S-47

412500378DEDJ

Control Number	WIID Number	Instrument Type
412500378	2001250-000168	DED

WESTCHESTER COUNTY RECORDING AND ENDORSEMENT PAGE
(THIS PAGE FORMS PART OF THE INSTRUMENT)
***** DO NOT REMOVE *****

THE FOLLOWING INSTRUMENT WAS ENDORSED FOR THE RECORD AS FOLLOWS:

TYPE OF INSTRUMENT DED - DEED
FEE PAGES 13 **TOTAL PAGES** 13

RECORDING FEES

STATUTORY CHARGE	$5.25
RECORDING CHARGE	$39.00
RECORD MGT. FUND	$4.75
RP 5217	$25.00
TP-584	$5.00
CROSS REFERENCE	$0.00
MISCELLANEOUS	$0.00
TOTAL FEES PAID	$79.00

TRANSFER TAXES

CONSIDERATION	$107,209,000.00
TAX PAID	$428,836.00
TRANSFER TAX #	2262

MORTGAGE TAXES

MORTGAGE DATE	
MORTGAGE AMOUNT	$0.00
EXEMPT	
YONKERS	$0.00
BASIC	$0.00
ADDITIONAL	$0.00
SUBTOTAL	$0.00
MTA	$0.00
SPECIAL	$0.00
TOTAL PAID	$0.00

SERIAL NUMBER
DWELLING

RECORDING DATE 09/24/2001
TIME 14:08:00

THE PROPERTY IS SITUATED IN WESTCHESTER COUNTY, NEW YORK IN THE: TOWN OF CORTLANDT

WITNESS MY HAND AND OFFICIAL SEAL

Leonard N. Spano

LEONARD N. SPANO
WESTCHESTER COUNTY CLERK

Record & Return to:
GOODWIN PROCTOR LLP
599 LEXINGTON AVE

NEW YORK, NY 10022

378 231-W-08707 12p TOO

DEED OF CONVEYANCE FOR WESTCHESTER COUNTY
[LAND AND IMPROVEMENTS]

THIS INDENTURE, made as of the 6th day of September, two thousand and one

BETWEEN

Consolidated Edison Company of New York, Inc., a New York corporation, having a principal place of business at No. 4 Irving Place, New York, NY 10003

party of the first part, and

Entergy Nuclear Indian Point 2, LLC, a Delaware limited liability company, having a principal place of business at 440 Hamilton Avenue, White Plains, NY 10601

party of the second part,

WITNESSETH, that the party of the first part, in consideration of ten dollars and other valuable consideration paid by the party of the second part, does hereby grant and release unto the party of the second part, the heirs or successors and assigns of the party of the second part forever,

ALL those certain plots, pieces or parcels of land and land under water, with the buildings and improvements thereon erected, situate, lying and being in the Village of Buchanan and/or the Town of Cortlandt in the County of Westchester and State of New York and more particularly described on Schedule A attached hereto and made a part hereof ("said premises").

Said premises are subject to all covenants, conditions, easements, agreements and restrictions of record including, but not limited to, provisions of letters patent and water grants, zoning and building regulations, and any state of facts that an accurate survey and personal inspection may reveal.

TOGETHER with, and SUBJECT to, all covenants, conditions, easements, agreements, restrictions and other interests granted, reserved and/or imposed in that certain Indenture made as of the 30th day of December, 1975 by Consolidated Edison Company of New York Inc. to Power Authority of the State of New York (the "PASNY Deed") recorded in Liber 7306, Page 736 in the Westchester County

Clerk's Office (the "Clerk's Office") on December 31, 1975 and/or shown on Map Numbers 18702 and 18703 on file in the Clerk's Office (the "PASNY Maps"), including without limitation, the pre-emptive rights to purchase certain undivided or tenancy in common interests (the "First Refusal Rights and Obligations") and the waiver of partition or sale for division (the "Partition/Sale for Division Rights Waiver") with respect to such undivided interests set forth on pages 28 and 29 of the PASNY Deed, but specifically excluding and reserving to the party of the first part and its successors and assigns the 345 KV transmission line and the 345KV transmission line easement described in paragraph 1 on page 7 of the PASNY Deed and delineated and designated "CE-4" on the PASNY Maps,

TOGETHER with, and SUBJECT to, all of the grants, rights, reservations and obligations more particularly described in the Declaration of Easements Agreement dated of even date herewith between the party of the first part and the party of the second part, which shall be recorded herewith and being and intended to be part of this conveyance of said premises, and in particular to the retention by the party of the first part of title to the "Seller Facilities", as such term is defined therein,

TOGETHER with all right, title and interest, if any, of the party of the first part in and to any streets and roads abutting the above described premises to the center lines thereof; TOGETHER with the easements and rights reserved by the party of the first part in that certain Indenture made on June 9, 1969 by Consolidated Edison Company of New York Inc. to Village of Buchanan, New York and recorded in Liber 6882, page 695 but specifically excluding and reserving to the party of the first part and its successors and assigns the right of reversion contained in such Indenture; TOGETHER with all other appurtenances and all the estate and rights of the party of the first part in and to said premises; TO HAVE AND TO HOLD the premises herein granted unto the party of the second part, the heirs or successors and assigns of the party of the second part forever.

This conveyance is made in the ordinary course of business and does not constitute all of the assets of the party of the first part.

AND the party of the first part, in compliance with Section 13 of the Lien Law, covenants that the party of the first part will receive the consideration for this conveyance and will hold the right to receive such consideration as a trust fund to be applied first for the purpose of paying the cost of the improvements and will apply the same first to the payment of the cost of the improvements before using any part of the total of the same for any other purpose.

The word "party" shall be construed as if it read "parties" whenever the sense of this indenture so requires.

IN WITNESS WHEREOF, the party of the first part has duly executed this deed the day and year first above written.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,

by ____________________

Name: Kevin Burke
Title: President + COO

First American Title Ins. Co. of New York
188 East Post Road
White Plains, New York 10601
(914) 428-3433 (800) 942-1893

Record and Return to:

Goodwin Procter LLP
599 Lexington Ave.
New York, NY 10022
Attn: Ross Gillman, Esq.

Entergy Nuclear Indian Point 2, LLC executes this Indenture as of the day and year first above written solely for the purpose of evidencing its acceptance of this Indenture and confirming its mutual and reciprocal rights and obligations pursuant to the First Refusal Rights and Obligations and the Partition/Sale for Division Rights Waiver.

ENTERGY NUCLEAR INDIAN
POINT 2, LLC

by

Name: Michael R. Kansler
Title: Sr. VP & COO

Entergy Nuclear Indian Point 3, LLC executes this Indenture as of the day and year first above written solely for the purpose of confirming its mutual and reciprocal rights and obligations pursuant to the First Refusal Rights and Obligations and the Partition/Sale for Division Rights Waiver.

ENTERGY NUCLEAR INDIAN
POINT 3, LLC

by

Name: Michael R. Kansler
Title: Sr. VP & COO

STATE OF NEW YORK)
) ss.:
COUNTY OF NEW YORK)

On the 5th day of September in the year 2001 before me, the undersigned, a Notary Public in and for said State, personally appeared Kevin Burke, personally known to me or proved to me on the basis of satisfactory evidence to be the individual whose name is subscribed to the within instrument and acknowledged to me that he/she executed the same in his/her capacity, and that by his/her signature on the instrument, the individual, or the person or entity upon behalf of which the individual acted, executed the instrument.

Notary Public

[Notarial Seal]

LISA B. WEEKS
Notary Public, State of New York
No. 31-4962521
Qualified in New York County
Commission Expires Feb. 20, 2002

STATE OF NEW YORK)
) ss.:
COUNTY OF NEW YORK)

On the 5th day of September in the year 2001 before me, the undersigned, a Notary Public in and for said State, personally appeared Michael K. Kausler, personally known to me or proved to me on the basis of satisfactory evidence to be the individual whose name is subscribed to the within instrument and acknowledged to me that he/she executed the same in his/her capacity, and that by his/her signature on the instrument, the individual, or the person or entity upon behalf of which the individual acted, executed the instrument.

Lisa B. Weeks
Notary Public
LISA B. WEEKS
Notary Public, State of New York
No. 31-4962521
Qualified in New York County
Commission Expires Feb. 20, 2002

STATE OF NEW YORK)
) ss.:
COUNTY OF NEW YORK)

On the 5th day of September in the year 2001 before me, the undersigned, a Notary Public in and for said State, personally appeared Michael K. Kausler, personally known to me or proved to me on the basis of satisfactory evidence to be the individual whose name is subscribed to the within instrument and acknowledged to me that he/she executed the same in his/her capacity, and that by his/her signature on the instrument, the individual, or the person or entity upon behalf of which the individual acted, executed the instrument.

Lisa B. Weeks
Notary Public
LISA B. WEEKS
Notary Public, State of New York
No. 31-4962521
Qualified in New York County
Commission Expires Feb. 20, 2002

DESCRIPTION OF PROPERTY

Buyer Real Estate - Indian Point

All that certain parcel of land situate in the Village of Buchanan, Town of Cortlandt, County of Westchester and State of New York that is bounded and described as follows:

BEGINNING at the point on the northwesterly line of Broadway in said Village where it is met by the line dividing the lands herein described, on the northeast, from lands conveyed to Entergy Nuclear Indian Point 3, LLC, on the southwest, which point occupies coordinate position

N 460,582.572 (y)
E 605,385.556 (x)

of the New York State Coordinate System, East Zone.

THENCE FROM THE SAID POINT OF BEGINNING northwesterly, northeasterly and again northwesterly along the said division line, first the following courses:

N 63°43'41" W 310.02 feet
N 63°30'45" W 229.13 feet
N 77°36'34" W 168.54 feet
N 63°41'22" W 215.25 feet
N 57°11'26" W 355.78 feet
N 38°17'00" E 1,229.13 feet
N 29°14'02" W 227.28 feet
N 51°43'00" W 433.65 feet and
N 38°17'00" E 19.47 feet

then on a non-tangent curve to the left, the center of which bears N11°17'55"W, the central angle of which is 236°51'06", the radius of which is 47.50 feet for 196.36 feet, and then

N 51°43'00" W 558.88 feet

to a point in the Hudson River. Thence through the waters of the Hudson River

N 38°17'00" E 632.86 feet and
S 51°43'00" E 114.00 feet

to a point at the Mean High Water Mark of the easterly shore thereof. Thence northeasterly and easterly along the Mean High Water Mark of the easterly shore of the Hudson River, as it winds and turns along a line that is generally defined by the following courses:

N 50°40'00" E 83.00 feet
N 58°20'00" E 35.00 feet
S 81°10'00" E 14.00 feet
N 37°40'00" E 70.00 feet
N 03°50'00" E 66.00 feet
N 23°40'00" E 29.00 feet
N 06°00'00" W 58.00 feet
N 19°20'00" E 28.00 feet
N 34°30'00" E 127.00 feet
N 46°20'00" E 32.00 feet
N 75°20'00" E 127.00 feet
N 49°56'00" E 191.00 feet
N 35°50'00" E 46.00 feet
N 58°20'00" E 59.00 feet
N 35°30'00" E 30.00 feet
N 65°00'00" E 39.00 feet
N 86°20'00" E 47.00 feet
S 50°40'00" E 32.00 feet
N 84°20'00" E 57.00 feet
N 62°50'00" E 76.00 feet
N 28°40'00" E 41.00 feet
N 02°20'00" W 89.00 feet
N 26°10'00" E 91.00 feet
N 48°50'00" E 32.00 feet
N 07°40'00" E 25.00 feet
N 55°30'00" E 51.00 feet
S 85°50'00" E 30.00 feet
S 38°30'00" E 11.00 feet
N 74°00'00" E 8.00 feet
N 29°00'00" E 26.00 feet
S 71°20'00" E 12.00 feet
S 51°00'00" E 27.00 feet
N 74°00'00" E 50.00 feet
N 49°00'00" E 35.00 feet
N 68°20'00" E 156.00 feet
S 80°20'00" E 51.00 feet
N 77°00'00" E 58.00 feet
N 53°10'00" E 41.00 feet
N 41°10'00" E 49.00 feet
N 05°20'00" E 14.00 feet

N 40°10'00" E 53.00 feet
N 64°30'00" E 35.00 feet
S 74°20'00" E 38.00 feet
S 34°30'00" E 16.00 feet
N 85°20'00" E 63.00 feet
S 45°50'00" E 25.00 feet
S 12°20'00" E 19.00 feet
S 44°10'00" E 113.00 feet
N 80°30'00" E 109.00 feet
S 82°50'00" E 91.00 feet
S 54°10'00" E 87.00 feet
S 31°10'00" E 71.00 feet and
S 53°20'00" E 25.87 feet

to a point at the line of lands now or formerly of the Village of Buchanan. Thence along the said Village of Buchanan lands, the following courses:

S 08°15'50" E 824.18 feet
S 53°16'20" E 106.06 feet
N 71°04'20" E 195.50 feet
S 13°43'00" E 402.00 feet and
S 51°43'00" E 166.00 feet

to another point on the northwesterly line of Broadway. Thence southwesterly along the said northwesterly line of Broadway

S 36°32'40" W 3,114.17 feet

to the point or place of beginning, containing 160.033 acres, more or less.

Prepared by
BADEY & WATSON
Surveying & Engineering, P.C.
U.S. Route 9
Cold Spring, New York 10516
(914)265-9217(V)
(914)265-4428(F)

Buyer Real Estate - Toddville

All that certain parcel of land situate in the Town of Cortlandt, County of Westchester and State of New York that is bounded and described as follows:

BEGINNING at the point formed by the intersection of the northerly line of Crompond Road (U.S. Route 202), as widened, and the westerly line of Locust Avenue, which point occupies coordinate position

N 896,354.80 (y)
E 662,280.30 (x)

of the New York State Coordinate System, East Zone (NAD 83).

THENCE FROM THE SAID POINT OF BEGINNING, westerly along the said northerly line of Crompond Road

N 78°31'33" W 253.19 feet (253.20 feet)

to a point on the easterly line of Lot 5 shown on that certain map entitled "Map No. 2 Shipley Park ...," which was filed in the Westchester County Clerk's office on May 15, 1930 as Map No. 3608. Thence along the easterly and northerly lines of said Lot 5

N 10°21'00" E 266.72 feet (266.74 feet) and
N 65°56'30" W 70.06 feet (70.07 feet)

to a point at the line of other lands formerly of Shipley Park and now or formerly of Portes. Thence along the said Portes lands and along the easterly and southerly lines of lands shown on that certain map entitled " Section 2 - Shipley Park North ...," which was filed in the Westchester County Clerk's office on February 7, 1974 as Map No. 18130,

N 01°50'00" E 369.87 feet (369.90 feet) and
S 88°10'00" E 99.99 feet (100.00 feet)

to a point at the line of other lands of the City of New York (Catskill Aqueduct). Thence along said other lands of the City of New York

S 01°50'00" W 329.88 feet (329.91 feet) and
S 65°56'30" E 189.03 feet (189.04 feet)

to a point at the westerly line of Locust Avenue. Thence southerly along the said westerly line of Locust Avenue

S 01°50'00" W 301.17 feet (301.19 feet)

to the northerly line of Crompond Road and the point or place of beginning, containing 2.527 acres, more or less.

