 Issue 5

- Implementation of R&D policy, organization and coordination of research studies to validate principles and criteria, development of requirements for codes and procedures which regulate nuclear and radiation safety

- Organization and control of qualifications for personnel and departmental control over nuclear and/or radiation safety of controlled material

- Reporting responsibility, to both the state and the public, regarding the state of nuclear facilities and radioactive material To implement this task, GosAtomNadzor of Russia considers the following activities important

  - Independent safety assessments for

    — Construction licensing
    — Operational licensing
    — Operation
    — Decommissioning

  - Licensing and permits for applicants or operating organizations to fulfill specified activities and definitions of license terms

  - Control the execution of license and permit terms by the examination of reports and on-the-spot inspections

76 The implementation of GosAtomNadzor's main tasks has required a complete restructuring of its policy This includes both the essence of its work and scope of its references GosAtomNadzor does not supervise industrial and mining enterprises formerly controlled by the USSR's Gospromatomnadzor Instead, GosAtomNadzor supervises the country's nuclear power plants and research reactors, as well as the organizations associated with the fuel cycle and nuclear materials that are part of the war industry and in civilian nuclear powered ships (i e , icebreakers) These were not controlled by the USSR's Gosatomenergonadzor Accordingly, a new organizational chart was developed and is presented in Figure 2-3

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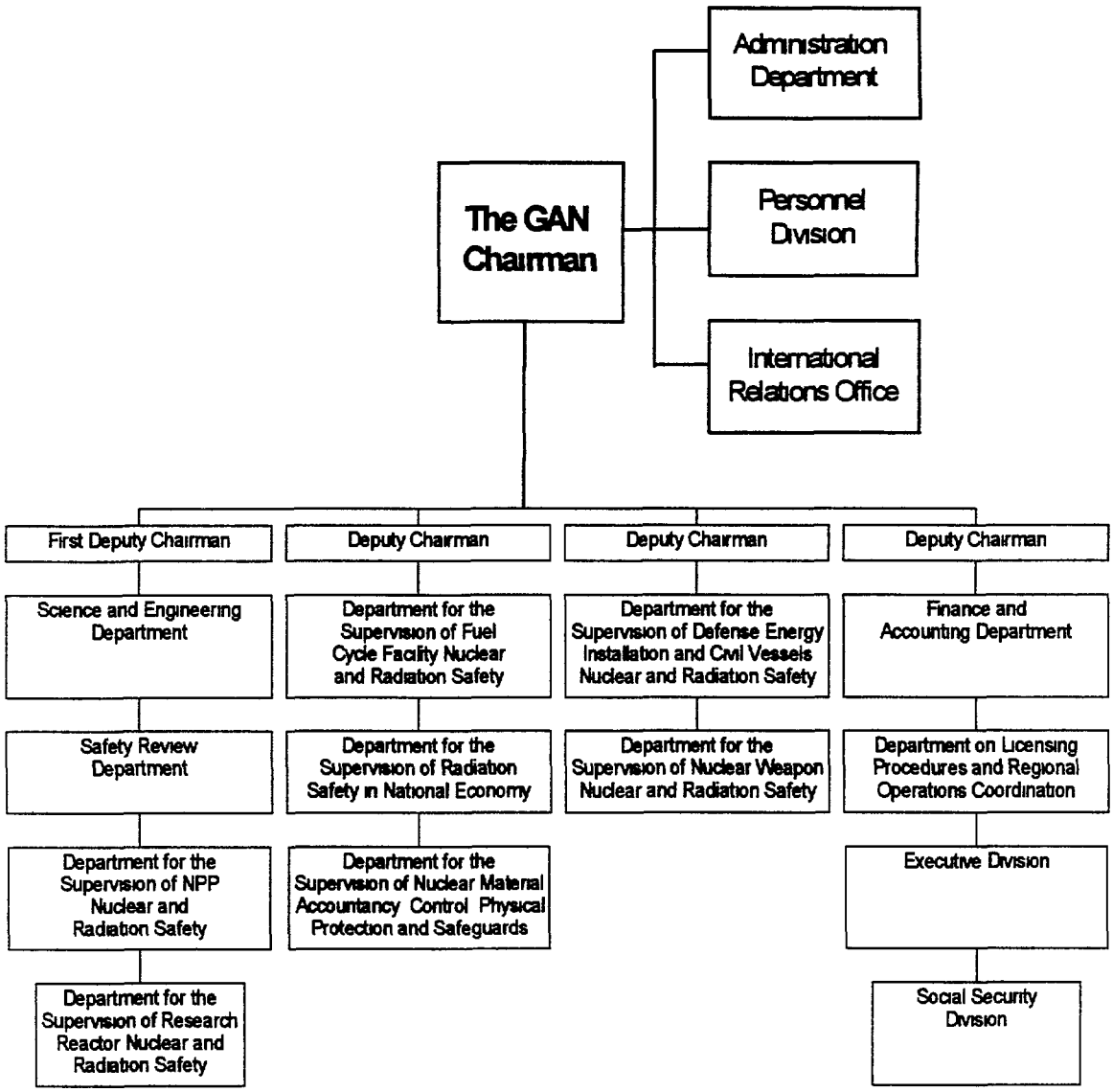
Figure 2-3
GAN Organizational Chart



Main Tasks of Transition Period

77 The restructuring of GosAtomNadzor is an ongoing process Soon after it was founded, GosAtomNadzor presented its understanding of its licensing-control tasks in a published policy statement as follows

- State supervision of nuclear and radiation safety in the territory of the Russian Federation
- Granting of licenses to fulfill activities on production and use of nuclear materials, atomic energy, radioactive substances and products based on them

78 According to this policy statement GosAtomNadzor, during this transition period, will be dealing with nuclear power plants only

79 For these nuclear power plants the main tasks during this transition period are as follows

- Establishment of supervisory organizations
- Development of licensing standards and procedures
- Granting of temporary permits for operation of existing NPP units
- Granting of temporary permits to complete ongoing NPP unit construction

Temporary Permits During the Transition Period

80 Temporary permits for the operation of existing NPP units and to allow the completion of ongoing construction are important because

- Documentation regulating licensing is not available yet
- It will take time to develop the necessary documents on nuclear and radiation safety for licensing
- Economic and political reasons do not allow the suspension of operation or construction of NPP units, even for a short period of time

81 For the above reasons, a simplified procedure for granting permits is a necessity It would require putting existing Russian power units under the control of a new established supervision body and could be performed quickly

82 Procedures have been developed and implemented for civilian nuclear power plants These are presented in the "Statute on the order of temporary permits granted by GosAtomNadzor of Russia to operate NPP units in Russian Federation", a similar statute for ongoing NPP construction sites is being developed

2 3 7 Currently Planned Capacity Additions

83 In Russia today, there are seven power reactors at different stages of completion at four different NPP sites within Russia

- Balakovo units 5 and 6 the units will be VVER-1000s
- Kalinin unit 3 this unit will be a VVER-1000
- Kursk unit 5 this unit will be a RBMK-1000
- Rostov units 1, 2 and 3 these units will be VVER-1000s

2 3 8 Additional Factors for the Russian Nuclear Sector

84 Other factors that have a significant bearing on the role of nuclear sector development in Russia's energy future are

Energy Security Diversity of Supply The existence of a nuclear sector provides a strong measure of protection against events that might threaten the availability and cost of fossil fuel supplies

Environmental Considerations In evaluating various approaches to generation capacity expansion in the Russian Federation, impacts to the environment must be considered For example, nuclear power does not produce the atmospheric emissions associated with fossil fuel plants, but it does produce high-level nuclear wastes that require long-term storage, and there is some risk posed by accidents These and other factors are difficult to quantify and were not included in the modeling, but are an important element in determining generation expansion options

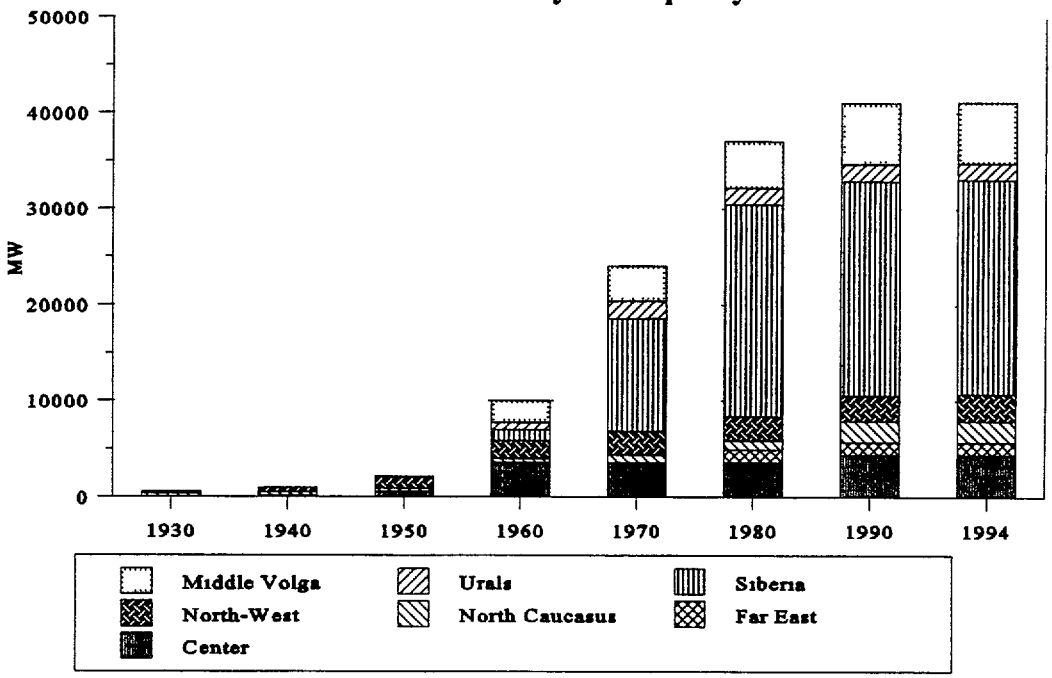
Infrastructure Resources and infrastructure exist in Russia to support the production of most nuclear power plant components required for power plant completion, safety-related upgrades, and new power plant construction

Reactor Safety The upgrades addressed in Section 2 3 5 above are designed to substantially increase the level of safety of Russian reactors The implementation of such upgrades is likely to increase the acceptance of nuclear power in Russia by the public and by the international community

2.4 HYDROELECTRIC ENERGY

85 The plan for Russia's electrification was the earliest initiative to build the country's economy and industry on a large scale Hydroelectric energy played a key role in the early development of Russia's electric energy system Figure 2-4 shows the growth of hydroelectric generation capacity in Russia

Figure 2-4
JEPAS Hydro Assessment
Growth of Hydro Capacity



2 4 1 Installed Capacity

86 As of January 1, 1994, hydropower plants accounted for 41,162 MW Of this, plants of 30 MW and above accounted for 40,852 MW Hydro's share is about 21% of the total installed capacity of the Integrated Power System of Russia The regional distribution of major hydroelectric plants is shown in Table 2-23 Table 2-24 gives some of the characteristics of each region's hydroelectric plants (Appendix I gives a plant-by-plant breakdown)

87 Four plants are currently undergoing rehabilitation Nizhne-Tulomskaya, Volkhovskaya, Volzhskaya (Center region), and Volzhskaya (Middle Volga) Without rehabilitation, it is expected that these plants will be out of service by the year 2000 Likewise, another four plants need rehabilitation, but work has not started on them Kamskaya, Ivankovskaya, Pavlovskaya, and Uglitchskaya These plants are also expected to be out of service by the year 2000 if work is not undertaken on them

Table 2-23
Regional Distribution of Existing Hydroelectric Power Plants

Region	Number of Plants	Capacity (MW)	Energy Output (GWh)
North-West	26	2,693	11,760
Center			
a conventional	6	3,615	13 220
b pumped storage	1	800	800
Middle Volga	4	6 348	18 900
North Caucasus	11	2 014	5 930
Urals[1]	5	1,748	4 890
Siberia	8	22,343	94,260
Far East	1	1 290	4 900
Subtotals	62	40,852	154,660
Small[2] plants	na[3]	310	1,350
Totals	na[3]	41 162	156 010

[1] includes Tyumen
[2] "small" implies less than 30 MW installed capacity
[3] na=not available

Table 2-24
Inventory and Energy Production Aspects of Existing Plants by Region

Region	No of Plants > 30 MW	No of Units	Installed Capacity (MW)	Winter Day				High Water Season (May) Day				Summer (July) Day				Avg Annual Energy (GWh)
				Available Capacity (MW)	Daily Capacity MW			Avail Cap (MW)	Daily Capacity MW			Avail. Cap (MW)	Daily Capacity MW			
					Avg Cap	Base Load	Peak Load		Avg Cap	Base Load	Peak Load		Avg	Base Load	Peak Load	
North West	26	85	2844	2844	1318	50	1268	2844	1647	50	1597	2844	1122	60	1062	12460
Center Conv PS	6 1	41 4	3615 800	3494 800	1112 228	700 0	412 228	3494 800	2678 526	700 0	1978 526	3494 800	1160 228	700 0	460 228	13220 800
Middle Volga	4	78	6348	4560	1500	400	1100	4560	3465	415	3050	4560	1650	415	1235	18900
Urals[1]	5	38	1755	1735	425	172	253	1728	803	275	529	1728	371	275	96	4890
North Caucasus	11	33	2166	2114	477	67	410	2114	1156	221	935	2114	984	221	763	6580
Siberia	8	78	22343	19443	10961	3174	7787	19443	7908	2784	5126	19443	11132	3505	7627	94260
Far East	1	6	1290	1290	600	200	400	1290	600	200	400	1290	600	200	400	4900

[1] Includes Tyumen

103

2 4 2 Reliability and Availability

88 It is reported that the trend over the last five years has been to use more and more hydropower for peaking energy This has meant the increased starting and stopping of turbines, sometimes as much as ten times a day, which has accelerated the degradation of system availability The amount of down-time has been steadily increasing for unit repairs and overhauls

89 In general, the hydro-turbines have been subject to decreasing service life for new units over the last 40 years That is, units installed before 1950 had a useful life of about 50 years Since that time, the reduction in specific metal content has lowered the useful life to about 30 years As a result, turbines are also showing signs of deterioration (e g , cavitation) at earlier stages in their production lives

90 In 1994, the remaining service life of the 66 largest existing hydro plants in Russia was analyzed The results are presented in Table 2-25

Table 2-25
Remaining Service Life of Hydro Plants

Remaining Service Life (years)	No of Plants	No of Units	Installed Capacity (MW)	Avg. Annual Energy Production (GWh)
50 and more	6	31	470	3 000
40 to 49	6	25	775	2 800
30 to 39	16	125	8 140	23 000
less than 30	38	333	34 060	139,200
Total	**66**	**514**	**43,445**	**168,000**

2 4 3 Retirement Program

91 There are no formal plans to retire any of Russia's existing hydroelectric plants A hydro plant's service life is typically controlled by the condition of the turbine and generators In general, the useful life of civil structures is much greater than that of the

equipment Existing hydro plants will continue to operate until a key component fails At that time, retirement or refurbishment will be evaluated Existing capital budgets for routine and preventative maintenance have dwindled

92 A considerable effort has already been made by the Russian Hydroproject Institute to evaluate the rehabilitation needs of almost all hydro plants in the country The options for life extension appear to be limited to increased budgets for preventative maintenance and equipment replacement

2 4 4 Environmental Issues

93 These issues have not been fully studied for all hydro plants in Russia under the current assessment However, for the specific plants recommended for investment (Appendix I), the environmental considerations (if any) have been included in the project investment discussions

2 4 5 Planned Capacity Additions and Replacement

94 Several hydroelectric plants in the Russian Federation have been identified for rehabilitation Previous studies by Russian engineers have identified many plants in need of rehabilitation Rehabilitation at some of these plants has started due to imminent equipment failure Four plants currently undergoing some type of rehabilitation were identified for priority investment to accelerate refurbishment and upgrades

- Nizhne-Tulomskaya
- Volkhovskaya
- Volzhskaya (Center)
- Volzhskaya (Volga)

95 These plants account for 4,957 MW and 20,460 GWh of existing installed capacity and energy production, respectively After rehabilitation, the plants will increase to 5,202 MW and 22,720 GWh of installed capacity and energy production, respectively, due to modern equipment and efficiency improvements

96 The proposed investment of $585 million would provide approximately a 40-year life extension for the four existing plants Without continued investment, these existing plants will likely be out of service by the year 2000

97 In addition, four hydroelectric plants have been identified as priority projects for new rehabilitation, including modernization and expansion

- Kamskaya
- Ivankovskaya

185

- Pavlovskaya
- Uglitchskaya

98 No rehabilitation construction has started yet for any of these plants except for Uglitchskaya, which is currently being repaired as a result of the failure of a portion of the draft tube lining

99 The estimated investment requirement for rehabilitating the four priority plants is $370 million over the five-year period 1995 to 1999 The proposed investment would provide approximately a 40-year life extension for these four existing plants The four plants account for a total of 810 MW of installed capacity and 2,560 GWh of average annual energy production After rehabilitation, the plants will increase to 891 MW of installed capacity and 2,631 GWh of average annual energy production due to modern equipment and efficiency improvements

2.5 TRANSMISSION, DISTRIBUTION, DISPATCH, COMMUNICATION, AND CONTROL

2 5 1 High-Voltage Transmission and Distribution

100 Russia's Integrated Power System is one of the largest in the world, spanning some 9,000 km from east to west and six time zones It holds the following large interconnected regional power systems (UPS) North-West, Center, Middle Volga, Urals, North Caucasus, Siberia, and Tyumen The power systems of the Far East region (Amur, Khabarovsk, Vladivostok) operate separately from the IPS In this report, Tyumen, which is part of the Urals UPS, is treated separately in the analysis of power needs However, for transmission purposes, it remains part of the Urals UPS The power systems of the new independent countries (Kazakhstan, Ukraine, Belorussia, South Caucasus States, Baltic States, Middle Asia States) are in synchronous operation with the IPS

101 As of January 1993, the total installed generation capacity of the IPS was 190 GW, with an annual production of some 850 billion kWh

102 As a result of diversity in daily maximum load shapes, it has been possible to reduce the total load demand of the IPS by 10 GW This factor, together with decreases in operational (spinning) reserves and the rationalization of the generation structure, are major advantages of the system's operation

103 Two separate voltage sequences have historically developed in the former USSR 110-220-330-750 kV in the western and southern parts of European Russia and 110-220-500-1,150 kV over the rest of the country After the dissolution of the former Soviet

Union, the majority of lines in voltage classes 330 kV, 750 kV and 1,150 kV became a part of the systems of the newly formed western states and Kazakhstan Nevertheless, the total length of 110-1,150 kV transmission lines in Russia is now 400,000 km, including 36,000 km of 500, 750 and 1,150 kV lines

104 The existing transmission network basically provides for energy transfers from power plants to consumers However, there are several places where the underdevelopment of transmission has created bottlenecks, preventing a reliable supply to consumers and limiting the full use of existing generation capacity

105 As a rule, Russia does not meet the N-1 planning criterion, a fundamental principle of transmission planning in most countries, although attempts have been made to meet this criterion in systems surrounding nuclear plants [6] To accommodate this lack of high transmission redundancy, special sophisticated emergency control procedures have been engineered and implemented in Russia These procedures are used routinely to preserve the operational stability of the power system following contingencies They automatically shed consumer loads, and disconnect either individual generating units or whole power plants, including nuclear units Such control actions and the risk to the safe operation of the nuclear plants could be avoided by strengthening the transmission system This issue argues for increased redundancy in the power transmission network, irrespective of normal power flow demands That incentive is reinforced by the needs imposed by the automation and modernization of Russia's industrial processes, the latter being more sensitive to power interruptions than has been the case in Russia heretofore

106 The interconnection transfer capability required between regions is largely determined by forecasts of normal or emergency flow Official forecasts of load/generation balances for Russia's regions reflect uncertainty in the pace of economic recovery, industrial modernization, nuclear plant retirement policy, and other factors

107 The collapse of the Soviet Union created important new problems for the IPS The transmission links that interconnect some regions of Russia were suddenly in foreign countries (e g , Kazakhstan, Ukraine, the Baltic states) The use of such ties became dependent on political relationships, and extremely large investments are needed to diminish Russia's vulnerability to those relationships Nonetheless, because transmission between regions is normally a fraction of the generation cost within a region, strong interconnections represent good "insurance" against forecast errors and political uncertainty

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6 N-1 means that the system can stay within acceptable limits for frequency and voltage fluctuations, despite the failure of one major component (a power plant or line segment) N-2 which is more strict means that the system can handle the failure of two major components

108 At the same time, changes in inter-regional transfer capability will affect regional generation requirements The former Soviet Union's mandatory value of a 13% to 14% capacity reserve margin for the country as a whole is now being revised The new planning target for this margin is being raised to about 16% to 18% This takes into account the new economic and political environments in which Russian utilities must now operate

109 System losses at all levels of the Russian power system are higher than those of western systems, owing partly to the use of smaller conductors, the longer distances, and the lack of facilities to control reactive power flows Losses are especially high in subtransmission and distribution systems, i e , at 110-220 kV and below, where an estimated 80% of the losses occur

2 5 2 Control, Communication, and Dispatch

110 The system operation organization in the IPS is hierarchical The Central Dispatch Office (CDO) is at the top of the hierarchy, it is responsible for controlling system conditions to meet the national electric demand, and for providing a reliable and economical electric energy supply The CDO is also responsible for coordinating day-to-day operations among separate interconnected power systems to assure stable, economic, and reliable operation The operational functions of each of the Interconnection Dispatch Offices (IDOs), which are under the direct supervision of the CDO, are basically similar to the corresponding functions of the CDO, although their responsibility is limited to their respective systems Each of these control centers is equipped with computers and an associated communication network to gather and process data from power plants, substations and their regional dispatch centers This computer system is a primary means by which dispatch functions are achieved

111 The responsibilities of the control centers are changing along with the structure of the electric power sector Their new responsibilities include

- Enhanced dispatch of generation and transmission systems will be needed to optimize fuel *cost* and improve system reliability In the past, the dispatch function minimized the *amount* of fuel used This major change in philosophy will require additional equipment and systems at the control centers

- The new structure of the Russian power market calls for more evaluation, scheduling, accounting and billing of electricity transfers between companies and between regions than have occurred in the past

- The AO Energos (utilities) are now independent from the CDO and the IDOs In fact, many parts of the bulk transmission system are not part of

the AO Energos at all Nevertheless, the CDO and the IDOs continue to coordinate activities on the bulk transmission system

- While approximately 50 of the largest generating plants remain under the direct control of the CDO and IDOs, most of the electric generating units, cogenerating heat units, and independent generating units are with the AO Energos and other companies Yet the CDO and IDOs need direct control of key generating units to control frequency and inter-company/inter-region electric energy transfers

2 5 3 Planning Performance Criteria

112 To bring the Russian power system infrastructure to the state where it meets an N-1 planning criterion would require the construction of a very large number of transmission facilities throughout the country Even where this would be desirable in the long term, it would be impossible in the short term because of the immense transmission distances and the enormous costs involved A special long-range transmission system reinforcement study should be undertaken to determine the degree to which the Russian power system should be modified to incorporate the N-1 planning principle Studies performed by the transmission working group began that process by using the N-1 criterion as a basis for establishing the minimum transmission required for several of the cases considered

113 Working Group 4's approach to analyzing and evaluating the performance of the transmission system, both before and after reinforcement, followed present Russian practices, standards and regulations The main guidelines used in the study to calculate maximum transfer capabilities between portions of the system are as follows

- The maximum allowable power flow under normal and maintenance conditions shall not exceed Pss/1 20, where Pss is the steady-state stability limit determined from load flow simulation studies

- The maximum power flow permitted under post-contingency conditions shall be within Pss/1 08, where Pss is the steady-state stability limit following an outage determined from load flow simulation studies

- No margin is estimated and no limit is set on transient stability calculations For certain emergency disturbances, however, checks are made for the stability of the dynamic transition from the initial state to the post-emergency state As a rule, a phase-to-phase-to-ground fault involving the outage of the faulted network component or disconnection of a power plant as a whole or its unit(s) is simulated for 330 kV through 750 kV transmission For 1,150 kV transmission, the initial disturbance is modified to include only a single phase-to-ground fault Three-phase faults are tested

for 110 kV and 220 kV transmission facilities The foregoing are general guidelines for transient stability simulation studies

- A general assumption is that power flow constraints are imposed by the criterion of maintaining stability in the transition to a post-emergency mode under normal and maintenance outage conditions without and with emergency control procedures (the N-1 principle), respectively

114 In practice, however, power flows (which under single contingencies, require emergency control to preserve stability) are allowed This is particularly true where a single transmission line has a higher voltage class (much greater power rating) than the surrounding system In those cases, the outage of the highest-voltage line could cause instability without emergency control actions In other cases the criterion is set aside because even with all available lines in service, the transmission capacity is inadequate to deliver electric energy from regions of ample supply to deficit regions

115 The major limitations imposed by the present control, communication and dispatch systems identified by the Joint Study can be summarized as follows

- Most control center equipment is obsolete and its maintenance is increasingly problematic The capability and capacity of the present equipment should be improved to meet secure power system operation requirements in the near future

- The main computer system's hardware and software are technologically outdated The aging system prohibits implementing the new functions required to support changes in the system operations of the IPS

- The communications among control centers, and between a control center and field monitoring devices, are constrained by data speed and channel capacity due to the obsolescence of communication media and equipment

- The amount of currently telemetered data from power plants and substations is insufficient for any advanced applications such as on-line economic load dispatch, state estimates and contingency evaluations

- The existing remote monitoring and control equipment at substations and power plants needs to be upgraded Since there is little or no manufacturer support or spare parts for existing equipment, it is common to "cannibalize" equipment in less demand for spare parts

- Most generating units do not take part in automatic daily load regulation
  Most instrument systems at the power plants were not originally designed to support remote monitoring and control

CHAPTER 3
FUTURE INVESTMENT OPTIONS

1 This chapter discusses several options for investment in Russia's power sector 1) energy efficiency improvements in the industrial, residential, transportation, agriculture, and service sectors, 2) thermal power plant modernization, conversion, fuel switching, life extension, and the completion of new plants, 3) nuclear plant completion, safety upgrade, and/or decommissioning, 4) the rehabilitation, modernization and expansion of existing hydro plants and the construction of new hydro plants, and 5) transmission and dispatch projects

3.1 ENERGY EFFICIENCY IMPROVEMENTS

2 There is a large potential to improve the efficiency of electricity use throughout the Russian economy As with other basic social goods, electricity prices were held low and there were few incentives to reduce consumption Also, industrialization policies favored the production of electricity- (and energy-) intensive goods, particularly in heavy industry

3 The *Russian Energy Strategy* identifies potential savings of 330 to 390 bkWh per year based on 1990 electricity consumption patterns (Table 3-1) For comparison purposes, total electricity consumption in 1990, including in-plant use and distribution losses, was 1,074 bkWh Sectoral consumption in 1990 was industry (without power plants) 554 bkWh, agriculture (not including rural housing) 67 bkWh, transport 104 bkWh, services 96 bkWh, and residential 78 bkWh In Table 3-1, efficiency potential has been broken down into two categories, measures requiring investment in new technology and operation and maintenance measures These potential savings estimates describe the effect if all current wasteful practices and technologies were replaced by those that are energy efficient The achievable savings are lower than the theoretical potential, as described below

Table 3-1
Electricity End-use Efficiency Potential (Based on 1990 Consumption)
Determined from the *Russian Energy Strategy*, bkWh

Sector	Total	Of Which	
		Investment Measures (Technology Measures)	Operation and Maintenance (Low Cost/No Cost)
Total for Russia	330-390	240-290	90-100
Industry & Construction	260-290	195-220	65-70
Agriculture	25-30	15-18	10-12
Transport	4-6	2-3	2-3
Services	27-32	21-25	6-7
Residential	30-35	23-27	7-8

4 Some improvements in the utilization of electricity will evolve as a result of economic reform As prices are freed to reflect actual costs through market forces (or in the case of regulated utilities, through regulatory reform), consumers will respond to higher prices by eliminating costly waste The first naturally occurring responses are called operation and maintenance measures (also referred to as low cost/no cost or housekeeping measures), reflecting the possibility of making improvements without the need for extensive capital investments (shutting off lights and equipment when not in use, for example)

5 It is important to note that some operation and maintenance measures will require investment and attention in order to fully realize these savings For example, meters will often need to be installed to monitor electrical and thermal performance, and energy managers will need training in the operation and maintenance skills that are required to eliminate energy waste Nevertheless, these low cost/no cost options do not require significant capital investment, and have not been considered in the cost estimates in this section

6 There is also a critical role for structural change within the Russian economy in altering electricity use This should occur at several levels of the economy, both between sectors (for example, a shift in economic activities away from industry to consumer products and services) and within branches of industry (a shift from heavy industry to light industry, a reorientation of industrial output and activities to those producing higher-value goods using less electricity, the production of more spare parts and higher-quality goods in the manufacturing sector to reduce the absolute number of units produced, etc) The possibilities and investment needs for structural change to reduce electricity consumption

are very difficult to quantify The efficiency benefits offered by structural change are a secondary benefit of decisions made for other economic reasons, and as such are not included in this Study's investment program for energy efficiency Also, structural changes that produce energy savings will mainly take place after the year 2000 when the economic crisis is over in Russia and favorable economic conditions exist

7 There are measures described in this Study that require capital investment (i e , the installation of energy-efficient equipment), that could produce large energy savings, and that have wide applicability This section identifies the major energy efficiency measures requiring capital investment, and estimates their costs and energy savings in the five major end-use sectors of the Russian economy industrial, residential, transportation, agriculture, and service For JEPAS efficiency investment calculations, the potential efficiency improvements shown in Table 3-1 were not completely taken into account Instead, Working Group 1 examined the investment requirements and efficiency potential of a large number of specific end-use efficiency measures The group's methodology and findings are described in greater detail for the 57 energy efficiency measures studied in the following sections and in Appendix D

3 1.1 Methodology and Findings

8 The underlying method for evaluating energy efficiency investments is to consider the installed cost and the lifetime electricity savings of each measure Working Group 1 developed the Russian End-Use Electricity Efficiency Model to estimate energy efficiency potential and to develop energy efficiency supply curves This model allows the user to select the lowest-cost set of energy efficiency measures and forecast the measures' energy savings and investment requirements for various industrial and non-industrial categories

9 Table 3-2 summarizes the 57 energy efficiency measures considered in this study and estimates the savings they would provide under Scenario A These estimates assume that equipment replacements will be made only when existing equipment reaches the end of its estimated design life In this case it was assumed that the average cost of saved energy would not exceed 4 cents/kWh This value was the result of analyses performed using the ICF optimization model, which was used to provide integrated least-cost planning for the JEPAS This model selected efficiency measures that are summarized in this list based on a comparison with supply costs (on a regional basis) after both were converted to 1994 dollars Hence, not all of the efficiency measures shown here were chosen by the ICF

Table 3-2
Energy Efficiency Measures for the Year 2010 (Scenario A)