Note: The distances in this description have been scaled by 0.9999144 to make them conform to the New York State Plane Coordinate System, East Zone (NAD 83). Values shown parenthetically are ground distances which can be achieved by multiplying the distances used in this description by 1.0000856. This note should appear in any document into which this description is incorporated.

BEING AND INTENDED TO BE the same land conveyed by Lakeland Central School District of Shrub Oak to Consolidated Edison Company of New York, Inc. by deed dated December 14, 1981 and recorded January 6, 1982 in Liber 7745, Page 706 and by deed dated October 13, 1988 and recorded November 23, 1988 in Liber 9373, Page 244.

Additional identifiers:

Tax Map Designation			Address	City/Village	Town	County
Sheet	Block	Lot				
43.14	2	1	(part of) Broadway	Buchanan	Cortlandt	Westchester
34.05	2	6	Locust Ave. and Crompton Road		Cortlandt	Westchester
34.05	2	2	Locust Ave. and Crompton Road		Cortlandt	Westchester

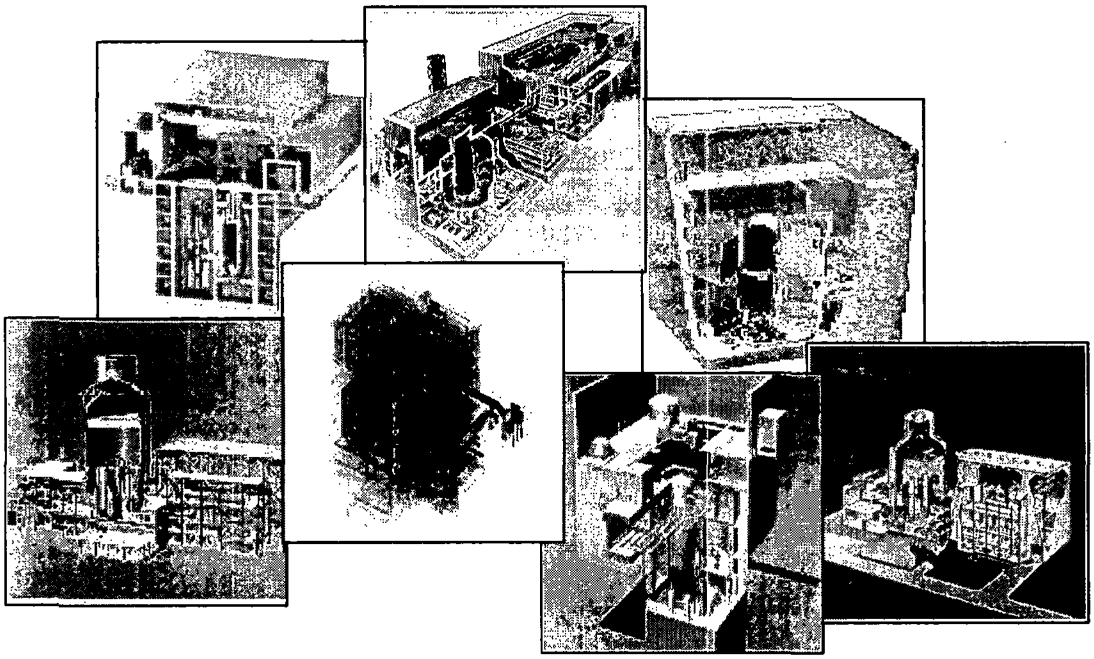
also.

Sheet 43.10 Block 2 Lot 1 (P/O)
Sheet 43.10 Block 1 Lot 1 (P/O)
Sheet 43.10 Block 2 Lot 2 (P/O)
Sheet 43.06 Block 1 Lot 1 (P/O)

S-48

A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010

Volume I
Summary Report



Prepared for the

United States Department of Energy
Office of Nuclear Energy, Science and Technology

and its

Nuclear Energy Research Advisory Committee
Subcommittee on Generation IV Technology Planning

October 31, 2001

NEAR TERM DEPLOYMENT GROUP MEMBERSHIP

Tony McConnell (Co-Chairman)
Vice President Engineering Services
Duke Engineering & Services

Louis Long (Co-Chairman)
Vice President Technical Services
Southern Nuclear Operating Company

Eric Beckjord
Consultant

Jeffrey Binder
Argonne National Laboratory

Shem Blackley
Consultant

Chaim Braun
Altos Management Inc.

George Davis
Westinghouse

Edward Klevans
Pennslyvania State University

Malcolm LaBar
General Atomics

Atambir Rao
General Electric - Nuclear Energy

Thomas Roberts
Exelon Corporation

John Taylor
Nuclear Energy Research Advisory Committee

Gary Vine
Electric Power Research Institute

DEPARTMENT OF ENERGY

Tom Miller
Director, Advanced Research Programs
Office of Nuclear Energy, Science and Technology

GEN IV ROADMAP NERAC SUBCOMMITTEE (GRNS) REPRESENTATIVES

Bobby Abrams
Duke Engineering & Services

Doug Chapin
MPR Associates

GEN IV TECHNICAL WORKING GROUP (TWG) LIAISON

Jack DeVine (LWR TWG Chairman)
Polestar Inc.

Phil Hildebrandt (Gas-Cooled TWG Chairman)
EMT Inc.

NTDG SUPPORT

Marty Martinez
JUPITER Corporation

Raymond Reith
Idaho National Engineering Laboratory

Table of Contents

EXECUTIVE SUMMARY iv

1 BACKGROUND 1

1.1 NUCLEAR POWER IN THE UNITED STATES 1
1.2 THE GENERATION IV PROGRAM, AND NEAR TERM DEPLOYMENT 2
1.3 THE NTDG EVALUATION 2

2 CONSIDERATIONS APPLICABLE TO ANY NTD INITIATIVE 4

2.1 KEY GAPS TO NEAR TERM DEPLOYMENT 4
2.2 OTHER IMPORTANT ISSUES 9
2.3 COST COMPETITIVENESS – CRITERIA FOR SUCCESS 12
2.4 DEPLOYMENT TIMELINE: MAJOR ELEMENTS AND THE CRITICAL PATH 13

3 EVALUATION OF REACTOR DESIGNS FOR NTD POTENTIAL 17

3.1 NEAR TERM CANDIDATES 17
3.2 OTHER CANDIDATES (NOT EVALUATED BY NTDG) 21
3.3 DESIGN EVALUATION AND COMPARISON 22

4 ACHIEVING NEAR TERM DEPLOYMENT – AN INTEGRATED STRATEGY 33

4.1 TWO TRACKS – WATER AND GAS 33
4.2 PHASED PLAN OF ACTION 34
4.3 AGGRESSIVE SCHEDULE 35
4.4 FUNDING REQUIREMENTS 36
4.5 INDUSTRY / GOVERNMENT COLLABORATION 38
4.6 ALTERNATE SCENARIOS AND CONTINGENCIES 41

5 SUMMARY CONCLUSIONS AND RECOMMENDATIONS 43

5.1 CONCLUSIONS 43
5.2 RECOMMENDATIONS 44
5.3 CLOSING THE GAPS 48

Executive Summary

Nuclear power plants in the United States currently produce about 20 percent of the nation's electricity. This nuclear-generated electricity is safe, clean and economical, and does not emit greenhouse gases. Continued and expanded reliance on nuclear energy is one key to meeting future demand for electricity in the U.S. and is called for in the National Energy Policy. Nevertheless, no new nuclear plants have been built in the U.S. in many years, and none are currently slated for construction.

The U.S. Department of Energy (DOE) has been working with the nuclear industry to establish a technical and regulatory foundation for the next generation of nuclear plants. The DOE Generation IV (Gen IV) Program is assembling a 30-year road map for advanced plant and fuel cycle research and development. To complement Gen IV, DOE also organized a Near-Term Deployment Group (NTDG) to examine prospects for the deployment of new nuclear plants in the U.S. during this decade, and to identify obstacles to deployment and actions for resolution.

The NTDG membership includes senior and experienced personnel from nuclear utilities, reactor vendors, national laboratories, and academia. It is co-chaired by executives from Duke Engineering & Services and Southern Nuclear Operating Company.

Since commencing its work in February 2001, the NTDG has evaluated a wide spectrum of factors that could affect prospects for near term deployment of new nuclear plants as well as the readiness and technical suitability of various new plant designs identified as candidates for deployment in that time frame.

This report consists of two volumes: Volume I, this Summary Report, is a synopsis of the NTDG evaluations, conclusions and recommendations. Volume II, the Near-Term Deployment Roadmap, is a comprehensive report of the group's work, including descriptions of the candidate designs that have been evaluated, the methods of evaluation, and the institutional, regulatory, technical and economic factors considered.

Generic Gaps and Other Issues

The NTDG identified nine generic issues that could influence the viability of any new nuclear plant project. Of these, five are considered to be "gaps" warranting directed action. These are:

- Nuclear plant economic competitiveness
- Business implications of the deregulated electricity marketplace
- Efficient implementation of 10CFR52
- Nuclear industry infrastructure
- National Nuclear Energy Strategy

Four other significant issues were identified:

- Nuclear safety
- Spent fuel management
- Public acceptance of nuclear energy
- Non-proliferation of nuclear material

All of these are important. In each case, the NTDG considered the issue as it stands today, its implications with respect to near term deployment, and actions to improve prospects for near term deployment. The NTDG recommendations incorporate these conclusions.

Also, the NTDG examined the schedule implications and constraints associated with completion of a new nuclear plant construction project in the U.S. by 2010, taking into account the sequence and anticipated durations of essential siting, engineering, licensing, construction and testing work. This evaluation led the NTDG to conclusions regarding the timing of key activities necessary to support deployment of new plants in that time frame.

Reactor Design Candidates

Through DOE, the NTDG issued a Request for Information (RFI) in April 2001 seeking input from the nuclear industry and the public on nuclear plant designs that could be deployed by 2010.[1] In response to the RFI, proposals were received from U.S. and international reactor suppliers identifying the eight reactor design candidates. These include advanced boiling water reactors (BWRs), pressurized water reactors (PWRs) and gas-cooled reactors, as follows:

Design	Supplier	Features
ABWR	GE	1,350 MWe BWR, design certified by NRC and built and operating in Japan
SWR 1000	Framatome ANP	1,013 MWe BWR, being designed to meet European Requirements
ESBWR	GE	1,380 MWe passively safe BWR, under development
AP600	Westinghouse	610 MWe passively safe PWR, design certified by NRC
AP1000	Westinghouse	1,090 MWe PWR with passive safety features Higher capacity version of AP-600, not yet certified
IRIS	Westinghouse	100-300 MWe integral primary system PWR, under development
PBMR	ESKOM	110 MWe modular direct cycle helium-cooled pebble bed reactor, currently planned for construction in South Africa.
GT-MHR	General Atomics	288 MWe modular direct cycle helium-cooled reactor, being licensed for construction in Russia.

The RFI issued by DOE stipulated six evaluation criteria applicable to near-term deployment, and requested that respondents specifically address these criteria. They are:

1. Regulatory Acceptance
2. Industrial Infrastructure
3. Commercialization Plan
4. Cost Sharing Plan
5. Economic Competitiveness
6. Fuel Cycle Industrial Structure

[1]The phrase "by 2010", as applied to near term deployment, is used throughout this report to imply deployment by the end of calendar year 2010, and has the same meaning as the phrase "in this decade".

The NTDG evaluated each candidate design against each of the six criteria. The NTDG also identified and assessed in each case the design-specific gaps to near term deployment, based on information provided by the respondents. From these evaluations, the NTDG formed judgments regarding each candidate's potential for deployment by 2010.

Conclusions

1. New nuclear plants can be deployed in the U.S. in this decade, provided that there is sufficient and timely private-sector financial investment.

2. To have any new nuclear plants operating in the U.S. by 2010, it will be necessary for generating companies to commit to new plant orders by the end of 2003, in order to proceed with preparation of Construction and Operation (COL) applications. This will require very near term action by prospective new plant owner/operators and strong support from the government.

3. Although conditions are currently more favorable for new nuclear plants than in many years, economic competitiveness in a deregulated electricity supply structure remains a key area of uncertainty with respect to near term deployment potential. The other gaps to near term deployment require attention; in particular, implementing an efficient and effective regulatory approval process for siting and licensing of new plants is an urgent matter, and will require use of new processes in 10 CFR Part 52, that have not been demonstrated in actual practice.

4. There are excellent new nuclear plant candidates that build on the experience of existing reactors in the U.S. and around the world, and could be deployed in the U.S. in this decade. Readiness for deployment varies from design to design, based primarily on degree of design completion and status of regulatory approval. Those that are the most advanced in terms of design completion and approval status appear to be economically competitive in some scenarios, but not all. Other new nuclear plant designs, which still require licensing and engineering, show promise for improved economic competitiveness.

   The design-specific gaps that must be overcome by the gas-cooled candidates to achieve near term deployment are somewhat greater than those facing most of the water-cooled candidates.

5. Achieving near term deployment will require continuing close collaboration between government and industry. Selections of new projects must be market-driven and supported primarily by private sector investment -- but government support is essential, in the form of leadership, effective policy, efficient regulatory approvals, and cost sharing of generic and one-time costs.

Recommendations

The NTDG has formulated recommendations for actions that can significantly enhance prospects for deployment of new nuclear reactors in the U.S, in this decade. These are:

1. Implement a phased plan of action for new nuclear plants, by means of industry/government collaboration on generic and plant-specific initiatives, as follows:

Phase 1: Refine and demonstrate the 10CFR52 process, as described in Volume II, Chapters 3 and 5.
Resolve the uncertainties regarding the new plant regulatory approval process through actual use, and secure regulatory approval for several reactor design and siting applications on a time scale that will support plant deployments in this decade.

Phase 2: Complete the design of several near term deployment candidates, as reviewed in Volume II, Chapter 5.
Complete the detailed engineering and design work for at least one light water and at least one gas-cooled reactor, in time to allow start of plant construction on a schedule that could achieve deployment by 2010.

Phase 3: Construct and start up new plants.
When regulatory approvals and completed engineering are in hand, construct and deploy multiple commercially viable new nuclear plants by 2010.

All three phases should be conducted on a market-driven basis, primarily with industry funding and government cost sharing support for Phases 1 and 2. To some degree, the phases will overlap in time.

2. Put in place appropriate government financial incentives for privately funded new plant licensing, design and construction projects. Such arrangement would establish the basis for industry/government collaboration on the three-phase action plan. Government support in Phases 1 and 2 would be primarily via cost-sharing arrangements, and in Phase 3 by means of government financial incentives.

3. Conduct an assessment of the nuclear industry infrastructure and its implications on near term deployment. Determine the key areas of infrastructure weakness and the actions needed to accommodate them.

4. Develop a National Nuclear Energy Strategy that supports implementation of the National Energy Policy. This strategy would put in place a working structure for the aspects of the National Energy Policy applicable to new plant deployment, and would cover a variety of topics such as roles and responsibilities, priorities, funding principles and processes, and required administrative and legislative actions.

1 Background

1.1 Nuclear Power in the United States

Nuclear power has had a substantial role in the supply of electricity in the United States for over three decades. Currently, 103 nuclear power reactors produce approximately 20 percent of the electricity consumed in this nation.

The performance of nuclear plants in the United States is excellent. Over the past 20 years, the average capacity factor for U.S. nuclear plants has increased from about 60 percent to over 90 percent. Over this same period, nuclear safety has been excellent and there have been substantial reductions in operating and maintenance costs, worker exposures to radiation, and quantities of radioactive waste. There has been steady progress in issues such as long-term disposal of used nuclear fuel. Nuclear plants emit no greenhouse gases, an attribute of increasing importance in the U.S. and around the world. Many U.S. nuclear power plant owners have applied to NRC to extend their plant licenses.

In short, nuclear power technology has matured to the point that it is now a vital and extraordinarily valuable part of the nation's electricity supply.

Despite this excellent performance, no new nuclear plants have been ordered in the U.S. in the last twenty-three years. The extended hiatus in new plant construction is due primarily to economic factors. Nuclear plants are capital intensive, and many of the U.S. nuclear construction projects in the late 1970s and 80s were hampered by expensive delays, caused by engineering and management problems, a cumbersome regulatory process and in some cases by public opposition. At the same time, decreasing natural gas prices and general surplus in electricity supply served as economic disincentives to building new nuclear plants. Deregulation of electricity supply in the U.S. has added a level of economic uncertainty that temporarily discourages the major capital investment and long-term commitment required for new nuclear plant construction.

The rapid economic growth in the 1990s, combined with limited new power plant construction, has reduced electricity supplies to dangerously low levels in some parts of the nation. Most of the new power plants that have been built are fueled by natural gas – and volatile natural gas prices in recent years have resulted in high electricity prices in some areas of the nation. And at the same time, there is increasing societal concern regarding the emissions of airborne pollutants, and particularly greenhouse gases such as CO_2.

It is clear that an increase in nuclear-produced electricity, and therefore the design, licensing and construction of new plants, will be needed to meet the nation's growing need for safe, clean and economical electricity generation. This vital role of nuclear power is a central message of the President's National Energy Policy.[2]

The nuclear industry responded to the National Energy Policy with "Vision 2020", which sets the goal of 50,000 megawatts of new nuclear generating capacity added to the U.S. grid by 2020. The Nuclear Energy Institute (NEI) took a lead role in formulating Vision 2020

[2] **National Energy Policy**, Report of the National Energy Policy Development Group, May 2001

and has established an Executive Task Force on New Nuclear Power Plants to help guide near term industry activities toward that goal.

1.2 The Generation IV Program, and Near Term Deployment

The U.S. Department of Energy (DOE) has been a leader in U.S. efforts to establish a technical and regulatory foundation for future generations of nuclear plants. In 2000, DOE embarked on an international initiative termed Generation IV (Gen IV) to assemble a plan – a "Roadmap" – for the research and development needed to support new nuclear energy systems that could become operational over the next thirty years. The Gen IV Program is being implemented under the guidance of the DOE Nuclear Energy Research Advisory Committee (NERAC), and specifically by the Generation IV Roadmap NERAC Subcommittee (GRNS).

To complement Gen IV, and in recognition of the importance of relatively near term energy supplies, DOE also established a Near-Term Deployment Group (NTDG). The NTDG objectives are:

- To assess prospects for the deployment of new nuclear plants in the U.S. during this decade by identifying and evaluating available new plant designs and by examining the regulatory, technological, and institutional gaps to near-term deployment.
- To recommend specific actions that could substantially improve prospects for deployment of new nuclear plants in this decade.

The NTDG has coordinated its efforts with those of NEI and its Executive Task Force on New Nuclear Power Plants, to ensure compatibility with ongoing industry activities. The recommendations in this Roadmap are complementary to NEI efforts and are essential to achieving Vision 2020.

1.3 The NTDG Evaluation

The NTDG commenced its activities in February 2001. The evaluation has comprised several distinct (although overlapping) activities, including:

- <u>Identification and assessment of generic issues</u>
  The NTDG identified nine generic issues that could influence the viability of any new nuclear plant project. Of these, five are considered to be "gaps" warranting directed action. These are:
  - Nuclear plant economic competitiveness
  - Business implications of the deregulated electricity marketplace
  - Efficient implementation of 10CFR52
  - Nuclear industry infrastructure
  - National Nuclear Energy Strategy

  Four other significant issues were identified:
  - Nuclear safety

- Spent fuel management
- Public acceptance of nuclear energy
- Non-proliferation of nuclear material

The NTDG evaluated each of these considering its current status, its implications with respect to near term deployment, and actions that may be needed to improve prospects for near term deployment. Also, the NTDG has examined the schedule implications and constraints associated with completion of new nuclear plant construction projects in the U.S. by 2010. Section 2 of this volume describes the NTDG evaluation of these generic issues.

- Identification and evaluation of specific reactor design candidates
  Through DOE, the NTDG issued a Request for Information (RFI) in April 2001 seeking input from the public and nuclear community on nuclear power plant designs that could be deployed by 2010 and generic issues that could impede this deployment. The RFI stipulated six evaluation criteria, established by GRNS and applicable to near-term deployment, and requested that respondents specifically address each in their submittals. The six criteria are described more fully in Section 3.3.

  In response to the RFI, proposals were received from U.S. and international reactor suppliers identifying eight reactor design candidates. These candidates include advanced light water reactors of both pressurized water and boiling water design, advanced gas reactors, and more innovative light water reactors. The NTDG evaluated these candidates, both individually and comparatively, in order to determine the prospects for deployment of a new nuclear plant in the U.S. by 2010, and the steps necessary to achieve that goal. This part of the evaluation is described in Section 3.

- Development of an integrated strategy
  Taking into account the generic and the design specific actions identified in the above assessments, the NTDG developed an integrated strategy, as described in Section 4. This strategy is based on a a dual-track phased plan of action, with sequence and timing necessary to achieve near term deployment of both water-cooled and gas-cooled reactors, and it includes provisions for government/industry collaboration, with appropriate cost sharing and other support actions.

- Conclusions and Recommendations
  Based on all of these evaluations, the NTDG developed a set of conclusions and recommendations, as presented in Section 5.

The NTDG evaluation of candidate reactor designs, as outlined above, addressed primarily the question of potential for deployment by 2010. In doing so, the NTDG examined technical and other aspects of the various designs and the detailed information provided in this Roadmap Report provides important insights into the potential effectiveness and value of each design. In several cases, candidate designs judged by the NTDG to be unlikely for deployment by 2010 are being evaluated in parallel by the Generation IV Program for long-term merit.

2 Considerations Applicable to Any NTD Initiative

This section describes the NTDG assessment of common factors, including generic gaps and issues that will affect any new nuclear project, considerations related to nuclear plant economics and the schedule challenges of new plant deployment by 2010.

2.1 Key Gaps to Near Term Deployment

Many of the factors that contributed to the two-decade hiatus in nuclear plant construction are still in play and must be dealt with effectively for any new nuclear project to succeed. Additionally, this long interval itself will pose challenges to the next nuclear plant to be built, regardless of plant design. Furthermore, some new conditions must be addressed.

The NTDG considers the following to be gaps to near term deployment, in the sense that they warrant some directed action if new nuclear plants are to be deployed by 2010. However, while they are individually important, they are not wholly separable or discrete. The recommendations proposed in Section 5 collectively address these gaps.

2.1.1 Nuclear Plant Economic Competitiveness

In order to attract the substantial financial capital required to license, procure and construct a new nuclear plant, a proposed new plant <u>must</u> be economically competitive in the de-regulated electricity marketplace. In assessing economic competitiveness, prospective investors will consider economic factors such as cost and cost uncertainty to complete the remaining engineering, construction cost, ability to complete construction on schedule, licensing risks, plant lifetime and projected operating, maintenance and fuel costs, projections of market conditions and alternative system generation costs.

In some respects, economic viability for a nuclear plant is difficult to demonstrate because:

- Nuclear plants are capital intensive, requiring substantial financial investment and time before the investor realizes any return. The long-term (i.e., life cycle) financial advantage of a nuclear plant must be sufficiently strong (particularly in a non-regulated environment) to outweigh the capital cost disadvantage.

- Historically, nuclear plant construction and operation have been vulnerable to costly interruption because of engineering and management problems, regulatory delays and public opposition.

- The two-decade hiatus in new plant construction in the U.S. implicitly discourages new plant investment.

<u>Implications:</u>

This is the most significant obstacle to new nuclear plant deployment. Future nuclear plant designs must be economically competitive. They must have capital costs significantly lower than those of the plants completed in the last two decades and operating and maintenance

(O&M) costs equivalent or lower then those of the best currently operating plants. These projected cost components must be predictable with high confidence. The net effect of predictable and lower capital cost and excellent O&M costs will be overall life cycle costs that are sufficiently attractive to secure private investment in competition with fossil plant investments.

As detailed in this report, the design candidates for near-term deployment have been developed with close attention to the necessity of economic competitiveness. Also, the substantial improvements in the nuclear plant licensing and regulatory processes have addressed many of the causes of high construction costs that affected earlier projects.

However, these improvements alone are not sufficient. Additional improvements in plant economic competitiveness need to be realized, such as aggressive measures to achieve faster, more economical construction schedules. Also, effective standardization of new plant designs, now a practical objective under the 10CFR52 licensing process, can significantly improve economic competitiveness, particularly for follow-on units in a design series.

Section 2.3 of Volume I and Chapter 4 of Volume II provide more details on the issue of economic competitiveness.

2.1.2 Business Challenges of the Deregulated Electricity Marketplace

Essentially all experience in building nuclear plants in the U.S. has been under the regulated utility framework. Aside from the heightened importance of economic competitiveness, the broad-scale deregulation in the U.S. electricity supply system is a significant change that creates both new challenges and new opportunities.

Challenges:

- **Risk**. Deregulation places the financial risk of new generation projects squarely on the plant investor. No longer can a regulated utility, with mandate to serve, finance a capital-intensive plant on the strength of its own certain economic value to the stockholders (i.e., a guaranteed adequate revenue stream, paid by ratepayers and underwritten by the regulator). To secure capital, project risks and rewards will have to meet the investment community's competitive standards.

- **Time-to-market**. The electricity market is influenced by regional, national and global factors such as the economy, fuel supplies, climate and weather. The time required to license and build new nuclear generation is too long to respond to short-term changes in market conditions.

Opportunities:

- **Business flexibility**. In a deregulated environment, nuclear plant investors can manage a new nuclear project on an expedited, cost-competitive basis. They can avoid the cumbersome constraints attendant to regulated operation such as open (or extensive) bidding and procurement processes. Thus, they should be able to build a new plant faster, and at significantly lower cost, than previous projects.

- **Electricity supply**. Investors can employ new business models in negotiating and committing to long-term contracts for sale of plant-generated electricity, unconstrained by regulated service area, and in taking advantage of price stability and fuel diversity. New opportunities to provide other network related functions such as ancillary services could provide additional revenue sources.

Implications:

This fundamental change in the electricity supply business can be capitalized upon by the nuclear industry. The NTDG judges that the new deregulated environment offers substantial business opportunity for successful nuclear ventures. However, the timing and form of such ventures have not yet been developed.

2.1.3 Efficient Implementation of 10CFR52

10CFR52 was developed in direct response to the inefficiencies, difficulties and financial risks experienced by the nuclear industry in licensing and constructing plants under the previous (10CFR50) process. However, major elements of the Part 52 process have not yet been demonstrated in actual practice. Given the complexity of the overall process of designing, siting, licensing and constructing a nuclear plant, the uncertainties associated with first-time application of this new regulation represent a significant risk to prospective new plant owner/operators.

The specific areas of uncertainty are:

- Design Certification (DC). Although there have been three successful DC applications under Part 52, each took 6-8 years. That duration would be far too long to permit deployment by 2010 of any plant not already certified, and is generally untenable for any new plant project in a deregulated electricity market. The NTDG believes that new plant DCs should be completed in a much shorter time frame for designs which are mature and for which DC applications are complete and technically sound.

- Early Site Permit (ESP). This is an essential licensing step, and one likely to be on the critical path for all new plants built in the U.S. To date, there have been no applications for ESP.

- Construction and Operating License (COL). The COL is a key feature of 10CFR52 that will permit the applicant to secure, prior to construction, the license to operate the plant contingent upon meeting pre-established NRC standards and without a post construction public hearing. This is a cornerstone of the 10CFR52 process, also on the critical path for new plant projects, – and it has not yet been demonstrated.

- Inspections, Tests, Analyses and Acceptance Criteria (ITAAC). Closely linked to the COL, ITAAC are to be used by NRC as a basis of ascertaining, during plant construction, that the licensee is meeting the requirements of the COL. A common understanding has yet to be established on the scope of ITAAC required in a COL and how the ITAAC process is to be implemented during construction. This is a complex matter, with potential implications on plant construction schedule and cost.

In parallel with efforts to clarify key Part 52 licensing processes, the industry and NRC are taking the first steps toward establishing a new, risk-informed, performance-based regulatory framework for future plants, including technical/design, operational and administrative requirements. This effort will take advantage of insights and principles from the recently completed revision of the NRC reactor oversight program. This will be a long-term effort, with benefits accruing to plants being deployed in the near-term as various parts of the framework are completed and available for use.

Implications:

Together, these areas of licensing uncertainty require near-term interaction by industry and NRC, and resolution on a priority basis, prior to full implementation of the 10CFR52 process. It is imperative that substantial effort be applied, in advance, to identify and preempt unnecessary (and costly) implementation difficulties.

Industry and NRC should also pursue the development of risk-informed and performance-based regulatory framework for future plants. The NTDG believes that strong progress toward a new regulatory framework will increase confidence of prospective applicants in the regulatory environment for new plants and encourage business decisions to proceed with new nuclear projects.

2.1.4 Nuclear Industry Infrastructure[3]

There has been no real growth in the nuclear industry for many years. The practical consequence has been gradual erosion and current shortfalls in such important infrastructure elements as:

- Qualified and experienced personnel in nuclear energy operations, engineering, radiation protection and other professional disciplines.
- Qualified suppliers of nuclear equipment and components (e.g., manufacturing organizations with N-stamp credentials, part 21 QA programs). This includes fabrication capability and capacity for forging large components such as reactor vessels.
- Contractor and architect/engineer organizations with personnel, skills and experience in nuclear design, engineering and construction.

Implications

Although the Congress, DOE and NERAC have taken steps to support and restore the nuclear industry infrastructure, the infrastructure deficiencies facing those who construct and

[3] This is an issue that affects all plant deployment prospects to some degree, and some more than others. The NTDG has considered it both as a common factor and as a potential plant-specific issue, as described in Section 3.

operate new plants cannot be fully resolved in advance. Some initial steps (e.g., advance planning, long-lead personnel initiatives) can help, however, and correction will occur as a natural outgrowth of building and operating new plants.[4]

A realistic expectation for the near term is that there will be some penalties due to infrastructure weakness, in forms such as cost pressure driven by supply and demand imbalance and excessive lead times for material and equipment delivery. The challenge for the initial project leaders will be to take proactive steps to prevent or minimize the adverse effects of infrastructure limitations.