SECTOR	EFFICIENCY MEASURES	SAVINGS - GWH
	Measures with Savings NPVs Less Than Zero	
Industry	Efficient florescent fixtures	7 325
Agriculture	Mercury and florescent lamps	3 945
Industry	Efficient and downsized motors	11,679
Industry	Improved furnace insulation	4 095
Agriculture	Downsizing electric motors	1 582
Misc	Other measures	314
	Subtotal	28,940
	Measures with savings NPVs from 0 00 to 0 50 cents per kWh	
Service	Efficient motors in buildings	1 208
Transport	Improved locomotives	3 071
Industry	Efficient motors	2,588
Service	Lighting controllers	5 705
Industry	Hall smelting process	2 046
Service	Efficient fluorescent lamps	1 335
Misc	Other measures	5 561
	Subtotal	21 514
	Measures with savings NPVs from 0 50 to 1 00 cents per kWh	
Agriculture	Improved insulation in pig barns	1 953
Industry	Efficient motors - 60 hp and above	3,521
Agriculture	Efficient heating in pig breeding	1,026
Service	Adjustable speed drive water pumps	3 948
Industry	Adjustable speed drive motors - above 135 hp	10,401
Misc	Other measures	2,298
	Subtotal	23,147
	Measures with Savings NPVs from 1 00 to 4 00 cents per kWh	
Residential	Compact fluorescent light bulbs	9 665
Industry	High pressure sodium lamps	2 263
Industry	Adjustable speed drive motors - up to 135 hp	13,546
Service	Adjustable speed drive building motors	5 796
Industry	Compact fluorescent light bulbs	2 212
Residential	Improved refrigerator insulation	1,768
Industry	Metal halide lamps	1 989
Misc	Other measures	533
	Subtotal	37,772
	Overall total	111,373

optimization model in all regions More specific details on methodology can be found in the Time-Phased Energy Efficiency Plan for Russia (Appendix D) and Appendix C

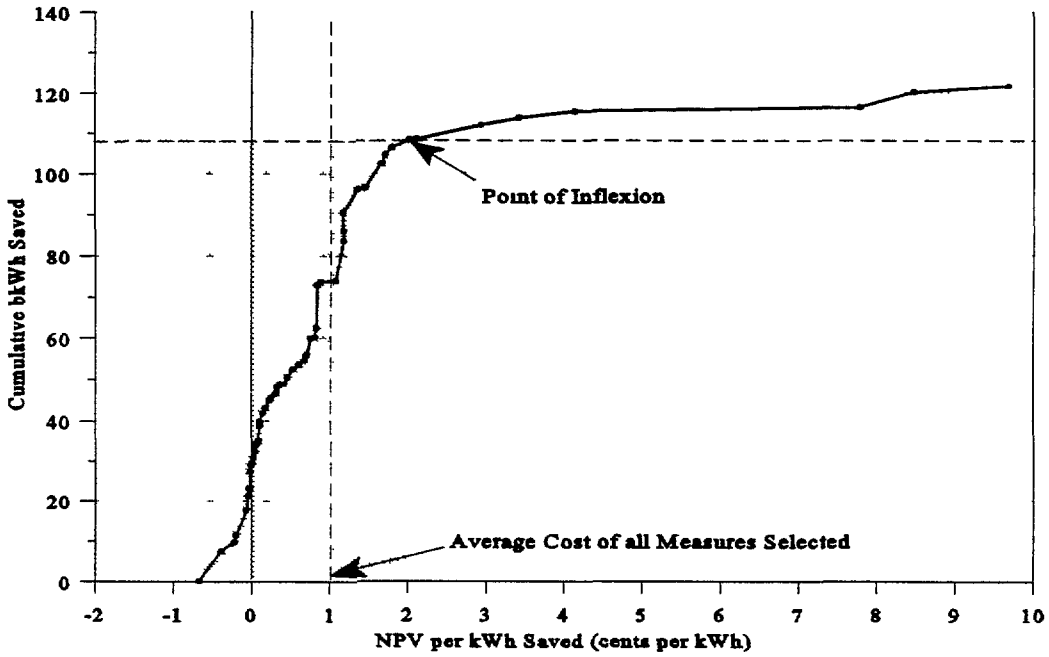
10 In summary, the Time-Phased Energy Efficiency Plan for Russia examined the sector of use for each measure, and estimated the total number of units and the number of eligible units [1] The actual number of units expected to be replaced is smaller than the number of eligible units because of various conditions that limit the economic application of efficiency measures The plan assumed market penetration rates for the energy efficiency measures (these rates are related to the need to replace worn-out equipment) The penetration rate for the measures in the industrial applications is 33% by the year 2000 and 90% by the year 2010 The penetration rate for the measures in the non-industrial applications is 20% by the year 2000 and 60% by the year 2010 Early replacement of equipment was not considered in these estimates, although some early replacements would be economically justifiable

11 Because of time constraints and the complexity of assessing the future power needs of an economy in transition, the Time-Phased Energy Efficiency Plan should not be viewed as a conclusive statement of the contribution that can be made by electricity efficiency In several ways, the study is conservative -- it considers only a representative set of major end uses and is limited to proven technologies In fact, Russia could become a showcase for advanced, efficient technologies U S costs were used when Russian costs were not available However, energy-saving products represent a huge potential growth industry for Russia, which could bring down these costs significantly Some measures, such as frost-free refrigerators, were not included because strictly based on the cost per kWh saved, this option does not look attractive at present

12 Fifty-two of the fifty-seven energy efficiency measures identified in Appendix D that have an incremental cost of less than 4 ¢/kWh are included in the Time-Phased Energy Efficiency Plan for Russia Motor efficiency improvement measures are particularly important in the industrial sector, and lighting efficiency measures have broad applicability in all five sectors Figure 3-1 illustrates the energy savings that could be achieved at various cost levels About 90% of the energy savings could be achieved at a cost of 2 cents per kWh or less

1 The total number of units represents the number of each technology that are expected to be used in Russia in 2010 Eligible units is the subset of the total units for which replacement (or retrofit) by efficient devices is technically feasible The actual number of units replaced is the number of devices that can be expected to be replaced (or retrofitted) by the years 2000 and 2010 under Scenarios A and B

Figure 3-1
Energy Efficiency Supply Curve



Note - Average costs of all measures selected is 1 cent/kWh
- Point of inflexion of the energy efficiency supply cure is at 2 cents/kWh

13 Table 3-3 presents the annual electricity savings and the cumulative costs of the efficiency measures for the years 2000 and 2010 Estimates are provided for two economic and power demand scenarios the optimistic scenario (Scenario A) and the pessimistic scenario (Scenario B), which are described in Chapter 1

Table 3-3
Annual Electricity Savings and Cumulative Costs
(from Measures Screened at 4 cents/kWh and Less)

Sector	Year	Savings (billion kWh)		Incremental Capital ($ million)		Total Capital Costs ($ million)	
		Scenario A	Scenario B	Scenario A	Scenario B	Scenario A	Scenario B
Industrial							
	2000	16 3	8 8	1,668	892	5,481	2,931
	2010	61 1	37 5	6,382	3,950	20 969	12,977
Residential							
	2000	3 5	2 8	755	614	10,073	8 187
	2010	15 1	11 7	3,278	2,545	43 720	33 948
Transportation							
	2000	1 5	1 5	42	42	123	123
	2010	5 1	4 8	146	139	422	402
Agriculture							
	2000	3 0	2 2	62	45	1,062	733
	2010	11 3	8 8	232	182	3 958	3,094
Service							
	2000	4 5	3 6	512	416	1 951	1,586
	2010	19 5	15 1	2,223	1 726	8 468	6 575
Total							
	2000	28 8	18 9	3,040	2,010	18,690	13,600
	2010	112 0	78 0	12 262	8 542	77,538	56 997

14 The total savings from the implementation of these measures is 19 to 29 bkWh in the year 2000 These savings are equivalent to the annual generation of eight to twelve 400 MW power plants By the year 2010, the savings potential increases with the further penetration of the measures, reaching 78 to 112 billion kWh These savings are equivalent to the generation of forty to fifty 400 MW power plants

15 Table 3-3 also describes the capital and incremental costs for the energy efficiency measures The capital cost is the replacement cost (where applicable) plus the additional cost required for more efficient equipment at the point in time where worn-out equipment is replaced The incremental cost is only the additional cost beyond the replacement cost

16 The capital costs of the energy efficiency measures are large By the year 2000, these costs range from $14 to $19 billion By the year 2010, they rise to $57 to $78 billion However, much of this cost is replacement cost The net present value (NPV) of

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incremental costs is $2 to $3 billion by the year 2000 for the two scenarios By the year 2010, the range is $9 to $12 billion

17 The industrial sector would account for approximately one-third of the capital costs and one-half of the incremental costs of the efficiency measures This sector also provides for somewhat more than half the electricity savings under this scenario Although the costs are substantial under Scenario A, it is important to note that the average cost of the cost-effective efficiency measures is less than 1 cent/kWh saved

18 Table 3-4 shows the geographic distribution of energy savings and costs for the year 2010 under Scenario A Two of the seven regions (Urals/Tyumen and the Center) account for approximately half of the energy savings and investment requirements

3 1 2 Barriers to Electricity Efficiency Potential

19 Even within developed market economies, barriers to energy efficiency exist Frequently, governmental bodies step in to help consumers transcend these market barriers The institutions that have played an important role in stimulating efficiency in Western economies have not yet been developed in Russia During the past several years, there has been a great deal of discussion, and several drafts, of a law on energy efficiency for Russia, although none of these versions has been enacted to date Critical aspects of such legislation will be the relative strength of regional bodies versus federal, and the encouragement of incentives over penalties A major barrier for Russia is the outdated nature of facilities and equipment Firms are now unable to manufacture the required machinery and equipment The level of efficiency of Russian equipment is now lower than that of imported equipment Financial resources are also lacking, so there is a need to create special funds for energy efficiency

Table 3-4
Geographic Distribution of Electricity Savings and Costs for Scenario A in the Year 2010

	North-West	Center	Middle Volga	North Caucasus	Urals & Tyumen	Siberia	Far East	Total
Total Savings (GWH)	8,309	32,359	11,140	7,414	27,047	21,404	4,325	112,000
Incremental NPV Cost ($ Million)	990	3,645	1,143	797	2,908	2,288	490	12,262
Capital Cost ($ million)	6,958	24,500	6,934	5,944	16,773	13,198	3,231	77,539

Monetary discount rate	15%
Electricity savings discount rate	0%
Investment period	15 years
Average cost of saved electricity <1¢/kWh	4¢/kWh
Non-industrial energy efficiency measure penetration	60%
Industrial energy efficiency measure penetration	90%

20 Of the actions that could be taken at the federal level, comprehensive laws on efficiency standards and labeling are of critical importance, not only for industrial, service, and residential equipment, but also for building materials and buildings themselves The federal government can also provide financial incentives to manufacturers or importers of energy efficiency equipment through the reform of taxation, depreciation, and investment policies

21 Foreign capital is needed if the energy savings amounts shown in the Study are to be achieved Priority areas of Russian investment are efficient lighting and motors and other dominant efficient technologies Priority should be given to foreign investments in the following areas

- Developing the capability for mass producing
  - energy-efficient motors
  - new lighting technologies (such as compact fluorescents and metal halide lights)
  - Automated electric ovens with thermal heating
  - heat pumps for agriculture
- Implementing new manufacturing methods (i e , process changes for oil and chemical plants using higher-quality catalysts)
- Establishing new demonstration projects for energy-efficient technologies and providing assistance for carrying out energy audits

3 1 3 Conclusions

22 The transition to a market-based economy will create large opportunities for energy efficiency The results of Working Group 1's analyses indicated that the average cost of the electricity efficiency options examined was 1 cent per kWh In the short term, a number of barriers to implementing efficiency measures must be overcome These include the shortage of capital, the shortage of price signals, the lack of Federal laws to encourage efficiency, and relatively weak and understaffed Regional Energy Commissions

23 Implementing efficiency measures will remain a major challenge in the coming years Energy efficiency investments are typically financed by users, and in Russia today, the economic depression makes this unlikely Financing from other sources will be needed in the medium term if these investments are to take place The lack of financing is a serious impediment to investing in efficiency improvements Government support of investments to improve efficiency (such as investment tax credits and revolving loan funds) could play an important role in opening the market for efficiency investments

3.2 THERMAL CAPACITY

3 2 1 Cost Development Methodology

24 Capital costs were estimated for both the construction of new un-sited generating units and for the rehabilitation of existing thermal power plants The capital cost information was required as input to the Working Group 5 modeling studies The methodology applied in the development of these capital costs is described below

25 Cost estimates for the rehabilitation of a large number of aging thermal units were prepared by estimating rehabilitation costs for a limited number of units and by limiting the number of potential rehabilitation schemes to be investigated for each unit As a first step, Working Group 2 developed categories of power plants based on turbine/generator capacity, boiler type and fuel type

26 Fuel type and unit size were key classification parameters These dictated boiler designs, which in turn dictated the magnitude of flue gas treatment required for rehabilitation A typical power station, generally consisting of multiple units, was selected by Working Group 2 in each category to be evaluated for alternate rehabilitation/ replacement options The typical plant unit was selected based on its similarity to other units of this size and fuel type so the results of rehabilitation could be extrapolated to include those other units In total, 24 categories were identified

27 Boiler and turbine design data sheets and heat balances were obtained giving design temperatures, pressures, flows, fuel feed rates, fuel analyses, major equipment types, etc Also, boiler drawings and station plans and cross-section drawings were obtained These documents were reviewed by Working Group 2 to understand the plant design parameters at initial construction The analysis was focused on ascertaining the criteria used in determining a plant's required rehabilitation Additionally, this review process allowed Working Group 2 to gain insight into the wide variety of fuels fired by Russian plants and the several types of plant designs needed to accommodate those fuels The plant designs reviewed included both condensing power plants (CPP) and combined heat and power (CHP) plants

28 Much effort was expended in the development of proposals for the rehabilitation of aging thermal power plants These proposals were formulated to provide capital cost, operating cost and performance information that could be used to characterize the entire inventory of aging thermal power plants scheduled for retirement before the year 2010 The rehabilitation proposals were developed by Working Group 2 after considerable discussions and work performed in Moscow

29 Using a combination of Russian and Western technologies, the method of rehabilitation of "typical" plants was determined Depending on the plant and its fuel

availability, more than one rehabilitation method may have been developed for economic and technical analysis The scope of work was defined for each rehabilitation alternative Where special technologies are employed, such as fluidized bed, combustion turbines, etc , equipment manufacturers were requested to assist in conceptualizing the rehabilitation effort Equipment suppliers were contacted, as required, for technical assistance

30 The primary Western technologies considered for rehabilitation are

- Combined cycle combustion turbines (CCCT)
- Atmospheric circulating fluid bed boilers
- Emission controls
  - SO_2 wet scrubber
  - SO_2 dry scrubber
  - Baghouse
  - Precipitator
  - NO_x reduction

31 For each rehabilitation alternative, a general arrangement drawing, elevations, heat balance, and a description of the alternative was provided In addition, to identify the requirements for the Russian work component, the required modifications to accommodate the Western technology were listed

32 The scope of work considered in developing the capital cost estimates was quite extensive The costs include new equipment and labor for dismantling existing equipment and for installing the new equipment In addition to estimating these direct costs, the estimates include related indirect costs as well as the owner's costs and project contingencies

33 A capital cost estimate was prepared for each alternative rehabilitation method The key components of the estimate were determined to be the following

- Western equipment
- Western indirects
- Russian equipment
- Russian material
- Russian labor
- Russian indirects (including contingency and owner's costs)

34 Working Group 2 was responsible for the development of the "Western costs " Equipment suppliers were contacted, as required, to obtain quotations for major Western equipment items These costs were provided in current (1994) dollars

35 Russian cost estimates for the installation of Western equipment and for Russian rehabilitation equipment and labor were prepared by Working Group 2 because all of this work will be performed in Russia The country's rapidly changing economic climate made it difficult to estimate the current costs of equipment and labor using Working Group 2's historical database, however To overcome this difficulty, it was agreed that Russian cost estimates would be based on a time period when sound economic data were available January 1991 was selected as the base period for all Russian estimates

36 Appendix F presents estimated rehabilitation costs for each of the alternatives considered for each plant category Western costs have been de-escalated to reflect January 1991 U S costs The Western costs are presented in dollars, while the Russian costs are presented in 1991 Rubles No attempt has been made to combine the two estimates because escalation rates from 1991 to the anticipated date of installation will be dramatically different for the two economies Adjustments to a common cost-basis year and for currency conversions are included in the Working Group 5 model

37 Operating and maintenance cost estimates (excluding fuel) were also estimated for each rehabilitation alternative evaluated for each of the plant categories These costs are also presented in Appendix F The operating cost estimates were developed by applying estimating procedures recommended by the Electric Power Research Institute's (EPRI) Technical Assessment Guide (TAG) Applying these procedures results in an estimate of operating and maintenance costs that includes the following components

- Operating labor
- Maintenance labor
- Maintenance materials
- Overhead charges
- Consumables

38 Estimates of typical U S fixed and variable operating and maintenance (O&M) costs at 1994 pricing levels, broken down by maintenance material, consumables and labor, were prepared

39 These typical U S O&M costs were converted to a Russian cost basis using the following assumptions

- Russian labor costs in 1994 are 10% of U S labor costs
- U S labor productivity in 1994 is 50% greater than Russian labor productivity
- Russian maintenance materials and consumable costs in 1994 are 70% of U S costs

3 2 2 Rehabilitation/Modernization of Aging Power Plants

40 As described in Chapter 2, some 600 thermal power plant units with a combined gross output of almost 80,000 MW will reach their projected retirement date by the year 2010 For each unit reaching the age of retirement, a number of options are available to generate replacement power This section discusses the option of rehabilitating and modernizing these units

41 The thermal power plants subject to retirement differ in their station configuration, power block size, fuel type, boiler design, thermal cycles, age, and other factors Because both Russian and Western technologies are available to upgrade and rehabilitate this wide variety of aging plant designs and the optimum technology for a given generating unit is dependent on that unit's specific technical characteristics, an approach was developed to allow a large number of generating units to be represented within a manageable number of rehabilitation strategies These are presented in Appendix F as Performance Characteristics for Existing Thermal Power Plants Scheduled to Retire (1994-2010)

42 The major characteristics of Russia's thermal plants considered for rehabilitation may be categorized using criteria similar to those described in Chapter 2 of this report

- Fuel type
- Unit type plants are either condensing power plants (CPP) or combined heat and power (CHP) plants
- Plant location plants are classified with respect to their location in seven regional power systems within Russia

43 Table 3-5 presents a breakdown of the existing thermal power plants that will reach retirement age by the year 2010 as a function of the type of fuel fired Although coal is an important fuel, it is clear that the majority of units subject to rehabilitation are fired by natural gas (with mazut residual fuel oil as a backup fuel) Where both natural gas and mazut are indicated as the fuel type, about 92% of the heat input (annual basis) is from natural gas, while the remaining 8% is from mazut

Table 3-5
Total Capacity of Thermal Plants Subject to Retirement
(by Fuel Type)

Fuel	Total Capacity (MW)	Total Capacity (%)
Natural Gas	450	0 6
Natural Gas/Mazut	44,051	55 8
Natural Gas/High-Quality Bituminous	6,369	8 1
High-Quality Bituminous	4 967	6 3
Low-Quality Bituminous	9 140	11 6
High-Quality Lignite	5,008	6 3
Low-Quality Lignite	8 920	11 3
Total	78,905	100 0

44 Where high-grade bituminous coal is used as a backup to natural gas, about 80% of the heat is generated by firing natural gas, while 20% comes from coal (primarily during the winter months) Coal firing is possible because the boilers were originally designed to fire both coal and natural gas

45 Table 3-6 presents the same inventory as a function of unit type Nearly 50% of the units are of the CPP type, while the remaining units are of the CHP type

Table 3-6
Total Capacity of Thermal Plants Subject to Retirement
(by Unit Type)

Unit Type	Total Capacity (MW)	Total Capacity (%)
CPP	39 054	49 5
CHP	39,851	50 5
Total	78 905	100 0

46 Table 3-7 presents a breakdown of the thermal power units considered for rehabilitation, by region More than 65% of this capacity is located in three regions -- Center, Urals, and Siberia -- which are the major regions of power production within Russia

Table 3-7
Total Capacity of Thermal Plants Subject to Retirement
(by Region)

Region	Total Capacity (MW)	Total Capacity (%)
North-West	4,482	5 7
Center	23,323	29 6
Middle Volga	9,027	11 4
Urals	19,998	25 3
Tyumen	2,632	3 3
North Caucasus	6,435	8 2
Siberia	10 856	13 8
Far East	2 152	2 7
Total	78,905	100 0

47 Several rehabilitation alternatives were considered for the retiring thermal plants In most cases, the reconstruction of the power block equipment utilizing Western technology was included as one of the alternatives Other alternatives included constructing circulating fluid bed combustors (CFB) to replace coal-fired boilers, repowering gas-fired boilers with combustion turbines, and replacing gas-fired boilers with combined cycle systems

48 Post-reconstruction performance and cost data were developed for each alternative These data are presented in Appendix F Descriptions of each rehabilitation alternative considered for each of the categories are also presented in Appendix F A comparison of the performance characteristics of existing thermal power plants scheduled to retire with the post-reconstruction performance provide information related to

- Heat rate improvement

- Operating cost improvement
- Availability improvement

49 Tables 3-8 (a) and 3-8 (b) present estimated full-load net plant heat rates for the units subject to rehabilitation as a function of the fuel fired for CPP and CHP units The heat rates for CPPs are presented as a function of both fuel fired and unit size, because size has a significant impact on heat rate Net plant heat rates for CHP units are given for operating seasons since there is a significant seasonal variation Because the CHP units are relatively small, size is not a significant correlating variable

50 Estimated heat rates are presented for the units both before and after rehabilitation The heat rates for coal-fired rehabilitated units presented in the tables reflect the reconstruction of the boilers and generating system in-kind, utilizing coal as the heat source Rehabilitation options based on switching fuels (from coal to natural gas) are not included in this summary table Estimated heat rates for the natural gas-fired units reflect the reconstruction of the steam boilers, except where such a rehabilitation case was not considered These cases are described in the footnotes to the tables

Table 3-8 (a)
Estimated Heat Rate Improvement for Rehabilitated Thermal Plants
(Condensing Power Plants)

	Full Load Net Plant Heat Rate (Btu/kWh)	
	Before Rehabilitation	**After Rehabilitation**
Natural Gas/Mazut-Fired Units		
Large Units (≥ 300 MW)	9 000	8 800
Medium Units (150-299 MW)	9,100 - 9,200	7 500 (1)
Small Units (< 150 MW)	9 700	6 700 (2)
Coal-Fired Units		
Large Units (≥ 300 MW)	9 600 - 9 700	9,200 - 9 400
Medium Units (150-299 MW)	9 800 -10 000	9,300 - 9 600
Small Units (< 150 MW)	10 800	10 500

(1) Reflects hot combustion air repowering of the boilers
(2) Reflects replacement of boilers with more efficient combined cycle units

Table 3-8 (b)
Estimated Heat Rate Improvement for Rehabilitated Thermal Plants
(Combined Heat and Power Plants)

	Full Load Net Plant Heat Rate (Btu/kWh)	
	Before Rehabilitation	**After Rehabilitation**
Natural Gas/Mazut-Fired Units		
Winter	5,200	5,100
Spring/Fall	6,100	6 100
Summer	7 000	6,900
Coal-Fired Units		
Winter	6,000 - 6,100	5,800 - 5 900
Spring/Fall	7,100 - 7,300	6,800 - 7,100
Summer	8,100 - 8,300	7 700 - 8,000

51 Similarly, the estimated changes in plant operating costs as the result of rehabilitation are presented in Tables 3-9 (a) and (b) These tables demonstrate that rehabilitation does not always improve operating efficiency In fact, variable operating costs for the rehabilitated units are higher than for the retiring units, primarily due to the costs for the air pollution control equipment associated with the rehabilitation program

52 An improvement in availability is anticipated as a result of the rehabilitation of the units, and the magnitude of the improvement has been estimated The estimated forced and planned outage rates for the units, prior to retirement and following rehabilitation, are presented in Appendix F for each plant category These outage rates were provided as input to the Working Group 5 modeling activities

Table 3-9 (a)
Estimated Changes in Fixed Operating Cost for Rehabilitated Thermal Plants

	Before Rehabilitation $/kW-yr	After Rehabilitation$/kW-yr
Natural Gas/Mazut-Fired Units		
Large CPPs (≥ 300 MW)	13 15	15 10
Medium CPPs (150-299 MW)	15 15 - 15 80	7 25 (1)
Small CPPs (< 150 MW)	17 75	19 70 (2)
CHPs	33 00	36 65
Coal-Fired Units		
Large CPPs (≥ 300 MW)	12 60 - 14 80	14 00 - 18 15
Medium CPPs (150-299 MW)	16 05 - 16 70	17 85 - 19 40
Small CPPs (< 150 MW)	20 45	22 75
CHPs	37 60	41 75

(1) Reflects repowering of the boilers using gas turbine discharge
(2) Reflects replacement of boilers with more efficient combined cycle units

Table 3-9 (b)
Estimated Changes in Variable Operating Cost for Rehabilitated Thermal Plants

	Before Rehabilitation $/MWh	After Rehabilitation $/MWh
Natural Gas/Mazut-Fired Units		
Large CPPs (≥ 300 MW)	0 85	0 85
Medium CPPs (150-299 MW)	0 95 - 1 00	0 30 (1)
Small CPPs (< 150 MW)	1 20	0 30 (2)
CHPs	1 25	1 50
Coal-Fired Units		
Large CPPs (≥ 300 MW)	1 20 - 1 40	1 85 - 2 15
Medium CPPs (150-299 MW)	1 50 - 1 55	2 35 - 2 55
Small CPPs (< 150 MW)	1 90	3 00
CHPs	5 15	7 65

(1) Reflects repowering of the boilers using gas turbine discharge
(2) Reflects replacement of boilers with more efficient combined cycle units

3 2 3 Fuel Switching/Fuel Upgrades

53 Improved energy efficiency and/or reductions in the cost of producing power can often be achieved by upgrading the solid fuel fired or by switching to another fuel source Activities directed towards optimizing fuels were considered beyond the scope of this program, instead, fuel switching was considered on a case-by-case basis as a part of the rehabilitation/modernization program The cases selected are

- Some 3,000 MW of capacity (6 x 500 MW units) located in the Urals are currently firing a low-quality bituminous fuel (Ekibastuz) The future availability of this fuel was considered doubtful and an alternate fuel, Beryozovsky high-quality lignite, was identified as a candidate for fuel switching The impacts of switching on the design of the boiler, mills, auxiliary equipment and emission controls were included in the investigation

- An additional 9 x 300 MW, also located in the Urals and currently firing Ekibastuz bituminous coal, were subjected to a similar analysis The possibility of retiring four of the units and replacing them with 2 x 500 MW boilers firing Beryozovsky lignite (at the same site) was evaluated

- Some 1,400 MW of capacity (7 x 200 MW), located in the Center region, are currently firing Beryozovsky lignite The high cost of transporting this fuel to the station (some 5,000 km), combined with the availability of natural gas as a potential alternate fuel, led to an analysis of replacing the coal-fired boilers with a natural gas-fired combined cycle system The system would include both new gas turbines and new or significantly modified steam turbines

Details of the impacts of fuel switching on the technology and investment costs associated with the modernization of the individual plants are presented in Appendix F

3 2 4 Life Extension Options

54 Working Group 2 focused on determining an investment plan for the rehabilitation of the aging fossil power plants scheduled to be retired by the year 2010 The results of this investigation form the basis for the investment requirements presented in this Study

55 Historically, older generating units were retired when new, larger and more economical base-loaded plants came on line More recently, however, because the rate of demand growth for electrical power has declined and heat rates for new units are not significantly less than for existing units, the construction of new, large units has been significantly reduced and these older units are no longer routinely retired and abandoned

56 For most of the Russian thermal plant categories considered, one of the primary alternatives evaluated was the reconstruction of the power plant, in kind, applying Western technology where appropriate to improve efficiency or other key plant performance variables This plant investment program would be expected to extend the life of the power plant by an additional 25 to 30 years Although costly, the investment requirements are significantly less than the construction of a new greenfield power station This alternative was designated as a rehabilitation/modernization approach, but it might be more properly referred to as a full life extension program

57 An alternative not considered in the development of this investment plan was a less aggressive life extension program This is sometimes referred to as "phased" or "limited" life extension This strategy is based on a much more limited approach to the rehabilitation of the units, instead of a major rebuild, and would significantly reduce investment costs The concept of limited life extension, as it might be applied to the aging Russian thermal units, is described below

58 The underlying assumption associated with the rehabilitation approach utilized in this Study was that upon reaching retirement age, a unit was taken out of service and was either retired or subject to a major rehabilitation In actual practice, however, this has not occurred Many of the Russian thermal units have passed their planned retirement date and, because of their need for power and lack of rehabilitation capital, they continue to operate Some of these units may be in very poor condition and may, in fact, be inoperable These units would be candidates for major rehabilitation programs Others may be in fairly good condition with no outward signs of having reached their retirement age These units would not require major capital investment as assumed in this Study

59 A large number of units, having reached their retirement age, are operating with high forced outage rates and relatively high annual maintenance costs These units are potential candidates for a limited life extension program A life extension program applied to these units would have the primary goal of continued operation while maintaining or improving availability, efficiency, operation and maintenance, and safety

60 Estimating the costs for a limited life extension program requires a systematic component evaluation to select the items in the plant that are possible candidates for rehabilitation, identify the repair or replacement options, and estimate the cost of each potential option The first phase of a unit evaluation includes prioritizing station components, examining station records, and conducting interviews and walkdowns at the station, and inspections and non-destructive testing of identified components Experience has indicated that, in most cases, critical items for consideration are

- Boiler
  - Steam drums
  - Superheater and reheater headers and tubing
  - Waterwalls
  - Economizers
  - Downcomers
  - Main steam and hot reheat steam piping
- Turbine
  - Rotors
  - Valves
  - Steam chest
  - Blades and nozzle blocks
  - Casing and shells
- Generator
  - Rotor shaft
  - Stator windings and insulation

- Retaining rings
- DC exciter
- Voltage regulator

61 In addition, other items (including balance of plant components) identified by plant personnel would be included in any life extension evaluation program

62 Each item identified for consideration is then subject to an economic evaluation to establish the cost of repair or replacement and the anticipated economic benefit associated with the activity (reduced maintenance, lower heat rate, etc) Decisions are then made, on a component-by-component basis, to rehabilitate the specific component or to "do nothing " The impact of the "do nothing" alternative on the projected future performance of the system may be considered when conducting this evaluation

63 It should be obvious that limiting life extension investment to key components in the system is considerably less costly than a complete rebuild of the power plant since only a fraction of the power plant equipment will be included In some cases a clear economic advantage (payback) can be demonstrated for the rehabilitation of a specific plant component, whether the component requires replacement or not, and such projects might be considered independent of life extension In other cases (improved safety, for example) the decision to implement the modification may not be so clear

64 The life extension cost ($/kW) for any unit is a function of the condition of the unit and the number and types of components requiring attention Units where the majority of the boiler and turbine components identified above require immediate rehabilitation would probably not be considered candidates for a limited life extension program of the type described above For some units, however, a relatively small investment may result in achieving the goal of continued operation while maintaining or improving availability, efficiency, operation and maintenance, and safety The potential for reducing investment requirements for the Russian power sector by applying a program of limited life extension should not be ignored

3 2 5 New Thermal Capacity

65 Tables 3-10 (a) and 3-10 (b) present performance and cost data for new (un-sited) thermal power plant technologies for both CPP and CHP plants The data reflect approximate levels of plant performance and cost They are intended to represent average or typical performance and cost for plants in a given category Actual performance and cost parameters may vary considerably due to variations in fuel quality, specific plant configuration, and site conditions For more detailed information refer to Appendix F Net plant heat rates for CHP units are given for winter months, and represent worst-case values for the year

Table 3-10 (a)
New Un-Sited Thermal Power Plants Performance and Cost Data
(Condensing Power Plants Only)

Unit Type	Fuel	Size (MW)	Full Load Net Plant Heat Rate (Btu/kWh)	Fixed Operating Costs ($/kW/yr)	Variable Operating Costs ($/MWh)
PC	Coal	300	9,300	15 00	2 20
PC	Coal	500	9 200	12 60	1 80
AFB	Coal	300	9 300	11 90	3 00
C C	NG	360	6 200	7 20	0 30
C C	NG	450	6 200	6 40	0 30