Over the longer term, substantial restoration of infrastructure will be needed to support construction and operations of an increasing number of nuclear plants. An important strategic element of this build-up should be an expansion of U.S. domestic capability in major component manufacture and assurance of competition in uranium enrichment services.

2.1.5 National Nuclear Energy Strategy

In view of the importance to the nation of a strong and growing nuclear generating capacity, and the evident difficulty in beginning new nuclear plant projects in the U.S. after a two-decade hiatus, strong and visible leadership from the Federal Government is essential. The National Energy Policy Report of May 2001 was an important first step; but it needs to be followed with a strategic plan that establishes specific nuclear energy goals, priorities and commitments for appropriate support.

Substantial effort and funding is required to bring to the marketplace a new and advanced nuclear plant design. Strong commitment and investment by industry is essential to this achievement. Consistent with the importance to the nation of a healthy and growing nuclear power capability and with the DOE overall responsibility to enable and maintain an adequate electricity supply, there is also an appropriate role for government financial and other support to the industry efforts to revive the nuclear option.

Over the last ten years, U.S. Government support for nuclear has been disproportionately low in comparison with that for other, competing electricity supply technologies. It is the NTDG view that increased and effective government support for nuclear power in the U.S. is needed.

Implications:

Section 4.1 outlines the NTDG recommended approach regarding government support for new nuclear power in the U.S. and more detailed presentation is provided in Volume II, Chapter 6. The underlying concept is that shared industry and government funding should be provided for activities necessary to satisfy safety-related design work and licensing

[4] One potential industry action that could have very positive near-term infrastructure benefit is the initiative under consideration to recover or complete existing sited nuclear power plants that have been shutdown or terminated before completion. Such projects could yield significant new nuclear capacity and would also stimulate immediate infrastructure growth, particularly in plant construction and in nuclear material and equipment supplies.

requirements for new plant construction, particularly those involving first-time implementation of new regulatory processes and or new and advanced design concepts. The recommendations in Section 5 are consistent with this approach.

Over the long term, government support is needed for research and development leading to fundamental technological advances. The Gen IV Program addresses these long-term needs.

2.2 Other Important Issues

Along with the generic gaps identified above, there are significant issues that could influence new plant deployment which require close attention. However, current industry and government actions are appropriate and no additional actions are needed to support NTD initiatives.

2.2.1 Nuclear Safety

Today's current plants are very safe and continue to improve. The certified designs have surpassed all regulatory and utility requirements for enhanced safety and are quantitatively safer than current plants. The close scrutiny of the NRC and stringent licensing requirements will ensure very high safety levels for all near term deployment plants.

Among the light water-cooled reactor (LWR) candidates considered for near-term deployment, safety approaches are comparable to or better than those of currently certified advanced reactor designs, and they will be evaluated by NRC against established and proven standards. The gas-cooled concepts employ different safety measures than light water plants,[5] but it is anticipated that these will achieve safety performance at least as good as currently certified advanced LWRs. In no cases are the near-term designs under consideration expected to present significant challenges with respect to nuclear safety.

The recent attack on the World Trade Center has raised concerns about the adequacy of sabotage protection at nuclear energy plants. Industry, NRC, and other responsible federal and state agencies are addressing this issue. A number of specific short-term actions have been taken, and longer-term implications are being evaluated. New nuclear plants will benefit from this examination and will implement the actions deemed necessary for existing plants.

Implications:

All new plants will meet the current, very high NRC standards and requirements regarding nuclear safety.

[5] The gas-cooled reactors licensed by the NRC and operated in the U.S. (Peach Bottom Unit 1 and Fort St. Vrain) are no longer operating and were significantly different in design than gas-cooled reactor design candidates under consideration for near term deployment.

2.2.2 Spent Fuel Management

From a technical standpoint, the safe handling and storage of spent nuclear fuel (SNF) has been among the most successful solid waste management programs in the industrial sector. Storage of spent fuel at a reactor plant site is well understood and fully demonstrated -- its cost is moderate, licensing is straightforward, and environmental impact is minimal. On-site storage has been determined to be acceptable for the extended life of currently operating plants and can be readily incorporated in the design of any new plants.

Long-term government responsibility for spent fuel disposal remains clear, and a presidential decision is expected soon regarding the suitability of the proposed federal repository at Yucca Mountain. Nevertheless, the long-term disposition of SNF remains a contentious open issue in the U.S. and a serious concern to many regarding the efficacy of proceeding with new nuclear plants.

The SNF management situation facing all nuclear plants over the longer term still requires resolution. The U.S. government must continue to make progress in fulfilling its responsibility for SNF disposition as mandated by the National Waste Policy Act of 1982 (as amended). This will require difficult political and societal decisions regarding land use, nuclear fuel resources and SNF transportation. Disposal and storage facilities (including permanent repository and monitored retrievable storage, as applicable) will have to accommodate existing SNF as well as that generated by existing plants during their extended lifetimes and by new plants.

Although these questions may be difficult and politically divisive, the technical implications are relatively straightforward, and their resolution is not made significantly more difficult by an increase in the quantity of SNF to be managed, because of new plants.[6] In contrast to the environmental implications of expanded operation of fossil fueled plants (e.g., SO_2, NO_X, greenhouse gas emissions), SNF disposal is a more tractable, less threatening problem from the standpoints of environmental protection and public health and safety.

Advanced plant designs and fuel cycles for the next generation, as being evaluated under the Gen IV Program, are expected to reduce the spent fuel management burden.[7]

Implications:

Long-term disposition of SNF is a legacy issue -- a significant matter of national policy. It affects nuclear fuel supply, use of natural resources and land, and it involves very significant cost. However, resolution of this long-term strategic issue is not a prerequisite to new plant construction.

[6] The Nuclear Energy Agency of the OECD has concluded that "nuclear waste management is fully consistent with the principles of sustainable development, and this issue should not be considered a barrier to the continued development of nuclear power". NEA News, 2001 – No.19.1, Pp 18-20.

[7] The Gen IV Program, which primarily focuses on long-term deployment of nuclear energy, has established as a major goal that "nuclear energy systems will minimize and manage their nuclear wastes and notably reduce the stewardship burden in the future, thereby improving protection of the public health and environment".

The reactor designs for new nuclear plants must provide adequate on-site storage capability to safely accommodate with substantial margin the full quantity of spent fuel to be produced by the plant. In support of this, nuclear industry spent fuel storage and cask suppliers must ensure that their products can accommodate the full range of anticipated fuel design and operating parameters.

2.2.3 Public Acceptance of Nuclear Energy

In the past, opposition to nuclear power by some segments of the public caused significant licensing and construction delays, at substantial cost. For that reason, public acceptance of new plants is a factor that prospective owners must consider.

Many recent public opinion surveys show positive and growing public support for building new nuclear plants.[8] This trend seems to be influenced by public recognition of the need for adequate electric power generation capacity and by growing awareness of the ongoing safe, clean and economical performance of today's plants. Continued excellent performance of existing plants should result in further increase in public support.

Experience in existing plant operations shows that achieving and maintaining public trust at the local level is extremely important. Successful nuclear plant operating companies have built that trust through open, direct and proactive communication with the public in their regions.

Implications:

NTDG views public acceptance as an important issue, but one that is not likely to strongly affect near term deployment potential. Continued safety and success in nuclear operations, for current and future plants, should yield steadily improving public trust and acceptance.

Current and future nuclear plant operators must therefore continue to place highest emphasis on safe operation of their plants and on maintaining consistent, open and honest communications with their constituents. On the national level, industry and government efforts should continue to present to the public accurate and balanced information regarding nuclear power.

2.2.4 Non-Proliferation of Nuclear Materials

As noted in the NTD RFI, non-proliferation is considered to be longer-term global fuel cycle issue, and is being addressed by the Generation IV Roadmap.

Extraction of weapons-usable material from spent commercial fuel is extremely difficult and more costly than other methods, and is not an issue in the U.S. for either current plants or new plants being considered for near term deployment. All of the design candidates

[8] "A new national survey finds that the dramatic increases in public support for nuclear energy have held at high levels, despite lower public concern about energy shortages. Almost two thirds of U.S. adults continue to support definitely building new nuclear power plants. Support has grown from 42 percent in October 1999 to 63 percent in July 2001." [Bisconti, September 2001]. Gallup and other media report similar results.

considered by the NTDG for near term deployment all utilize fuel cycles that do not re-cycle fuel. Therefore they share the same strong proliferation resistance as existing U.S. reactors.

Implications

The current non-proliferation practices for operating nuclear power plants apply to NTDG plants. This issue is not relevant to near term deployment.

2.3 Cost Competitiveness – Criteria for Success

Volume II provides a comprehensive explanation of the new deregulated electricity marketplace and its implications regarding cost competitiveness of new nuclear plants, and a supporting computational model. Evaluation of the results of this study leads to the following observations regarding the necessary attributes of new nuclear designs, if they are to achieve cost competitiveness:

- Nuclear plant "time to market" is a key factor affecting economic competitiveness in the deregulated marketplace. Long lead-times prior to construction and long construction periods reduce economic competitiveness and increase project risk.

- Resolution of licensing issues before project commitment is essential to ensuring acceptably short lead-times. Resolving in advance the issues of economic need for the project, site licensing and permitting, and NRC safety regulatory approval of the design are necessary to prevent an open-ended licensing process when the plant is under construction and interest during construction accumulates.

- Depending on market conditions, project overnight capital cost (including engineering, procurement and construction (EPC) cost, owners cost, and contingencies) need be contained at about 1,500 $/KWe or less. Overnight capital costs of 1,200 $/KWe or less should secure broad market acceptance. Break-even nuclear capital costs will depend on market prices, determined in turn by the cost of fossil fuels to the marginal generating unit. Higher overnight capital cost figures could prove economic in localities with sustained high market prices, or under specially structured power purchase agreements (PPAs). Large nuclear plants will require a total as-spent investment, expressed in current year dollars, as high as $2B.

- Nuclear plant production costs (fuel and O&M expenses) should be held to 10 $/MWh or less. The major advantages of nuclear power plants are their low and stable running costs, which makes them ideal for long-term bilateral contracts. In order to allow competitively priced contracts, production costs should be kept as low as possible to provide adequate margins for capital cost recovery and profits.

- Nuclear plant lifetime capacity factors should be sustained at 85 percent or higher, in order to maximize incoming revenues and the potential for margin capture. This is a strong advantage of nuclear and another key to economic competitiveness.

- Achieving high safety performance is essential to the economic well being of the plant. Regulatory-mandated shutdowns and inspections will reduce incoming revenues, increase capital outlays for recovery and reduce plant profitability.

- Nuclear project developers and owners should locate their plants in specific locations likely to experience high and sustained market clearing prices. In general, locations where market prices can be forecasted to remain above 40 $/MWh for at least the first ten operating years, would be preferable.

- Nuclear plant owners should strive to anchor their generation in long-term bilateral PPAs, based on the prevailing local market prices (at or about 40 $/MWh). The major selling point of an operating nuclear plant is the very low volatility of its annual prices. This should allow competitively priced long-term PPAs, which will provide adequate margin capture.

- Nuclear plants should strive to obtain the best financing package possible, based on all of the above. Typical values could include containing the return on investment (ROI) requirements to 15 percent or less, allowing debt repayment periods as much longer than 10 years as feasible, and reducing equity financing to 40 percent or lower.

- The most important observation derived in this study is that the deregulation of the energy markets did not eliminate the prospects for capital-intensive base load generation options such as nuclear and coal-fired plants. Nuclear plant designers and operating companies are adjusting to the requirements of the new energy markets. The cost and performance targets discussed above are expected to be achieved in real projects, enabling the long-term role of nuclear power in the future energy markets could be sustained and enlarged.

2.4 Deployment Timeline: Major Elements and the Critical Path

This section outlines the necessary sequence of major events involved in designing, licensing and building a nuclear plant, their sequence and logical relationships and their approximate durations.

2.4.1 Timeline Elements

The activities involved in designing, licensing and building a new nuclear plant, and their approximate time frames and schedule relationships, are described in Volume II. In summary, they are as follows:

Activity	Description	Nominal Time frame
Site Licensing (ESP)	– Preparation and submittal of an application for Early Site Permit (ESP) per 10CFR52 – NRC review, interaction with applicant, public hearings (if required), and ESP Issuance	3 years total, including: – 1 year preparation – 2-year NRC review and approval This is a likely critical path

Activity	Description	Nominal Time frame
		activity for new plant projects.
Design Certification (DC)	– Preparation and submittal for Design Certification (DC) per 10CFR 52; may include extensive engineering, analysis and testing – NRC review, interaction with applicant, public hearings (if required), and rulemaking	– Preparation time: 1-3 years, depending on technical issues, precedents – 3-year NRC review and approval (2 years in some cases as discussed below) –
Plant Licensing (COL)	– Preparation and submittal for Construction and Operation License (COL) per 10CFR 52 – NRC review, interaction with applicant, public hearings, and COL Issuance – Could be combined or conducted in parallel with ESP and /or DC	– Preparation time: 1-year, presuming ESP/DC applications have been submitted – 1-year NRC review and approval, not including hearings, (with pre-existing ESP and DC) – 3-year NRC review and approval, not including hearings, for COL without pre-existing DC This is a critical path activity, in all cases.
Detailed Engineering and Testing	Includes all engineering, design, and testing needed to build the plant, beyond that needed for licensing	3-6 years – Depends on complexity of design, precedent or pre-existing design work – Presumed not to be on the critical path
Long Lead-time Procurement	Procurement of material and equipment which must be ordered in advance of start of construction to prevent critical path impact	– Reactor vessel, other large vessels are usually the pacing items, require minimum of 2 years prior to delivery – Can be kept off critical path with early (pre-COL) financial commitment

Construction	Includes: – Pre-construction and site preparation activities – Plant construction (first structural concrete to fuel load) – Fuel load and pre-operational testing	Minimum of 4 years for a large single unit site, 3 years for first module of a modular plant, for critical path work (plant construction, fuel load and testing). – Site preparation, ~1-2 years, not on critical path – Some previous U.S. project construction time frames have exceeded 10 years; recent overseas construction times have been in the 4-5 year range.

2.4.2 The Nominal Schedule for Near-Term Deployment

Based on the main elements outlined in the table above and target of commercial operation by the end of 2010, the NTDG offers the following general observations regarding schedule:

1. Critical path construction must start by the beginning of 2007 at the latest, for any realistic potential to achieve commercial operation in 2010. Therefore, the COL must be in hand by that time.

2. For designs already certified, and assuming two to three years for ESP and COL (from first submittal to full NRC approval), initial application must be submitted to the NRC by the end of 2003 or early 2004, depending on degree of ESP and COL overlap, in order to obtain the COL in time for construction start in early 2007.

   NTDG considers this three-year time frame for ESP and COL approval for a certified design to be achievable. It is based on the assumption of an uncontested COL (no formal hearings), since all design and siting issues would have been previously resolved with hearing opportunity at the time of resolution. With significant overlap of the ESP and COL processes, the ESP/COL processes could be completed in less than three years. For example, with simultaneous ESP and COL submittals, the time required for NRC approvals is likely to be controlled by the ESP process, the longer of the two. Thus simultaneous ESP/COL processes could be completed in two years, exclusive of hearings.

3. For designs not yet certified, it may be possible to combine the Final Design Approval (FDA) phase of the DC and/or ESP with the COL process, and to secure COL in a four to five year time frame (that is, by the end of 2006), assuming significant overlap between ESP and COL applications. In this scenario, the COL includes essentially all of

the NRC design review and approval process that would otherwise be part of the FDA phase of the DC, but would not include the rulemaking phase of the DC. This allows construction and operation of an approved design, with DC proceedings undertaken at a later date, after plant operation, so that the design that is finally certified for standardized construction has the benefit of any lessons learned from the first construction project. However, this is a significantly more challenging licensing approach, and success (in that time frame) will depend on such factors as technical completeness and quality of licensing submittals, timeliness of both NRC and applicant resolution of emerging issues, and a smooth and conclusive hearing process.

4. For any new plant design, it is NTDG's view that the activities that precede site-specific licensing (e.g., business decisions, site selection, selection of NSSS, and preparation of licensing applications) must be largely concluded in the 2003 time frame to achieve high confidence that the plant can be placed in service by 2010.

2.4.3 Timeline Variations and Opportunities for Acceleration

The above depicts a nominal or baseline schedule for near-term deployment and identifies realistic constraints and interim milestones. However, the actual sequence and duration of engineering, licensing, procurement and construction activities could follow any number of alternate scenarios as discussed in Volume II, Section 5. Some key factors affecting the likelihood that a given plant can be completed by 2010 are:

- The licensing preparation and approval durations could be longer or shorter than the nominal case, depending primarily on the degree of pre-application work needed (e.g., engineering, testing and analysis). These will vary from design to design.

- The willingness of the plant owner/operator and/or the plant investors to finance expensive critical path activities on a risk basis, prior to full licensing (particularly COL), will affect the total schedule. Lower risk approaches (such as deferring non-licensing engineering and long-term procurement until after receipt of COL) would add several years to the overall time frame (compared to the nominal case), and in some cases could preclude operation by 2010.

- Critical path construction time frames for the smaller plants, and particularly for modular designs, could be shorter than the nominal case assumption (four years). On the other hand, actual construction experience in the U.S. suggests that significantly longer construction periods are quite possible as well.

- Variations permitted within the 10CFR52 licensing process (such as pursuing a COL without a DC, as is under consideration for the PBMR and GT-MHR) could decrease the total licensing time, but entail more licensing risk.

3 Evaluation of Reactor Designs for NTD Potential

3.1 Near Term Candidates

The reactor designs considered in this evaluation of near term prospects for new nuclear generation were those identified in response to the RFI issued by DOE in April 2001. The intent of the NTDG evaluation was to determine those sufficiently mature in design and licensing to support deployment in this decade, and to assess their respective advantages, disadvantages and readiness for near term deployment.

In all, eight plant designs were assessed. Their key features are summarized on the following table:

Design	Supplier	Size and Type	Key features
ABWR	GE	1,350 MWe BWR	Advanced evolutionary LWR, design certified by NRC and built and operating in Japan.
SWR 1000	ANP Framatome	1,013 MWe BWR	Advanced BWR design; to meet European Requirements
ESBWR	GE	1,380 MWe BWR with passive safety features	Based on earlier passive SBWR design, but higher in capacity and decreased in physical size per installed KWe.
AP600	Westinghouse	610 MWe PWR with passive safety features	Advanced passive PWR, design certified by NRC
AP1000	Westinghouse	1,090 MWe PWR with passive safety features	Higher capacity version of AP-600; not yet certified
IRIS	Westinghouse	100-300 MWe PWR	Integral primary system plant design; eliminates classic LOCA accidents.
PBMR	ESKOM	110 MWe modular pebble bed gas-cooled reactor	Modular direct cycle helium-cooled pebble bed design, currently planned for construction in South Africa.
GT-MHR	General Atomics	288 MWe prismatic graphite moderated gas-cooled reactor	Modular direct cycle helium-cooled reactor being licensed for construction in Russia, for power production and disposition of excess Russian weapons-grade plutonium.

The following sections provide additional information on the eight candidates.

3.1.1 ABWR

General Electric (GE) developed the 1,350 MWe Advanced Boiling Water Reactor (ABWR) in cooperation with the Tokyo Electric Power Company and Hitachi and Toshiba. The ABWR incorporates design features proven in many years of worldwide BWR operating experience, along with advanced features such as vessel-mounted reactor recirculation pumps, fine-motion control rod drives and a state-of-the-art digital, multiplexed, fiber-optic control and instrumentation system.

The ABWR design was reviewed and certified by the NRC in 1996, under the provisions of 10CFR52. It is the only one of the reactor designs evaluated for near term deployment for which all engineering is complete and there is actual construction and operating experience. Two ABWRs, Kashiwazaki-Kariwa Units 6 and 7 went into commercial operation in Japan in 1996 and 1997 and are currently in their fifth cycle of operation. More recently, two ABWR units received regulatory approval and are now under construction in Taiwan.

3.1.2 SWR 1000

SWR 1000 is a 1,013 MWe BWR developed by Framatome Advanced Nuclear Power (F-ANP) in conjunction with German electric utility companies and European partners. The SWR 1000 design combines proven, conventional BWR features with passive safety features to provide enhanced safety benefits. The plant is designed to meet European requirements, including relevant requirements in Germany's nuclear codes and standards and other recommendations proposed by German and French reactor safety commissions for the European Pressurized Water Reactor (EPR).

A four-year design phase for the SWR 1000 was completed in 1999 and included the development of a site-independent safety analysis report, a probabilistic safety analysis report, and projected construction costs. FANP advises that in parallel with efforts to market the SWR 1000 in Europe, they may consider entering the U.S. market. However, to date, no action has been taken to adapt the design to meet U.S. standards or to prepare for submittal to the NRC for design certification.

3.1.3 ESBWR

ESBWR is a 1,380 MWe, natural circulation, passively safe boiling water reactor developed by GE, in concert with several international utilities, designers and research organizations. The design is based on its predecessor 670 MWe passively safe SBWR, initially developed in the early 1990's with DOE support, and it also utilizes many design features of the ABWR. The substantially higher plant power, combined with extensive reconfiguration and simplification of the reactor systems and containment structure, make possible very significant cost reduction in comparison with both SBWR and ABWR.

Although the ESBWR offers attractive advantages, GE is not yet moving ahead with detailed engineering and design certification of the plant. GE's current plan is to proceed with ESBWR in a "step-wise" fashion -- first with design certification, as funding becomes available, and then with detailed engineering, but only with the commitment and financial support of a plant customer.

3.1.4 AP600

The AP600 is a 610 MWe PWR. The core, reactor vessel, internals, and fuel are essentially the same design as for present operating Westinghouse PWRs. Fuel power density has been decreased to provide more thermal margin. Canned rotor primary pumps, proven in the naval program and in fossil boiler circulation systems, have been adopted to improve reliability and maintenance requirements. The innovative aspect of the AP600 design is its reliance on passive features for emergency cooling of the reactor and containment, provided by natural forces such as gravity, natural circulation, convection, evaporation, and condensation, rather than on AC power supplies and motor-driven components.

Extensive testing of the AP600 passive cooling systems has been completed and supported by independent confirmatory testing by NRC to verify the design and analyses of the passive emergency cooling features. NRC has certified the AP600 design. Additional detailed design work would be needed before the plant would be ready for construction.

3.1.5 AP1000

The AP1000 is a 1,090 MWe PWR of the same basic design as the AP600, but up-rated in power to achieve economy of scale. The AP1000 passive safety systems are essentially the same as those for the AP600, except for some changes in component capacities. The power up-rate has been achieved by increasing the length and number of fuel assemblies, by increasing the size of the reactor vessel and primary components, and by increasing the height of the containment and the size and capacity of the secondary plant energy conversion components. The AP1000 generating cost is estimated to be 30 percent less than that of AP600, because the additional power rating is achieved with a only a small increase in capital cost.

AP1000 application to NRC for design certification is scheduled for submittal to NRC by January 2002. Pre-application reviews with NRC are already underway. As with the AP600, additional detailed design work must also be done before the plant will be ready for construction.

3.1.6 IRIS

IRIS is an innovative small (100-300 MWe) pressurized water reactor under development by Westinghouse. The key feature of the IRIS design is the integrated primary system – that is, all primary system components, including the steam generators, coolant pumps and pressurizer are housed along with the nuclear fuel in a single, large pressure vessel. As such, IRIS offers potential safety advantages, primarily related to the elimination of any potential for large-break loss of coolant accident; and its small size and modular design may simplify on-site construction and be deployable in areas not suitable for large nuclear plants.

IRIS is currently in the conceptual engineering stage, and is being developed by an international consortium and with some support from the DOE via the NERI Program.[9] The

[9] The U.S. DOE Nuclear Energy Research Initiative (NERI) annually awards funding to selected promising nuclear projects.

integral primary system configuration introduces significant design and licensing challenges that will be difficult to overcome, particularly in the relatively short time frame established for this near term deployment assessment. In key design details, IRIS is fundamentally different from any reactor licensed and operating in the United States. For that reason, extensive analysis and testing will be needed as a prerequisite to NRC licensing and commercial deployment in the U.S. The IRIS sponsors' response to the NTDG RFI identifies this needed development and testing.

3.1.7 PBMR

The Pebble Bed Modular Reactor (PBMR) is a 110 MWe graphite-moderated, helium-cooled reactor. Heat generated by nuclear fission in the reactor is transferred to the helium and converted into electrical energy in a gas turbo-generator via a Brayton direct cycle. The PBMR core is based on the German high temperature gas cooled technology and uses spherical fuel elements. The fundamental objective of the gas-cooled reactor design concept is to achieve an exceptional level of nuclear safety, via fuel design that effectively precludes the possibility of a core melt accident.

The first PBMR is planned for construction in South Africa, under a joint venture led by ESKOM. The plant design is currently in the detailed engineering stage and is preparing licensing application material for review by the South Africa regulatory authorities. Exelon, the largest nuclear utility in the U.S., is a member of the joint venture and anticipates a follow-on PBMR project in the U.S. The U.S. PBMR project is in the early stages of preparation for application to the NRC for an ESP and a COL under 10CFR52.

Of the reactor designs evaluated by NTDG, the PBMR is the only one for which there is currently a potential customer actively involved and investing in the plant's development. Although Exelon's continued involvement is not assured, this is a significant factor in the PBMR potential for deployment in the U.S. by 2010.

3.1.8 GT-MHR

The Gas Turbine – Modular Helium Reactor (GT-MHR) is a graphite-moderated helium cooled reactor. Each unit generates 288 MWe, with up to four units comprising a complete plant. Heat generated by nuclear fission in the reactor is transferred to the coolant gas (helium) and converted into electrical energy in a gas turbo-generator via a Brayton direct cycle. The fuel consists of spherical fuel particles; each encapsulated in multiple coating layers, formed into cylindrical fuel compacts and loaded into fuel channels in graphite blocks. The GT-MHR design offers very high thermal efficiency (approximately 48 percent) and outstanding nuclear safety.

The GT-MHR is being developed under an international program in Russia for the disposition of surplus weapons plutonium. Government and private sector organizations from the U.S., Russia, France, and Japan are sponsoring the development work. General Atomics (GA) has the lead responsibility for providing U.S. technical support. The Russian GT-MHR demonstration plant is planned to be operational in 2009.

A parallel GT-MHR commercial plan has been assembled and could lead to adaptation of the design to utilize uranium fuel. The detailed design produced in Russia would be converted to U.S. standards and revised as necessary for the U.S. application. At this point, GA is actively seeking a U.S. owner/operator.

3.2 Other Candidates (not evaluated by NTDG)

The NTDG evaluated those candidate reactor designs submitted per the requirements of the DOE Request for Information, as described above. For completeness, it is noted that other designs may also be deployable by 2010. However, these were not evaluated and the NTDG offers no judgment as to their feasibility as near term deployment candidates.

3.2.1 EPR

The European Pressurized water Reactor (EPR) is a very large (1,545 MWe or 1,750 MWe) design developed in the 1990s as a joint venture by French and German companies, Framatome and Siemens. The basic design was completed in 1997, working in collaboration with other European nations, and conforms to French and German laws and regulations. As the EPR design was being developed, there was substantial cooperation between the European utilities developing EPR user requirements and the U.S. utilities leading the US ALWR Program and its Utility Requirements Document. The EPR was not submitted to the NTDG in time to support an assessment. Further, as with the SWR 1000, the designer, Framatome ANP, has not made a decision regarding entry into the U.S. nuclear market.

3.2.2 System 80+

The System 80+ is a 1,350 MWe PWR design developed by ABB-CE (now merged with Westinghouse). It conforms to the ALWR Utility Requirements Document and was certified by NRC in May 1997. Plants based on the System 80+ design have been built in Korea. However, as of this time Westinghouse has chosen not to market the System 80+ design in the U.S.

3.2.3 CANDU

Canada's CANDU reactor designs use multiple pressure tubes containing nuclear fuel assemblies in the active core region, which permit on-line refueling. Heavy water is pumped through the pressure tubes to remove heat and is also used to moderate neutrons in a low-pressure vessel (the Calandra) that surrounds the pressure tube region. CANDU reactors have been deployed outside Canada (e.g., Romania, South Korea). Recent advances to this design use light water cooling but retain heavy water moderation in the Calandra. This approach holds significant promise for improved maintainability and economics. Most CANDU designs are in the medium (500-1,000 MWe) size range.

3.3 Design Evaluation and Comparison

The following sections summarize the NTDG evaluation of the eight candidate reactor designs. These include assessment of each candidate's compliance with the six criteria established by GRNS for the NTDG, identified design-specific gaps, projected cost performance, schedule considerations, and overall potential for deployment by 2010.

In each of these evaluation categories, the NTDG conclusions for all eight candidates are summarized in tabular form. Tabular summaries are intended to provide a concise comparison of the relative merits and demerits of the reactor designs evaluated. The underlying individual evaluations, in much more detail, are presented in Volume II, Chapter 5.

3.3.1 Criteria

The six evaluation criteria established by the GRNS as a basis for near term deployment, as stated in the NTD RFI, are as follows:

1. Regulatory Acceptance	Candidate technologies must show how they will be able to receive either a construction permit for a demonstration plant or a design certification by the U.S. Nuclear Regulatory Commission (NRC) within the time frame required to permit plant operation by 2010 or earlier.
2. Industrial Infrastructure	Candidate technologies must be able to demonstrate that a credible set of component suppliers and engineering resources exist today, or a credible plan exists to assemble them, which would have the ability and the desire to supply the technology to a commercial market in the time frame leading to plant operation by 2010 or earlier.
3. Commercialization Plan	A credible plan must be prepared which clearly shows how the technology would be commercialized by 2010 or earlier, including market projections, supplier arrangements, fuel supply arrangements and industrial manufacturing capacity.
4. Cost Sharing Plan	Technology plans must include a clear delineation of the cost categories to be funded by government and the categories to be funded by private industry. The private/government funding split for each of these categories must be shown along with rationale for the proposed split.