Key AFB = atmospheric fluidized bed
C C = combined cycle
PC = pulverized coal
NG = natural gas

Table 3-10 (b)
New Un-Sited Thermal Power Plants Performance and Cost Data
(Combined Heat and Power Plants Only)

Unit Type	Fuel	Size (MW) (winter)	Full Load Net Plant Heat Rate (Btu/kWh) (winter)	Fixed Operating Costs ($/kW/yr)	Variable Operating Costs ($/MWh)
C C (cogen)	NG	330	4,500	7 90	0 30
C C (cogen)	NG	260	4,700	10 00	0 40
C C (cogen)	NG	27	4 800	19 90	0 45
PC	Coal	180	5 800	19 80	2 60
AFB	Coal	180	5 800	15 70	3 60

Key AFB = atmospheric fluidized bed
C C = combined cycle
cogen = cogeneration unit
PC = pulverized coal
NG = natural gas

3.3 NUCLEAR ENERGY

66 The Joint Parallel Nuclear Alternatives Study (JPNAS) is a parallel study to the JEPAS This study sought to assess the costs of enhancing the safety level of Russian nuclear power plants (NPPs), the decommissioning of units with the RBMK-1000 and first-generation VVER-440 reactors, the completion of NPP construction, NPP repowering into a fossil fuel plant, and the construction of new-generation NPPs In the framework of the JEPAS, the JPNAS provided the data on the nuclear sector which were needed to exercise an integrated resource planning model for Russia's power sector

3 3 1 Cost Development Methodology

67 A U S -based Engineering Economic Database (EEDB)[2] was used as a basis for developing the cost estimates required for this Study The EEDB was selected because of its capability to achieve consistency and comparability across a variety of cost estimates for dissimilar items

68 The EEDB cost models are quantity (materials and related installation hours) driven, reflecting the specific design features of the U S power plants represented by the technical data models The EEDB technical data models are based on actual power plant design and construction experience Additionally, the data models have been periodically checked against actual field data to assure their compatibility with current U S technical practice and cost experience

69 The direct costs were estimated in terms of quantities of commodities, equipment and installation labor that reflect the design features of the power plant of interest Costs were developed from the estimated quantities based on actual design features, or adjustments of quantities for representative or similar design features found in the data base

Base Construction Cost Basis

70 The cost options were first developed by U S experts using EEDB detailed data models (U S basis) They were then modified by detailed technical data provided by Russian experts to reflect actual Russian NPPs, and then finally converted to Russian conditions, based on the conversion factors provided by Working Group 5 and shown in Table 4-6

71 For each system or facility, the following procedure for direct cost estimation was implemented

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2 This database is operated and maintained by Raytheon Engineers and Constructors a U S -based engineering and construction firm

- The U S experts selected the design prototype for the system/facility from the EEDB database
- The prototype parameters such as mass, size, capacity, etc were refined and corrected on the basis of detailed technical information provided by the Russian experts
- The cost estimation of the system/facility was computed on the basis of the corrected parameters

72 For each unit an indirect cost, owner's cost, contingency and "total" were calculated for each direct cost in accordance with EEDB procedures and methodology Indirect costs were calculated by taking into account the magnitude and type of construction, craft labor requiring supervision, engineering costs and construction duration The owner's cost and contingency for each unit were calculated as a percentage of the base construction cost (BCC) [3] The economies associated with multiple units on a single plant site were taken into consideration, and are reflected in the cost estimates

O&M Costs

73 The non-fuel O&M costs were developed on a Russian basis from EEDB procedures and data These costs were based on detailed unit staffing levels provided by the Russian experts and an estimated relative allowance for expendable materials The non-fuel O&M costs were developed in terms of both fixed and variable costs

74 The fuel costs were developed by the Russian experts The assumed model of the nuclear cycle consists of eight phases, from uranium extraction through the final disposal of spent fuel This composition of the fuel cycle corresponds to the so-called open or once-through cycle when there are no fuel reprocessing and related activities Other possible fuel cycles (closed cycle with the use of reprocessed uranium and plutonium, thorium cycle) are less ready for practical implementation and were therefore excluded from consideration in this Study

75 The basic assumptions used to assess the cost of the nuclear fuel cycle are as follows

- Due to the existence of large stocks of extracted uranium in various forms in Russia, price escalation for nuclear fuel over the entire period of the Study need not be considered

3 EPRI *1993 Technical Assessment Guide*

- The costs incurred at different times during the nuclear fuel cycle should be levelized to the moment of placing the fabricated fuel into the reactor [4]

- The price of nuclear fuel is determined on a unit-by-unit basis depending on the enrichment of the fuel used

76 Three scenarios of the prices for nuclear fuel were suggested a minimum price scenario, an average price scenario and a maximum price scenario (the average price scenario is part of the reference case in the integrated model) The specific assumptions for these scenarios are as follows

- *Minimum* - the price of enriched uranium is assumed to be zero This reflects the fact that a very large stock of enriched uranium, including highly enriched uranium, exists in Russia This scenario represents an extreme case designed with the objective of investigating, within the integrated model, the marginal system impact of the cost of nuclear fuel In reality, this case could occur only for limited quantities of nuclear fuel

- *Average* - the costs are at the prices on the world unrestricted market [5] This market is served mainly by the CIS countries, including Russia

- *Maximum* - all costs are the prices characteristic of long-term contracts for major producers in the world market [6]

Decommissioning Costs

77 Decommissioning costs have two principal components direct impact costs and socio-economic costs For the purposes of this discussion, direct impact costs include the costs of all on-site and off-site activities directly associated with the decommissioning process

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4 The levelization of different time costs in this context means the levelization of all fuel cycle costs to the time of placing the fuel into the reactor Such a procedure is necessary for nuclear fuel to account for substantial time differences among the various investments required However this levelization is different from the cost levelization to be implemented within the integrated model of a power system The latter levelizes all the costs to one selected time point, usually the beginning of the planning period

5 *The Economics of the Nuclear Fuel Cycle* OECD (Organization for Economic Co-operation and Development)/NEA (Nuclear Energy Agency) Revised Final Draft NEA/EFC/DOC(93)1, June 1993

6 *Nuclear Fuel* A biweekly report from the editors of *Nucleonics Week* Vol 19, No 10, May 9, 1994

78 The duration of activities and their manpower resource requirements formed the basis for the present estimate The Russian experts developed the definition of the decommissioning phases, their duration, the outline of activities for each of the phases, and the manpower requirements for each activity The decommissioning process is divided into three sequential phases preparation for decommissioning, preparation for a long-term safestore, and the long-term safestore itself (analogous to the U S -type process with long-term safestore)

79 The cost drivers considered in this study for estimating socio-economic costs are as follows staffing levels at the unit during normal operation, staffing levels at the unit during various decommissioning phases, the duration of the decommissioning broken down into phases, town site demographics, costs of retraining and relocating staff made redundant by decommissioning, continued compensation for redundant workers, and allowance for living accommodations at a new location

80 Substitute heat sources for district heating may be required when NPPs are shut down for decommissioning These costs associated with decommissioning have not been estimated in the JPNAS, but were accounted for in the Working Group 5 modeling

81 Also not considered in this Study is the construction of additional generating capacity at the site or in the vicinity of a decommissioned reactor unit It is obvious that this scenario may mitigate or completely eliminate the socio-economic costs

3 3 2 Assessed Nuclear Options

82 The JPNAS analyses were structured on the cost assessment of six options for the Russian nuclear power sector which were identified in the Terms of Reference (TOR) They are as follows

Option 1 Provide safety upgrades to all RBMK and first-generation VVER-440/230 reactors to allow their operation until the end of service life at safety level acceptable to the West

Option 2. Decommission RBMK and first-generation VVER 440 reactors

Option 3 Repower partially completed VVER-1000 NPPs as fossil fuel plants The representative plant used in this study was Rostov-1

Option 4 Complete the partially completed VVER-1000 reactors, with safety levels comparable to the West

Option 5 Provide safety upgrades to operating plants with the VVER-440 /213 and VVER-1000 reactors to permit the operation of these reactors at reduced levels of risk

Option 6 Build a new evolutionary power plant NP-500

83 The cost estimates derived here were based on defined concepts and also on drawings and specifications for some specific upgrades and units provided by Russian experts These cost estimates are summarized in Table 3-11 and are presented in greater detail in Appendix G It should be noted that these assessed options are attempts to implement the Study Terms of Reference For options that include safety upgrades (options 1, 4, and 5), Working Group 3 operationally defined, for the purposes of this Study, a set of upgrades that raised the level of safety at the associated NPPs and that might be acceptable to potential investors This set of upgrades included the following

- A subset of the upgrades developed by the Russian engineers for the International Users Group (IUG) of Soviet Designed Reactors and published in a March 1994 report prepared for the World Association of Nuclear Operations (WANO) that includes all the upgrades directly associated with reactor and plant safety [7]
- The implementation of a confinement/containment system for RBMK and first generation VVER-440s
- Certain additional engineering studies from the current Russian program to identify upgrades not included in the two previous items

84 It is important to note that risk is not only reduced by design measures but also by operational improvements Therefore, the Russian safety program includes measures aimed at improving operation and maintenance, quality control, diagnostic methods, administrative controls, and personnel qualifications and training The safety culture is also improved by periodic safety assessments and personnel experience

Option 1

85 ***Safety upgrades to units with RBMK-1000 and VVER-440 Reactors*** The minimal upgrades for the units with RBMK-1000 and first-generation VVER-440 reactors are as specified in the March 1994 WANO reports entitled *Improvement of RBMK-1000 Nuclear Power Plant Safety* and *Improvement of VVER-440/230 Nuclear Power Plant*

7 It should be noted that the major part (>85%) of the IUG-set are directly associated with reactor and plant safety

Safety, and in particular, in Chapter 3 of these reports, "Major Measures on Safety Enhancement to be Implemented in the Future " Not all of the IUG recommendations were costed because some of the items addressed improvements in availability and operation, and not in safety The upgrades that were costed are listed in Appendix G

86 Safety upgrades that have already been completed as part of the current Russian upgrade program have not been included in the Study Prorated costs associated with completing safety upgrades that are currently in process were included Additional engineering studies and confinement/containment systems aimed at addressing safety issues not included in the current program are also included in the Study

87 The major measures for the safety enhancements of these nuclear power plants have been categorized by the IUG on the basis of the specific plant elements which they address, namely

- Integrity of the primary loop
- Measures to avoid or control transients
- Integrity of the containment/confinement
- Protection from fires
- Accident management
- Reactivity control
- Methods, studies, and procedures

88 For the purposes of this Study, three containment functions were conceptually designed and costed These were

- a U S -style full containment system for RBMK-1000 and first-generation VVER-440 reactors

- a jet condenser pressure suppression system and a metal confinement structure of Russian design over the operating floor for RBMK-1000s

- a jet condenser pressure suppression system without additional confinement elements for the first-generation VVER-440 reactors

89 The evaluated over-night costs of safety upgrades to the RBMK-1000 units ranged from $35 to $90 million for the confinement and jet condenser designs, and from $136 to $228 million for the full containment designs The evaluated over-night costs of safety upgrades to the first-generation VVER-440 units ranged from $29 to $39 million for the confinement and jet condenser designs, and from $87 to $111 million for the full containment designs

Option 2

90 ***Decommissioning*** The Study assessed the cost of decommissioning units with RBMK-1000 and first-generation VVER-440 reactors Two approaches were considered a Russian approach and a U S approach Both approaches were based on data provided by the Russian experts The social costs of decommissioning were assessed in the same way for both approaches

91 The Russian approach to decommissioning was used as the reference case in the JEPAS This approach is analogous to the approach for the long-term safe storage of the plant until the time of final plant dismantling accepted in the United States The Russian approach is based on Russian Federation studies tempered by maintenance, repair and replacement experience As such, it reflects decommissioning procedures that regulatory and utility organizations find acceptable in the Russian Federation today

92 The U S approach was included in this Study at the request of the U S experts It is based on a process with immediate full plant dismantling The U S approach is based on the results of U S studies tempered by the effects of actual experience As such, it reflects decommissioning procedures that regulatory and utility organizations find acceptable in the United States today

93 The U S approach to decommissioning Russian nuclear power plants was developed as a hypothetical case on the basis of nuclear regulation, financial conditions, and the technology base existing in the United States Neither approach can be claimed to be optimal

94 The evaluated costs of the planned decommissioning of RBMK-1000 units ranged from $169 to $198 million for the Russian approach, and from $49 to $77 million for the U S approach The evaluated costs of the planned decommissioning of VVER-440 units ranged from $108 to $124 million for the Russian approach, and from $48 to $64 million for the U S approach

95 The evaluated costs of the early decommissioning of RBMK-1000 units ranged from $172 to $200 million for the Russian approach, and from $52 to $81 million for the U S approach The evaluated costs of the early decommissioning of VVER-440 units ranged from $109 to $125 million for the Russian approach, and from $49 to $65 million for the U S approach

Option 3

96 ***Repowering Rostov-1*** The Rostov site was selected by the JPNAS experts as a representative repowering site for the purposes of this Study This site was initially planned as a four-unit VVER-1000 NPP, however, the plant construction has been discontinued Unit 1 is approximately 95% complete, while Units 2, 3 and 4 are only about 50, 10 and 5% complete, respectively The site, installed systems and equipment have been maintained by the plant staff since construction at the plant was halted

97 Two alternatives were evaluated

- Repowering the unit utilizing multiple gas turbines in combination with HRSGs (heat recovery steam generators) to generate steam to drive the existing nuclear cycle steam turbine-generator (gas turbine combined cycle) This was found to have several disadvantages, including 1) the major investment in gas turbine equipment required to match the existing turbine steam requirements, 2) the large volume of natural gas required to fire these turbines, and 3) the substantial increase in station output from the combined gas turbine/steam turbine generators Such disadvantages indicated that this option would not be an attractive alternative

- Repowering Rostov-1 as a coal-fired plant under the premise of the maximum use of equipment which is already installed The basic concept involves producing supercritical steam in fossil-fueled boilers to drive additional high-pressure topping turbines The exhaust steam flow from this system is cooled so as to match inlet conditions of the partially completed nuclear unit turbine The combined output of the generators driven by the topping turbines and those driven by the partially completed nuclear plant turbine is approximately 1,500 MW To implement the repowering, substantial development of fossil fuel resources and railroad capacity will also be required Site development for coal storage and ash disposal is also needed The JPNAS has not estimated these costs

98 This option is the most costly of the six options considered by Working Group 3 As a result, it was not chosen by the planning models The overnight cost of repowering Rostov-1 as a fossil fuel plant was estimated at $557 million

Option 4

99 ***Completion of Kalinin-3*** This option involves completing the construction of Kalinin-3, a VVER-1000/320 plant, which is reportedly 75% complete If this option is exercised, construction will be restarted after a period of relative inactivity This period of inactivity was assumed to be at least two years in duration, long enough to require some

rework of certain plant systems and structures It is reasonable to assume that if the plant is completed, it will incorporate safety upgrades to permit operation at safety levels comparable to those in the West The cost of completing the Kalinin III reactor (75% complete) with safety upgrades was estimated at $146 million

100 In addition, Working Group 3 assessed the costs for the completion of Balakovo units 5 and 6, Kursk unit 5, and Rostov unit 1 These units are 30, 15, 75, and 90% complete, respectively

Option 5

101 ***Safety upgrades to operating VVER-1000 and VVER-440/213 reactors.*** These safety upgrades involve the modification of operating VVER-1000 and VVER-440/213 reactors so that they can operate at a reduced level of risk As the basic set of upgrades, the recommendations for IUG were taken that correspond to the published WANO reports dated March 1994 [8]

102 Additionally, the costs of engineering studies aimed at addressing safety issues that were not included in the WANO guidance were assessed

103 The evaluated costs of safety upgrades to operating VVER-1000 units ranged from $16 to $29 million The evaluated costs of safety upgrades to operating VVER-440/213 units ranged from $11 to $14 million for designs using the confinement and jet condenser approach, and $69 to $86 million for designs using the full containment approach

Option 6

104 ***New-generation nuclear power plants.*** Russia has developed several advanced NPP concepts with enhanced safety features in a program analogous to the U S advanced reactor program The design considered in this Study is the 635 MWe NP-500 (since December 1994, this project has been denominated as VVER-640) The NP-500 is one of the Russian Federation's evolutionary nuclear power plants with a medium power reactor rated at 1,800 MW The NP-500 was developed to achieve a higher level of safety than nuclear power plants operating in the Russian Federation by applying passive safety systems and providing a double protective containment shell

105 The evaluated costs of constructing an NP-500 are $529 million for the first unit and $440 million for the second unit, if a two-unit plant is built

8 *Improvements of VVER-1000 Nuclear Power Plant Safety* and *Improvement of VVER-440/213 Nuclear Power Plant Safety*

Table 3-11
"Overnight" Base Construction Cost Estimate Summary

Option Description			Project[1] Duration (Months)	Total Cost[2]	
				High/Low (10^6 $)	High/Low ($/kW)[3]
Option 1 Continuation	With Confinement and Jet Condenser	RBMK-1000 (1000 MW)	24	90/35	90/35
		VVER-440/230 (440 MW)	21	39/29	90/66
	With Full Containment	RBMK-1000 (1000 MW)	36	228/136	228/136
		VVER-440/230 (440 MW)	36	111/87	252/198
Option 2 Planned Decommissioning	Russian Approach	RBMK-1000 (1000 MW)	516	198/169	198/169
		VVER-440/230 (440 MW)	516	124/108	282/245
	U S Approach	RBMK-1000 (1000 MW)	144	78/49	78/49
		VVER-440/230 (440 MW)	120	64/48	145/108
Option 2 Early Decommissioning	Russian Approach	RBMK-1000 (1000 MW)	480	200/172	200/172
		VVER-440/230 (440 MW)	480	125/109	284/247
	U S Approach	RBMK-1000 (1000 MW)	144	81/52	81/52
		VVER-440/230 (440 MW)	120	65/49	147/110
Option 3 Conversion of a VVER-1000 to Fossil Fuel (1500 MW)[4]			24	557	371
Option 4 Completion/Upgrade of a VVER-1000 (1000 MW)[4]			26	146	146
Option 5 Upgrade of a VVER-440 /213 (440 MW)			21	14/11	32/25
Option 5 Upgrade of an Operating VVER-1000 (1000 MW)			18	29/16	29/16
Option 6 New Generation NP-500 (635 MW)			48	529/440	833/693

1 RBMK Project Duration: 1 year shutdown for jet condenser/confinement, 3 year shutdown for full containment Both include fuel channel replacement
VVER Project Duration: 6 month shutdown for jet condenser/confinement 3 years for full containment
2 Base construction cost with owner's cost and contingency
3 Based on Gross Electric Capacity
4 Only one unit evaluated

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3 3.3 Projects Proposed for Implementation

106 ***Development of the Optimal Implementation Strategy for Safety Upgrades of Operating NPPs.*** In the JPNAS, the costs of implementing various safety upgrades have been developed Russian and international expert groups have conducted many studies of the safety of Soviet-designed NPPs The development and implementation of a methodology is recommended This methodology would allow, on the basis of -- 1) the studies already performed, 2) the available experience and knowledge of the specific safety systems and the facility as a whole, and 3) some additional studies involving Probabilistic Safety Assessments (PSA) -- to rank the suggested safety upgrades in accordance with their risk so that the maximum benefit of the investments in safety upgrades could be ensured, with due consideration of the financial constraints

107 As a continuation of this activity and because the recommendations of the IUG include PSAs for each operating VVER, it is proposed that a level 2 PSA be performed for Balakovo-1 A generic PSA for the VVER-1000 is currently in process for Kalinin unit #1 as part of a joint Russian GAN - US NRC program Russian engineers' application of the generic PSA methodology to a specific Russian power plant would complete the technology transfer inherent in the PSA project Many problems in the PSA process have been identified and solved by U S engineers This knowledge will now be used to help Russian engineers improve their PSA methodology

108 ***Completion of the Design of the NP-500 and NP-1000 (Evolutionary Reactors) to a Sufficient Level of Detail to Provide for a Full-Scale Licensing Process.*** The NP-500 and NP-1000 are approaching design completion Their designs include innovative passive and active systems Further work is needed to verify the operational reliability of the designs, including the environmental requirements of these systems It is proposed that Russian engineers undertake such verification and optimization of design features with the support of U S experts, to facilitate the licensing of the NP-500 and NP-1000 in a manner consistent with international practice Additionally, to further design completion and the subsequent construction process, this project will make available to Russian engineers cost estimating and project management tools Note that such tools will be useful across the entire spectrum of electricity sector projects

109 ***Development of the Decommissioning Program in the Context of a Specific RBMK-1000 Reactor*** The level of maturity of the Russian approach to decommissioning is characterized by a lack of comprehensive regulatory guidance and the absence of options for the disposition of spent fuel and radwaste A conclusion which may be drawn from the JPNAS is that Russian planning for decommissioning is not at the stage where the decommissioning of a specific plant can be undertaken

110 It is proposed that this project identify an RBMK reactor which is likely to be decommissioned in the near term In the context of decommissioning the identified reactor, the following objectives will be addressed

- Recommend appropriate regulatory development
- Specify details and the progression of decommissioning activities
- Develop detailed cost and schedules
- Identify U S technology that supports and facilitates NPP decommissioning

111 Note that the results of this project will be applicable to the decommissioning of other RBMK reactors

3.4 HYDROELECTRIC

112 Hydroelectric plant characteristics and financial investment data were used to prioritize existing hydro plants for rehabilitation, modernization and expansion, and to prioritize new hydro plants for completing committed construction and starting new construction

113 For this Study, four categories of hydroelectric plants were established to identify potential plants for investment The four categories are

Category 1	Existing Plants, Committed Rehabilitation
Category 2	Existing Plants, New Rehabilitation
Category 3	New Plants, Committed Construction
Category 4	New Plants, New Construction

3 4 1 Cost Development Methodology

114 All capital cost data presented in this section reflect the estimated "overnight" capital costs (the cost excluding interest during construction) of rehabilitation and new construction as of January 1, 1991, excluding any interest or financing costs These costs include all equipment, labor and materials necessary for rehabilitation or new construction

115 Average operating costs for the Russian hydro system are about $15/kW and $3/MW/hr for fixed and variable costs, respectively

116 No escalation of the annual capital costs has been included in the costs presented for hydro rehabilitation and new construction

3 4 2 Existing Hydro Plants

117 To maintain the hydroelectric generation system's existing capacity through the year 2010, investments will be required to complete construction at plants currently under rehabilitation Investments will also be needed for new rehabilitation at other plants to preclude the need to retire them prior to the year 2000

118 ***Category 1 - Existing Plants, Committed Rehabilitation.*** Four hydroelectric plants currently under rehabilitation were identified as priority projects Nizhne-Tulomskaya, Volkhovskaya, Volzhskaya (Center) and Volzhskaya (Middle Volga) Without investment, these plants will likely be out of service by the year 2000 The characteristics of the four plants are shown in Table 3-12 They will require an investment of approximately $585 million over the five-year period 1995 to 1999 (Table 3-13) The cost breakdown by equipment, labor and material components is shown in Table 3-14 The proposed investment would provide a 40-year life extension for the four plants These plants currently have 4,957 MW of installed capacity and 20,460 GWh of average annual energy production After rehabilitation, they will have 5,202 MW of installed capacity and 22,720 GWh of average annual energy production as a result of the installation of modern equipment and efficiency improvements

119 ***Category 2 - Existing Plants, New Rehabilitation.*** Four hydroelectric plants were identified as priority projects for new rehabilitation including modernization and expansion Kamskaya, Ivankovskaya, Pavlovskaya, and Uglitchskaya Without investment, these plants will likely be out of service by the year 2000 The characteristics of the plants are shown in Table 3-12 No rehabilitation construction has begun on any of these plants except for Uglitchskaya, which is currently being repaired as a result of the failure of a portion of the draft tube lining The estimated investment requirement for rehabilitating the four priority plants is $370 million over the period 1995 to 1999, as shown in Table 3-13 The cost breakdown by equipment, labor and material components is shown in Table 3-14 The proposed investment would provide a 40-year life extension for the four plants They currently have 810 MW of installed capacity and 2,560 GWh of average annual energy production After rehabilitation, they will have 891 MW of installed capacity and 2,631 GWh of average annual energy production as a result of the installation of modern equipment and efficiency improvements

3 4 3 New Hydro Plants

120 Russia has substantial untapped hydropower resources The economic potential for hydropower has been estimated at about 850,000 GWh/year of deliverable energy At present, the average annual energy production from hydro plants is about 160,000 GWh/year, representing only 19% of the estimated available hydro resources in Russia (significantly less than most European countries and the United States) Most of the undeveloped hydro resources are located in Siberia and the Far East While approximately

50% of the hydro resources in the European part of Russia (west of the Ural Mountains) has been developed, less than 5% of the resources have been developed to date in Siberia and the Far East

Table 3-12
Characteristics of Priority Existing Plants for Rehabilitation

Priority Rank	Plant Name	Region	Generation Capacity (MW)		Avg Annual Energy (GWh)		Capital Investment	
			Existing	New	Existing	New	Total ($Million)	$/kW
Existing Plants, Committed Rehabilitation								
1	Volzhskaya (Middle Volga)	Middle Volga	2,541	2,649	10 520	11 100	250	94
2	Volzhskaya (Center)	Center	2,300	2,400	9 300	10,900	250	104
5	Nizhne-Tulomskaya	North-West	50	57	280	310	25	439
6	Volkhovskaya	North-West	66	96	360	410	60	625
		TOTALS	**4,957**	**5,202**	**20,460**	**22,720**	**585**	**112**
Existing Plants, New Rehabilitation								
3	Pavlovskaya	Urals	166	180	500	503	20	111
4	Kamskaya	Urals	504	552	1,760	1,800	240	435
8	Ivankovskaya	Center	30	33	130	150	25	758
7	Uglitchskaya	Center	110	126	170	178	85	675
		TOTALS	**810**	**891**	**2,560**	**2,631**	**370**	**415**

Note Capital investment cost ($/kW) was computed based on the "new" capacity because it was assumed that without rehabilitation, these plants will be out of service by the year 2000

Table 3-13
Investment Plan for Priority Existing Plants for Rehabilitation

Plant Name	Investment Requirement, $ Million, per Year					
	1995	1996	1997	1998	1999	Total
Existing Plants, Committed Rehabilitation						
Volzhskaya (Middle Volga)	37 5	50	75	50	37 5	250
Volzhskaya (Center)	37 5	50	75	50	37 5	250
Nizhne-Tulomskaya	5	12 5	7 5			25
Volkhovskaya	9	21	21	9		60
TOTALS	**89**	**133 5**	**178 5**	**109**	**75**	**585**
Existing Plants, New Rehabilitation						
Pavlovskaya	4	10	6			20
Kamskaya	36	48	72	48	36	240
Ivankovskaya	5	12 5	7 5			25
Uglitchskaya	17	42 5	25 5			85
TOTALS	**62**	**113**	**111**	**48**	**36**	**370**

121 To meet increasing demand through the year 2010, investments were identified to complete the construction of new plants Priority plants for future construction were also identified

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Table 3-14
Cost Structure for Priority Existing Plants for Rehabilitation

Plant Name	Cost Structure - $ Million (1991)			
	Equipment	Labor	Materials	Total
Existing Plants, Committed				
Volzhskaya (Middle Volga)	38	63	149	250
Volzhskaya (Center)	38	63	149	250
NizhneTulomskaya	4	6	15	25
Volkhovskaya	9	15	36	60
TOTALS	89	147	349	585
Existing Plants, New Rehabilitation				
Pavlovskaya	3	5	12	20
Kamskaya	36	60	144	940
Ivankovskaya	4	6	15	25
Uglitchskaya	13	21	51	85
TOTALS	56	92	222	370

122 ***Category 3 New Plants, Committed Construction.*** Six new plants under committed construction were identified for priority investment Aushigerskaya, Zelentchukskaya, Zaramagskaya, Zagorskaya-1 Pumped-Storage, Bogutchanskaya, and Bureyskaya Construction is proceeding slowly at each of these plants due to a lack of financing The characteristics of these plants are shown in Table 3-15 These plants require an investment of approximately $4 24 billion over the seven-year period 1995 to 2001, as shown in Table 3-16 These projects will add 6,861 MW of installed capacity and 27,694 GWh of average annual energy production when completed The cost breakdown by equipment, labor and material components is shown in Table 3-17

123 ***Category 4 New Plants, New Construction*** Three new hydroelectric plants were identified for priority investment to start construction Zagorskaya-2 Pumped Storage, Ziuratkulskaya, and Pravdinskaya Construction has not yet started at any of these plants, with the exception of the Zagorskaya Plant, where Stage 1 is under construction and Stage 2 is planned The characteristics of these plants are shown in Table 3-15 They will require an investment of approximately $620 million over the period 1995 to 2001, as shown in Table 3-16 The cost breakdown by equipment, labor and material components is shown in Table 3-17 When completed, these new plants will add 823 MW of installed capacity and 860 GWh of average annual energy production

Table 3-15
Characteristics of Priority New Plants for Construction

Priority Rank	Plant Name	Region	Generation Capacity		Avg. Annual Energy		Capital Investment	
			Existing (MW)	New (MW)	Existing (GWh)	New (GWh)	Total ($ Million)	$/kW
New Plants, Committed Construction								
2	Bogutchanskaya	Siberia	0	3,000	0	17,600	1,400	467
5	Zelentchukskaya	North Caucasus	0	262	0	769	204	779
3	Zaramagskaya	North Caucasus	0	342	0	789	233	681
6	Bureyskaya	Far East	0	2,000	0	7,100	2,200	1,100
8	Aushigerskaya	North Caucasus	0	57	0	236	103	1,807
1	Zagorskaya- 1 PS	Center	800	1,200	800	1,200	100	250
		TOTALS	800	6,861	800	27,694	4,240	700
New Plants, New Construction								
7	Ziuratkulskaya	Urals	0	10 4	0	30	15	1,442
4	Zagorskaya-2 PS	Center	0	800	0	800	570	713
9	Pravdinskaya	North-West	0	12 7	0	30	35	2,756
		TOTALS	0	823 1	0	860	620	753

Note Capital investment cost ($/kW) computed based on the incremental (new minus existing) capacity

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Table 3-16
Investment Plan for Priority New Plants for Construction

Plant Name	Investment Requirement, $ Million (1991) per year							
	1995	1996	1997	1998	1999	2000	2001	Total
New Plants, Committed Construction								
Bogutchanskaya	140 0	210 0	210 0	210 0	210 0	210 0	210 0	1,400
Zelentchukskaya	20 4	40 8	61 2	61 2	20 4			204
Zaramagskaya	23 3	46 6	69 9	69 9	23 3			233
Bureyskaya	220 0	330 0	330 0	330 0	330 0	330 0	330 0	2 200
Aushigerskaya	20 6	51 5	30 9					103
Zagorskaya- 1 PS	20 0	50 0	30 0					100
Total	444 3	728 9	732 0	671 1	583 7	540 0	540 0	4,240
New Plants, New Construction								
Ziuratkulskaya	3 0	7 5	4 5					15
Zagorskaya-2 PS	57 0	85 5	85 5	85 5	85 5	85 5	85 5	570
Pravdinskaya	7 0	17 5	10 5					35
Total	67 0	110 5	100 5	85 5	85 5	85 5	85 5	620

Table 3-17
Cost Structure for Priority New Plants for Construction

Plant Name	Cost Structure - $ Million (1991)			
	Equipment	Labor	Materials	Total
New Plants, Committed Construction				
Bogutchanskaya	194 0	337 7	868 3	1,400
Zelentchukskaya	35 0	47 3	121 7	204
Zaramagskaya	63 2	47 4	122 4	233
Bureyskaya	236 0	550 0	1 414 0	2 200
Aushigerskaya	9 0	26 0	68 0	103
Zagorskaya- 1 PS	0 0	28 0	72 0	100
TOTALS	537 2	1 036 4	2,666 4	4 240
New Plants, New Construction				
Ziuratkulskaya	1 3	3 8	9 9	15
Zagorskaya-2 PS	83 0	136 0	351 0	570
Pravdinskaya	15 0	6 0	14 0	35
TOTALS	99 3	145 8	374 9	620

3 4.4 Summary

124 Russia's hydro capacity of 41,162 MW will decrease over the next 15 years as existing plants are retired The cost to rehabilitate these plants was calculated to determine the investment required during the period 1995 to 2001 New hydro plants currently under construction were also identified for priority investment

125 It was assumed that investment in hydro plant rehabilitation and new plant construction will take place during the period 1995 to 2001 Without investment, it was assumed that approximately 5,767 MW will be retired between 1995 and 2000 With investment, this lost capacity will be replaced with capacity from the rehabilitation of existing plants at a slightly greater rate to account for increases in efficiency That is, approximately 6,093 MW will be added between 1995 and 2000 at an average rate of 1,015 MW/yr

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126 With further investment, new capacity is added with the capacity from new plants based on the Russian designers' construction schedule, assuming investment for all new plants begins in 1995

127 Under these assumptions, Russia's future hydro capacity is shown in Table 3-18, including the drop-off due to the retirement of existing units, the replacement of retired capacity with capacity from the rehabilitation of existing plants, and an increase in capacity due to the construction of new plants The annual increase in capacity is summarized in Table 3-18

Table 3-18
Future Hydro Capacity (MW)

Category	1995	1996	1997	1998	1999	2000	2001
Existing Plants with Retirement	40 201	39 240	38 279	37 318	36 357	35,395	35 395
Replacement Capacity with Rehabilitation of Existing Plants	867	1 912	2,957	4 002	5 047	6 093	6 093
New Capacity with Construction of New Plants	0	200	597	2,076	4 176	6 050	6 884
Totals	41 068	41,352	41 833	43,396	45 580	47 538	48 372

Table 3-19
Annual Increase in Hydro Capacity, MW

Category	1995	1996	1997	1998	1999	2000	2001	Total
Existing Plants, Committed Rehabilitation	867	867	867	867	867	867	0	5,202
Existing Plants, New Rehabilitation	0	178	178	178	178	179	0	891
New Plants Committed Construction	0	200	374	1,279	1 900	1,674	634	6 061
New Plants, New Construction	0	0	23	200	200	200	200	823
Totals	867	1 245	1 442	2,524	3,145	2 920	834	12 977

3.5 TRANSMISSION, DISTRIBUTION, COMMUNICATION, DISPATCH, AND CONTROL

3 5 1 Cost Development Methodology

128 Estimations of the cost for each transmission project relied on certain assumptions concerning which components will be supplied by Russian sources and which will be imported The following general guidelines were used in the cost estimation process

129 The estimation of transmission line costs assumed that engineering and construction labor and materials, including tower steel, conductors, line hardware and insulators, would be sourced within Russia It was assumed that the labor and materials for the design and construction of all substations, including all civil works and basic buildings, would be of Russian origin

130 For costing purposes, it was further assumed that all electrical and electronic equipment would either be the subject of a joint venture with foreign firms or imported directly As a result, the prices for such equipment were assumed to be at the general

world price level This assumption would extend to a limited portion of building construction, e g , heating, ventilating and air conditioning systems

131 It was also assumed that a small portion of the engineering content of each project could be imported, particularly where Western methods could either expedite project completion, reduce project costs, or affect a technology transfer of value to Russian industry

132 Western cost estimates (as of January 1995) were adopted directly Russian cost estimates are much more difficult to predict under the current conditions of high inflation, material shortages, and weaknesses in the construction infrastructure For these reasons, it was felt to be more realistic to adjust Western costs based on projections of the relationship between Russian and Western labor rates and materials prices

133 Transmission line costs are composed predominantly of materials, largely steel and aluminum, and labor (e g , engineering, surveying, construction supervision, erection labor) Table 3-20 lists typical Western costs, exclusive of right of way, for lines of 330 kV to 1,150 kV ac and ±750 kV dc

Table 3-20
Representative Western Transmission Line Costs
(Excluding Right of Way)

	($ x 1000/km)					
	%	330 kV	500 kV	750 kV	1150 kV	1500 kV DC
Materials & Equipment	60	198	276	420	630	510
Engineering & Labor	40	132	184	280	420	340
Total	100	330	460	700	1 050	850

134 ERI's memorandum of July 8, 1994 suggests that the Russian materials cost are approximately 70% of the values shown, and that Russian engineering and labor costs are about 20% These adjustments are made in Table 3-21, except that engineering and labor prices are arbitrarily doubled on the basis that foreign content would be included in certain types of work

Table 3-21
Representative Russian Transmission Line Costs
(Adjusted Prices, Including Right-of-Way)

	($ x 1000/km)				
	330 kV	500 kV	750 kV	1,150 kV	1,500 kV DC
Materials & Equipment	139	193	294	441	357
Engineering & Labor	53	74	112	168	136
Right of Way	18	23	34	51	42
Total	210	290	440	660	535

135 Right-of way costs in Russia are very difficult to estimate and were arbitrarily considered as approximately 12% of the materials costs

136 The cost estimate for communication, control, and dispatch projects consists of two parts foreign and local The base year for both is 1995 The local cost is further broken into three parts equipment, materials, and labor and services The costs include 10% contingency and project management

3 5 2 Transmission Projects

137 Most of the projects studied in the transmission area are interconnections between regions of the Russian Integrated Power System To avoid numerous uncertainties (generation/load forecast, economic and political situation), inter-regional transmission projects were selected that represented a need independent of future load/generation assumptions or an almost certain need for increased transfer capability Intra-regional projects were also considered because they either increase the reliability of the existing transmission system or provide for the delivery of power from plants under construction by integrating them into the power system While the studies undertaken were not comprehensive in terms of the overall transmission problems of Russia, the methodologies developed during this work will expedite the analysis of problems not specifically included in the JEPAS

138 For most of the transmission projects discussed below, the following analyses have been conducted

- load flow study of the existing and improved system, including outages
- dynamic study of the improved system
- list of line and station equipment to be supplied
- cost estimation

Detailed documentation can be found in Appendix H

139 ***Inter-Regional Projects*** Four inter-regional projects were examined The North-West and North-West-Center Transmission Reinforcement Program, the Middle Volga/Center/North Caucasus Reinforcement Program, the Ural-Tyumen System Integration Project, and the Siberia-Center Reinforcement Program

140 *North-West and North-West-Center Transmission Reinforcement Program* Several performance problems are often encountered in the North-West Region

- The transfer capability of the existing Kola-Karelia-Leningrad tie is seriously limited, especially under outage conditions
- In efforts to maintain system reliability, nuclear power plant units can be tripped by the emergency control system
- The transfer capability of the existing interconnection between the North-West and Center is seriously limited, especially under outage conditions

141 These problems could be aggravated in the event that some obsolete units at the Kola and Leningradskaya nuclear power plants were shut down after the year 2000 The construction of approximately 740 km of single-circuit 330 kV line and 930 km of 750 kV line with considerable upgrading of existing 330 kV and 750 kV stations is suggested to help resolve these system limitations

142 *Middle Volga/Center/North Caucasus Reinforcement Program* The North Caucasus Region virtually always suffers power and energy shortages Its bulk transmission system is not well integrated with the contiguous Russian Center Region and is directly connected by only two long 220 kV interconnections Most power to the North Caucasus is delivered from the Center via Ukraine However, the power that can be delivered via existing interfaces is not sufficient for the region This limitation has forced the curtailment of from 200 to 500 MW of the load over the past several winters, requiring rolling blackouts to accommodate power deficiencies A transmission reinforcement program consisting of four complementary 500 kV transmission additions is proposed to address these problems and to improve the flexibility of system operation

143 *Ural-Tyumen System Integration Project* The Tyumen Power System operates within the Ural Interconnected Power System It has ample generating capacity, but is unable to deliver all available surplus power and energy to deficient areas of the Ural because of limited transmission connection to those areas The construction of approximately 420 km of 500 kV line and the installation of related equipment at two stations is proposed as a solution to this bottleneck

144 *Siberia-Center Reinforcement Program* The analysis of power balances revealed a 3,000 MW deficiency in 2005 and a 6,000 MW deficiency in 2010 for the Center Region It also showed that the Siberia Region could have a 28 to 35 billion kWh surplus of electric energy in 2005 to 2010, which would be sufficient to cover the above deficiency Several options were considered, each of which could create a high-capacity interconnection between the Siberia and Center regions Each option serves several important objectives and would gain advantages from

- time diversity (three to six hours)
- load shape diversity
- mutual assistance in emergencies
- difference in generation characteristics (economy interchange), based on a prevalence of hydro plants in Siberia and a dominance of thermal and nuclear plants in the European systems
- providing access to energy from the vast coal deposits in Siberia
- reinforcement of the network-building functions of the Russian integrated grid

145 The design of a bulk transmission configuration capable of reliably delivering 3,000 MW initially (Stage 1) and 6,000 MW ultimately (Stage 2), from Siberia to Central Russia is proposed The transmission distance involved is 3,500 to 4,000 km The existing network of 500 kV and the uncompleted 1,150 kV ac and 1,500 kV dc lines are the bases of the alternatives considered

146 ***Intra-Regional Projects*** Three intra-regional projects were assessed the Eastern Siberia Reinforcement Project, the Integration of the Omsk Power System, and the Integration of the Boguchanskaia Hydroelectric Plant Program

147 *Eastern Siberian Reinforcement Project* At the time of system peak demand, the Chitinskaia and Buryatskaia systems have a combined capacity shortage of about 700 MW The Irkutsk system enjoys a substantial surplus of hydroelectric capacity This surplus, however, cannot be transferred to the east due to inadequate transmission capacity The construction of approximately 870 km of a single-circuit 500 kV transmission line and four 500 kV stations is proposed This project would also be a major step in meeting the eventual goal of synchronous operation of the Far Eastern System and the Integrated Power System of Russia

148 *Integration of the Omsk Power System* The Omsk Power System can be supplied reliably when the Russian and Kazakhstan power systems are operated synchronously However, the strained political relationship between Russia and Kazakhstan raises concerns regarding the adequacy of power supply to the Omsk Power System, should the interconnected operation of the Russian and Kazakhstan power systems be disrupted This project contemplates the construction of approximately 750 km of 500 kV transmission lines and their integration into the existing 500 kV network

149 *Integration of the Boguchanskaia Hydroelectric Plant* The program proposed here is designed to provide adequate transmission capacity to integrate this plant into the Siberian power system and to improve the transfer capability from the Angara hydroelectric cascade to the west The principal components of the project include the construction of approximately 1,250 km of 500 kV lines and 550 km of 1,150 kV lines with station upgrading

150 ***Cost Estimate and Inter-regional Transfer Capability*** The estimated costs and construction periods for the transmission projects are summarized in Table 3-22 Table 3-23 gives estimates of the transfer limits among Integrated Power System regions resulting from the implementation of the transmission projects

Table 3-22
Estimated Cost and Construction Period for Transmission Projects

Transmission Projects	Investment (Million $)	Construction Period (years)
Internal North-West (Kola-Karelia-Leningrad)	575	4
North-West to Center Tie (Leningrad-Kalinin)	200	4
Middle Volga/Center/North Caucasus Reinforcement	430	5
Ural-Tyumen System Integration	170	3
Siberia-Center Stages 1 2	5 810*	15
Eastern Siberia Reinforcement (Irkutsk-Chitinskaia)	300	5
Integration of the Omsk Power System	325	5
Integration of the Boguchanskaia Hydro Plant	995	4
Total Transmission	8 805	

* The data shown are an average of the alternatives

Table 3-23
Preliminary Estimates of Transfer Limits Between Russian IPS Regions as a Result of Implementing JEPAS Projects

Project	N W - Center	Center N Caucasus	M Volga Center	Urals-M Volga	Tyumen Urals	Kazak. Urals	Siberia Kazak.	Siberia Urals	Urals-Center	Kazak. Center
Existing System	1500 (900)		3000 (2800)	1800 (2800)	1500 (15000	1600 (1600)	1200 (1400)			
North West to Center Reinforcement	2300 (1650)									
North Caucasus Supply		1000 (1000)								
Tyumen Ural Reinforcement					2500					
HVDC Center Siberia Tie 2005								3000 (3000)	3000 (3000)	
HVDC Center Siberia Tie 2010			6000 (5800)	4800 (5800)				6000 (6000)	3000 (3000)	
AC Center Siberia Tie 2005			6000 (5800)	4800 (5800)				3000 (3000)		
AC Center Siberia Tie 2010			6000 (5800)	4800 (5800)				6000 (6000)	3000 (3000)	
AC + DC Center Siberia Tie 2005						4600 (4600)	4200 (4600)			3000 (3000)
AC + DC Center Siberia Tie 2010			6000 (5800)	4800 (5800)		4600 (4600)	7200 (7400)			3000 (3000)

Notes Numbers in parentheses are reversed flow limits
Realization of the flow will in some cases depend on the completion of projects internal to the sending region, which are not cited in this table
Center North Caucuses values assign no credits to existing ties that pass through the Ukraine

3 5 3 Subtransmission and Distribution Loss Reduction Program

151 Three typical radial distribution systems were selected

- supply system for a city
- supply system for a rural area
- supply system for gas pipelines and neighboring district

152 Studies indicated that with improvements in voltage control, VAR flow controls will be needed in the near future along with improved dispatching facilities The projected loss reductions, as calculated for the example systems above, amount to 100 kW for every MVAR of capacitor added to the system The total cost of proposed distribution projects is estimated at $250 million

3 5 4 Communication, Control, and Dispatch (CCD) Projects

153 The following improvements to the CCD systems at the Central Dispatch Office (CDO) and seven existing Interconnection Dispatch Offices (IDOs) are recommended

- The control centers at the CDO and IDOs and the associated data communication network are to be upgraded over a four-year period This includes the replacement of computer hardware and software, and improvements to the existing control center facilities The upgrade will allow the implementation of new functions to address the changes taking place in the IPS and to provide a reliable and economical system operation A large portion of the application software (e g , load frequency control, on-line economic dispatch, state estimate) will be developed by the Russian in-house team

- The communication systems between the CDO and all IDOs are proposed for upgrading in a phased approach A new fiber optic communication link will be installed as part of this project to interconnect the CDO, and the North-West, Center and North Caucasus IDOs This new link will fulfill the data and voice communication requirements by the control centers covering Russia's major load areas Also, data links between the selected substations and power plants will be upgraded to solve the bottleneck problem with the present data communication lines

- New remote terminal units (RTUs) will be installed at major power plants to interface the plant control systems with their respective control centers The plant instrumentation system will be modified, where needed, to accept raise/lower signals for the automatic generation control from the new control centers

- At selected substations, the existing telemetry device will be replaced with a new RTU, and the current data monitoring system will be expanded to install an enhanced supervisory control and data acquisition system This upgrade will provide the CDO and IDOs with real-time information on the transmission network to increase system viability and reliability Without this upgrade, the functioning of the newly installed control centers will be compromised

- A backup facility will be established for each control center to cope with the possibilities of the main center being out of service The backup center will be equipped with minimal hardware, yet be fully capable of taking over the basic functions of the main control center Also, the major communication links will have alternative paths This measure is required to eliminate a single failure component in the dispatch hierarchy

- Guidelines and a prototype integrated microprocessor control system will be developed at several substations and generating plants This initial investigation of integrated microprocessor control by the Russian power engineers is needed soon, because many future transmission and generating plant systems will be using integrated microprocessor systems They need to develop the understanding and guidelines before major projects using this technology are approved

154 Economic benefits of $71 3 million per year have been identified for these measures This results from reduced fossil fuel usage because of better economic dispatch of generating units, and reduced losses on the transmission system

155 Operational benefits have also been identified for 1) enabling the CDO and IDOs to better handle the new power market in which the IPS now operates, 2) increased reliability of the transmission and generating systems (including the nuclear plants), 3) operating closer to transmission line transfer limits, 4) better VAR flow in the transmission system and between the transmission and distribution system, 5) reduced maintenance of generating units, and 6) improved regulation of frequency and voltage

156 The total estimated cost for the proposed project is $308 3 million in foreign exchange costs and Russian rubles 911 8 million in local costs

157

CHAPTER 4
MODELING RESULTS

4.1 DESCRIPTION OF FORECASTING MODELS

1 To determine the investment requirements for the Russian power sector's development, the Joint Electric Power Alternatives Study used two integrated planning models a Russian simulation model and an American integrated resource planning model Detailed descriptions of these models are given in Appendix C The two models are mutually complementary and, together, they provide a solid analytical framework for integrated least-cost planning

2 The Russian simulation model uses the experience gained in planning for the power sector, and the results of a screening analysis of the cost-effectiveness of various power generation technologies and energy conservation options Based on heuristic knowledge and pre-feasibility studies, the Russian model performs the following functions

- develops capacity and power balances for each regional power system (with respect to inter-regional capacity and power exchanges)
- determines a preferred sequence of capacity build-up for various types of electric power plants (including the modernization and reconstruction of existing power plants and new construction)
- identifies thermal power plants' requirements for different fuels for each regional power system (with regard to constraints on the use of individual types of fuel)
- determines the environmental impacts of electric power plants within each regional power system with respect to stack emissions
- determines investment requirements for decommissioning, rebuilding existing power plants, and constructing new plants and inter-regional transmission lines

3 The American optimization model, IPM, is designed to solve the same set of problems using the same data developed by the JEPAS Working Groups However, rather than using a simulation framework, IPM employs a formal dynamic linear programming cost-minimization framework The major features of IPM include

- a dynamic optimization structure that provides a least-cost solution and accurately evaluates inter-temporal tradeoffs
- accurate system dispatch and operations simulation
- explicit modeling of the trade-off between decommissioning and safety upgrades of nuclear units
- simultaneous cost minimization of electric and heat supply
- simultaneous optimization of electric supply and demand-side technologies to provide an integrated resource plan

4 The American model provides a formal structure for optimizing the development of the power sector that includes a detailed description of its dynamics, and minimizes total costs over the entire planning period IPM's ability to take into account a variety of constraints typical of the system as a whole and its major elements allows for investigating the influence of major factors on the system's development Hence, IPM can be used not only for developing the best options under specified conditions but also for studying the sensitivity of solutions to a range of inputs reflecting major uncertainties

5 Electricity demand in the Russian model makes use of two aggregated characteristics the winter daily load curve and the number of hours of maximum load use per year to determine the technical feasibility of using hydro plants, thermal power plants (TPPs) and nuclear power plants (NPPs) during the intense period of maximum load

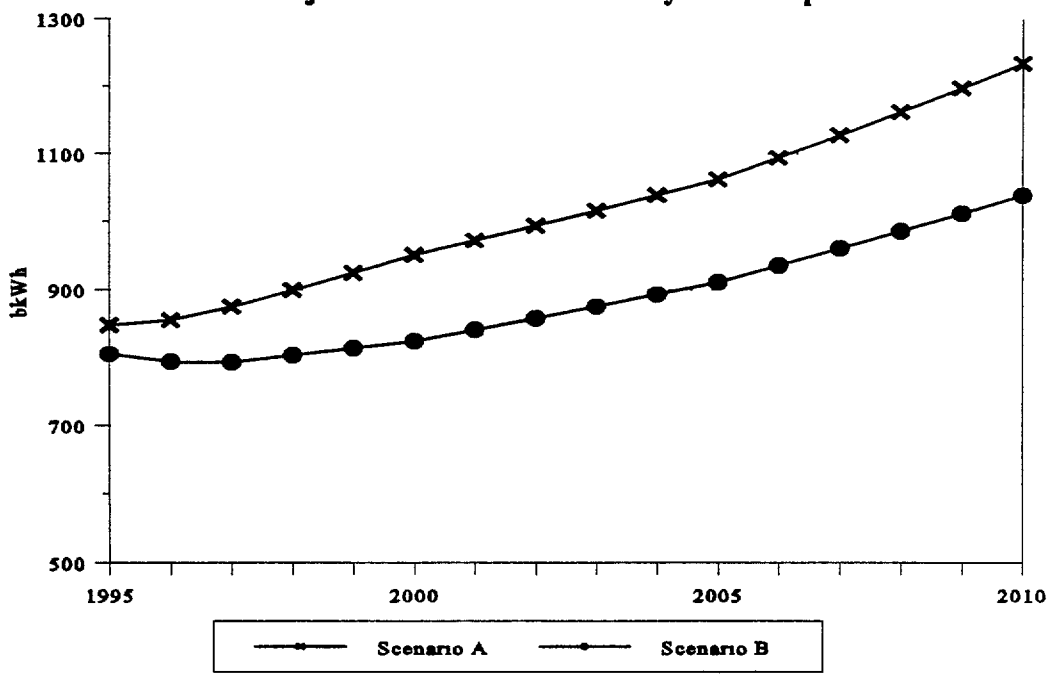
6 The American model describes electricity demand by three seasonal load duration curves (for the winter, summer and spring-autumn periods) These load duration curves are derived from hourly load projections using typical load profiles by season and day-type, and annual energy projections for each sector The use of the three curves makes it possible to describe demand patterns and the participation of all types of power plants in greater detail

4.2 FUNDAMENTAL ASSUMPTIONS USED IN MODELING

4.2.1 Electricity Demand and Capacity Requirement Assumptions

7 The projections of electricity consumption within the Integrated Power System are shown in Figure 4-1 for the two scenarios described in Chapter 1 Projections were also developed for annual electricity consumption and annual peak demand for each regional power system Working Group 5 disaggregated the regional total annual electricity consumption estimates into three sectoral categories industry, residential/commercial, and agriculture These sectoral load projections and hourly historical load data were used to develop hourly load projections for each region The resulting estimates, along with regional annual consumption and peak demand forecasts, were the electricity demand estimates used in the JEPAS analysis The maximum load projections for each of the regional power systems and for the IPS are shown in Table 1-3

Figure 4-1
Projected Trends in Electricity Consumption

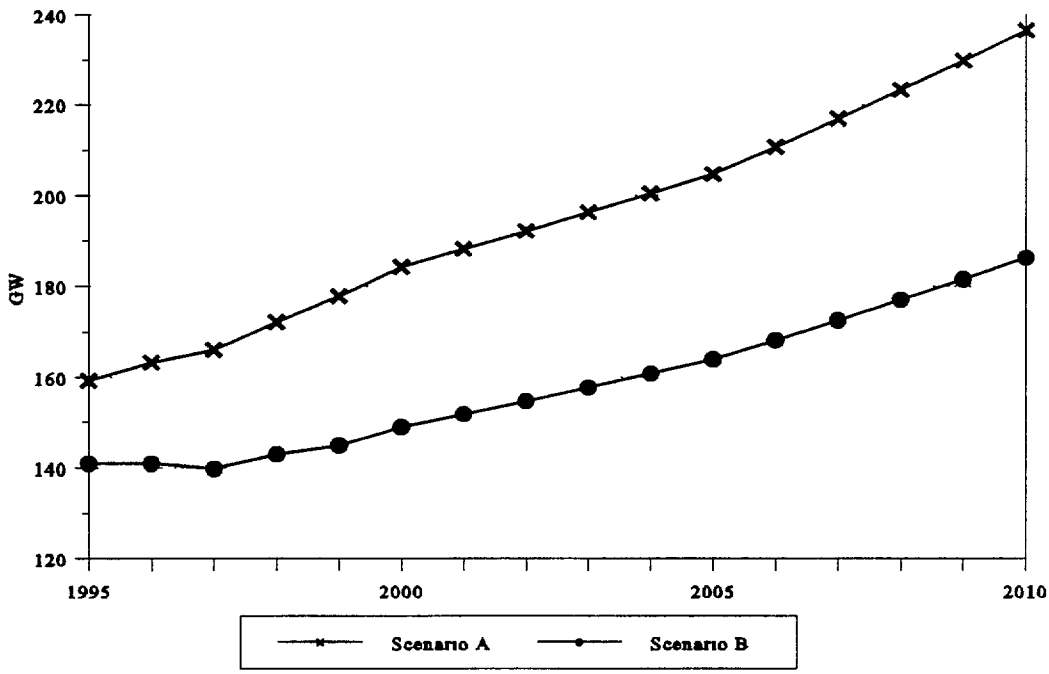


8 The design reserve margin for synchronized operation within the IPS was set at 13% of the total peak load under the former planning guidelines of the USSR Integrated Power System The reserve margins for individual regional power systems range from 11-14%, except for the isolated Far East, where it has been set at 20% In Russia's rapidly changing

environment, reserve margins may need to be increased However, the need for changes in reserve margin requirements is still being analyzed and is uncertain at this time

9 The total generating capacity requirements as (defined by the above conditions under the two demand scenarios) are shown in Figure 4-2 It should be noted that while this discussion focuses on meeting demand on the basis of capacity only, energy efficiency gains effectively meet electricity needs by reducing demand Energy efficiency options were analyzed separately and are reported in Section 4 4

Figure 4-2
Total Capacity Requirements



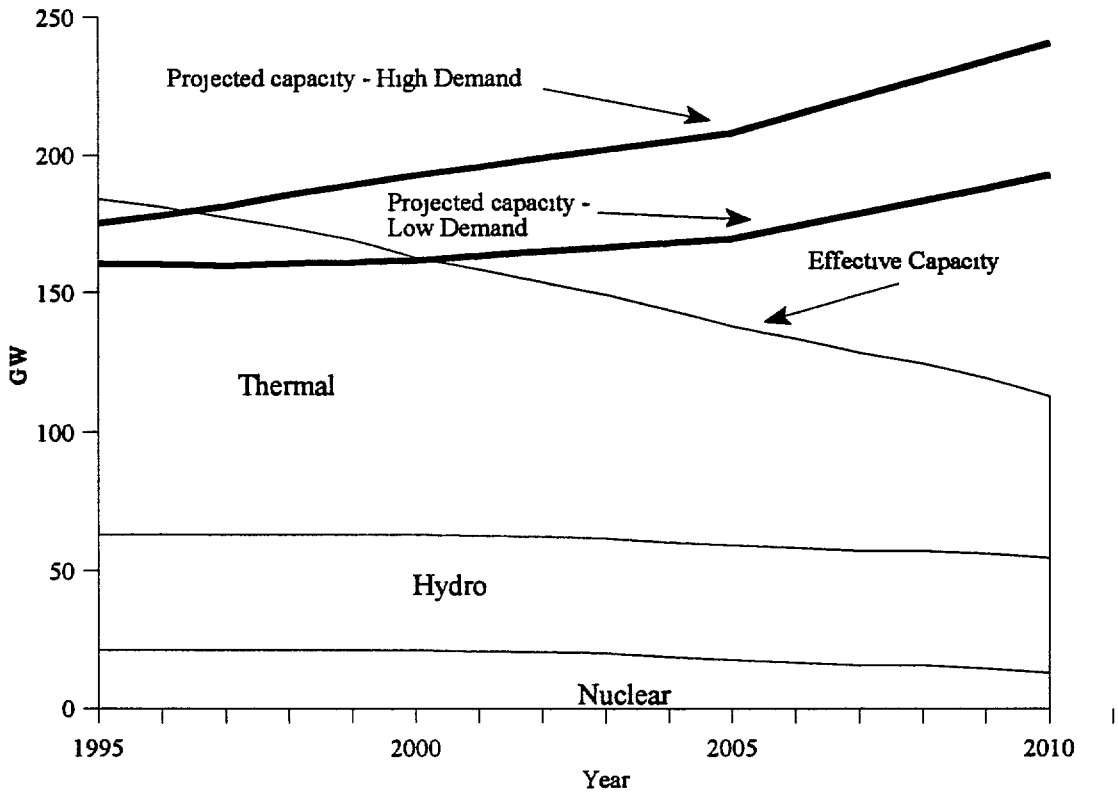
10 The actual system capacity derived from existing generating units was determined based on the assumptions that

- TPPs and NPPs will normally be decommissioned after they reach the end of their design lives (However, the North Caucasus and Ural regions are currently experiencing capacity deficits For these regions, TPP life extensions are needed during the period 1995 through 1997)

- hydro capacity will not decrease, because all needed upgradings of existing units are expected to be performed within the time period

11 The difference between required capacity and the falling capacity of the existing stock of power plants determines the amount of required *generating capacity replacements* or *energy efficiency gains* and additions The required increase in capacity under the two demand scenarios can be seen as the difference between the existing capacity and the required capacity levels in Figure 4-3

Figure 1
Effective Capacity Reduction Dynamics for Russia's Power Plants



Note The effective capacity is determined by adjusting the actual installed capacity by an amount equal to the fraction of total capacity that is historically out of service due to routine maintenance or equipment failures The adjustment factor used in this study is 13 %

12 The detailed projections of generating capacity needs in Table 4-1 indicate that

- By 2005, the required capacity replacements and additions for the IPS are expected to be nearly twice as high in Scenario A as in Scenario B

- Over the full study period, more than 80% of the capacity needs are concentrated in the European regions of Russia (including the Urals)
- The Urals and North Caucasus power systems currently have capacity deficits
- In a number of regional power systems (e g , the Center, North-West, Siberia) the existing capacities are more than required

Table 4-1
Relative Generating Capacity Levels (mln kW)

Years / Power Systems	Scenario A				Scenario B			
	1995	2000	2005	2010	1995	2000	2005	2010
IPS of Russia	6 2	-32 6	-71 1	-127 8	19 9	-5 2	-33 5	-80 5
European Part of the IPS	3 5	-26 8	-57 2	-100 5	13 5	-7 3	-29 9	-66 4
North-West	2 4	1 3	-4 5	-10 0	3 4	3 6	-1 6	-6 0
Center	4 2	-8 0	-17 3	-37 8	8 9	-1 7	-5 8	-23 8
Middle Volga	2 9	-1 3	-4 3	-9 6	4 1	1 2	-1 5	-5 5
North Caucasus	-3 6	-6 7	-8 9	-12 5	-2 5	-4 5	-5 9	-8 7
Urals	-2 4	-12 1	-22 2	-30 6	-0 4	-5 9	-15 1	22 4
Tyumen	0 8	-0 4	-2 4	-5 4	1 8	1 4	-0 5	-3 3
Siberia	1 3	-4 3	-8 5	-15 6	3 5	0 1	-2 4	-8 5
Far East	0 6	-1 1	-3 0	-6 2	1 1	0 6	-0 7	-2 3

'- indicates a capacity deficit

4.2 2 Heat Demand Assumptions

13 One of the distinguishing features of the Russian IPS is the high share of combined heat and power plants (39% in the European regions and 36% in the entire IPS) This fact necessitates that the analysis of electricity requirements incorporate the future demand for heat supply

14 The forecasts of total heat consumption under the two demand scenarios are presented in Table 4-2 Considerable change is expected to occur in the heat consumption pattern, mostly as a result of the increase in residential and service sector consumption and the fall in industrial consumption The change in heat consumption dynamics in Russia makes evaluations of the possible scale of heat supply development difficult

Table 4-2
Projected Requirements for Heat from Centralized Sources and the Power Sector (Million Gigacalories)

	1993	1995	2000	2010
Scenario A				
Total Requirements for Centralized Heat	1,950	1,880	1 950	2 050
Of Which Heat Supplied by the Power Sector	940	890	905	1 010
Scenario B				
Total Requirements for Centralized Heat	1,950	1,850	1,870	1,900
Of Which Heat Supplied by the Power Sector	940	880	885	905

15 The potential heat output from TPPs is shown in Table 4-3 Based on the information summarized in this table, the American and Russian models meet heat demand with either CHPs or stand-alone boilers based on the lowest life cycle cost alternative