5. **Economic Competitiveness**	The economic competitiveness of candidate technologies must be clearly demonstrable. The expected all-in cost of power produced is to be determined and compared to existing competing technologies along with all relevant assumptions. (Includes plant capital cost, first plant deployment cost, other plant costs)
6. **Fuel Cycle Industrial Structure**	Candidate technologies must show how they will operate within credible fuel cycle industrial structures, i.e., they must utilize a once-through fuel cycle with LEU fuel and demonstrate the existence of, or a credible plan for, an industrial infrastructure to supply the fuel being proposed.

3.3.2 Compliance with NTDG Criteria

The NTDG evaluation of the degree to which each of the candidate reactor designs meets the intent of the six criteria for near term deployment is summarized on Table 3.4.1-1. The NTDG judgments in each case are based on the information submitted by the respondent, on additional information provided (including presentations at NTDG meetings) and on the experience and judgment of the NTDG team members.

Details of the RFI responses and the NTDG evaluations are provided in Volume II, Section 5.

Table 3.4.1-1: Criteria Conformance Comparison

Design	1 Regulatory Acceptance	2 Industrial Infrastructure	3 Commercial-ization Plan	4 Cost Sharing Plan[10]	5 Economic Competitiveness	6 Fuel Cycle Industrial Structure
ABWR	Meets criterion. Design is NRC Certified.	Meets criterion. International infrastructure exists and has been demonstrated on Asian ABWR projects.	Can meet criterion. ABWR has been successfully commercialized in Japan and Taiwan.	Meets criterion. No design-specific government funding requested.	Can meet criterion. ABWR costs have high certainty (based on actual experience), but U.S. economic competitiveness is uncertain because of relatively high capital cost; ABWR may be competitive in some market scenarios.	Meets criterion. ABWR utilizes conventional fuel of proven design.
SWR 1000	Can meet criterion. SWR 1000 design developed to meet European requirements; translation/revision to U.S. requirements will be difficult but could be achieved in time for 2010 deployment if initiated very soon.	Meets criterion. Strong international infrastructure is in place.	Indeterminate. Plan not provided; SWR 1000 commercialization in the U.S. is contingent upon FANP decision re U.S. business strategy.	Indeterminate. Cost sharing requested for design certification only. (Source and amount of funding to complete first-time engineering is not identified.)	Can meet criterion. Projected costs are attractive, but they are highly uncertain, particularly under U.S. conditions.	Can meet criterion. SWR 1000 will utilize new fuel assembly design, but requires development and qualification.

[10] Consistent with the requirements established by NTDG (see Section 3.3.1), the statements in this column address primarily the completeness of the proposed cost-sharing plans. They do not reflect NTDG judgment regarding the appropriateness of the requested level of government support and the likelihood that it will be available. These questions are addressed in Volume II, Chapters 5 and 6.

Design	1 Regulatory Acceptance	2 Industrial Infrastructure	3 Commercial-ization Plan	4 Cost Sharing Plan[10]	5 Economic Competitiveness	6 Fuel Cycle Industrial Structure
ESBWR	Can meet criterion. ESBWR design incorporates ABWR and SBWR design features, both previously reviewed by NRC.	Meets criterion. Same international infrastructure as demonstrated on Asian ABWR projects would support ESBWR.	Does not meet criterion. ESBWR commercialization plan is predicated on prior successful commercialization of ABWR. Therefore it is not likely to support deployment by 2010.	Meets criterion. Cost sharing requested for design certification and detailed design.	Can meet criterion. GE did not provide cost projections; however, based on GE design economic targets and GE preliminary estimates of material quantities, ESBWR would likely be economically competitive.	Meets criterion; ESBWR utilizes conventional fuel of proven design (same fuel as ABWR).
AP600 and AP1000	AP600 meets criterion. Design is NRC Certified AP1000 can meet criterion. AP1000 is not yet certified, but is based on AP600 and AP1000 pre-application steps are in process.	Both meet criterion. Strong international infrastructure in place.	Both can meet criterion. Both are mature designs, but require substantial financial investment to complete the detailed design. Because it is already certified, AP600 design completion costs are somewhat (~10%, as estimated by Westinghouse) lower than AP1000.	Both meet criterion. The Westinghouse plan proposes cost sharing and supporting rationale for design certification and detailed design.	Both can meet criterion. Because of smaller capacity, AP600 has higher capital and operating costs than AP1000. Based on Westinghouse projected costs, AP-600 may be competitive in some U.S. market scenarios; AP1000 would be competitive in today's market	Both meet criterion. AP600 and AP1000 will utilize conventional nuclear fuel.
IRIS	Does not meet criterion. Design certification in time frame needed to support 2010 deployment is very unlikely, because of extensive analysis and testing required.	Can meet criterion. International IRIS design team, which includes manufacturing capability, has been assembled.	Does not meet criterion. Commercialization plan (in time to support 2010 deployment) is unrealistic.	Meets criterion. Identified cost sharing would support IRIS engineering, testing and licensing.	Indeterminate. Westinghouse projections on IRIS costs are highly conjectural; if true, IRIS would be economically competitive, but there is not yet a sufficient basis for confidence.	Meets criterion, for initial fuel loads. However, more highly enriched fuel loads, proposed to be used in later years, would require new manufacturing capability.

Design	1 Regulatory Acceptance	2 Industrial Infrastructure	3 Commercial-ization Plan	4 Cost Sharing Plan[10]	5 Economic Competitiveness	6 Fuel Cycle Industrial Structure
PBMR	Can meet criterion, provided that several challenging technical issues (including fuel issues) can be resolved and demonstrated to NRC satisfaction in the time frame needed for 2010 deployment. U.S licensing submittal information must be adapted from the German / South African design and test work. Pre-application steps with NRC are in progress.	Can meet criterion. International team is being assembled. Design contracts are in place for major equipment.	Can meet criterion. PBMR already has a potential US customer (Exelon) with substantial - albeit conditional - commitment. Presuming successful continuation of the South African project and Exelon decision to proceed with a U.S. project, PBMR commercialization plan is credible.	Meets criterion. Proposed government cost sharing is primarily for licensing activities, including the NRC confirmatory fuel characterization and test programs.	Can meet criterion. However, projected PBMR economics are preliminary and have high uncertainty. Satisfactory economics rely on deployment of multiple modules and successful development of the design.	Can meet criterion. PBMR safety and reliability hinge on successful fuel development and high quality fuel manufacture. Current plan includes ambitious program to develop, test, license and produce PBMR fuel, and presumes that initial U.S. fuel loads will be procured from a foreign supplier.
GT-MHR	Can meet criterion, provided that several challenging technical issues (including fuel issues) can be resolved and demonstrated to NRC satisfaction in the time frame needed for 2010 deployment. U.S licensing submittal information must be adapted from the Russian design and test work.	Can meet criterion, provided that the Russian industrial infrastructure can be qualified as a commercial supplier in the U.S. This may be difficult to achieve in the time frame required for deployment by 2010.	Can meet criterion. However, this presumes continued U.S. government support to the Russian project, timely identification of U.S. customer and industry partners, and technical success with Russian project.	Meets criterion. Cost share proposal is predicated on continued U.S. Government support to Russian project and presumes substantial private sector participation for commercialization.	Can meet criterion. However, projected GT MHR economics are preliminary and have high uncertainty. Satisfactory economics rely on deployment of multiple modules and successful development of the design.	Can meet criterion. GT MHR safety and reliability hinge on successful fuel development and high quality fuel manufacture. Current plan includes ambitious program to develop, test, license and produce GT MHR fuel.

3.3.3 Design Specific Gaps

The following are the design-specific gaps identified by each of the RFI respondents and/or by the NTDG review teams:

Design	Design Specific Gaps
ABWR	– Economic competitiveness, under some scenarios
SWR 1000	– Commitment by Framatome ANP – Licensing to U.S. regulatory and industry standards
ESBWR	– Design certification and completion of detailed design
AP600	– Financial support for completion of detailed design – Economic competitiveness, under some scenarios
AP1000	– Design Certification – Financial support for completion of detailed design
IRIS	– Steam generator design, control, and accessibility for inspection and maintenance – Integrated system safety performance, including transient response and primary system/containment interaction – Internal CRDM development (and/or adequacy of conventional CRDMs with long drive trains)
PBMR	– Continued commitment by Exelon, to support South African project and to proceed with U.S. project – Fuel development, characterization, manufacture, testing and regulatory acceptance – Performance of in-reactor high temperature materials – Power conversion system uncertainties with respect to components, materials and reliability
GT-MHR	– Conversion of Russian prototype information and analyses, into documentation suitable for US application. – Successful continuation of Russian project – Fuel development, characterization, manufacture, testing and regulatory acceptance – Performance of in-reactor high temperature materials – Power conversion system uncertainties with respect to components, materials and reliability

3.3.4 Economic Competitiveness of Reactor Designs Based on Vendor-Specific Data

As detailed in Volume II, the NTDG performed an economic analysis of the generation costs of several reactor designs, based on design-specific cost data provided by the vendors in response to the DOE RFI and subsequent communications. The submitted cost data are based on the assumption of success in the development, design and licensing activities of the various designs. The results of the analyses are summarized below.

1. The total generation ("busbar") costs of all the reactor designs considered by the NTDG fall within the range of 36$/MWh to 46 $/MWh. (Generation costs in this range correspond to overnight capital costs that meet the economic competitiveness criteria presented in Section 2). These costs are well within the range of expected market prices, which are estimated by the NTDG to vary between 35 $/MWh and 55 $/MWh or higher. Thus, nuclear plants are expected to be generally competitive on a total cost basis, with market prices likely to prevail in the U.S. in the future. As such, nuclear plants should be included as potential supply options in utility generation expansion studies.

2. The deregulation of the energy markets did not price new nuclear plants out of the market. Given the low production costs of 10 $/MWh, adequate margins exist between nuclear production costs and market prices to allow an appropriate return on the investment. Should the nuclear designs reviewed here achieve the cost/performance data reported in Volume II, they should be able to compete in the deregulated energy markets.

3. Nuclear plants should represent economic power supply options in specific market situations. More detailed and localized economic analyses will have to be performed to clarify whether a specific reactor design would prove a long-term competitive choice in a local market under specific contracting arrangements.

4. Nuclear plants, at the low end of their lifecycle generation costs, present costs lower than the likely range of future market prices. Nuclear plants at the high end of the cost uncertainty range still fall within the band of likely market prices.

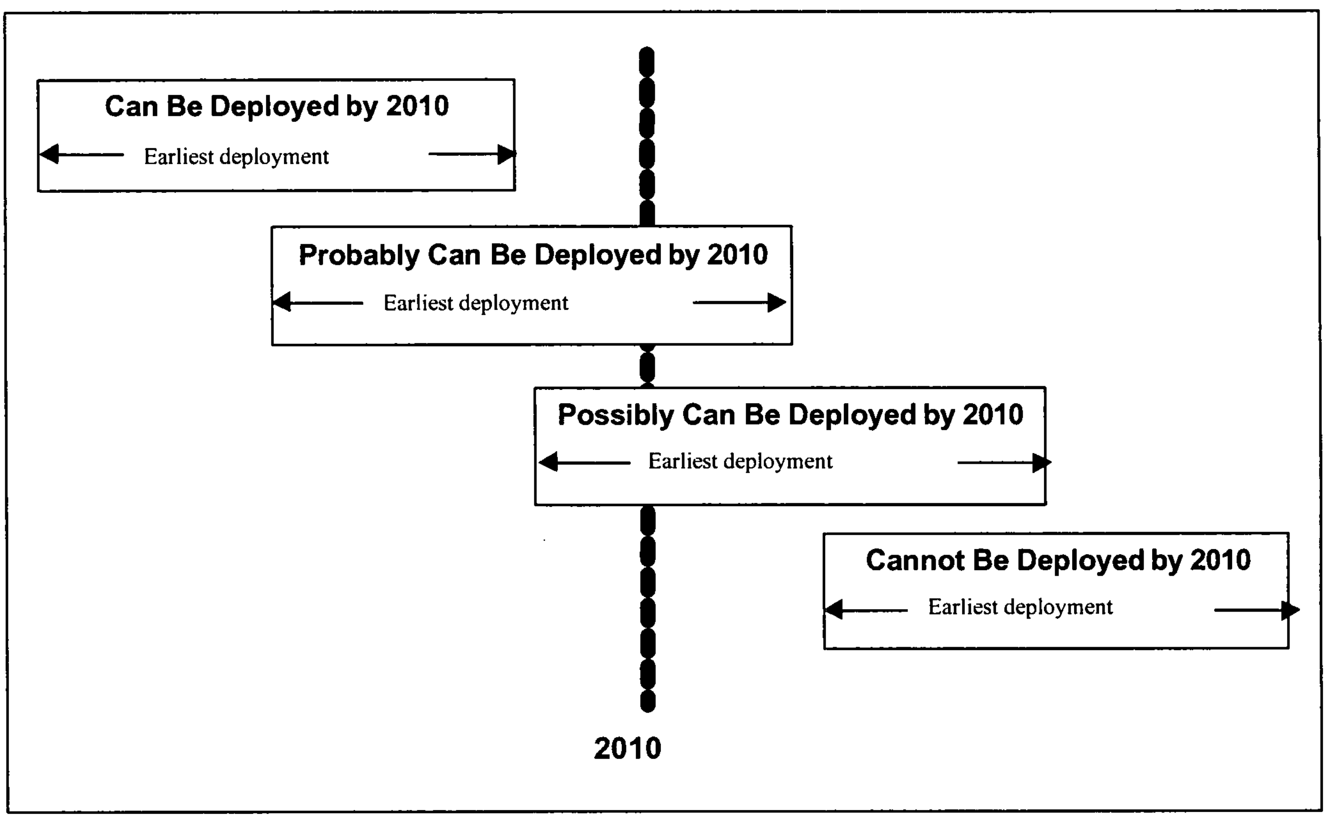
5. The issue of first years of life costs should be further evaluated. It is possible that some reactor designs will be competitive in their specific markets from the first year of operation going forwards. In other cases and based on local conditions, a specially structured Power Purchase Agreement (PPA) may have to be devised, to allow recovery of a substantial fraction of the costs in the early years of life.

3.3.5 Potential for Deployment by 2010

This section summarizes the potential for deployment by 2010 of each of the eight candidates evaluated. Potential is addressed primarily in terms of *readiness* – that is, such factors as the amount of prerequisite engineering and certification work already completed, the cost and time needed to perform that which is not already complete, and the potential for timely commitment of the funding (as indicated by expressions of interest by prospective customers) necessary to perform the siting, licensing, early procurement and other work needed.