Table 4-3
Heat Possibly Available from Thermal Power Plants (Million Gigacalories)

Years / Power Systems	1993	Scenario A				Scenario B			
		1995	2000	2005	2010	1995	2000	2005	2010
IPS of Russia	911 8	862 1	876 6	923 8	977 9	850 4	827 4	851 9	874
European Part of IPS	703 5	659 0	661 4	684 3	725 8	653 4	639 7	652 6	666
North-West	59 8	55 7	57 6	60 2	70 4	55 7	53 8	53 6	59
Center	287 1	277 2	280 2	290 0	310 7	277 2	274 0	282 1	288
Middle Volga	127 6	124 6	122 0	125 3	130 0	122 6	118 3	118 4	119
North Caucasus	25 0	22 7	23 1	23 8	24 2	22 2	22 6	22 4	23
Urals	204 0	178 8	178 6	185 1	190 2	175 7	171 1	176 1	176
Tyumen	13 2	12 8	12 8	12 8	13 2	12 8	12 8	12 8	13
Siberia	164 8	158 9	168 8	187 8	196 4	155 6	148 3	157 4	163
Far East	30 2	31 4	33 5	38 9	42 5	28 7	26 5	29 1	30

4 2 3 Fuel Pricing Assumptions

16 Two fuel price forecasts were analyzed One forecast was used for both Reference Cases A and B, it assumed that fuel prices in Russia would be based on domestic supply and demand In this case, fuel prices are expected be set to cover the full cost of production and delivery from Russian sources of supply The full-cost price forecast for major fuels in different economic regions of Russia is provided in Table 4-4 These prices were used as the basis for the Reference Case analyses conducted for the JEPAS

Table 4-4
Fuel Price Forecast, $/tsf
Based on Fuel Sector Enterprises Being Self-Financing
(Full Cost of Production)

	1996 - 2000		2001 - 2005		2006 - 2010	
Regions	**Gas**	**Coal***	**Gas**	**Coal***	**Gas**	**Coal***
Center	43	35	65	52/51	75	57/54
North-West	45	38	67	55	77	60
North Caucasus	47	40	74	60	81	65
The Volga Basin	40	30	62	46/43	70	51/46
Urals	36	26	54	39/34	64	44/37
North Tyumen	16	-	32	-	40	-
West Siberia	35	13/13	52	23/18	62	28/21
East Siberia	46	19/6	60	32/9	72	37/12
Khabarovsk Krai	70	45/48	90	63/59	100	68/62
Primorye	-	50	-	65	-	65

*) The upper figure is for bituminous coal the lower is for Kansk-Achinsk lignite

17 A second forecast assumes a radical change in Russia's pricing and taxation policy Under this change, a substantial share of tax receipts would be replaced by royalties for using natural resources and minerals Royalties would be set such that oil and gas prices in Russia would be brought into conformity with the world market prices More precisely, domestic prices for exported fuels would be set at levels comparable to those in Central Europe The price forecast for major fuels by economic region based on this world pricing policy is presented in Table 4-5 The impact of such a change in fuel prices was evaluated in the model studies

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Table 4-5
Fuel Price Forecast, $/tsf
Based on Equivalent World Market Pricing

	1996 - 2000		2001 - 2005		2006 - 2010	
Regions	**Gas**	**Coal***	**Gas**	**Coal***	**Gas**	**Coal***
Center	62	45/43	80	60/59	95	68/64
North-West	64	48	82	63	97	72
North Caucasus	65	49	86	68	100	76
The Volga Basin	59	40/35	75	54/51	90	62/56
Urals	55	35/28	69	47/42	84	55/47
North Tyumen	30	-	45	-	55	-
West Siberia	53	21/15	67	31/26	80	40/31
East Siberia	55	28/8	77	40/17	90	49/22
Khabarovsk Krai	80	54/51	105	71/67	115	80/72
Primorye	-	55	-	60	-	65

*) The upper figure is for bituminous coal the lower is for Kansk-Achinsk lignite

4 2 4 Escalation of Russian Capital Cost Assumptions

18 One of the main problems addressed by the Joint Study concerns the estimates of capital costs for Russia's power sector Specifically, this means anticipating the future relationships between Russian and world prices of major plant cost components basic metals, equipment, construction materials and labor

19 The estimates of the future relationships between Russian and world market prices for equipment and materials are based on the assumption that Russia's domestic prices will not exceed world prices Currently, relatively cheap labor and energy costs in Russia enable its industry to offer lower prices for capital goods This difference is expected to diminish over the study period Table 4-6 indicates that the rate at which Russia's

domestic prices rise to world levels will vary greatly for different components of plant costs This rate will also depend on the pace of economic reforms

Table 4-6
Comparison of Cost Components for Russian and U.S Power Plants (Multipliers)

Year	Metals	Construction Materials	Equipment	Labor
1994	0 75	0 70	0 50	0 10
2000	0 75 - 1 00	0 70 - 0 85	0 50 - 0 60	0 20 - 0 30
2010	0 85 - 1 00	0 80 - 0 90	0 60 - 0 90	0 35 - 0 60

20 A relatively high initial price level for metals and building materials costs (0 70-0 75 of the U S prices) in 1994 results in relatively slow escalation rates for these investment components in the future The highest escalation rates are expected for labor costs, however, the actual rate of labor cost escalation will depend heavily on the rate of economic reform Consequently, there is a high degree of uncertainty concerning the rate of labor cost escalation

21 While recognizing the uncertainty in estimating the future ratios between Russian and world market prices, the Joint Study used uniform ratios for each type of new or modernized plant Uniformity was essential in order to meaningfully compare all the supply alternatives

22 Working Groups 2 and 3 obtained initial information on Russian and U S costs (in constant 1994 $) and their structures to provide a basis for comparing overnight costs for the new and modernized plants Table 4-7 shows the escalation rates for a complete range of technologies developed by the working groups According to this table, the escalation rates of overnight costs for different types of plants vary considerably due to different cost structures Consequently, the competitiveness of different technologies will vary over the study period

Table 4-7
Overnight Cost Escalation Factors

Technology Type for Capital Escalation		Escalation Multiplier			
		1995	2000	2005	2010
Pulverized Coal	500 MW new CPP	1 000	1 150	1 369	1 577
Combined Cycle	400 MW new CPP	1 000	1 147	1 301	1 448
Nuclear	500 MW - NP-500	1 000	1 120	1 410	1 722
Modernizations					
Oil/Gas	CPP 300 MW	1 000	1 128	1 279	1 425
Coal	CPP 150 MW	1 000	1 197	1 445	1 700
Oil/Gas	CHP Various sizes	1 000	1 198	1 411	1 641
Coal	CHP Various sizes	1 000	1 253	1 522	1 811
All new and reconstruction options were assumed to have the same O&M escalation, as follows					
Variable O&M		1 033	1 214	1 249	1 286
Fixed O&M		1 098	1 750	2 174	2 700

4 2 5 Representative Costs of Power Generation Technologies Used in the Modeling

23 Tables 4-8 and 4-9 present escalated overnight capital costs for the upgrading and new construction of representative plant types These escalated overnight costs were developed by applying the capital goods, labor, and materials escalation rates presented in Table 4-6 to the overnight costs provided by the working groups Tables 4-8 and 4-9 also present the corresponding operating and performance characteristics for these representative plant types

Table 4-8
Characteristics of Different TPP Upgrade Technologies

Retrofitting Technologies	Technology Categories		Fuel Types		Heat Rates, Btu/kWh	Non-fuel Costs, $/kW		Overnight Costs, $/kW		
						Fixed	Variable	1994	2000	2010
1	2		3		4	$/Kwy 5	$/MH	6		
K-300 Reconstruction	G-1	N1	NG[1], M[2]	Gas, Residual Fuel Oil	8 694	11 49	2 27	253 7	342	501 6
CCP-360	G-1	6B212	NG	Gas	6 300	5 87	1 82	465	557 8	694 5
CCP-250	G-2	3	NG, M	Gas, Residual Fuel Oil	7 468	7 25	1 82	421 4	532 1	704 1
CCP-360	G-2	4	NG	Gas	6,300	5 87	1 82	508 7	602 4	738 9
CCP-220	G-2	612	NG	Gas	6,460	9 05	1 82	545 5	641 6	784 2
K-500 Reconstruction	C-1	1 1 2	BL[3]	Ekibastuz Coal	9,226	13 98	11 89	430 3	558 3	761 8
K-500 Switching over to Kansk-Achinsk Coal	C-1	2 1	LH[4]	Kansk-Achinsk Coal	9,226	13 98	11 89	400 6	532 0	739 6
K-300 Reconstruction	C-2-A	1 1	BL	Ekibastuz Coal	9,378	16 41	14 1	477 9	610 0	821 6
K-300 Reconstruction	C-2-A	2 1	LH	Kansk-Achinsk Coal	9,378	16 41	14 1	454 9	595 8	826 3
K-300 Reconstruction	C-2-B	1	LL[5]	Moscow Basin Coal	9 402	16 41	14 1	470 2	613 6	836 5
K-300 Reconstruction	C-2-C	1 1	BH[6]	Kuznetsk Coal	9 310	16 41	14 1	414 5	547 4	758 2
K-300 Reconstruction	C-2-D	1 1	BL	Donbass Coal	9 388	16 41	14 1	452 1	589 7	805 8

Retrofitting Technologies	Technology Categories		Fuel Types		Heat Rates, Btu/kWh	Non-fuel Costs, $/kW		Overnight Costs, $/kW		
						Fixed	Variable	1994	2000	2010
1	2		3		4	$/Kwy 5	$/MH	6		
K-150 Reconstruction	C-3-A	2 1	LL	Local Coal	9,511	18 58	15 92	473 1	634 8	886 1
K-150 Reconstruction	C-3-B	1 1	LH	Kansk-Achinsk Coal	9,511	18 58	15 92	501 3	656 2	899 7
K-200 Reconstruction	C-4-A	1 1	LH	Kansk-Achinsk Coal	9,438	17 83	15 27	469 6	615 4	843 1
K-200 Reconstruction	C-4-B	1 1	BH	Kuznetsk Coal	9,426	17 83	15 27	493 6	654 5	900 4
CCP-115-CHP	G-4	1 W1	NG M	Gas	4,544	36 65	8 3	544 5	694 1	919 9
T-100 Reconstruction	C-5-B	1 1 W1	BH	Kuznetsk Coal	5,826	41 76	42	651 8	879 7	1243 0

Key
1 NG = natural gas
2 M = mazut (residual oil)
3 BL = low-quality bituminous coal
4 LH = high-quality lignite coal
5 LL = low-quality lignite coal
6 BH = high-quality bituminous coal

Table 4-9
New Thermal Power Plant Characteristics

New TPP Equipment Types	Fuel Types		Heat Rates, Btu/kWh	Non-Fuel Costs		Overnight Costs, $/kW		
				Fixed, $/kW/yr	Variable, $/MWh	1994	2000	2010
CPP-CCP-360	NG	Gas	6 194	9 04	1 82	599	720	903
K-500	BH	Kuz Coal	9 226	12 58	11 9	752	960	1,286
K-300	BH	Kuz Coal	9 310	14 97	14 07	816	1043	1 398
K 500	LH	K-Ach Coal	9 226	12 58	11 9	772	960	1 286
K 300	LH	K-Ach Coal	9 310	14 97	14 07	816	1043	1 398
CHP-CCP-260	NG	Gas	4 556	10 0	2 14	666	823	1 045
T-115	BH	Kuz Coal	5 861	19 81	14 35	1 107	1 400	1 848
T-115	LH	K-Ach Coal	5 861	19 81	14 35	1 107	1 400	1 848

24 Hydroelectric generation options were evaluated by Working Group 4 Hydro plants that were scheduled for completion by 1997 are assumed to be done on schedule Hydro plants scheduled to be completed thereafter were treated as options in the model study The schedule and costs of the hydro program were included in the models

25 As is typically done in generation capacity planning studies, the overnight capacity costs provided by the working groups were adjusted for estimated interest during construction costs (IDCs) These interest costs can be a substantial proportion of total investment requirements Table 4-10 presents capital costs, including IDCs, for selected capacity options evaluated in this study The escalated capital and fixed and variable operation and maintenance costs, along with the fuel costs presented in Table 4-4, form the basis for determining optimal choices to meet projected capacity requirements

Table 4-10
Costs for Representative Fossil and Nuclear New Plant Options

Technology Type		1995			2000			2010		
		Capital $/kW	FO&M $/kW/yr	VO&M $/MWh	Capital $/kW	FO&M $/kW/yr	VO&M $/MWh	Capital $/kW	FO&M $/kW/yr	VO&M $/MWh
Pulverized Coal	500 MW new CPP	942	14	1 9	1,083	22	2 2	1,486	34	2 4
Combined Cycle	400 MW new CPP	682	7	0 3	782	11	0 3	988	17	0 4
Nuclear	500 MW new (NP-500)	1,144	17	0 3	1,281	27	0 3	1,970	42	0 3
Modernizations										
CPP (Oil/Gas)	300 MW	552	6	0 3	623	10	0 3	787	16	0 4
CPP (Coal)	150 MW	552	21	2 6	661	34	3 1	938	52	3 3
CHP (Oil/Gas)	Various	455	32	1 3	545	51	1 5	747	79	1 6
CHP (Coal)	Various	619	40	7 9	776	64	9 3	1,121	99	9 8

All costs are expressed in January 1994 U S dollars Capital costs include interest during construction
FO&M is fixed operation and maintenance costs VO&M is variable operation and maintenance costs

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4.3 STRUCTURE OF THE ANALYSIS: THE REFERENCE CASES AND CHANGE CASES

4 3.1 Analytical Framework

26 The purpose of this Joint Study modeling was to obtain information needed to answer questions of importance to policy makers, system planners and investors Such questions include

- What is lowest-cost combination of investments needed to meet expected demand, while maintaining the reliability of the system?
- What are the cost implications of energy policy decisions, e g , maintaining the present share of nuclear and coal generation in the overall mix of generation capacity?
- Can investment savings be achieved by expanding the inter-regional transmission facilities to move electric power between regions?
- What are the implications of programs to increase the efficiency of electricity end-use?
- What are the cost implications of early decommissioning or upgrading the safety of first-generation RBMKs and VVER 440-230 NPPs?
- What are the implications of shortages in investment capital for power system investment?

4 3 2 Definitions of Terms

27 A **Scenario** refers to a set of assumptions about the future of the Russian economy and its electricity demand These economic scenarios assume a certain level of energy efficiency gains and include specific fuel price assumptions Electricity demand scenarios are derived from the economic scenarios

28 The term **Reference Case** refers to a characterization of the entire Russian power system, a demand scenario and certain policy assumptions The characterization of the existing power system consists of regional aggregations of plant types into eight conventional and three nuclear categories Life extension and modernization options for thermal plants are available for approximately 20 types of plants For nuclear plants, new plants and safety upgrades are included as options Characteristics of the high-voltage

transmission system between regions are included, intra-regional transmission and distribution is not characterized

29 The term **Scenario Case** is used to describe the analysis of changes in reference case parameters whose future values are uncertain, e g , fuel prices, capital availability, discount rates, fixed charge rates In a sensitivity case model run, one or more parameters in the reference case are varied to study the effects on investment costs and changes in plant and transmission capacity needs

30 The term **Change Case** or **Decision Case** is used to describe the analysis of changes in reference case parameters that are determined by technology, policy or by specific economic structural developments (e g , changes in demand for and sources of space heating)

4 3 3 Reference Cases

31 Two Reference Cases were analyzed The principal difference between them is electricity demand As described previously, Reference Case A has electricity demand dropping until 1996, and reaching levels about 20% higher than the 1990 level in 2010 Reference Case B has electricity demand dropping until 1997, and then slowly recovering to 1990's level by 2010 Both Reference Cases assume that all cost-effective end-use efficiency measures are undertaken and that the demand scenarios have incorporated the demand reduction resulting from these measures Besides demand levels, the two cases differ in following

- the level of heat demand
- the amount of inter-regional imports and exports of electric capacity
- the level of life extension in the early years of fossil units required to meet demand in the Urals and North Caucasus regions

Other assumptions are common to both cases

32 With respect to the retirement schedules of fossil fuel-fired power plants for both Cases, it is assumed that plants will be retired at the end of each unit's design life (except as noted in the early years in the North Caucasus and Urals)

33 The choice of whether or not to rehabilitate a unit with a modern equivalent unit depends on the need for power, the costs of the replacement options, and the economics of alternative supply options The Study has assumed that retiring CHP units must be

modernized or replaced with equivalent CHP units, or stand-alone boilers, although not necessarily ones based on the same fuel or technology

34 With respect to existing nuclear power stations, the Reference Case assumptions are drawn from the JNPAS report Both cases treat each decision to upgrade or close as an option Hence, decisions to close or upgrade existing units depend on the need for power, the costs of upgrading and decommissioning, and the economics of alternative sources of supply

35 Repowering Rostov 1 as a coal plant and the completion of Kalinin 3 with upgrades to acceptable safety levels were included as options

36 New NP 500-650 MW nuclear power plants (a pressurized water reactor design with passive safety features) are also available as supply options starting in 2001 While the new *Russian Energy Strategy* is based on a new 1,000 MW plant, it was not considered in this study because these units will not be available until late in the planning period

37 Hydroelectric generating capacity is assumed to remain constant in the Reference Cases, although upgrades to existing plants are treated as options There are no changes in inter-regional bulk power transfer capability over the period, and reserve margins remain as previously set at 13% for Russia as a whole On a regional basis, firm imports from neighboring regions with excess capacity are permitted to contribute to the reserve margin

4 3 4 Change Cases

38 Alterative cases were analyzed for the following categories

- ***Scenario cases,*** designed to analyze alternative assumptions about such factors as fuel prices, capital costs, and heat demand

- ***Nuclear decision cases,*** designed to evaluate alternative approaches to nuclear safety upgrade options, nuclear decommissioning costs and options, and the nuclear share of total generation capacity, including several options for completing partially built units

- ***Non-nuclear decision cases,*** designed to evaluate alternative power sector development options including energy efficiency, life extension, additional technologies, easing air pollution control regulations, and expanding the system's transmission capacity

39 Each of these cases was analyzed against both Reference Case sets of assumptions

4.4 RESULTS OF MODEL STUDIES

4 4 1 Comparison of Results of the Two Models for the Reference Cases

40 The Reference Cases for the two power demand scenarios were analyzed using both the Russian and American models The results are similar for the two models (see Table 4-11) The slight differences in the total electric capacity increments between these results are attributed to differences in the methods of computing electric capacity requirements set by the Russian and American sides

Table 4-11
Capacity Additions and Replacements from 1995 through 2010
(Reference Cases, GW)

	Scenario A		Scenario B	
	Russian Model	American Model	Russian Model	American Model
New HPP	3 3	2 7	3 3	2 7
New NPP	3 8	3 1	2 0	1 4
NPP Upgrades	20 6	19 1	20 6	18 1
Gas or Oil CPP	49	33 5	20 7	20 0
Gas or Oil CHP	52 6	71 1	45 7	41 2
Coal CPP	8 4	3 3	5 1	2 0
Coal CHP	10 6	10 6	7 7	10 8
Total Capacity Additions	148 3	143 5	105 1	96 7

41 Both models concluded that by 2010, the HPP share in the total installed capacity of the Russian Integrated Power System will amount to 17% and 23% in Scenarios A and B, respectively

42 There is some difference in nuclear capacity between the two models The models confirm the cost-effectiveness of upgrading existing nuclear power plants aimed at increasing their safety and design service life, with the exception of four first-generation VVER-440 units (at the Kola and Novovoronezh nuclear power plants) under both scenarios and one RBMK unit at the Leningrad Nuclear Power Plant under Scenario B This is due to those reactors' short service lives after upgrading (the design service lives of these reactors expire in 2002-2004) Despite the early decommissioning of the older VVERs and RMBKs, the capacity of existing NPPs by 2010 in the American model is

somewhat higher than in the Russian model This is attributed to the fact that the American model takes account of the extension of existing NPPs' life span by 2 years, as a result of the "down-time" period during which upgrading occurs, whereas the Russian model assumes that the NPPs' design life span of 30 years will remain unchanged

43 In both cases, the scale of new nuclear capacity is small since in European Russia, it is economic only in the period up to 2005 and in the Far East, only beyond 2005 (see Table 4-12)

Table 4-12
NPP Projected Capacity at 2010 Levels (Reference Cases)
(GW)

	Scenario A		Scenario B	
	Russian Model	American Model	Russian Model	American Model
Existing NPPs	12 9	15 0	12 9	15 0
New NPPs Including	3 8	3 1	2 0	1 4
North-West	0 6	0 3	-	-
Center*	1 0	1 0	1 0	1 0
North Caucasus	1 0	0 6	1 0	0 4
Far East	1 2	1 2	-	-
Total	16 7	18 1	14 9	16 4

*Kalinin 3 completion

44 According to these results, the share of nuclear capacity in the total installed capacity of Russia's IPS in both cases will decline from 10% in 1993 to 7-8% in 2010

45 Both models confirm that thermal plants will continue to provide the largest share of capacity additions and replacements over the time frame, amounting to 70-75% by 2010 for Russia as a whole, and 75-80% for the European regions Both also predict that gas-fired combined cycle plants will account for 63-65% of total generating capacity additions and replacements through 2010 under Case B and 69-73% under Case A

46 Both model results show that the largest number of new plants will be combined cycle units However, the growth rates for combined cycle units are lower under both cases with the Russian model than with the American model This is explained by the Russian

model's evaluation of gas supply limitations As a result of considering the physical limits of the Russian natural gas infrastructure, the Russian model predicts lower rates of commissioning for new combined cycle units and somewhat higher figures for coal-fired capacity additions These differences apply largely to the Siberia, Far East and Urals regions

47 The Reference Case investment requirements for the modernization and construction of new and replacement nuclear and thermal plants are shown in Table 4-13

Table 4-13
Investment Requirements, $ billion

Period	Scenario A		Scenario B	
	Russian Model	American Model	Russian Model	American Model
Up to Year 2000	22 8	26 4	10 4	9 6
2001 - 2005	36 5	31 8	21 5	19 8
2006 - 2010	46 3	55 7	35 2	39 9
Total	105 8	113 9	67 2	69 3

48 As illustrated in Table 4-13, the total investment requirements projected for the period 1995 through 2010 are consistent The models project total investment requirements through 2010 ranging from $106 to $114 billion in Reference Case A, and $67 to $69 billion in Reference Case B In Reference Case A, investment requirements in the Russian model are below the American estimates, because the Russian model has assumed that a larger amount of life extension will occur in the capacity-short regions of the North Caucasus and Urals This lower near-term investment profile in the results leads to higher investment requirements in the 2000 to 2005 time frame as the five-year life extension period is concluded In Reference Case B, the two models yield markedly similar investment projections

4 4 2 Results of the Change Cases Based on the American Model, IPM

49 Tables 4-14 through 4-19 present the results of the model study change cases analyzed using the American model

Table 4-14
Scenario Cases

Case	Results
Low Nuclear Capital Costs In this change case, the construction costs of new nuclear power plants are reduced by 20% to reflect potential plant cost savings associated with the introduction of NP-1000 reactors, or possible improvements in methods for estimating the capital costs of the NB-500 reactors	Because nuclear capacity is capital-intensive, the nuclear capacity additions in these cases increase overall investments, however, total system costs decline because of the lower variable cost of nuclear generation Under high load conditions, the investments are 17% ($19 7 billion) higher than Reference Case A, and under low loads the investments are 26% ($18 1 billion) higher than Reference Case B The system cost savings are $2 1 billion and $1 3 billion under high and low load respectively Among the scenario change cases, the largest change in investments and capacity addition decisions occurred in the cases where nuclear capacity costs were reduced by 20% In these cases, substantial amounts of new nuclear capacity are added In both cases, the combination of nuclear capacity and stand-alone boilers to meet heat demand were found to be lower-cost options than combined cycle CHP capacity
Lower Nuclear Fuel Prices In order to examine the impacts of the nuclear fuel market being in situation of a substantial excess of supply over demand, a case was modeled in which the nuclear fuel price remained below that of the reference case assumption for the entire study period	Lower nuclear fuel price assumptions had a much smaller effect on nuclear capacity additions than lower nuclear capacity costs Under the high load scenario, investment costs increase by 3% while system costs decrease by 2% Under low load conditions, investment costs increase by 2%, while system costs decrease by 2%
Higher Nuclear Fuel Prices One of the key issues in this study is the role of nuclear power in Russia's long-term energy plan These change cases examined the impacts of higher nuclear fuel prices on capacity mix and costs	Higher nuclear fuel price assumptions have only a small impact on capacity addition decisions, investment costs decrease by $0 7 and $0 3 billion in the high and low load cases, respectively, as some decisions shift away from capital-intensive nuclear capacity Total system costs increase by $2 6 and $2 7 billion under the high and low load conditions

Case	Results
Fossil Fuel Price Sensitivity The Reference Case analyses are based on full cost of production fuel prices in Russia An alternative set of prices based on "world" prices for natural gas and coal has been evaluated -- the price assumptions for this change case were described above in Section 4 2	Under high load conditions this case leads to an increase in nuclear capacity additions of 5 2 GW and a 3 4 GW increase in coal CPP capacity additions These increases are offset by declines in gas-fired combined cycle CHP and CPP installations Under low load conditions, coal CPP capacity still increases by 3 4 GW, while nuclear capacity increases by only 0 6 GW from the Reference Case Investment costs increase in this scenario under high load growth conditions, but decrease with low load growth Total system costs increase by about 4% in both the low and high cases
Lower Heat Demand This change case was designed to analyze the sensitivity of projected investment requirements to a change in heat demand assumptions In these runs, the projected Reference Case heat demand was reduced This reduction was phased in over time starting as a 0% reduction in 1995, increasing to 30% by 2010	The results for this case indicate that a reduction in heat demand would lead to a corresponding reduction in CHP capacity additions Since total electric demand remains at the same level this reduction in CHP capacity additions must be replaced by other types of capacity, including combined cycle and coal CPPs and nuclear capacity Given that electricity demand in this case remains at the Reference Case levels, the reduction in heat demand has virtually no impact on cumulative investment costs

50 Table 4-15 presents total investment and system costs for the scenario cases analyzed Results are presented for both the high (A) and low demand (B) scenarios

Table 4-15
Costs of Scenario Cases

	Investment Costs through 2010		System Costs through 2010	
	Billion January 1994 $	% Change from Reference Case	Billion January 1994 $	% Change from Reference Case
High Load Cases				
Reference Case A	113 9	NA	143 6	NA
Lower Nuclear Capital Costs	133 6	17 3	141 5	-1 5
Lower Nuclear Fuel Prices	117 5	3 1	140 9	-1 9
Higher Nuclear Fuel Prices	113 2	-0 6	146 2	1 8
Fossil Fuel Price Sensitivity	115 0	0 9	149 4	4 0
Lower Heat Demand	115 1	1 1	143 8	0 1
Low Load Cases				
Reference Case B	69 3	NA	116 7	NA
Lower Nuclear Capital Costs	87 4	26 2	115 4	-1 1
Lower Nuclear Fuel Prices	70 8	2 3	114 2	-2 1
Higher Nuclear Fuel Prices	69 0	-0 4	119 0	2 0
Fossil Fuel Price Sensitivity	68 3	-1 5	121 5	4 2
Lower Heat Demand	69 0	-0 3	115 5	-1 0

Capital investment requirements are not present valued System costs are present valued

4.4 3 Summary of Scenario Case Results

51 As noted above, only the cases in which actual capital costs for new nuclear units are assumed to be 20% lower than the costs included in the Reference Cases have a significant influence (upward) on investment requirements System costs for these cases are only 1 5 and 1 4% lower than the high and low Reference Cases, respectively Considering the scarcity of long-term financing in Russia, it does not seem prudent to dedicate such a large sum to an investment that is little more than a break-even proposition at best

52 The other scenario cases have only a marginal impact on investment and system cost requirements

Table 4-16
Nuclear Decision Cases

Case	Results
No New Nuclear Construction In this change case new nuclear power plants are not included as capacity options The results of this case show the costs associated with a policy of not allowing the construction of any new nuclear power plants This is the only case not run for both load forecast scenarios, since little new nuclear capacity was constructed in Reference Case B (low demand growth)	Under high load conditions, the new nuclear capacity of 3 1 GW constructed in the Reference Case is replaced mostly by new combined cycle CHP capacity (3 0 GW) and to a lesser extent by coal-fired steam cycle capacity (0 3 GW) With this restriction on new nuclear capacity, investment requirements decrease by 1 2% and total system costs increase by a small amount This case was not analyzed under low demand conditions due to the relatively small amount of new nuclear capacity added in the corresponding Reference Case
Full Containment Safety Upgrade This change case considers the cost impacts of adopting the full containment approach to safety upgrades of existing nuclear units	Under high load growth, the only change in the selection of which existing nuclear plants to upgrade is at the Leningrad plant where unit number 2 is not upgraded All other plant upgrade choices are the same as in the corresponding Reference Case A Under low load growth conditions, Leningrad 2 and Kursk 1 are not upgraded, although they were selected in Reference Case B Under both load forecasts, investment costs are $1 3 billion lower in these cases than in the Reference Cases, but total system costs increase by about 1 7%
Early Nuclear Decommissioning This case accelerates the closure of nuclear power plants by five years In some cases opportunities for early closure are limited by technical factors such as system balancing and local load requirements	Under high load growth assumptions, early decommissioning has little effect on the model's nuclear upgrade choices Relative to Reference Case A the only change is that Leningrad 1 is not selected for upgrading Under low load growth conditions, Leningrad 1 and 2 and Kursk 1 are not upgraded although they were selected in Reference Case B Investment costs increase by about $3 billion under both load growth forecasts Total system costs also increase, but by a smaller amount
American-Style Decommissioning The Reference Cases and all of the other change cases assume that nuclear decommissionings are conducted using the standard Russian approach these cases assess the impacts of adopting a policy of decommissioning using American-style decommissioning practices	Under high load growth, Kola 1 is selected for upgrading All other upgrading choices are the same as in Reference Case A Under low load growth conditions selections are identical to the Reference Case The cost impacts of these cases are minimal

Case	Results
Constant Nuclear Share In this case, the share of nuclear power in the generation capacity mix is held constant at current levels To maintain a constant share as demand and capacity grow over time, nuclear generating capacity is added at the same rate as total generating capacity is brought on-line	Under high load conditions, all existing nuclear units are selected for upgrading In addition, 11 4 GW and 6 5 GW of new nuclear capacity are added in the high and low load cases, respectively Under these cases investment costs increased by a substantial 5%, but the impact on total system costs is very small
Decommissioning of Kursk 1 in 1995, with the Option to Complete Kursk 5 In this case, Kursk 1 is decommissioned in 1995 and the completion of Kursk 5 is added as an option	This option is selected for completion in both the high and low load cases, and both investment and system costs are reduced
Nuclear Completion Options In this case, several existing but currently not completed, nuclear power plants were added as options Balakovo units 5 & 6, Rostov 1, and Kursk 5 The completion of the Rostov 1 nuclear plant as a conversion to a coal-fired plant is also included as an option, as it was in the Reference Cases	In both the high and low load conditions, Kursk 5 and Rostov 1 are selected for completion, but Balakovo 5 and 6 are not selected Both investment and system costs are lower than in the corresponding Reference Cases

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53 In general, the nuclear decision cases had only marginal impact on the model's nuclear plant upgrade decisions under the high demand growth scenarios, but significant differences in upgrade selections occurred in the low demand growth scenarios The cost impacts of the nuclear decision cases are summarized in Table 4-17

Table 4-17
Costs of Nuclear Decision Cases

	Investment Costs through 2010		System Costs through 2010	
	Billion January 1994 $	% Change from Reference Case	Billion January 1994 $	% Change from Reference Case
High Load Cases				
Reference Case A	113 9	NA	143 6	NA
No New Nuclear Construction	112 6	1 2	143 8	0 1
Full Containment Technology	113 8	-0 1	146 0	1 7
Early Nuclear Decommissioning	117 0	2 8	145 0	1 0
American Style Decommissioning	114 1	0 2	143 6	0 0
Constant Nuclear Share	119 5	4 9	143 8	0 1
Decommission Kursk 1	113 1	-0 7	143 5	-0 1
Nuclear Completion Options	112 8	1 0	143 0	-0 4
Low Load Cases				
Reference Case B	69 3	NA	116 7	NA
Full Containment Technology	68 0	1 8	118 8	1 8
Early Nuclear Decommissioning	72 1	4 1	117 7	0 9
American-Style Decommissioning	69 3	0 0	116 6	-0 1
Constant Nuclear Share	73 1	5 5	117 0	0 3
Decommission Kursk 1	68 5	1 2	116 5	-0 1
Nuclear Completion Options	68 0	1 8	116 3	-0 3

Capital investment requirements are not present valued. System costs are present valued.