For any candidate, the *likelihood* of deployment by 2010 also depends on factors such as the proponents' business and financial strategies, regional and national electricity supply and cost of alternative fuels. It may be that for reasons of economic competitiveness, some of the candidates judged to be higher in readiness are less likely to be deployed by 2010 than others that require more front-end investment but have potentially more attractive cost performance.

In this evaluation, the terms "can be deployed", "probably can be deployed", "possibly can be deployed" and "cannot be deployed" reflect the judgment as to whether the work necessary to deploy the plant in this decade could realistically be accomplished. In the case of those candidates designated as "probably can be deployed" and "possibly can be deployed", substantial and timely private sector investment, and very successful and timely completion of technical and regulatory work would be required (to an extent that varies from case to case) to achieve near term deployment. These determinations are not quantifiable and in each case represent NTDG collective judgment of potential along a continuum of possibilities, as shown in the following graphic.



The Figure above depicts graphically the NTDG judgments regarding each of the designations used to connote potential for deployment. The horizontal dimension in each box represents graphically a range of plausible deployment dates for the evaluated design candidates; the designations "can be", "probably can be", etc. reflect the position of the box relative to the 2010 target schedule. In all cases, these are largely qualitative judgments, backed by the assessment of actions required to achieve near term deployment.

Following are synopsis statements of potential for deployment, for each of the candidates:

Design	2010 Deployment Readiness
ABWR	The ABWR can be deployed in the U.S. by 2010. NRC has certified the ABWR design, and all detailed design (except site-specific) is complete. The construction time frame has been demonstrated in Japan. Although ABWR construction and operating costs should be highly predictable, economic competitiveness in the U.S. is uncertain based on current trends in the electricity market.
SWR 1000	SWR 1000 possibly can be deployed in the U.S by 2010. Given the resources and capability of the international sponsors, it is *possible* that an aggressive initiative to deploy an SWR 1000 in the U.S. by 2010 could be successful – however, the challenges of translating and refining the design to meet U.S. requirements and licensing the plant on an accelerated schedule would require very early commitment and major financial investment. At present, FANP has not yet decided to enter the U.S. new plant marketplace and has not provided a commercialization plan, suggesting that it is unlikely that SWR 1000 will be deployed in the U.S. by 2010.
ESBWR	ESBWR possibly can be deployed in the U.S. by 2010. The ESBWR conceptual design is relatively mature and offers the promise of economic competitiveness and excellent safety and reliability. However, GE currently is planning a "step-wise" ESBWR development, in which design certification could proceed initially but detailed engineering would not proceed until after certification is in hand and only if commercial support is available – and potentially not until there have been several ABWR orders. On that basis, ESBWR deployment by 2010 would not be possible. However, if GE chooses (in the relatively near future) to accelerate that schedule, deployment by 2010 can be achieved.

Design	2010 Deployment Readiness

AP600 and AP1000

AP600 or AP1000 probably can be deployed in the U.S. by 2010.

Westinghouse plans to pursue AP600 or AP1000, but not both.

NRC has certified the AP600 design. However, detailed engineering remains to be completed and the plant's economic competitiveness in the U.S. is uncertain, based on current trends in the electricity market.

The AP1000 design has promise for economic competitiveness and is relatively mature, based on the certified AP-600 design. To be deployed by 2010, however, the following will be required:

- Sufficient near-term financial support for detailed engineering and licensing
- A successful NRC design certification (based on the already-certified AP600)

IRIS

IRIS cannot be deployed in the U.S. by 2010.

The design is still highly conceptual and it includes innovative features that will require extensive testing and analysis. The schedule submitted by Westinghouse does not support deployment by 2010.

PBMR

PBMR probably can be deployed in the U.S. by 2010.

PBMR is unique among the NTDG candidates in that it has a potential customer (Exelon), participating in the South Africa project and actively pursuing this design for U.S. application. Nonetheless, deployment by 2010 would require:

- That the South Africa project continues successfully
- That Exelon decides to proceed with a U.S. PBMR project, and commits to early (prior to COL) procurement of long lead-time plant components.[11]
- A successful, expedited ESP/COL schedule
- Resolution of several challenging technical issues, including those related to fuel reliability, energy conversion system and in-reactor high temperature materials.

[11] Subsequent to the NTDG evaluation, Exelon announced that it intends to delay its decision to proceed with the PBMR by a year, and that one or two technical issues that create uncertainty with regard to PBMR licensability will need to be resolved for Exelon to proceed. The South African demonstration plant has also been delayed by one year. Exelon advises that it still plans to proceed with its ESP application in 2002, but will delay the COL schedule. This recent development is an example of the uncertainty inherent in the NTDG judgments regarding deployment potential.

Design	2010 Deployment Readiness
GT-MHR	GT-MHR possibly can be deployed in the U.S. by 2010. For deployment by 2010, the following will be required: – Success in the Russian GT-MHR project (in turn, requiring continued U.S. Government support). – GA must secure, in the near future, adequate investment from prospective customer(s) to fund engineering and licensing applications for the U.S. plant. – A successful, expedited ESP/COL schedule – Resolution of several challenging technical issues, including those related to fuel reliability, energy conversion system and in-reactor high temperature materials. While these conditions could be met, it is unlikely that all will be done in time to support 2010 deployment.

4 Achieving Near Term Deployment – an Integrated Strategy

This section presents an integrated strategy to achieve the goal of near term deployment, addressing the generic gaps and other issues outlined in Section 2 and the design-specific gaps and implementation needs outlined in section 3.

At the center of this integrated strategy is a phased approach to project planning and execution for new plants that aggressively pursues regulatory approvals and design completion, leading to construction and startup of multiple new plants by 2010. Success of this strategy, and therefore to near term deployment of new plants, requires effective industry/government collaboration.

4.1 Two Tracks – Water and Gas

As described in Section 3, candidates for near term deployment include both water-cooled and gas-cooled reactor designs. Carrying both tracks forward is essential to a prudent national energy strategy.

Most commercial reactor experience in the U.S. and around the world is with light water cooling[12]. U.S. regulatory process, plant engineering, design, safety analysis, construction and operational experience are based in large measure on the more familiar light-water reactor (LWR) technology. However, it is generally accepted that LWRs are most competitive economically in large (1,000 MWe, or larger) plant sizes and, as outlined above, such large projects involve very high initial capital expenditure and for that reason have not been attractive to prospective investors. In contrast, the new gas-cooled designs are smaller modular units and therefore pose substantially lower investment risk and better flexibility to serve regions with lower electricity demand, and they allow suppliers to add incremental capacity and better match increasing demand.

Near term deployment efforts should be pursued on a dual-track basis, providing maximum potential for success of both water-cooled and gas-cooled designs.

Two tracks are necessary because water and gas-cooled plants offer very different (and complementary) advantages, because they are likely to be attractive to different customers in different regions of the country, and because they are distinctly different in terms of readiness for deployment and the actions necessary to achieve near term deployment.

The dual-track strategy would include some generic activities, particularly those involving the licensing process, which would provide common support to water and gas-cooled candidates. For design-specific work, activities to support the development and near term deployment of designs of both types (several, if market interest is sufficient to support) should be carried out in parallel.

[12] All 103 commercial power reactors in the U.S. are LWRs. Two gas-cooled plants – Peach Bottom Unit 1 and Fort St. Vrain – were licensed by NRC but are no longer in operation. The new gas-cooled candidates, as described in Chapter 3, are significantly different in design from these early gas-cooled reactors.

4.2 Phased Plan of Action

Achieving the goal of near term deployment will require timely and successful actions in several different areas. In order to apply properly prioritized emphasis and support as the work proceeds, the NTDG recommends a phased plan of action that reflects not only the steps needed to achieve near term deployment but also their required timing and sequencing. The phased approach will also permit ongoing measurement of progress and validation or adjustment of the work, as needed to achieve the end objective.

The action phases to achieve new plant deployment in this decade are as follows:

- Phase 1: Regulatory Approvals
- Phase 2: Design Completion
- Phase 3: Construction and Startup

Phased actions by industry and government would accomplish, in a coordinated way, the essential regulatory and technical work, both generic and design-specific, to make possible new nuclear plants in this decade. Work in Phases 1 and 2 would be supported by a combination of private and public investment. The number of parallel project activities and the pace of the work would be driven by the marketplace; in no case would work proceed and federal funding be applied without the commitment of substantial private investment.

4.2.1 Phase 1: Regulatory Approvals

Phase 1 includes a broad set of actions, both generic and plant-specific, related to application of the 10CFR52 regulatory process:

- Preparation and submittal of early site permit (ESP) applications, and follow-up interactions with NRC, as necessary to demonstrate the ESP process for a range of siting scenarios and to secure multiple ESPs
- Preparation and submittal of applications for reactor design certifications (or FDAs for gas reactors), and follow-up interactions with NRC, as necessary to demonstrate an efficient DC/FDA process and to secure multiple design approvals
- Preparation and submittal of applications for combined construction and operating license (COL) for each NTD design to be supported in Phases 2 and 3
- Development of generic guidance to ensure efficient, safety-focused implementation of key Part 52 processes, including ESP, COL and ITAAC. This may include application of certain elements of the new regulatory framework, as it is developed and parts are judged "ready for use" by applicants.

4.2.2 Phase 2: Design Completion

In Phase 2, the detailed testing, engineering, and planning necessary to permit start of construction would be completed for those designs with sufficient private sector investment to proceed to deployment, contingent on DOE cost sharing. Phase 2 is a dual track effort, involving parallel government/industry collaboration in support of at least one ALWR design and at least one gas-cooled reactor design. In each case, the work would include:

- Detailed design and evaluation, including first-of-a-kind engineering
- Nuclear and component and plant system testing
- Plant materials testing, if needed
- Fuel development and testing, if needed
- Balance of plant/power conversion system testing, if needed

4.2.3 Phase 3: Construction and Startup

Phase 3 covers the actual construction and startup of new nuclear plants selected by the marketplace, including associated activities such as site work, plant structures, equipment procurement and installation, quality assurance, construction testing, and the like.

Phase 3 will continue as a dual track effort:

- For the ALWR(s), conventional and fully commercial construction project approaches are envisioned.
- For the gas-cooled reactor(s), given the level of testing required to confirm regulatory compliance and commercial performance, the best path to success may involve a demonstration project. DOE and potential private sector investors should evaluate the feasibility, practicality, and commercial objectives of such a project. The evaluation should include consideration of siting such a demonstration project on federal land.

Phase 3 funding is primarily through private financing, with government support provided in the form of environmental credits and other financial incentives of the kind already being provided to other (non-nuclear) electricity generating systems.

4.3 Aggressive Schedule

To achieve deployment by 2010, the phased plan of action must be implemented on an aggressive schedule, taking maximum advantage of coordinated efforts by industry consortia (or “family of plant” entities) working together and with government to achieve earliest possible deployment of each design with sufficient market support to achieve commercial operation.

Measures to achieve aggressive project schedules will include:

- Parallel efforts on regulatory approvals for siting, design approval, and combined license. All of the timelines for NTD designs shown in Volume II of this Roadmap propose significant overlapping of these activities. In many cases, the optimum schedules have been discussed with NEI and/or NRC for feasibility.

- Parallel efforts on Phases 1 and 2, such that detailed engineering work is completed concurrently with (or very soon after) regulatory approvals, in order to support construction start as soon as site permits and COL approvals are in hand. Again, all of the timelines for NTD designs shown in Volume II of this Roadmap propose significant overlapping of these Phase 1 and Phase 2 activities.

- Early procurement of many plant components, to ensure timely delivery of long lead-time items (e.g., large vessels), to support completion of detailed engineering, and to support early construction start soon after COL approval.

- Early actions to secure all necessary state and local approvals from all entities as needed. These actions include environmental and other investigations, and preparation and submittal of permit applications.

These aggressive project schedules necessarily require more up-front investment than would be required with more conservative, sequential project planning and execution. As such, projects implemented on aggressive schedules will require innovative business arrangements, such as consortia among designers, constructors, NSSS and major equipment suppliers, and plant owner/operators, with strong and common incentives to successfully build and operate new plants. Such consortia could include multiple future owner/operators, each willing to build one or more plants, which pool resources and expertise behind a chosen design. This enables cost and risk sharing within a broader investor base, and greater benefits from standardization of common engineering and programmatic efforts, state-of-art construction and operational management systems and equipment to optimize the cost and schedule of multiple plant projects. These teams of owner/operators are referred to within the industry as "family of plant" organizations.

The government's role in making such projects succeed is important, and includes the essential element of cost-sharing the one-time costs associated with the phased approach, as well as providing economic incentives (e.g., federal tax credits) as discussed below to encourage industry investment.

4.4 Funding Requirements

Volume II of this report presents a number of recommendations for industry and government funding, in support of near term deployment. The estimated funding requirements for all of the design candidates as well as for generic and site-specific needs are tabulated in aggregate in Appendix J of Volume II. Actual funding levels will depend on which activities secure adequate private investment to meet DOE cost sharing criteria.

Among the NTDG recommended actions, the primary funding needs will be for the dual-track, three phase activities described above. A summary of the estimated funding for that work is as follows:

Phase 1: Regulatory Approval

All above activities are to be cost-shared equally by industry and DOE. The total resource requirements over a four-year period are estimated to be:

Activity	Estimated Cost
Generic regulatory tasks including resolution of issues and development of guidance for ESP, COL, ITAAC verification, and construction inspections, and development of a risk-informed regulatory framework	$13M
ESP Demonstrations for an adequate range of siting scenarios	$30M
DC completion for designs based on previously certified or NRC-reviewed designs	$30M per application
COL completion for approved sites and designs	$10-15M per application
COL completion for designs that defer design certification and seek NRC design approval via COL (e.g., gas reactors)	$100M to $150M[13]

Phase 2: Design Completion

The funding requirements for Phase 2 vary widely, depending on design-specific needs. This work has been completed for one certified design, and significant work has already been completed for some of the uncertified NTD designs. The cost to complete NTD designs that are not yet certified range from roughly $150M to $300M per design. In some cases, private sector investors are willing to fund design completion at a funding rate significantly above the 50/50 cost share formula applied to Phase 1.

Phase 3: Construction and Startup

Phase 3 will be funded primarily through private financing, with government support provided in the form of environmental credits and other financial incentives of the kind already being provided to other (non-nuclear) electricity generating systems, as described in Section 4.5 and in Volume II, Chapter 6.

[13] Because this regulatory approval involves substantial engineering work, this funding estimate bridges into Phase 2 activities and could extend beyond the Phase 1 completion schedule above

The above funding recommendations address site-specific, generic and design-specific needs. For the design-specific applications, in cases where there are several candidates for government funding that could meet the above criteria, priorities for funding allocation should be market-driven, based on:

1. Realistic potential for successful deployment (as indicated by commercial interest and financial support in place)

2. Concept merit/added value (i.e., credible likelihood that the design will achieve significant improvement over today's reactors)

3. Maturity of technology and the developers' stated needs

Based on their assessment of the work needed and the projected availability of private investment, NTDG estimates that the typical yearly DOE total funding requirement will be approximately $100 million from 2003 to 2007, for phases 1 and 2. Details are provided in Volume II.