4 4 4 Summary of Nuclear Decision Case Results

54 These cases have important findings with respect to nuclear policy and decisions on safety upgrades and decommissioning

- Halting all nuclear construction (including upgrades) only marginally affects investment and system costs Compared to Reference Case A, the investment costs declined by 1 2%, and system costs increase by 0 1%

- The full containment safety upgrade option (assuming it is technically feasible) is economically competitive with the jet condenser option included in the Reference Cases Investment costs are marginally lower (1 and 1 8% for the high and low demand cases, respectively), and system costs are marginally higher (1 7 and 1 8% for the high and low cases, respectively)

- Moving the decommissioning date forward 5 years has only a marginal impact on investment and system costs Investment costs increase 2 8 and 4 1% for the high and low cases, respectively System costs increase by only 1 and 9%, respectively

- American-style decommissioning (compared to the Russian style included in the Reference Cases) has negligible impact on investment or system costs

- If the nuclear share of the generation mix is held constant at its current level over the study period, investment costs are approximately 5% higher in both cases System cost are essentially the same

- Decommissioning Kursk 1 with the option of completing Kursk 5 has very little impact on either investment or system costs

- The completion of some nuclear units under construction, namely Kursk 5 and Rostov, slightly reduces both investment and system costs (1 to 1 8% reductions in investment costs and 4 and 3% reductions in system costs for the high and low cases, respectively)

- In all cases, it appears cost-effective to decommission rather than upgrade Kola 1 & 2, and Novovoronezh 3 & 4, and in most of the low demand cases, Leningrad 1 It is recognized, however, that there are intra-regional constraints such as transmission and fuel availability and social and economic policy considerations that would make such a decision non-economic, particularly in the case of the Kola units

4 4 5 Non-Nuclear Decision Cases

Table 4-18
Non-Nuclear Decision Cases

Case	Results
Relaxed Air Pollution Emissions Requirements This case examines the implications of relaxing environmental standards by not requiring sulfur dioxide pollution control equipment on modernized units In order to evaluate the costs of meeting the revised stack emissions standards discussed in Chapter 2, two cases were run in which the requirements for SO_2 scrubbers from new and modernized coal plants were removed	This resulted in large increases in coal consumption under both low and high load growth conditions Capacity additions were also affected coal CPP capacity additions increased by over 5 3 GW in the high load case and 3 6 GW in the low load case Gas combined cycle CHP capacity was reduced by the same amount. Thus, with lower coal capital costs the model found it economical to build coal CPPs instead of gas combined cycle CHPs Additional heating boilers were built to meet the heat demand Total capital investments were reduced by $4 2 and $4 5 billion in the high and low load cases respectively Total system costs were also reduced, but by less than $1 billion. While the blanket removal of requirements for SO_2 emissions controls is not considered a viable option for Russia s power plants this case demonstrates the potential for savings through careful evaluation on a case by-case basis of the costs and benefits of scrubbing stack gasses In certain cases strategies such as using low-sulfur fuels or permitting life extensions without requiring SO_2 scrubbing may afford reasonable cost savings options
Life Extension Options In this case the model was given the option to continue the operation of existing plants for an additional five years beyond their design lives This was based on a projected incremental capital cost that was well below the cost of a complete full modernization of the same unit. The case retained the Reference Case options of retiring the plants as scheduled or plant modernization, in addition to the five-year life extension	In this case estimated total investment requirements were reduced by 14 7% under high load conditions and 18 2% under low load conditions Under high load conditions, life extensions also serve to substantially reduce near-term investment requirements Cumulative investment requirements through 1999 in the reference case were $21 0 billion. In contrast, in the life extension case estimated cumulative investment requirements through 1999 were $13 2 billion. Near term investment requirements are also reduced under low demand conditions but by a smaller amount of $2 1 billion. In both scenarios, life extensions are also selected in later years as substantial amounts of existing capacity reach their scheduled retirement dates
Combustion Turbine Options In the Reference Cases, simple cycle combustion turbines were not included as a generation capacity option This change case was undertaken to determine the benefits of including combustion turbines as a supply option	These cases indicate that simple cycle combustion turbines are an attractive generation option in many regions Under the high load growth conditions the model chooses to add a total of 46 9 GW of simple cycle combustion turbines by 2010 Under the low load growth, a lower but still substantial amount of simple cycle combustion turbines are added, totaling 18 8 GW in 2010 Because combustion turbines are relatively low cost, total investment requirements are projected to decline by 22% in the high load case and 13 5% in the low load case Because the model did not consider physical limits within Russia s current and future natural gas distribution system, these results overstate the potential for savings based on the use of simple cycle combustion turbines but are indicative of the fact that this option is important with respect to investment requirements
Life Extension and Simple Cycle Combustion Turbine Options This case is a combination of the previous two it provides options for both life extension and simple cycle combustion turbines	The cases in which a combination of life extensions and simple cycle combustion turbines were included as capacity options had the largest impact on investment requirement projections Under the high load conditions, projected total investment requirements are reduced by $38 billion, or 33 4% In the low load case projected investment requirements were reduced by a smaller but still substantial 28 3% Simple cycle combustion turbine capacity additions in the two cases total 48 3 GW and 13 4 GW

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Case	Results
Additional Transmission Capacity Into the North Caucasus In the Reference Cases it was assumed that the existing transmission line from the Center Region through Ukraine to the North Caucasus is fully utilized with a capacity of 1 700 MW This is the only substantial inter-tie between the North Caucasus UPS and the rest of Russia A transmission change case was undertaken in which we simulated the impacts of the line through Ukraine becoming unavailable and the 1 000 MW line currently under construction to directly link the Center and North Caucasus being completed by 1996	The results for these two runs indicate that additional generation capacity primarily simple cycle combustion turbines, is needed in the North Caucasus to replace the lost transmission capacity through the Ukraine
20% Discount Rate A discount rate of 12% has been assumed in the Reference Cases In these change cases a discount rate of 20% has been used.	The results for this analysis indicate that higher discount rates change the optimal mix of capacity additions In general, all else being equal those options with higher variable costs will fare better with higher discount rates because these operating costs occur further out in time than up-front capital costs and are discounted more heavily In these change cases, the capacity mix shifts towards coal and natural gas steam turbine CPP and away from CHP capacity New nuclear capacity additions are also reduced from 3 1 GW in the optimistic Reference Case to 1 GW in the optimistic change case The 1 GW of new nuclear capacity is Kalinin 3, which is still selected by the model for upgrade (Note Caution must be used in interpreting the system cost impacts of these cases, since costs are present valued using different discount rates)
Energy Efficiency Options As noted in the description of the Reference Cases certain economical energy efficiency measures are embedded in the Reference Case demand scenarios Working Group 1 analyzed the potential for additional savings through the use of major energy efficiency measures in Russia The results show that there is substantial potential for electricity demand reduction through the implementation of a wide range of economical measures in many end-use applications (e g residential appliances lighting, industrial motors) The efficiency change case evaluates the costs and savings of these measures relative to generation supply-side options In this case the Reference Case electricity demand forecasts are assumed to exclude direct energy efficiency measures including low cost/no cost measures and efficiency gains from structural changes in the economy This case allows the choice of pro-active energy efficiency and supply options The results provide an estimate of the optimal mix of supply and energy efficiency options and the related investment requirements for each	The results indicate that energy efficiency investments can lead to capacity reductions totaling 6 3 GW and 4 6 GW respectively in the high and low scenarios by 2010 The cost impacts are significant, investment costs decrease by over 5% in both cases, and total system costs decrease by $3 2 and $1 9 billion in the high and low load cases

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55 As shown in Tables 4-18 and 4-19, the non-nuclear decision cases generally had much more significant cost impacts than the nuclear decision cases

Table 4-19
Costs of Non-Nuclear Decision Cases

	Investment Costs through 2010		System Costs through 2010	
	Billion January 1994 $	% Change from Reference Case	Billion January 1994 $	% Change from Reference Case
High Load Cases				
Reference Case A	113 9	NA	143 6	NA
Relaxed Air Pollution Controls	109 7	-3 6	142 8	-0 6
Life Extension Options	97 1	-14 7	141 5	-1 5
Simple Cycle CT Options	88 8	-22 0	142 3	-0 9
Life Extension and Combustion Turbines	75 9	-33 4	140 2	-2 4
20% Discount Rate	109 9	-3 5	104 2	-27 5
Energy Efficiency Options	107 7	- 5 4	140 4	- 2 2
Low Load Cases				
Reference Case B	69 3	NA	116 7	NA
No Air Pollution Equipment	64 8	-6 5	116 0	-0 6
Life Extension Options	56 7	-18 2	115 8	-0 8
Simple Cycle CT Option	59 9	-13 5	116 6	-0 1
Life Extension and Combustion Turbines	49 6	-28 3	115 8	-0 8
20% Discount Rate	62 6	-9 6	82 5	-29 3
Energy Efficiency Options	64 7	- 6 6	114 8	- 1 6

Capital investment requirements are not present valued System costs are present valued

4 4 6 Summary of Non-Nuclear Decision Cases

56 These cases all have significant, indeed major, impacts on the investment or system cost requirements It is clear from the analyses that, in addition to major nuclear policy issues, key decisions in the areas of energy efficiency, life extension of existing plants, and the addition of simple cycle gas turbines as a supply option dramatically affect the level of investment requirements and system costs

57 In combination, a number of the options analyzed in these cases -- including energy efficiency and life extension (in this analysis, only a 5-year life extension option is included) programs, and the addition of simple cycle gas turbines as a supply option -- could reduce the investment requirements and system costs in the range of 30% compared to the Reference Cases

58 As the 20% discount rate case shows, the discount rate will have a major impact on system costs and a significant impact on investment costs The level of environmental regulation is also important and depends on what standards are eventually adopted This analysis, as noted elsewhere, has assumed very stringent environmental regulations in the Reference Cases

4 4 7 Summary of American Model Study Conclusions

59 Based on the results described above, the following conclusions can be made

- There is a need for immediate investment to maintain and upgrade the electric generation and transmission capability of Russia
- There is a broad range of estimated investments required in the Reference Cases, ranging from $69 billion in Reference Case B to $113 billion in Reference Case A Much of this wide range in investment projections is attributable to the difference in the electricity demand levels used in the two Reference Cases
- The various change cases further expand the range of investment requirements from a low of $50 billion under the low demand scenario to $134 billion under the high demand scenario
- There are substantial opportunities for reducing electricity requirements through energy efficiency Efficiency measures offer attractive low-cost solutions for meeting Russia's energy needs
- The life extension of existing capacity, even for the relatively short period of five years, can significantly postpone capital investment requirements
- Simple cycle combustion turbines are a low-cost means for meeting Russia's capacity requirements However, there are practical limitations on the extent to which this technology can be employed due to regional and seasonal natural gas availability issues

- More detailed intra-regional work is warranted to evaluate the potential impacts of energy efficiency options, simple cycle combustion turbines, life extension, and nuclear plant decommissionings

- The modeling results indicate that it would be economical to decommission several older nuclear plants The units that do not appear to be candidates for upgrading include Kola 1 and 2, and Novovoronezh 3 and 4 Upgrading these units is uneconomic due to their relatively short remaining operating lifetimes More detailed intra-regional analysis should be undertaken to evaluate the feasibility of decommissioning these units

- While lower nuclear capital costs can make new nuclear capacity an attractive capacity option for reducing system costs over the long run, substantially higher capital investment would be required compared to other less capital-intensive capacity alternatives

4.5 POLICY CONSIDERATIONS

60 Final investment decisions for the Russian power sector, as in all other countries, will be subjected to various factors emanating from the energy, economic and social policies of the government Security and the diversity of energy supply are priority policy matters for most governments, and Russia is no exception The policy considerations identified below are recognized by the Joint Study as being the factors that will be used to adjust the results that come from modeling and to influence decisions on investment by type of generation and regional capacity mix

4 5 1 Socio-economic Policies and Financial Constraints

61 The government gives high priority to the impacts of power sector investment on employment levels in key areas of the fuel and energy complex, namely, coal mining, hydroelectric plant construction, nuclear fuel production, and thermal power sector engineering and equipment manufacturing

62 As a matter of industrial policy, Russia intends to maximize the capability of its domestic industry to design and manufacture the most efficient, environmentally benign, and proven power sector technologies

63 The minimization of capital investment requirements in the early period (as distinct from life cycle costs) is an important policy objective due to limitations on the capital availability This objective also supports investment choices that keep future technology options open

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64 The scarcity of funds over the next five years dictates that careful assessments will have to be made between the cost and benefits of compliance with 1) environmental emission standards that are now applicable to fossil power plants and 2) nuclear reactor safety standards This consideration applies to standards at the federal and local levels

4 5 2 Energy Policies

65 Less natural gas is expected to be available to the power sector than would be indicated by a generation mix based purely on considerations of least-cost Constraints on natural gas availability are likely due to fuel export policies, existing constraints on natural gas transmission and distribution, and shortages of investment to expand the domestic gas grid

66 Russia intends to continue a policy of maintaining diversity in the fuel mix for the power sector as between natural gas, coal, nuclear and hydroelectric This policy will enter investment decision arena, where the modeling results indicates that the life cycle costs for power plants using different fuels in a particular region are quite close

4.6 PREFERRED CASE FOR POWER SECTOR DEVELOPMENT AND CORRESPONDING INVESTMENT REQUIREMENTS

67 The results presented above using the American model reflect only the requirements indicated by Russian power system economic optimization Definitive plans for power sector investment will take other factors into account

68 The future structure of the Russian power sector will not only be aimed at achieving economic efficiency but it will also have sufficient flexibility to adapt to evolving social and political conditions To meet these requirements, the preferred cases for demand scenarios A and B were developed by Russian JEPAS Working Group 5 participants as a compromise among 1) the Reference Case results in the Russian and American models, 2) the results of scenario change cases using alternative assumptions about the future conditions of the power sector, and 3) additional non-economic criteria policy considerations

69 The preferred case differs from the Reference Case results in the following ways

- In order to reduce investment requirements for the most difficult period from now until the year 2000, the least-expensive approach for thermal plant rehabilitation (i e , life extension by means of replacing specific equipment components) is recommended In addition, the use of simple-cycle gas turbines is recommended towards the same end

- In regions where new combined cycle CPPs are only slightly more economical than nuclear plants (the North-West and the Center), the construction of both is recommended [1] At the same time, it is recommended that a new combined cycle CPP be built in Krasnodar Krai in the Northern Caucasus Although the Rostov NPP is an economical choice for the North Caucasus, its commissioning has not yet been approved by the local authorities and it cannot be commissioned in time to meet the intense power needs of the region

- In regions where the cost efficiency of coal-fired CPPs is only slightly higher than the cost of combined cycle CPPs (the UPS of the Urals), the construction of new coal CPPs and the rehabilitation of existing ones are recommended along with the combined cycle technology

- However, in the Urals and Siberia where coal-fired CHPs are slightly more costly than the combined cycle CHPs, the conversion to combined cycle technology is not recommended

- Taking into account that there are numerous physical constraints involved in rehabilitating existing plants, only the partial replacement of steam turbine CHPs with combined cycle CHPs is recommended for plant rehabilitations, while up to 30% of existing capacity may continue as steam turbine CHPs

- In Siberia, where the major 3,000 MW Boguchany HPP has been under construction for many years, the preferred case assumes its completion, in order to ensure employment for the large construction force currently committed to the project

- The evaluation of capacity balances for Siberia and the North-West argue in favor of higher (i e , >13%) capacity reserve margins In the case of Siberia a higher capacity provides for a reliable energy supply under dry year conditions, while in the North-West it is needed to offset uncertainties about the schedule of nuclear safety upgrade completions

70 The effect of the above Preferred Case departures from the American model's optimization results leads to significant changes in capital requirements This is due to more capital-intensive NPPs, coal-fired thermal plants, and HPPs The use of thermal life-extension and simple-cycle gas turbines to meet capacity needs is, of course, less than in

1 Because the completion of the Balakovo NPP (units 5 and 6) is less expensive than building a new NPP in the Center it might be advisable to shift the capacity of the NPP into the Middle Volga UPS with a corresponding transfer of capacity and power to the Center UPS

the pure economic optimization cases Overall, the Preferred Case investment requirements through the year 2000 are 20% lower than in Reference Case A and 10% lower than in Reference Case B

71 Throughout the study period the Preferred Case mandates significant changes in the future capacity mix 1) the share of rehabilitation versus new construction is considerably higher, 2) the proportion of simple-cycle and combined cycle thermal units versus steam turbines increases in European Russia and the Urals in particular, 3) the overall capacity of coal-fired steam turbine CPPs and CHPs increases (with a corresponding growth in coal consumption), while their share in the new capacity mix is reduced, and 4) the relative proportion of CHPs is higher at the expense of CPPs

72 Capacity and investment requirements for the Preferred Case under two demand scenarios are shown in Tables 4-20 and 4-21

Table 4-20
Capacity Add-Ins and Replacements for Russia, Preferred Case (GW)

	1995-2000		2001-2005	
	A	B	A	B
ALL TYPES				
New Units	27 0	5 7	12 9	9 3
Rehabilitation and Upgrades	5 5	2 8	27 6	18 7
Total Additions	32 5	8 5	40 5	28 0
Life Extension	12 1	4 2	-	-
HPP Total*	0 6	0 4	2 3	2 1
NPP Total*	2 0	1 0	3 3	0
CHP				
New Units	15 6	4 3	4 4	6 0
Rehabilitation and Upgrades**	3 9	1 5	12 6	12 1
Total Additions	19 5	5 8	17 0	18 1
Life Extension	8 2	4 2	-	-
CPP				
New Units	8 8	1 3	2 9	1 2
Rehabilitation and Upgrades**	1 6	1 3	15 0	6 6
Simple cycle gas turbines included in above	1 4	-	2 9	1 2
Total Additions	10 4	1 3	17 9	7 8
Life Extension	3 9	-	-	-

* excluding rehabilitation and upgrades
** including rehabilitation using simple-cycle gas turbines

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Table 4-21
Russia Preferred Case
Investment Requirements for the Integrated Power System of Russia
($ billions)

	1995-2000		2001-2005	
	A	B	A	B
I Demand Side	4 6	3 0	10 8	8 2
II Supply Side				
Life Extension	2 8	0 9	0 0	0 0
Rehabilitation and Upgrades	5 4	3 8	16 8	12 0
New Units	12 3	2 9	17 3	10 0
Total Supply Side	20 5	7 7	34 1	22 0
Hydro				
Rehabilitation	1 1	1 1	0 0	0 0
New Units	1 9	1 9	3 0	3 0
Total Hydro	3 0	3 0	3 0	3 0
Nuclear				
Upgrades	1 2	1 2	0 0	0 0
New Units	3 2	0 2	4 1	0 0
Total Nuclear	4 4	1 4	4 1	0 0
CHP				
Life Extension	1 9	0 9	0 0	0 0
Rehabilitation*	2 0	0 7	7 3	7 9
New Units	5 7	0 8	7 7	6 5
Total CPP	9 6	2 4	15 0	14 4
CPP				
Life Extension	0 9	0 0	0 0	0 0
Upgrades	1 1	0 8	9 5	4 1
New Units	1 5	0 0	2 5	0 5
Total CPP	3 5	0 8	12 0	4 6
Simple Cycle Combustion Turbines	0 6	0 0	1 1	0 5
III Transmission Networks 220 kV and above	2 1	0 8	5 1	3 3
Total Investment Requirements	**27 2**	**11 5**	**50 0**	**33 5**

* including rehabilitation using simple-cycle gas turbines

73 An analysis of the structure of investment requirements (Table 4-21) reveals the following

- the rehabilitation of existing HPPs, NPP upgrades, and life extension and rehabilitation of thermal plants account for a considerable proportion of

investment requirements Under Scenario A this proportion would make up 30% of investment until 2000, and 34% for the period 2001-2005 Under Scenario B, this proportion is even higher (33% and 36%) Since rehabilitation and life extension involve much lower capital costs than new construction, rehabilitation accounts for a much lower share of investment requirements than capacity additions

- Through the year 2000 the rehabilitation of existing hydro plants and nuclear upgrades account for a sizeable proportion of overall investment (over 8% under Scenario A and 20% under Scenario B), while in 2001-2005 these requirements are negligible

- In 2001-2005 the increase in overall investment in supply-side options under Scenario A is relatively higher than in the previous period when compared to the increase in capacities This is due to the escalation of rehabilitation and new construction costs, and to an increase in the share of capital-intensive new hydro and nuclear power plants In contrast, until the year 2000 investment is primarily allocated to the completion of plants under construction

- Under Scenario B the proportion of new construction in investment requirements is relatively small throughout the period Therefore, even considering cost escalation, the investments required under Scenario B will increase more slowly than capacity additions

4.7 STRATEGIC DIRECTIONS

74 The analysis carried out by the Joint Study has revealed important new strategic options for all those concerned with the Russian power sector's investment needs over the next ten to fifteen years The Russian Preferred Case, described in Section 4 6, reflects important policy considerations identified by the Russian Government and recognized by the Joint Study However, the American and Russian participants in the Joint Study also recognized that the final determination of investment decisions will be a continuous process In market economies no power sector investment plan is ever immutable Such plans are planning blueprints that are subject to adjustment in accordance with policy and other considerations, such as demographic and macroeconomic changes, and the cost of investment capital

75 By analyzing the impacts on investment of a large number of supply and demand reduction options for meeting Russia's electricity needs, the Joint Study has shown that energy efficiency, simple cycle gas turbines, and fossil power plant life extension can

reduce near-term investment costs to a significant degree As those entities involved in investment decisions for electricity use and supply in Russia make definitive choices for electricity supply and efficiency investments, the JEPAS analysis has shown that Russia should give highest priority to the following areas for the period 1995-2000

- Promotion of and investment in improvements in the efficiency of electricity end-use
- Rehabilitation and nuclear safety upgrades, particularly for first-generation nuclear power reactors
- Construction of inter-regional and intra-regional transmission between surplus and deficit areas
- Fossil thermal plant modernization and rehabilitation In the context of the evaluation of the benefits and costs of fossil power plant rehabilitation and modernization, the costs and benefits of options for life extension options should be considered as a way of deferring major expenditures
- Completion of nuclear power plants that are in advanced stages of construction
- Construction of new gas-fired simple cycle and combined cycle plants

76 For the period 2000-2010, the JEPAS analysis has shown that the following areas will be increasingly important

- Construction of new-generation NPPs
- Completion of HPPs
- Commercialization of clean coal power generation technologies
- The western and eastern extension of transmission between Siberian hydro capacity and demand centers in the Center and in Siberia may become important in this period because of the development of the national wholesale market Further studies will be needed to determine the benefits and costs in view of the high capital costs

CHAPTER 5
INVESTMENT REQUIREMENTS AND SOURCES OF FINANCE

5.1 CURRENT SITUATION

1 Traditional sources of financing from the Russian Government's budget allocations have been largely removed and the power sector is in the process of becoming financially independent The most important and largest source of financing now and for the foreseeable future is internally generated funds Sales of newly privatized power sector enterprises are another source of future funding Sources of borrowed funds are also being identified, and steps are being taken to attract foreign capital into the power sector

2 Electricity tariffs set by the regional and federal energy commissions are based upon the cost of service, but currently they do not cover full costs For an initial three years, the tariffs include an investment component, this arrangement is likely to be extended However, customers' payments of tariffs have not been adequate to cover the industry's investment requirements The pervasive non-payments problem has left the industry strapped for cash, the high level of inflation and the cross-subsidies inherent in the tariffs are also a problem

3 Initially, power sector enterprises will find borrowed funds and equity financing difficult to obtain because of a lack of satisfactory financial information This means that potential lenders are currently unable to determine the creditworthiness of enterprises such as RAO EES Rossii and the AO Energos However, the future potential for borrowing or leveraging assets is quite high because most power sector companies have hardly any long-term debt outstanding

4 The current investment climate in Russia is difficult Changing legal, regulatory and political systems, and the high levels of inflation have caused the level of new investment in Russia to be less than anticipated Because it does not generate a significant source of foreign exchange, the power sector has been experiencing more difficulty in attracting new investment relative to foreign exchange-generating industries such as oil and gas As a result, the sector will need to rely more heavily upon domestic sources of financing However, for new credits, especially medium- and long-term loans, enterprises will initially need to borrow in foreign currencies because there is currently no such lending available in Russian rubles

5 Notwithstanding the changing investment climate and economic conditions, the power sector has already taken positive steps to address the current situation and to prepare for the future The process of identifying capital requirements, locating investors and lenders, and meeting their requirements is underway There have been clear signs of increasing investor interest, particularly in the purchase of RAO EES Rossii shares, in project development for new lending from multilateral financial institutions and export credit agencies, and in the capitalization of many new investment funds

5.2 SOURCES OF FINANCING

5 2 1 Internally Generated Funds of Electric Companies

6 As the power sector moves towards becoming financially self-sufficient, the main source of funds for RAO EES Rossii and the AO Energos is internally generated funds, which comprise customers' payments of electricity bills less expenses (operating costs, interest expenses and taxes) Currently, the amount of internally generated funds available is less than what the power sector needs to be self-sufficient The most acute problem is the high level of customers' nonpayment of electricity bills Other contributing factors are the absence of full cost recovery in an economy with rapidly increasing prices, insufficient depreciation charges, and punitive taxes Additional barriers to self-financing include cross-subsidies between consumer groups due to the existence of reduced tariffs for the residential and agricultural sectors (they are being gradually rescinded for the residential sector)

7 It is estimated that the non-payment of bills is currently as high as 45% of total billings for some power companies The estimate for total outstanding electric sector receivables at the end of 1994 was 15 trillion rubles (approximately $3 75 billion) Both the Russian Government and RAO EES Rossii attach a very high priority to resolving the payments crisis Recent actions include increasing the ability of customers to settle their accounts through non-cash transactions including barter and bills of exchange Other actions that have been recommended include the implementation of a system of indexing receivables and payment penalties to keep pace with inflation, and the termination of service in the event of non-payment However, for social and political reasons, service termination is not always possible

8 It is likely that if the payments crisis were resolved, some of the power sector enterprises would generate enough cash flow to cover their operating expenses and to fund a portion of their capital investment requirements However, the ability to fully cover costs depends heavily upon the continued willingness of the regional and federal energy commissions to grant tariff increases that match real cost increases plus inflation Energy

commissions are understandably concerned about the ability of both industrial and residential consumers to pay increasingly high electricity tariffs

9 In 1991-1992 electricity tariffs in Russia increased at a much slower rate than other prices, particularly after the liberalization of prices for most goods in 1992 In contrast, in 1993 and 1994, the electricity tariff increases were almost the same as those for manufactured goods' prices they increased 11 and 3 33 times, respectively, and at the end of 1994, when the average retail tariff was 58 4 R/kWh (1 8 ¢/kWh) In 1994 a decision was made to drop the cross-subsidization of households and agricultural consumers by industrial consumers in accordance with the President's Decree, electricity tariffs for the residential sector are now set by regional energy commissions, but the price cannot exceed the cost of production by more than 5%

10 The Federal Energy Commission (FEC) sets wholesale electric power prices in Russia These prices are calculated for all production enterprises and network companies based on their total annual income derived from electricity sales The total annual income must cover current operating expenses, plus yield a minimum necessary profit to cover capital expenditures, to pay dividends, to service loans, and to pay taxes

11 According to Russian tariff-setting methods, electric power tariffs include a moderate investment component In 1994 the standard size of this component amounted to 15% of the price of electricity sold by RAO EES Rossii and to 8% for AO Energos The latter norm could be increased by a decision of a regional energy commission Suggestions have been made to extend this procedure for another three years

12 Depreciation deductions are an important component of internally generated funds Because of high inflation rates that exceed allowable revaluations of fixed assets, the amount of depreciation charged has not kept its value and the industry is in a state of self-liquidation The indexation of fixed assets (in rubles)--by a factor of 25 at the beginning of 1993 and by a factor of 20 at the beginning of 1994--has not restored (even by half) the value of 1990 depreciation deductions Another revaluation of fixed assets at the beginning of 1995 compensated for 1994 inflation This revaluation increased the depreciation deductions, but was not sufficient because it failed to allow for any increases in the rate of depreciation

5 2 2 Equity

13 Sales of additional shares of stocks are an important source of financing, although to date this has not been a significant source of funding Privatization vouchers, which were used to purchase shares on the voucher auction, were valued at 10,000 rubles and were given away by the government Power company shares were sold to employees and management for nominal values, and the proceeds of shares for cash have mostly gone to the government However, these early actions have caused a secondary domestic market

to develop, and this is a critical step in the long-term process of maximizing the market value of power sector shares For the power sector, the attractiveness of selling stock will be determined by the future market value of the shares and, in the case of the shares still owned by the government, whether or not the proceeds of the stock sales will be available to the power sector

14 The long-term prospects for Russian equities are good The market is developing at a fair pace The secondary trading of shares has been increasing, although daily trading volumes are very low by U S standards and the market remains volatile (the price of RAO EES Rossii stock increased from $5/share in May 1994 to $30/share in September 1994, but then went down to $10/share at the end of 1994) Many of the market participants are speculators and hedge funds that are willing to acquire shares despite being unable to properly value their shares Market values for Russian equities remain very low for several reasons The investment climate in Russia means that investors are seeking high returns to compensate for the risk The lack of company financial information, low liquidity and inadequate securities regulations keep prices low and investors away Institutional equity fund managers would invest in the Russian equity market if problems of stock registration were eliminated In the case of power sector shares, prices remain low due to poor business fundamentals (low or negative cash flow) and the uncertainty about the sector's future ownership and market structure

15 The 1994 year-end market valuation for RAO EES Rossii at $10/share is $1,400 million Since RAO owns roughly half of all power sector assets, total market capitalization for the industry is approximately $2,800 million This is considerably lower than market valuations of comparable integrated electric companies in other countries, when viewed on the basis of size (electricity production and capacity) Table 5-1 shows the valuation of selected electricity generators compared to RAO EES Rossii This table provides an indication of the potential for growth in the market valuation of RAO EES Rossii and other power sector companies

Table 5-1
Comparative Valuation of Electricity Generators

Country	Company		Market Capitalization to			
		Mkt Cap	Capacity	Production	Capacity	Production
		$ Million	$ 000 per MW	$ 000 per GWh	(GW)	(bkWh)
USA	Southern Company*	13 993	466	97	30	145
UK	National Power PLC	8 261	344	76	24	109
Russia	RAO EES Rossii	1,400	13	5	108	382

* includes distribution assets as well as generation and transmission

16 Given the lack of financial information, it is not possible to value shares based upon future cash flows or dividend growth A very rough estimate of the potential for market valuation can be made based upon values of generating assets Although this is not the proper way to value shares since the value of the assets is based upon future earning capacity, asset size is used here as an initial estimate For example, if Russian generating assets are valued at no less than one-third of the market value of U S generating assets, the market value for the total Russian power sector (approximately 200,000 MW) would increase tenfold to $30 billion, or over $100 per share for RAO EES (not including transmission or distribution assets) This provides some indication of the potential for raising capital through the sale of authorized shares or the issuance of new shares

17 Following the completion of the voucher auction in 1994 and anticipated cash sales in 1995, the government will continue to hold 51% of the shares in RAO EES Rossii, which in turn owns controlling shares in the 72 AO Energos As majority owner, the government's decision of when to sell its stock and how to dispose of the proceeds is of great importance to the power sector If the government sold its shares to the public and reinvested the proceeds in power sector bonds or preferred shares, the government could provide the power sector with needed investment capital and credit

18 The purchase of shares by foreigners is already occurring Foreign holdings of RAO EES Rossii stock have been estimated to be about 2.5% of shares outstanding The decision of foreigners to invest is different from domestic investors due to the foreigners' need to use foreign currency to purchase ruble-denominated shares This makes the issuance of shares a potential option for attracting foreign investment to power sector companies, assuming investors are willing to accept the foreign currency risk

19 RAO EES Rossii has been approached by well-known investment banks to work with the company on its first offering of shares through the American Depository Receipt (ADR) process This process would allow RAO EES Rossii to move eventually to pension funds, insurance companies, and other institutional investors It would provide RAO EES Rossii with prestige in the international equities market and could lead the way for some of the other AO Energos to follow suit The demand for RAO EES Rossii shares offered through the ADR process has not been fully analyzed

20 A number of equity investors represented by special investment funds for Russia have emerged The Framlington Fund, sponsored by the European Bank for Reconstruction and Development (EBRD) and Credit Commercial de France, has already invested in two Russian projects (one in the oil and gas sector), and several new projects are in the final stages of preparation The Pioneer Fund, a U S fund based in Boston, was capitalized with $3 million to invest and expects to grow to $100 million The Brunswick Fund, capitalized at $10 million, is targeting oil and gas, utilities (electrical energy and telecommunications on the national and regional levels), and mineral extraction/ processing The Alliance ScanEast Fund is a Finnish venture capital fund with a focus that includes power generation and oil and gas The U S Fund for Large Enterprises in Russia has been set up to provide equity and other types of financing to enterprises that occupy key positions in the Russian economy Other funds set up to invest in small and medium-size enterprises could be a source of funding for smaller-scale energy efficiency projects

21 Domestic strategic investors could be another important source of investment Strategic alliances with domestic partners, such as RAO Gazprom, the main supplier of fuel to the power plants, could be developed to the advantage of both parties Alliances with industries such as telecommunications or large industrial exporters of energy-intensive products may also prove useful Alliances with such domestic partners could help develop a source of foreign exchange for RAO EES Rossii and the AO Energos

22 The power sector's efforts to attract foreign strategic equity investors are showing some results Several cooperative agreements and joint ventures with European electric utilities could turn into important strategic alliances Several private power developers (primarily from Finland, Germany, China and the United States) are negotiating power projects that involve the export of electricity Other developers are looking at captive private power projects Some developers have offered to buy existing generating assets

5 2 3 Borrowed Funds

23 Because the Russian power sector has no significant amounts of long-term debt outstanding, its theoretical potential for borrowing is large However, the commercialization of the newly-privatized entities has not been completed, and much work and many changes need to occur before power sector entities will be able to borrow money from traditional lenders to the utility industry commercial banks, institutional

lenders, and the public Some international financial institutions such as the World Bank or the EBRD will be willing to help enterprises meet their credit conditions Other lenders will wait until those banks have made a commitment to lend before they will even begin to consider lending to the power sector Investment banks may be willing to consider underwriting a short-term domestic bond issue

24 Before they can readily access borrowed funds, power companies will need to develop and demonstrate creditworthiness, prepare acceptable financial statements, prepare business plans and project feasibility studies, and develop new project structures that will accommodate lenders' and equity investors' requirements Once this has been accomplished, more sources of borrowed funds will be available

25 Power sector creditworthiness will be difficult to establish until tariffs cover full costs, regulations are firmly in place, contracts are well-documented, executed and expected to be enforced, and the payments crisis is improved The high level of investment risk for Russia in general will not make it easy for the power sector to obtain credits It will be necessary to identify a source of foreign exchange for the repayment of loans Establishing creditworthiness could take several years to achieve, so continual progress needs to be made in this direction For enterprises that have not yet begun to establish creditworthiness, it is critical that they begin the process soon Some enterprises have already begun this process

26 Financial disclosure is another prerequisite to borrowing funds Lenders will need to see that the company is performing and be able to monitor its financial condition and performance To access credits from foreign borrowers, financial statements will need to be restated into Western-style accounting statements The financial statements will also need to be audited RAO EES Rossii, with assistance from the United States Agency for International Development (USAID), has already begun this process Some of the larger AO Energos--MosEnergo and LenEnergo--have also begun to do the same

27 Project definition materials will also need to be prepared For international financial institutions, in addition to demonstrating financial and economic viability, a project must be justified within the context of a least-cost plan and the technology used must be proven Further, there must be competitive bidding for equipment and services Projects financed by official investors must be consistent with certain policy objectives including plant safety, environmental performance, and energy efficiency

28 In light of the long lead time needed to establish creditworthiness, the uncertain investment climate, and the need to identify a source of repayment in dollars, the first several capital-intensive projects will need to be structured on a stand-alone project-finance basis, as independent power projects, or as hybrid projects that have some degree of independence Projects will need to involve Russian partners with relative financial strength such as RAO Gazprom, RAO EES Rossii, large AO Energos, industrial

companies and foreign private power developers Sources of foreign exchange for loan repayments will need to come from a combination of barter transactions, electricity exports, monetization of energy efficiency or fuel savings, or repayments from the export proceeds of selected industrial customers Once the ruble is stabilized and exchange rate and convertibility risks decline, the indexation of power purchase contracts for exchange rate changes may be sufficient

29 Not all projects can be structured on a project finance basis Investments in transmission and dispatch upgrades, nuclear safety upgrades, environmental improvement projects, and small energy efficiency projects may not lend themselves to project financing Here, corporate financing or government backing will be required, and establishing creditworthiness will be an essential condition for lending

30 Potential foreign official sources of finance for the Russian power sector are foreign governments (bi-laterally or multi-laterally), international financing institutions (IFIs) such as the EBRD, The World Bank, and the International Finance Corporation (IFC, the private sector lending arm of the World Bank group), foreign government-sponsored organizations such as Export Credit Agencies (ECAs), investment promotion agencies such as the U S Overseas Private Investment Corporation (OPIC), investment advisory groups (Russian Project Finance Bank), investment funds capitalized by official financial institutions (Framlington) and commercial banks with or without risk reducing agencies (like The Multilateral Investment Guarantee Agency [MIGA] or the World Bank's guarantee scheme) The financing tools available from these sources include limited recourse project finance, export credits (with or without a government guarantee), guarantees, equity investments, and some technical assistance

31 After lending $1 11 billion for oil projects and $50 million for the coal sector in 1993 and 1994, The World Bank has proposed expanding its energy lending to include the power sector The Bank would require that projects be part of least-cost solutions to addressing the current problems, be able to demonstrate full-cost recovery (including capital costs), and meet its environmental standards A World Bank loan would probably have a guaranty of repayment from the Ministry of Finance Lending to projects for the construction of new capacity in capacity-deficit regions will probably require co-financing from other financial institutions

32 MIGA encourages foreign investment by providing investment guarantees against the risk of currency transfer, expropriation, war and civil disturbance, and breach of contract by the host government In 1993, MIGA issued its first coverage in Russia to Multiserv Russia (a Belgian company) for its investment in equipment in Magnitogorsk Additional guarantees could be provided for lending to the power sector which could help attract strategic investors and lenders

33 The IFC has already committed over $100 million to Russia to date, although not in the power sector Globally, IFC infrastructure financings have been growing at a rate of 25% per year, with power receiving the largest share This pattern could be extended to Russia on the conditions that the privatization and restructuring process succeeds, and that the appropriate legal and regulatory framework for private project finance is developed in the power sector

34 The EBRD finances both public and private sector projects in Russia It has committed ECU (European Currency Unit) 884 million through August 1994, a sum that represents over 18% of loans approved by the EBRD Board of Directors The investments thus far have been concentrated in the oil and gas sector, although lending to the power sector is under consideration for 1994/95 Issues that need to be addressed include the implementation of an overall power sector strategy that addresses nuclear safety and energy efficiency, the adequacy of tariffs--particularly as related to the financial viability of the project--and the implementation of innovative methods of financing with adequate security EBRD projects will concentrate on the refurbishment and repowering of conventional power plants, mostly oil- and gas-fired

35 G-7 export credit agencies are potential sources of insurance and credits for exports to Russia Their involvement has been strongly supported by the G-7 The amount of financing to be provided by ECAs, however, will be based on a number of factors, including the availability of sovereign guarantees Because most power sector equipment will not be imported, ECA assistance will be limited to the imports of specific pieces of equipment and access to new technologies To date, most ECA activity in Russia's energy sector has been in oil and gas The largest suppliers of export credits to Russia have been Germany and Japan, followed by Italy and the United States

36 The U S OPIC has significant authority to guarantee loans, lend directly, and provide insurance against political risks to U S business interests OPIC has $200 million of financing and $200 million of political risk insurance available per project, and could support one or two power projects a year in Russia OPIC also has provided approximately 50% capitalization for several equity funds that could invest in the Russian power sector OPIC project financing can support commercially viable projects with a strong U S involvement through equity ownership, participation in management, or participation in financing The privatization of the power sector would be essential for unlocking these investment funds

37 The Russian domestic bond market is another potential source of financing, although currently, only short-term treasury notes are being issued by the Ministry of Finance The potential for power companies to issue bonds is good, provided they can demonstrate an ability to pay the interest and principal, which will likely require increased tariffs Given the lack of long-term domestic debt and high levels of inflation, short-term bonds are likely to be the first type of domestic bonds issued for the power companies, which may

not be appropriate for financing long-term investment programs However, short-term bonds are worth pursuing to provide the companies with funds for working capital, life extension programs, and construction financing

38 Russian commercial banks are expected to evolve into an important source of finance for the power sector, but this has not yet occurred The potential for financing from this banking sector will be limited in the short run There are several issues that must be resolved First, the banks must restructure and recapitalize, a process that will require resolving their own poorly performing portfolios This process is likely to continue for several years Until recently the ruble interest rate has been less than the rate of inflation, so foreign currency lending has predominated and there has been no incentive to save Although there has been rapid progress in improving the payments clearing process, more work is needed Second, the legal and regulatory framework for banking remains weak, also, laws governing fraud and false advertising, banking supervision, and capital and accounting standards are inadequate

39 Foreign commercial banks are only beginning to establish a presence in Russia A number of banks have opened representative offices, branches or joint ventures in Moscow or St Petersburg The main focus of the Western bank offices is to service their Western clients and provide correspondent banking services Lending to the Russian power sector by commercial banks will probably lag that of the multilateral and bilateral financing institutions Western commercial banks are not currently providing credits beyond short-term trade credits to Russian projects This pattern of lending stems from the overall investment climate in Russia as well as the banks' desire to avoid risk Debt negotiations have clouded the possibility of additional Western commercial bank lending in Russia, although this issue is being resolved As Western companies express an interest in the power sector in Russia and as IFIs begin financing power projects, Western commercial banks may follow their clients into Russia, provided they have appropriate collateral and guarantees against excessive risk The World Bank and EBRD guarantee programs could assist in this effort and the banks are encouraging them

5.2 4 Government Financing

40 Direct financing from the Russian Government has been declining and is unlikely to increase given the tight budgetary requirements of the federal government and the privatization of the power sector However, there are several important ways in which the government could assist the power sector

- Investment of the proceeds from power sector enterprises' stock sales into the power sector through bonds, preferred stock or grants

- Willingness to provide sovereign guarantees for foreign currency borrowing from multilateral development banks and export credit agencies

- Tax relief for power sector enterprises, especially enterprises that will need to make significant capital improvements over the next several years Tax relief could come in the form of investment tax credits, lower tax rates, tax holidays, and increased allowances for depreciation

- Support for energy efficiency programs The implementation of energy efficiency improvements will cause the power sector to need less capital (as much as 17% less) Therefore, it is in the interests of the government to provide as much support to energy efficiency programs as possible Support could be in the form of special-purpose funds and various forms of tax abatement

41 Technical assistance funds are another source of funding that is available to the government for the benefit of the power sector Generally, these funds are available for industry restructuring and reforms, and project preparation Agencies participating in these programs are the USAID, European Union TACIS, the United States Trade and Development Agency (TDA), the UK Know-How Fund, the EBRD technical cooperation funds and internal budget, the World Bank Technical Assistance Funds, and the IFC The TDA has listed power projects as one of its priority areas and has already funded several power project feasibility studies Project preparation through one of these funding sources is likely to enhance the likelihood of attracting support from official sources of project finance

42 The EBRD also administers the Nuclear Safety Account (NSA), an ECU 135 million grant fund set up for safety upgrades at reactors that present the most serious safety risks Its projects seek to address priority safety problems in the most cost-effective way, taking into consideration the eventual closure of unsafe plants The NSA is providing ECU 90 million in funding for a project involving the Kola, Novovoronezh, and Leningrad reactors The EBRD is prepared to consider lending from its ordinary resources for safety upgrades of nuclear plants or alternative sources of energy related to the closure of unsafe plants

43 In addition, the European Investment Bank (EIB) administers a $1 2 billion Euratom fund for the European Union It provides funding for up to 50% of nuclear safety projects at low rates This fund could be a source of nuclear safety finance in Russia, although currently EIB does not operate its programs in Russia

5.3 FINANCING STRATEGIES

5 3 1 Amount of Financing and Type of Investment

44 The JEPAS indicates a wide range of investment requirements for the period 1995-2010 Because it is difficult to develop financing strategies for investments made beyond the next ten years, this analysis addresses primarily the period from 1995 to 2005 Investment requirements and potential sources of financing are shown in Table 5-2 This table shows aggregate amounts potentially available from the four different sources discussed in Section 5 2 These figures are indicative and are based upon expert judgment and research conducted over the past year, including preliminary discussions with international financial institutions, investment banks, power sector enterprises, and public accounting firms

45 Total investment requirements for generation assets for the next eleven years, as described more fully in Chapter 4, range from a low of $23 billion to a high of $58 billion depending largely upon assumptions regarding the demand for electricity and the retirement schedule of existing generating assets Between $2 8 billion and $8 3 billion will be needed over the next three years, and it is this amount that will be the most difficult to obtain given existing economic conditions in Russia These figures do not include amounts required for working capital, which ordinarily may be considered minimal, but in the case of Russia could be significant given the existing nationwide problem of non-payments

46 Financing strategies will differ by type of investment required and will no doubt change over time as electric power industry restructuring is implemented, regulations and laws change, and economic conditions improve To some extent financing strategies will also vary by region, since certain regions will require more investments than others, possess a different mix of resources, have specific social policies to consider, and operate in different regulatory environments Financing strategies will also be based upon the relative attractiveness of specific projects to investors, policy makers and regulators Future cash flows, ownership, and business risk also vary between types of investment, and will influence the sources and amount of financing available as well as the ease with which financing can be obtained

Table 5-2
Analysis of Sources of Finance (Generation Only)

	Scenario A - High Demand				Scenario B - Low Demand			
	1995-1997	1998-2000	2001-2005	Total	1995-1997	1998-2000	2001-2005	Total
Investment Requirements								
Upper Range	8,301	18,055	31,790	58,146	3,880	5 666	19,795	29,341
Lower Range	5 320	15,614	25,451	46,385	2,829	6,344	14,391	23,564
SOURCES OF FUNDS								
Internally Generated Funds								
Upper Range	6 226	12,639	20,664	39,528	2,910	3,966	12,867	19,743
Lower Range	3 990	10 930	16 543	31,463	2,122	4,441	9,354	15 917
Sales of Power Sector Shares								
Upper Range	830	1,806	4 769	7 404	388	567	2,969	3,924
Lower Range	532	1,561	3 818	5,911	283	634	2,159	3,076
Borrowed Funds								
Upper Range	1 245	3,611	6,358	11,214	582	1,133	3,959	5,674
Lower Range	798	3,123	5 090	9,011	424	1 269	2,878	4,571
Government Credits/Subsidies								
Upper Range	0	0	0	0	0	0	0	0
Lower Range	0	0	0	0	0	0	0	0
Total Sources of Financing								
Upper Range	8 301	18,055	31,790	58,146	3,880	5,666	19,795	29,341
Lower Range	5,320	15,614	25,451	46,385	2,829	6,344	14,391	23,564
% from Borrowed Funds	15%	20%	20%	19%	15%	20%	20%	19%
% Financed from Sales of Stock	10%	10%	15%	13%	10%	10%	15%	13%
% from Internally Generated Funds	75%	70%	65%	68%	75%	70%	65%	68%
% from Government	0%	0%	0%	0%	0%	0%	0%	0%
Total Sources of Financing	100%	100%	100%	100%	100%	100%	100%	100%

47 New generation plants (gas-fired simple cycle and combined cycle) can be built by independent power producers, the utility, or a combination of both Structures for financing independent power projects are gaining more acceptance internationally and this could be a very attractive option for Russia because it would minimize Russian Government financing and provide access to private sources of debt and equity However, independent power projects require a level of contract enforcement that may not yet exist in Russia Other barriers to independent power development include uncertainty regarding who would purchase the power (a wholesale market or a regional distribution utility), at what rate the power would be purchased (a single uniform wholesale tariff or a regional tariff), and the types of entities that will be allowed to become independent power producers (Energos, industrials, new joint venturers, combined heat and power producers) Also, independent power projects will need to find a way to repay foreign loans In addition to independent power development, consideration should be given to utility-owned plants that can be financed with export credits to cover 85% of the imported components AO Energos that can demonstrate creditworthiness will be good candidates for conventional utility ownership of new plants or as joint venture partners in consortiums of independent power developers

48 Fossil plant modernization, rehabilitation, and life extensions can use some of the same strategies for obtaining financing as new plants These projects can be made more attractive if the assets or companies are sold , whether wholly or partially to private companies with or without foreign ownership If the Russian power sector divests of generation, as is being proposed, many opportunities will arise to purchase generation assets A critical factor in the valuation of the assets will be the tariffs , which have not yet been determined Another option is for the Russian power sector to sell some of its assets and lease them back A mechanism for doing this is further described in Section 5 4

49 Transmission and dispatch center projects will need to be financed from a combination of internally generated funds and commercial borrowing It should be possible to demonstrate the economic viability of these investments to multilateral development banks or commercial banks, if such term lending becomes available in Russia Until then, a higher percentage of internally generated funds will be required It may be possible to finance a transmission project on a non-recourse basis based upon a specified tolling arrangement

50 Traditionally energy efficiency projects are more difficult to finance than supply-side investments, they thus need special incentives and programs The difficulty in financing energy efficiency projects arises from uncertainties in realizing profits from cost savings (as opposed to revenue generating investments) and because the investments will be made primarily by energy end-users, which may be diffused throughout Russia and not in good economic conditions themselves Also, lenders are not nearly as familiar with energy savings lending as they are with evaluating investment in new generating or transmission assets However, certain aspects of energy efficiency investments make them very attractive Many such investments have short payback periods and could pursue short-

term financing Also, certain large energy-intensive industrial users may be creditworthy enough to borrow on their own account to implement an energy savings program, or they can enter into borrowing arrangements with the small number of third-party lenders who are familiar with performance contracting and shared savings arrangements The potential for energy efficiency financing is tremendous, but will require innovation and additional government support through tax policies and special-purpose funds Legislation for energy conservation, which would include a fund, is currently pending

51 It will be difficult to acquire external financing for safety upgrades at existing nuclear plants in Russia because of the perceived risk of an accident and potential liability for private sector investors as a result of that risk Therefore, internal cash generation may be the only significant source of funding for near-term safety upgrades This produces an urgent need for many nuclear power plants and utilities to become self-financing so that they can raise cash to implement sorely needed safety upgrades Multilateral development banks, export credit agencies and bilateral grants are the most likely secondary sources for near-term safety upgrades to supplement internally-generated funds

52 External and commercial financing for the completion of nuclear power plants already under construction should be easier to acquire because they are of a new and more safe design However, an important test case for the commercial financing of partially completed nuclear power plants is being considered at the EBRD financing the Slovak Mochovce nuclear power plant's completion Although the EBRD does not maintain a policy inhibiting nuclear power plant projects financing, the issue has roused sensitivities that may hamper future EBRD "nuclear" lending While the EBRD/Mochovce case could provide an important precedent for commercial financing for nuclear completion projects, it should not automatically preclude "nuclear" lending by other export credit agencies and multilateral development banks

5 3 2 Ability to Generate Funds from Operations

53 The major near-term constraint on investment from internally generated funds and in attracting investors is the cash balance condition in the industry Internally generated funds will be the primary source of investment capital, especially during the 1990s before widespread creditworthiness can be established and domestic capital markets developed Russian electric companies will need to retain as much of their cash from operations (retained earnings and depreciation deductions) as possible However, regulatory bodies may support this desire only as long as the increases in electricity tariffs are not considered to be too much of a burden for consumers

54 Over the next ten years it is expected that the power sector will need to generate between 65% and 75% of its financing requirements from internally generated funds In dollar amounts this ranges from $16 to $40 billion, with between $2 and $6 billion

required over the next three years Obtaining enough internally generated funds over the next three years is the most important issue for power sector financing

55 In order to raise funds from operations, the power sector will need to ensure that tariffs are set at levels that cover all operating costs and include additional costs to cover its capital investment program In addition to the level of investments, tariff requirements will be significantly affected by government policies on tax rates, the tax deductibility of capital expenses, the method and rate of depreciation, and accounting methods for recovering capital costs The mix of sources of capital and the cost of capital are important factors that will be influenced more by market conditions than government policies The number of electricity users affected by tariff increases plus the allocation of increases across type of consumers is also an important component of tariff requirements While the JEPAS has not performed a revenue requirements analysis for the power sector, a preliminary analysis of the impact on tariffs as a result of varying amounts of investments, government policies and assumptions is shown in Table 5-3 and discussed below This analysis does not include tariff increases that need to be charged to cover fuel and other operating costs

56 Three methods of calculating incremental tariffs with varying assumptions are presented in Table 5-3 Option #1 assumes that all of the investments are paid from pre-tax income in the year in which they are incurred For example during the period 1995-1997 where $3 8 billion is required, it is assumed that tariffs will increase by an aggregate amount of $3 8 billion, or 0 16 cents per kilowatt-hour It is also assumed that tariff increases are spread evenly over all electricity consumption throughout Russia (2 5 bkWh) Similar to Option #1, Option #2 assumes that all of the investment requirements will be financed from internally generated funds, but uses a cost recovery methodology where the costs of long-term assets are recovered in rates over 30 years through annual depreciation and capital charges In Option #2 returns to equity holders are taxable and tariffs paid by customers include the tax obligation Depreciation is considered to be a tax deductible expense Option #3 is similar to Option #2 in that investment requirements are recovered in tariffs over time based upon depreciation and capital charge allowances In Option #3 a mix of 30% debt and 70% equity is assumed Interest on debt is tax deductible and the return on equity is again considered taxable

Table 5-3
Analysis of Incremental Tariffs Needed to Support Indicated Capital Investment Requirements

		Scenario A			Scenario B		
		1995-1997	1998 - 2000	2001 - 2005	1995-1997	1998 - 2000	2001 - 2005
Investment Requirements ($ million)	Upper	8,301	18,055	31,790	3,880	5,666	19,795
	Lower	5 320	15 614	25,451	2,829	6,344	14,391
bkWh Generated		2,578	2,774	5,080	2,393	2,441	4,378
Option #1 Requirements Met through Tariffs (cents/kWh)	Upper	0 32	0 65	0 63	0 16	0 23	0 45
	Lower	0 21	0 56	0 50	0 12	0 26	0 33
Option #2 Requirements Met through Internally-Generated Funds Capitalized (cents/kWh)	Upper	0 16	0 54	1 04	0 08	0 23	0 58
	Lower	0 10	0 42	0 83	0 06	0 21	0 48
Option #3 Requirements Met through Debt (30%) and Internally-Generated Funds, Capitalized (cents/kWh)	Upper	0 14	0 46	0 89	0 07	0 20	0 49
	Lower	0 09	0 36	0 71	0 05	0 18	0 41

57 The analysis indicates that the tariff increases needed to cover the investment requirements will almost always be less than one cent per kilowatt hour provided that 1) investments are paid from pre-tax income or are recovered over time and 2) tariff increases are spread over a very large number of electricity users Over the short term, expensing capital investments in the year in which they are incurred (Option #1) would be the most expensive method of financing investment requirements because it will have the greatest impact on tariff increases Table 5-3 indicates that in the near term, meeting investment requirements through pre-tax income on an annual basis (Option #1) would be twice as expensive per kWh as recovering them over time (Option #2) Moreover, it is important to note that if investment expenses are not tax deductible as indicated in Option #1, the tariff impact from the investment program would double (assuming a 50% income tax rate) and would be four times that of Option #2 in the period 1995-1997 In later years, especially after 2000, cumulative capital charges increase to the point where they exceed the cost of annual investment expenses, although the timing of this will depend upon the cost of capital, tax rates and depreciation rules In the analysis shown in Table 5-3 this begins to happen in 2001

58 As mentioned, the analysis shown in Table 5-3 is preliminary and useful only to indicate some of the impacts of various policies and market conditions on tariffs As noted, if investments are expensed in the year in which they are incurred, it is critical that they be tax deductible or the impact on consumers will be onerous Clearly, lower income tax rates and allowances for accelerated depreciation will allow for lower tariffs to consumers It is also important to note that although capital recovery charges cause lower tariffs in early years, this may not be possible to implement if the power sector is unable to generate sufficient cash to fund the investment program Under capital recovery accounting, funds must still come from either operations or third-party sources In Table 5-2 it is assumed that external sources of financing can provide a maximum of 25% of investment requirements If the power sector is unable to generate the remaining 75% (between $2 1 and $6 2 billion), it would not be able to adopt the capital recovery methodology assumed above, this could occur only if additional cash proceeds are generated from sales of stock or assets

59 The cost and the mix of capital will also affect the relative level of tariffs If capital costs are higher than the 15% equity and 10% debt indicated in Table 5-3 (which is certainly possible), expensing investment requirements in the year in which they are incurred becomes relatively more attractive Regarding the mix of equity and debt, debt is always less expensive than equity due to the tax deductibility of interest payments Also, the cost of debt is generally lower than the cost of equity because of its preference in bankruptcy At some point (generally assumed to be between 60% and 70% debt) it no longer remains less expensive to use more debt because the leverage of the enterprise will increase the risk of bankruptcy

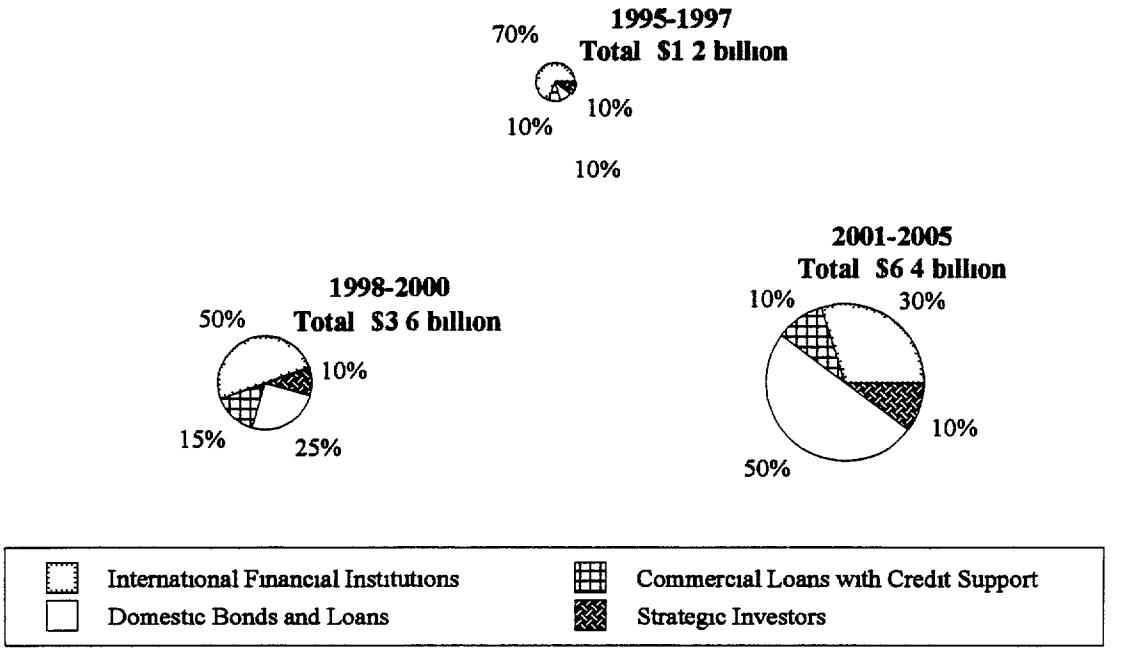
60 The analysis in Table 5-3 assumes that tariff increases will be spread over all electricity users, however, this may not be the policy adopted in Russia Investment requirements vary by region and it is likely that certain investments will have a disproportionate effect on tariffs in a particular region For example, in regions with supply deficits (North Caucasus and Urals), the introduction of new capacity will cause a much larger tariff impact than noted in Table 5-3 if the increase is applied only to electricity users in the region As new supplies are brought on line, these fundamental issues will be critical to resolve

5 3.3 Availability of Debt from Any Source

61 It is estimated that the power sector will be able to borrow approximately 20% - 30% of its capital requirements over the next ten years, or between $4 6 and $11 2 billion Borrowing is limited to 20-30% for several reasons First, the creditworthiness of power sector enterprises will take time to establish and will be greatly influenced by general economic and business climate issues for Russia as a whole Second, medium- and long-term domestic capital is not available in Russia and will take years to develop Third, foreign sources of borrowing, while extremely important as gap financing over the short term, will be limited in the long term due to the large domestic content in power sector investments and the foreign exchange risk inherent in repaying dollar-denominated debt with domestic revenues

62 The estimated breakdown of borrowed funds (for the upper range, Scenario A) is shown in Figure 5-1 Although international financial institutions will be an excellent source of financing over the next several years, there are limits on the amounts that can be loaned to any sector and country It is estimated that international financial institutions can provide the Russian power sector with between $950 million and $2 7 billion over the next six years However, as noted above, very stringent credit criteria will have to be met to realize this level of borrowed funds Other sources of debt financing include foreign commercial loans (most likely as co-financing with international financial institutions) and new issues of domestic bonds and loans Beginning in 1998, guarantees on foreign borrowing will affect the amount of foreign borrowing available, especially during the next three years Tax policies for power sector enterprises will influence the amount of internally generated funds available for the investment program Tax credits, accelerated depreciation, and lower tax rates would improve the sector's ability to be financially independent Direct subsidies or credits from the government may be required to provide financing for nuclear and energy efficiency investments

Figure 5-1
Estimated Breakdown of Borrowed Funds (Scenario A - Upper Range)



5 3 4 Cost of Financing

63 Except for government-subsidized credits and limited amounts of term loans from multilateral development banks, all new financing for the power sector will be very expensive over the next several years As power companies develop a history of profitability, the risk of investing will be reduced and the cost of funds will decline, but it is not possible at this point to predict when this will happen

64 It is difficult to estimate the actual costs of financing for equities Typical returns for equity in an independent power project are about 25% per annum Many emerging market growth funds have earned returns averaging 30% to 40% per year It is likely that equity investors in the Russian power sector are currently looking for returns in excess of 15% per year

65 It is easier to determine the costs of debt capital because they are based upon a stated rate of interest plus the cost of credit enhancements such as loan guaranties, risk

insurance, and standby commitments In addition there are often high placement, appraisal and legal fees that are added to the cost Currently there are no sources of long-term ruble debt available, and short-term rubles loans are still in excess of 200% per year Long-term foreign currency loans are available from multilateral development banks and other government-supported loan programs such as the IFC, OPIC and export credit agencies While the costs of these loans varies, most of them are lent at market or near-market rates of interest Including all of the associated costs, ten-year loans could cost as much as 15% per year One exception to this is The World Bank, which lends at lower interest rates (about 7%) and for longer terms (up to 17 years) However, the foreign exchange risk on World Bank loans is covered by a sovereign guarantee Frequently, the guarantor will charge the borrower a fee of several percentage points for having provided a guarantee This would raise the cost of the loan

66 Foreign loans can become more expensive than anticipated if the Ruble depreciates at a rate faster than electricity prices are increasing

5 3 5 Capital Mix

67 Over the near term (next three years) the availability of debt and equity from any source will be more important than the cost of capital and the particular mix of equity and debt Power sector enterprises must establish credit from any source and lay the groundwork for their participation in the capital markets of the future Over the longer term the power sector must begin to develop strategies that will lead to a larger share of domestic financing In order to do this, the power sector must play a role in capital market development in Russia This can be done through support for capital market development as well as becoming a more active participant in the delivery of financial services

5.4 ILLUSTRATIVE PROJECTS AND MODELS FOR INNOVATIVE FINANCING

5 4 1 Projects

68 The Joint Study was asked to summarize projects that had already been identified by Russian and foreign institutions and enterprises, and that might be candidates for funding by international lenders and/or investors The list shown in Table 5-4 is not intended to be exhaustive It is a representative set of named projects, some of which have already been the subject of pre-feasibility and feasibility studies, and memorandums of agreement

Table 5-4
List of Projects Evaluated for Possible Financing

1	Krasnodar Power Plant	A 3 x 450 MW, gas-fired power plant near the town of Mostovskaya in North Caucasus
2	Urengoi Power Plant	A 4 x 225 MW plus 24 MW gas-fired steam turbine near Yamalo Nenets in Tyumen
3	Cherepovets Trans Line	A 270 km, 750 kV transmission line in the North-West that would permit the Cherepovets region to be supplied from the Kalininskaya Power Plant
4	Beloparoskaya Hydro Plant	A 103 MW peaking hydroelectric power plant in the North-West
5	Shakhtinskaya CHP Plant	A partially-built 70 MW CHP plant at Shakhti in the North Caucasus
6	Kamenskaya CHP Plant	A 90 MW CHP plant at Rostov in North Caucasus
7	Cherepetz Power Plant	Rehabilitation of 4 x 150 MW and 3 x 300 MW, coal-fired units in the Cherepetz State District in the Central Region
8	Shuikino Power Plant	A 2 x 450 MW expansion of the Shuikino Power Plant
9	Kola-St Petersburg Transmission Line	A 330 kV line from Kola to Karelia and a 750 kV line from Karelia to St Petersburg
10	North-West to Center Transmission Line	A 330 kV and a 750 kV line between the two regions
11	North-West Region Power	Reconstruction of the power control center for the North-West Region
12	Moscow Central Dispatch Office	Modernization of the Moscow Central Dispatch Office
13	Moscow Oil Refinery	Energy conservation
14	Lenenergo Power Plant	Repowering the Lenenergo Power Station by adding three 50 MW gas turbines
15	RBMK power plants	Develop decommissioning plans
16	NP500	Initiate siting and project preparation procedures for licensing a new NP500
17	Kalinin NPP	Complete construction of Kalinin 3
18	Rostov NPP	Complete construction of Rostov 1

5 4 2 Financing Models

69 This section focuses on the kinds of financing that might be used for four very different projects a gas combined-cycle power plant in Krasnodar, a transmission line in the North-West (Cheropovets region), energy efficiency improvements at the Moscow Oil Refinery, and the completion of a nuclear power plant (Kalinin 3) Three approaches to innovative financing that could be applied to the power sector are also described More detail on these project financing structures and innovative financing concepts can be found in Appendix J

70 ***Krasnodar 1,350 MW (3 x 450 MW) Gas Combined-Cycle Plant*** (to be built by KubanEnergo to supply power in the deficit North Caucasus Region) Two alternative approaches to financing this project are proposed The first would create a joint venture between RAO EES Rossii and KubanEnergo, with the latter as primary project developer using a straight-term loan facility RAO EES Rossii would provide hard currency funding as part of its equity contribution to the joint venture, and this contribution would be translated into ruble debt Assuming, as RAO EES Rossii does, that tariffs in the North Caucasus reach world levels by 1999, preliminary analysis shows that this project would not only be attractive for RAO EES Rossii and KubanEnergo, but it would also provide returns that could attract a private developer The second approach considered for Krasnodar is the use of a "leveraged lease " This alternative might be preferred if KubanEnergo's balance sheet could not support the debt that 80/20 or even 50/50 debt/equity financing would impose In such a case, RAO EES Rossii would own the plant and lease it back to KubanEnergo, while KubanEnergo would enter into a turnkey contract to build the plant for RAO EES Rossii

71 ***Cheropovets Transmission Line, a 750 kV Connection between the Vologodskaya Grid and the Kalinin Nuclear Power Plant*** The parties involved in this project would be Volagnaenergo (which is a distribution company in need of power), RAO EES Rossii, the owner of the transmission grid, and Rosenergoatom, the operator of the Kalinin NPP Under Federal Energy Commission regulations, only RAO EES Rossii is allowed to own high-voltage transmission lines, hence, it is likely that this project would have to be financed on a corporate basis by a bank such as The World Bank Such financing would require a sovereign guarantee, i e , the guarantee of the Russian Government that the loan would be repaid This project might well appeal to other international financial institutions as it could reduce the need for new power plants for a period of years

72 ***Energy Efficiency Improvements at the Moscow Oil Refinery (MOR)*** A preliminary energy audit of this plant has identified savings in electrical energy use that are highly attractive when measured both in energy savings and return on investment The amounts needed are relatively small, but the MOR is in a financial crisis (as with many energy firms doing business domestically) due to non-payments Because the MOR has little ability to borrow from Russian lenders because of its situation, the opportunity exists for

Mosenergo (the electric power utility serving the Moscow region) to lease the energy-savings equipment to the MOR and other companies in similar predicaments MOR benefits from leasing, as distinct from borrowing to purchase, because lease payments are treated as an operating expense, whereas loan repayments are after-tax This could be seen as a demand-side management (DSM) transaction in that Mosenergo benefits by the amount of investment in new capacity it has avoided as a result of improving efficiency at the MOR

73 ***Completion of Kalinin 3*** The Joint Study's optimization model selected the completion of this unit as an economic alternative when compared with alternative fossil plant options Kalinin 3 is a second-generation VVER-1000 reactor which is already 75% complete It is located in the Center power pool region The Joint Study has estimated that $243 million and four years would be required to commission this unit Subject to licensing and operating regulations and the approval of MinAtom and Rosenergoatom, this unit could be a candidate for private sector financing under a leveraged lease arrangement that would return the unit to government control prior to the end of design life Using a 60-40 debt/equity ratio, private investors would have to find approximately $100 million Assuming that such operators would be able to conclude a long-term fuel supply contract at the same prices used in this Study, this unit would bid very low prices in a wholesale market pool and would have the potential to provide investors with very attractive returns on investment Private investors from the West would require assurance that acceptable safety standards had been achieved The International Finance Corporation, which typically takes minority stakes in private sector-financed projects, has no policy prohibition against participating in nuclear power projects

5 4 3 Innovative Financing Mechanisms

74 Consideration should also be given to an innovative approach to resolving the non-payments problem that involves the creation of Deferred Revenue Accounts (DRAs) This cash management tool, which would necessitate the close cooperation of the commercial banking system, RAO EES Rossii and the Central Bank, would mandate a system of temporarily diverting customers' revenues, thus allowing banks to accumulate a pool of funds large enough so that the interest on the funds would be sufficient to pay customers' electricity bills It is estimated that the application of this concept to industrial customers could not only alleviate current cash flow constraints, but also generate a source of long-term funding for RAO EES Rossii and other power sector enterprises

75 As the pool of deferred revenues is being built up, a three-year credit facility, fully secured by the deferred revenue account, is extended to the customer to offset the temporary loss of revenues Once the pool is in place, the credit facility is repaid The customer pays an amount equal to its electricity bills and RAO EES Rossii pays the remainder of the credit facility

76 DRAs have sufficient flexibility to be implemented nationwide over a short time or implemented over several years for specific applications

77 For project financing, two innovative financing mechanisms could be pursued RAO EES Rossii could be the primary issuer of a new negotiable debt instrument to tap domestic savings Unlike commercial banks or the Ministry of Finance, RAO EES Rossii could offer a kWh-denominated debt instrument, backed by its power generating capacity These units would be redeemable either in kWh or rubles for their kWh value at the time of maturity or prepayment As the price of kWh is adjusted to inflation, the holders of these issues would be protected against currency erosion from inflation As a result, the length of the debt issue should exceed what is currently available in the Russian market, and the interest rate should also be considerably lower than current market rates

78 A guarantee fund that would act as a catalyst in encouraging energy efficiency projects, independent power production and environmental improvements could be developed fairly quickly Among other things, the fund could guarantee longer maturities of loans, thus leveraging corporate borrowing capacity and speeding up the implementation of new investments

CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

1 The five working groups prepared conclusions and recommendations based on their investigations and analysis These are presented below

6.1 WORKING GROUP 1 - ENERGY EFFICIENCY

Conclusions

2 The Joint Study has concluded that energy efficiency should be given a high priority by those in the power sector

3 There is a large potential for energy efficiency improvements throughout the Russian economy By installing efficient end-use technologies, power consumption could be reduced by up to 5 GW and 29 billion kWh by the year 2000, and 20 GW and 112 billion kWh per year by the year 2010 These values do not include energy savings resulting from low-cost/no-cost measures, and from structural changes in the Russian economy

4 In all sectors of the Russian economy, a significant portion of the savings potential is associated with lighting and motor improvements

5 Industry accounts for the largest portion of the savings potential However, energy use for the residential and service sectors is growing the fastest, and there is a significant potential for saving energy in these two customer sectors Substantial savings can also be realized in the transportation and agricultural sectors

6 Energy efficiency improvements could be achieved at relatively low cost The average cost of energy saved by the measures recommended in this Study is approximately one U S cent per kWh Although the cost of replacing outdated equipment with new equipment is high, the incremental cost of the new equipment is relatively low and quite easily justified

7 At present, there are some barriers to the installation of efficient technologies Energy-efficient equipment is not always available locally There is also a considerable shortage of funds for investment in energy efficiency Even if these barriers can be overcome, capital for such investments by consumers may not be available To overcome some of the

barriers, it will be enough to change the legal and regulatory framework In other cases, special energy efficiency programs will be required

8 The changes in the demand for and use of electricity will vary among the AO Energos, depending upon the effect of economic restructuring on local economic activities To be most successful, energy efficiency programs must be designed for unique local conditions The planning for energy sector development in a region should be based on providing least-cost energy services to the consumer The AO Energos must play an important role in the design and delivery of energy efficiency programs

9 Through direct contact with their customers, the AO Energos should educate consumers about the possible ways of saving energy, and provide financial services for energy efficiency measures This will mean an increase in the number of services relative to what the AO Energos have provided in the past

Recommendations

10 Several regulatory, institutional and economic measures must be undertaken before energy efficiency programs can be implemented

11 In the near future, a law on energy conservation must be passed to

- implement the principle of planning at least-cost to meet the energy needs of consumers
- increase economic incentives and de-emphasize fines
- shift the responsibility for the development and implementation of energy conservation to the administrative regions
- create a federal and regional Energy Conservation Fund
- expand the range of energy conservation standards for energy consuming equipment and end-uses, and adopt sanctions for non-compliance
- adopt energy conservation standards for new buildings and local enforcement
- establish demonstration projects for energy-efficient technologies

12 Government support is needed for energy efficiency, including tax incentives and loans, and accelerated depreciation

13 Customs waivers or reductions should be allowed for the import of highly energy-efficient equipment that is not presently produced in Russia

14 Assistance through the Energy Conservation Fund should be provided as loans to be paid back within a reasonable amount of time The Fund is to be endowed by an increase

in taxes on energy for enterprises, but overall, taxes are to be reduced Access to loans through the Fund would be provided on the basis of competitive bidding Funds should be provided on a non-competitive basis for education and information programs and energy audits

15 It is necessary to establish market-type corporate bodies to ensure the implementation of energy efficiency

16 In the longer term, favorable conditions should be provided for consumers to invest in large energy efficiency projects

17 Joint ventures should be created for the manufacture of energy-efficient equipment for which there is a deficit in Russia Favorable conditions for the formation of such enterprises should also be created

18 Major investments should be made in energy-efficient lights, energy-efficient motors and other dominant efficient technologies

19 Information and training programs should be set up in the area of energy savings

20 Priority should be given to investments in the following areas

- developing the capability for mass producing energy-efficient motors and new lighting technologies (such as compact fluorescent and metal halide lights)
- implementing new process technologies for oil and chemical plants using high-quality catalysts
- demonstration projects for energy-efficient technologies

21 A number of areas of energy efficiency improvement merit further study, including providing assistance for carrying out energy audits, reducing power consumption, and establishing a market for energy-efficient equipment

6.2 WORKING GROUP 2 - THERMAL POWER PLANTS

Conclusions

22 Some 79 GW of thermal plant capacity, which is evenly divided between CPP and CHP units, will reach the end of its design life by the year 2010 This retiring capacity represents 40% of Russia's current total electric generating capacity More than 54 GW of this capacity is located in three regions the Center, the Urals and Siberia Approximately 39 GW of the retiring capacity will have reached the end of its life by the year 2000, and more than 13 GW of this total has reached its maximum service life

23 The modeling results for Reference Cases A and B indicate that 69 2 and 27 4 GW of new thermal generating capacity (CPPs and CHPs, respectively) will need to be installed through the year 2010 Under Reference Case A, 19 2 GW would be installed through the year 2000, while 3 5 GW is required under Reference Case B during the same period Given the lead time for the construction of new plants, these results, particularly for Reference Case A, indicate the need for an aggressive development program On a regional basis, near-term new plant capacity requirements are concentrated in the North Caucasus, Urals and TransBaikalia

24 The modeling results for Reference Cases A and B indicate that 49 0 and 47 1 GW of reconstructed thermal generating capacity (CPPs and CHPs, respectively) will be installed through the year 2010 In both cases the bulk of the reconstructed capacity, 40 1 and 41 5 GW, respectively, would be installed after the year 2001

25 The adoption of advanced technologies for new thermal power plants and the reconstruction of retiring power plants can have an important impact on meeting Russia's future electric energy needs, and could involve significant changes in the current fuel supply mix (natural gas verses coal)

26 The modeling results indicate that new simple cycle combustion gas turbines might be an attractive power supply option in certain regions The low capital cost of combustion turbines could have measurable impact on reducing total investment requirements

27 While reconstructing retired thermal plants was found to play a significant role in meeting future power needs, the associated investment costs are large Modeling results for the limited life extension demonstrate a reduction in total investment requirements, through the year 2010, ranging from $12 6 to $16 8 billion, depending on the load forecast scenario While it is not possible to capture these savings fully, opportunities for more limited life extension programs, which could serve to meet power needs at lower levels of investment, may exist

28 New and reconstructed thermal units will be required to meet certain emission standards Achieving these standards will require the application of appropriate emission reduction technologies Options for coal-fired boilers include combustion technologies such as low-NO_x burners, fabric filters for particulate collection, and flue gas desulfurization Advanced, environmentally-friendly technologies, such as gas-fired combined cycles and circulating fluid bed boilers will also reduce emissions

Recommendations

29 Plant-level evaluations of modernization and life extension options are needed for thermal power plants The inventory of retiring thermal power units should be examined on a plant-specific basis These examinations should be directed toward identifying thermal plants that might be good candidates for life extension/reconstruction programs with a focus on options with lower levels of investment As appropriate, detailed designs/cost estimates for modernization, life extension and upgrades should proceed

30 The North Caucasus Region is an example of a region with a significant near-term need for additional power generation capacity The Krasnodar Krai (Kubananergo) has the largest self-generating capacity deficiency in the region Cognizant of this need, RAO EES Rossii, Kubanenergo and others have formulated plans to build modern gas-fired combined cycle units in the Kubanenergo system The modeling results appear to support this approach It is recommended that work proceed quickly toward the development of combined cycle capacity in Krasnodar Krai Such a project could serve as a major demonstration of this highly efficient and environmentally sound technology, and as a blueprint for replication in other parts of Russia

31 When rehabilitating and constructing new thermal power plants, special attention must be paid to environmental requirements A program to identify the best emission reduction technologies for application to Russia's power sector is recommended The program should address methods of developing the manufacturing capability for the identified technologies (joint ventures, etc) in Russia Equipment for continuous emission monitoring is recommended to demonstrate compliance with emission limits

32 Advanced technologies such as gas turbine combined cycles and circulating fluid bed boilers should be given serious consideration to improve thermal efficiencies and environmental performance, and to take advantage of the availability of low-quality solid fuel Developing manufacturing capability for these advanced technologies, through joint ventures or other means, should be investigated

6.3 WORKING GROUP 3 - NUCLEAR

33 The *Russian Energy Strategy* emphasizes the importance of the power sector in the country's economic development under the new conditions Nuclear power plays a crucial role in this development The JEPAS has confirmed the important contribution that nuclear power makes to the Russian power sector

Conclusions

34 The JEPAS found that future investment in the power sector should include investments in nuclear power plant safety upgrades, plant completions, evolutionary plant designs, and as appropriate, the decommissioning of first-generation reactors

35 Investments in NPP safety upgrades are competitive with investments in alternative energy sources It is economic to continue the operation of most existing nuclear power plants with the safety upgrades evaluated in this Study Four units do not have sufficient remaining operating life to economically justify the implementation of all the safety upgrades evaluated because revenues must be set aside to prepare for decommissioning in the short term

36 New nuclear capacity is an economic supply option in some regions

37 In the initial study period, investments in safety upgrades of the existing NPPs are considered as a priority for both Scenarios A and B

Recommendations

38 It is necessary to proceed with introducing the safety upgrades evaluated in this Study at existing nuclear power plants, where approved by the regulatory authority and economically justified The implementation of such safety upgrades could encourage foreign investment in Russia's nuclear power sector

39 The JEPAS shows that with the scheduled service life remaining, it is not economic to implement all of the safety upgrades evaluated in the Study for Kola 1 and 2 and Novovoronezh 3 and 4 (and Leningrad-1 for Scenario B) The decommissioning of these units should be considered comprehensively on the basis of local area conditions, and on a site-specific basis

40 The completion and commissioning of Rostov 1, Kursk 5, Kalinin 3, and Balakova 5 should be considered in the context of regional least-cost plans with their full safety review Rostov 1 and Kalinin 3 have been identified as priorities for investment

41 The design of the NP-500 and NP-1000 evolutionary reactors, which will be the basis of the nuclear energy sector's future development, should be developed to a sufficient level of detail to permit their certification by regulatory bodies

42 The legislation required to support the safe development and operation of nuclear power in Russia should be completed as soon as possible

43 The JEPAS estimated the cost of a specific set of NPP safety upgrades The Study did not quantify the safety significance of these upgrade measures There are, however, studies conducted in both Russia and internationally which have assessed the safety significance of many of these upgrades It may be useful to conduct a study combining the results of the above with the following goals

- maximizing the safety benefit of investments in safety upgrades within the limitations of the available financing
- assessing the level of safety improvement derived from implementing each measure

6.4 WORKING GROUP 4 - HYDROELECTRIC POWER, TRANSMISSION AND DISPATCH

Hydroelectric Power Development

Conclusions

44 Eight hydro power plants were identified as requiring rehabilitation to permit them to operate effectively after the year 2000 The total capacity of these plants is 6,093 MW Their rehabilitation would cost approximately $900 million between 1995 and 2001

45 Six plants under construction and three proposed plants were identified as candidates for investment The total capacity of these plants is 6,884 MW Their development would require $4 8 billion

Recommendations

46 Detailed designs, cost estimates, and financing plans should be prepared for hydro rehabilitation and new construction projects that are shown to be part of regional least-cost plans

Transmission Projects

Conclusions

47 The transmission system of Russia has bottlenecks in places that limit transfer capability and reduce the reliability of supply Eleven intra-regional and inter-regional transmission projects/programs have been identified for priority investment, the two most urgent of which are described below

48 The North-West Region consists of three main utility systems Kola, Karelia, and Leningrad, the last of these is by far the largest The Karelia system, deficient in generation, now depends strongly on imports from Kola and the Leningrad system Its supply is unreliable since ties in both directions are weak, as is the tie from the Leningrad system to the Center Region These limitations have two serious results

- The lack of redundancy in both internal ties and ties to the Center Region means that a transmission outage forces the sudden tripping of one or more nuclear generating units at either Leningrad or Kola

- The weakness of these ties leaves the entire North-West Region vulnerable to either temporary outages or the eventual decommissioning of nuclear plants at either Leningrad or Kola

49 The North Caucasus Region, which was previously supplied via ties through the Ukraine, is now virtually isolated and suffering severe power shortages Ties to the Ukraine at 500 kV, 330 kV, and 220 kV are now of limited value due to transfer problems to and within the Ukraine, as well as political and energy balance issues within the Ukraine The remaining two long 220 kV ties from the North Caucuses to the Center have only 200 MW of transfer capability

50 Sub-transmission system losses exceed Western norms Eighty percent of the losses are in the distribution system A specific list of projects and priorities was developed to reduce these losses

Recommendations

51 Transmission improvement is needed for the North-West Region The reinforcement projects proposed consist of both 330 kV and 750 kV lines and substations, at an aggregate total cost of approximately $775 million

52 The strengthening of the Center - Middle Volga - North Caucasus intertie is needed It is recommended that four 500 kV transmission projects be constructed, aggregating about 1,000 km One of these projects will feed directly to the North Caucuses, and the others would reinforce the internal systems of the Center and Middle Volga regions to enable

increased transfers to the North Caucuses These projects, totaling about $430 million, will increase the transfer capability from the Middle Volga to the Center Region by 2,000 MW and from the Center to the North Caucuses by 1,200 MW

53 In addition to the priority transmission projects, special emphasis should be given to the detailed study of constructing a high-voltage transmission intertie from Siberia to the Center with a 3-6 GW capacity This would enhance the Integrated Power System of Russia, promote overall economic efficiency, and improve the reliability of supply

Dispatch Control Projects

Conclusions

54 The technology in the control centers is not adequate to meet the current system requirements or the requirements of a developing electricity market Two high-priority projects are discussed below

55 The control, communication and dispatch systems of Russia consist of a Central Dispatch Office in Moscow and a number of regional dispatch offices These centers and their communication links have limited channel capacity and are unable to accommodate modern software This impedes the optimization of operating costs and reduces reliability They are thus limited in their ability to gather and use data to advantage

56 Control and dispatch of the North-West UPS was formerly assigned to a control center in Riga, Latvia It is now housed in temporary quarters in St Petersburg, and needs to be both upgraded and moved to a separate building Its priority is dictated by 1) the temporary facilities now in place, 2) the fragile interconnections within and external to this region and 3) the importance of modern control in maximizing the safe operation of nuclear stations at Kola and near St Petersburg

Recommendations

57 *The North-West Control Center* This project would consist of constructing and equipping a new control center building, purchasing modern application software, upgrading data acquisition systems at substations within the region, modernizing load frequency controls within the region, and reconstructing the communication systems between the North-West Region Center and the Central Dispatch Office in Moscow The aggregate cost of these improvements would be approximately $59 million

58 *Central Dispatch Office* It is recommended that the dispatch center which coordinates all operations of the Unified Power System be modernized This would consist of reconstructing and modernizing the existing central dispatch facilities, taking full

advantage of the North-West-Central dispatch communications upgrade cited above, and preparing the Central Dispatch Office for similar upgrades to other regions The estimated cost for this project is $20 million

6.5 WORKING GROUP 5

Conclusions

59 The JEPAS has confirmed the importance of the electric power sector to the economic development of Russia under the new conditions The principal conclusions of the JEPAS are consistent with the importance given to the electric power sector in the *Russian Energy Strategy*

Strategic Directions

60 JEPAS analysis shows that when finalizing power sector and energy efficiency investment decisions, Russia should give highest priority to the following areas for the period 1995-2000

- improvements in the efficiency of electricity end-use
- nuclear safety upgrades, particularly for first-generation nuclear power reactors where approved by regulators
- to further the IPPs development, expansion and strengthening of inter-regional and intra-regional transmission, particularly between surplus and deficit areas, and the modernizing of control/dispatch centers
- fossil thermal plant modernization and rehabilitation using state-of-the-art technologies with the consideration of life extension options
- completion of those nuclear power plants that are in advanced stages of construction
- construction of new gas-fired simple cycle and combined cycle plants
- completion of the design and permit process for new-generation nuclear power plants

61 The JEPAS analysis shows that the following areas will be increasingly important during the period 2000-2010

- completion of large under-construction HPPs
- construction of clean-coal generation plants
- construction of new-generation NPPs

Investment Requirements

62 Under Scenario A the indicated range of required investment is $26-34 billion over 1995-2000 and $35-48 billion for 2001-2005

63 Under Scenario B, the indicated range of required investment is $12-16 billion for 1995-2000 and $20-33 billion for 2001-2005

Financing Sources

64 Financing from the Russian Government's budget allocations has been largely removed and the power sector is becoming financially independent The most important and largest source of financing now and for the foreseeable future is internally generated funds

65 Electricity tariffs set by the regional and federal energy commissions are based upon the cost of service, but currently they do not cover full costs Customers' payments of tariffs have not been adequate to cover the industry's investment requirements A pervasive non-payments problem has left the industry strapped for cash, the high level of inflation and the cross-subsidies inherent in the tariffs are also problems

66 Initially, power sector enterprises will find borrowed funds and equity financing difficult to obtain because of a lack of satisfactory financial information However, the future potential for borrowing or leveraging assets is quite high because most power sector companies have hardly any long-term debt outstanding

67 Depreciation deductions are an important component of internally generated funds Because of high inflation rates that exceed allowable revaluations of fixed assets, the amount of depreciation charged has not kept its value and the industry is in a state of self-liquidation

68 The long-term prospects for Russian equities are good Market values for Russian equities remain very low for several reasons, and the investment climate in Russia means that investors are seeking high returns to compensate for the risk The lack of company financial information, low liquidity, and inadequate securities regulations keep prices low and investors away

69 The theoretical potential for borrowing is large However, the commercialization of the newly-privatized entities has not been completed, and much work and many changes need to occur before power sector entities will be able to borrow money from traditional lenders to the utility industry

70 There are several important ways in which the government could assist the power sector

- investment of the proceeds from power sector enterprises' stock sales into the power sector through bonds, preferred stock or grants
- willingness to provide sovereign guarantees for foreign currency borrowing
- tax relief in the form of investment tax credits, lower tax rates, tax holidays, and increased allowances for depreciation
- support for energy efficiency programs

71 The EBRD administers the Nuclear Safety Account, an ECU 135 million grant fund set up to fund safety upgrades at reactors that present the most serious safety risks

Recommendations

72 The following measures should be taken by the power sector to implement needed improvements

73 It is recommended that high priority be assigned to energy efficiency to realize potential energy savings of 29 bkWh by the year 2000 and up to 112 bkWh by 2010 Market-oriented incentives should be introduced to improve end-use efficiencies The development of energy service companies and joint ventures should be encouraged These would provide equipment, energy management techniques and financing for energy efficiency improvement

74 Where approved by the regulatory authority and economically justified, safety upgrades of RBMKs (9,000 - 11,000 MW) and first-generation VVER nuclear power reactors (880 MW) should be implemented This is estimated to require $1 0 billion between 1995 and 2000 These will require financial support from the Russian Government and, to the extent possible, international financial institutions

75 A major goal for RAO EES Rossii and AO Energos should be the rehabilitation and modernization of older thermal plants so as to extend their operating lives and improve their environmental and operational performance Approximately 79 GW fall into this

245

category, of which about 39 GW will require modernization by the year 2000 Plant-level evaluations should be undertaken to determine modernization requirements and the extent to which life extension may be possible at lower capital cost

76 A high priority of Russia's technological and investment policy for the power sector should be the utilization of simple cycle and combined cycle gas turbines (4,000-18,000 MW until 2000 and 38,000 to 83,000 MW until 2010), while developing domestic capability for their manufacturing, including joint ventures with Western partners

77 To provide for the commissioning until 2010 of 1,400-3,100 MW of new nuclear capacity and 12,000-13,700 MW of environmentally-cleaner coal-fired units, the priority of Russia's long-term scientific and technological policy should be the development of new-generation design NP 500, NP 1000, and cleaner coal power units, as well as developing the potential for their manufacturing

78 Further detailed study, including project identification, of the electricity and fuel supply situation in the North Caucasus, Urals, and the TransBaikalia area should be given high priority This work should take into account specific factors at the local level and apply least-cost utility planning tools It is estimated that 24,000 MW will need rehabilitation and that around 24,000-36,000 MW of new capacity will be required in these regions, as well as the strengthening and expansion of transmission interties

79 Further feasibility studies are needed for the western and eastern extensions of the transmission lines to link Siberian generation capacity and demand centers in European Russia to the west and to TransBaikalia in the east

80 The issues in electricity interconnection among the CIS republics and other neighboring countries should be investigated The potential for Russia to trade electricity with China and Central Europe should also be investigated

81 Government support is needed to ensure the further development of a self-financing power sector under conditions of widening economic reforms and to create conditions conducive to attracting financing and capital investment The major directions of such support should be

- to improve the state system of regulating natural monopolies, which includes the regulation of electricity and heat tariffs at both the federal and regional levels, as well as an appropriate legal and standards infrastructure

- to implement economic mechanisms for increasing internal cash generation by power entities and improving the efficiency of these funds' allocation to operating entities

- to establish a mechanism to facilitate the rational allocation of power sector investment funds between the federal and regional levels as a transition measure to a new regulatory system

- to create incentives to attract funds into the power sector from both domestic and foreign sources on both an equity and debt basis

82 It is recommended that the part of retained earnings which is directed into investment be made tax deductible, including the part collected through centralized investment funds

83 To create economic stimuli and attract investment into the power sector, government guarantees should be established at both the federal and regional levels, ensuring investors' right of recourse, and rights to the repatriation of capital and profits for foreign investors

84 As an interim measure, funds should be generated at the federal level to finance modernization and rehabilitation, and a mechanism should be developed to allocate these funds between the federal and regional levels

85 On the basis of further changes and definition of the ownership structure, restructuring of the power sector should proceed to set up a competitive environment and to improve rate setting in electric energy markets

86 A legal and tax infrastructure conducive to investment by independent power producers should be created

87 It is necessary to develop a comprehensive program for the public sale of government-held power sector stock at an acceptable value Funds from these sales should be used for reinvestment to provide needed investment capital for the power sector

88 In the nuclear power sector, an economic mechanism should be developed that increases internally generated funds through tariffs without damaging the competitiveness of nuclear energy in the energy market A portion of these internally generated funds would be centralized in a national reserve which would finance priority safety upgrades, plant completions, decommissioning and partially new NPP construction Opportunities should be created to attract loans into the nuclear sector with corresponding government guarantees The possibility of converting the nuclear sector into stock companies should be studied as well as the corresponding issues of right-of-recourse guarantees for potential domestic and foreign investors

89 Environmental standards should be developed that would allow for differentiation among new, existing and rehabilitated thermal plants