4.5 Industry/Government Collaboration

4.5.1 Formalizing a National Nuclear Energy Strategy

The National Energy Policy establishes the importance of nuclear power in meeting the nation's current and future energy needs. This formal statement by the government is an extremely important underpinning for the actions required to revitalize and expand the use of nuclear power in the U.S.

The logical next step in implementing aspects of the Policy related to nuclear power is to formulate an implementation strategy. This strategy would put in place a working structure for the aspects of the Energy Policy applicable to new plant deployment, and would cover a variety of topics such as roles and responsibilities, priorities, funding principles and processes and required administrative and legislative actions.

With respect to near term deployment of new plants, the NTDG envisions the strategy as codifying the principles, methods and actions presented in this Roadmap. A recommendation to that effect is included in Section 5.

4.5.2 Industry/Government Cost-Sharing

As described above, successful execution of the phased approach demands a commitment by industry and government to share in the one-time costs to achieve near term deployment. In a de-regulated electricity supply system, nuclear energy must be economically viable on a stand-alone basis. Prospective nuclear plant owner/operators must be able to secure project financing on the strength of the demonstrated business value of that investment – otherwise, investors will go elsewhere.

At the same time, reinvigorating the nuclear option is a matter of national importance. Yet the obstacles to be overcome in doing so are substantial. In particular, the initial costs of designing and licensing the next plants, after the long hiatus and utilizing untried new licensing processes, will be very high and could preclude nuclear plant reentry to the U.S. marketplace on a purely competitive basis. In light of government's responsibility to ensure a stable, safe and self-sufficient energy supply for the nation, some level of government financial support on a cost-sharing basis with the nuclear industry for these up-front efforts -- many of which are applicable to all designs -- is therefore appropriate.

NTDG envisions an appropriate model for shared industry and government funding based on several principles:

- Industry should carry prime responsibility for attracting and committing the substantial investment required to build new plants, and for all aspects of the life-of-plant (after construction) financial support. For any cost-sharing scenario, viability and value-added is first indicated by availability of private sector investment.
- Government funding should be applied in areas where government actions have added cost or uncertainty to the licensing process. For example, implementation of 10CFR52 will involve unpredictable and potentially high costs for the first users, costs that should be offset by government financial support.
- With respect to new plant development, government funding should be applied primarily in areas involving one-time costs or generic costs needed to ready new plants for the marketplace, and only where there is evident value-added by the new plant options.
- Over the longer term, government should support research and development necessary to achieve fundamental improvements in such areas as sustainability, compatibility with the environment and nuclear safety. The basic objective of the Gen IV Program is to identify such opportunities for long-term improvement and the R&D needed to realize them.

4.5.3 Cooperative Agreement

The U.S. Advanced Light Water Reactor (ALWR) Program experience with significant government-industry cost sharing demonstrated the value of a cooperative agreement in establishing an efficient and effective cost-sharing process that supports marketplace needs.

Cost sharing must be administered in a way that permits timely and flexible management of resources. The normal manner in which private sector cost sharing is implemented is by turning over invested funds (either in cash or in-kind work) to an industrial entity to utilize on its authority and within its assigned scope of responsibility. In such arrangements, the participants share the risks and the return on the investment is obtained through royalties, and profit sharing.

Such an arrangement can serve a wide scope of needs for public-private partnership, including a broad-based consortium to address industry wide needs (e.g., ESP and COL process development and improvement) as well as design-specific consortia dealing with DC or design-specific COL matters.

For design-specific consortia, such agreements give authority to the lead industrial organizations (e.g., reactor suppliers) to use the shared funds at the discretion of each consortium and within its procurement procedures, to achieve the mutually agreed-upon objectives of the assigned scope of work. Joint management committees are established, composed of executives representing the government and the industrial cost-sharing organizations, to define the objectives and the overall plan for the effort to which the lead organization must adhere. This avoids overlapping cumbersome procurement and management efforts by both the government and the lead industrial organization.

An approach along these lines is recommended for near-term deployment activities.

4.5.4 Other Mechanisms for Government Financial Support

Along with cost sharing of generic or plant-specific activities, the Government can provide effective and appropriate financial support to nuclear plant near term deployment activities, consistent with the national importance of continuing reliance on nuclear energy. These include:

Tax and other incentive arrangements:

The Federal Government routinely establishes financial incentives – typically in the form of investment tax credits – to encourage private sector investment in areas considered important to the national interest. Examples in the energy sector are tax credits for generating systems utilizing renewable fuels and for non-emitting technologies. Actions that serve to make possible continued and expanded reliance on safe, clean nuclear energy clearly merit such incentive treatment, particularly in light of the deregulated electricity marketplace that effectively discourages such investment. Other tax-related approaches that should be considered are accelerated depreciation, access to tax-exempt state government financing, and encouragement of long-term power purchase agreements.

Government support to the energy industries should maintain a reasonably "level playing field". In a deregulated marketplace, inequitable support – for example, higher tax credits for avoided emissions to some kinds of electricity producers than to others – creates a cost penalty that can aggravate the already difficult challenge of achieving economic competitiveness.

As a general principle, incentives for new nuclear plants should be equivalent to comparable incentives elsewhere in the energy industry. For example, incentives for major capital investments in the oil and gas industry, or for coal generation would be appropriate for new nuclear energy plants. Similarly, incentives in place to encourage renewable energy sources are a good model for non-emitting nuclear energy.

Risk Management Support

The next nuclear plants to be built will be, in effect, first-of-a-kind ventures, both in terms of the detailed plant design (certified, but never built) and the regulatory process (10CFR52, in place for years but never used for an actual construction process). Inevitably, first-of-a-kind projects involve some level of programmatic risk and uncertainty.

These financial risks represent an obstacle to any commercial entity seriously considering such an approach. The Federal Government could choose to augment the above tax-based incentives with additional measures to encourage nuclear plant construction. These more aggressive steps might be offered on a temporary basis to get initial plants built, then diminished as experience allows. Such augmented incentives might include reduction of business risk by providing loan guarantees for a portion of the private investment, to cover overruns or delays that may result from the implementation of new licensing processes.

4.6 Alternate Scenarios and Contingencies

It is quite possible that future unanticipated events or circumstances could dictate changes in priorities or approaches to energy planning in the U.S., including changes to the preferred approach to near term deployment. For example, the recent attack on the USA by terrorists and the subsequent war on terrorism could place energy resources in the Middle East at risk.

An energy crisis, brought about by problems in the Middle East or elsewhere, could stress the nation's fossil energy resources and create increased pressure to achieve greater energy independence and a higher level of electrification of our commercial, industrial, and transportation infrastructure. Under such circumstances, the nation would probably shift to higher reliance on electricity and natural gas in the transportation sector, and place greater reliance on coal and nuclear energy for power generation. To accelerate such a change in energy strategy, the federal government might take action to encourage attendant actions (such as new plant installations) on an accelerated schedule.

Similarly, other scenarios could alter the implementation strategy for new nuclear plants. These might include higher than anticipated fossil fuel prices, severe delays in NRC licensing of new designs, major shifts in national or global economic conditions, significant changes in direction regarding economic deregulation of electricity, and greater prominence of health and safety issues related to fossil fuel consumption. Each of these would present challenges to a national nuclear energy strategy and could dictate more rapid action to build new nuclear plants.

If there were a need for accelerated nuclear energy plant construction, several actions are possible. The NRC could accelerate the licensing process as much as possible, consistent with safety requirements. Investment incentives would focus on rapid market response. Design choices for new plants would trend more toward proven technology and choices with very high assurance of rapid deployment and minimum chance of project delays. In such situations, it is likely that designs that are already certified or are near completion of NRC certification would be chosen for installation. It is also likely that existing nuclear sites would be preferred for new plant siting, particularly those previously evaluated for the addition of one or more nuclear plants.

Under such urgent circumstances, and with special treatment, new nuclear plants could be deployed on the shortest possible time frame. Achievable deployment dates would depend primarily on when such a national need was identified.

5 Summary Conclusions and Recommendations

5.1 Conclusions

The following is a summary of the most significant conclusions drawn by the NTDG in the course of their assessment, and as described in this report:

1. New nuclear plants can be deployed in the U.S. in this decade, provided that there is sufficient and timely private-sector financial investment.

2. To have any new nuclear plants operating in the U.S. by 2010, it will be necessary for generating companies to commit to new plant orders by the end of 2003, in order to proceed with preparation of COL applications. This will require very near term action by prospective new plant owner/operators and strong support from the government.

3. Although conditions are currently more favorable for new nuclear plants than in many years, economic competitiveness in a deregulated electricity supply structure remains a key area of uncertainty with respect to near term deployment potential. The other gaps to near term deployment require attention; in particular, implementing an efficient and effective regulatory approval process for siting and licensing of new plants is an urgent matter, and will require use of new processes in 10 CFR Part 52, that have not been demonstrated in actual practice.

4. There are excellent new nuclear plant candidates that build on the experience of existing reactors in the U.S. and around the world, and that could be deployed in the U.S. in this decade. Readiness for deployment varies from design to design, based primarily on degree of design completion and status of regulatory approval. Those that are the most advanced in terms of design completion and approval status appear to be economically competitive in some scenarios, but not all. Other new nuclear plant designs, which still require licensing and engineering, show promise for improved economic competitiveness.

   The design-specific gaps that must be overcome by the gas-cooled candidates to achieve near term deployment are somewhat greater than those facing most of the water-cooled candidates.

5. Achieving near term deployment will require continuing close collaboration between government and industry. Selections of new projects must be market-driven and supported primarily by private sector investment, but government support is essential, in the form of leadership, effective policy, efficient regulatory approvals, and cost sharing of generic and one-time costs.

5.2 Recommendations

1. **Implement the phased strategy for new nuclear plants, by means of industry/ government collaboration on generic and plant-specific initiatives**
This recommendation comprises three time-staggered phases, as follows:

1a. Demonstrate and refine the 10CFR52 process

Objective: Resolve the uncertainties regarding the new plant regulatory approval process through actual use, and secure regulatory approval for several reactor design and siting applications on a time scale that will support plant deployments in this decade.

Action: Develop generic guidelines for ESP, COL and ITAAC verification, and proceed with a series of industry/government cost shared generic, site and/or design-specific initiatives including:

- Early site permit (ESP) applications,
- Applications for reactor design certifications (or FDAs for gas reactors),
- Combined construction and operating license (COL) applications,
- Continuing development of a risk-informed, performance based regulatory framework.

These are all Phase1 activities, as defined in Section 4. Only those initiatives capable of obtaining sufficient private sector funding support to complete the initiative, assuming DOE cost sharing, should proceed.

Responsibility: NEI, NRC, DOE and applicants.

Timing: 2002 – 2006. The schedule for each Phase 1 activity will be dictated by the overall objective of new plant deployment by 2010. Although individual timeline requirements will vary for different sites and reactor designs, much of this work is on the critical path to deployment and it is therefore important that Phase I work commence in year 2002 or early 2003. Based on the timeline constraints discussed in Section 2 the bulk of Phase I work must be complete by 2006. The exception is the new plant regulatory framework, which can proceed as a continuing, parallel activity.

1b. Complete design of several near term deployment candidates

Objective: Ensure that the detailed engineering and design work for at least one light water and at least one gas-cooled reactor is completed in time to allow start of plant construction on a schedule that could achieve deployment by 2010.

Actions: Proceed with Phase II work as follows:

ALWR Track: Industry / government cost share for at least one market-selected initiative for the engineering, testing and design, to the degree that permits plant order and construction.

Gas Reactor Track: Industry / government cost share for at least one market-selected initiative for the engineering, testing and design, to the degree that permits plant order and construction.

Note: only those initiatives that secure private sector funding support sufficient to complete the work, assuming DOE cost sharing, should proceed.

Responsibility: DOE and applicants.

Timing: 2003-2007. In order to support deployment by 2010, Phase 2 work must be complete for both the ALWR and gas reactor tracks by 2007. Earlier completion may be possible for some design options.

1c. Construct and start up new plants

Objective: Complete construction and deploy multiple commercially viable new nuclear plants by 2010.

Action: When regulatory approvals and design work are in place, proceed with plant construction work and associated activities. This work should be privately funded, but supported by government incentives as discussed in Section 4.

For ALWR(s), this could entail conventional and fully commercial construction project approaches. For gas-cooled reactor(s), this action may involve evaluation, and potentially implementation of a demonstration project, perhaps at a federal facility.

Responsibility: Owner/operators of new plants, with government involvement as necessary.

Timing: 2005 – 2010

2. Put in place appropriate government financial incentives for privately funded new plant licensing, design and construction projects.

Objective: Assist prospective owners/investors in dealing with the financial challenges and risks of the deregulated electricity marketplace.

Action: Identify and implement actions by the federal and state governments to reduce the risks associated with private sector investment in capital-intensive new nuclear plants. These could include accelerated depreciation; investment tax credits; access to tax-exempt state government financing; negotiated long-term power purchase agreements; and, federal and state tax incentives for diversity in fuel supply and/or emission-free generation.

Responsibility: DOE should take the lead in formulating and proposing the appropriate government actions, with support from industry via NEI.
The Administration, and the Congress to implement, as appropriate.

Timing: 2002-2003

3. Conduct an assessment of nuclear industry infrastructure.

Objective: Determine the key areas of infrastructure weakness and the actions needed to accommodate them.

Action: Assemble a team comprising experts from industry, government and academia to assess methodically and quantitatively the various elements of infrastructure that could affect design, construction and operation of new nuclear plants in this decade, and to identify solutions to adverse conditions.

Responsibility: NEI leadership, with DOE participation and support.

Timing: 2002

4. Develop a National Nuclear Energy Strategy for implementation of the National Energy Policy.

Objective: To fulfill the vision for nuclear power articulated in the National Energy Policy

Action: Put in place a comprehensive strategy for industry and government, with priorities and action plans. The Strategy should:

- Clearly explain why our national security, economic strength, and environmental quality require – and will benefit from – greater reliance on nuclear energy.
- Commit the federal government to embracing the nuclear energy industry's Vision 2020, which has as its goal the addition of 50,000 MWe of new nuclear generation by 2020.
- In the near term, commit the federal government to a nuclear energy supply R&D investment strategy that is in balance with that for other energy supply options.
- Reaffirm the commitment of the Administration to expedite applications for new plants through the NRC, consistent with safety regulations, as called for in the National Energy Policy.
- Commit DOE to enter into market-driven, public-private partnerships to execute those new plant initiatives that garner the necessary industry support for cost sharing with DOE.
- Commit DOE to undertake a stronger leadership role in forging a consensus among the relevant DOE Offices, scientific and energy policy leaders, and government contractors, toward an integrated and effective national policy on nuclear fuel cycle issues, focused initially on establishing centralized used fuel management.
- Develop a plan of action to expand this Vision 2020 milestone to greater reliance on nuclear energy in the 2030 to 2050 timeframe, based on further advances in nuclear technology, developed under DOE leadership in partnership with industry.
- Seek broad support from Congress for a national nuclear energy strategy.

Responsibility: DOE, with input and support from the industry

Timing: 2002

5.3 Closing the Gaps

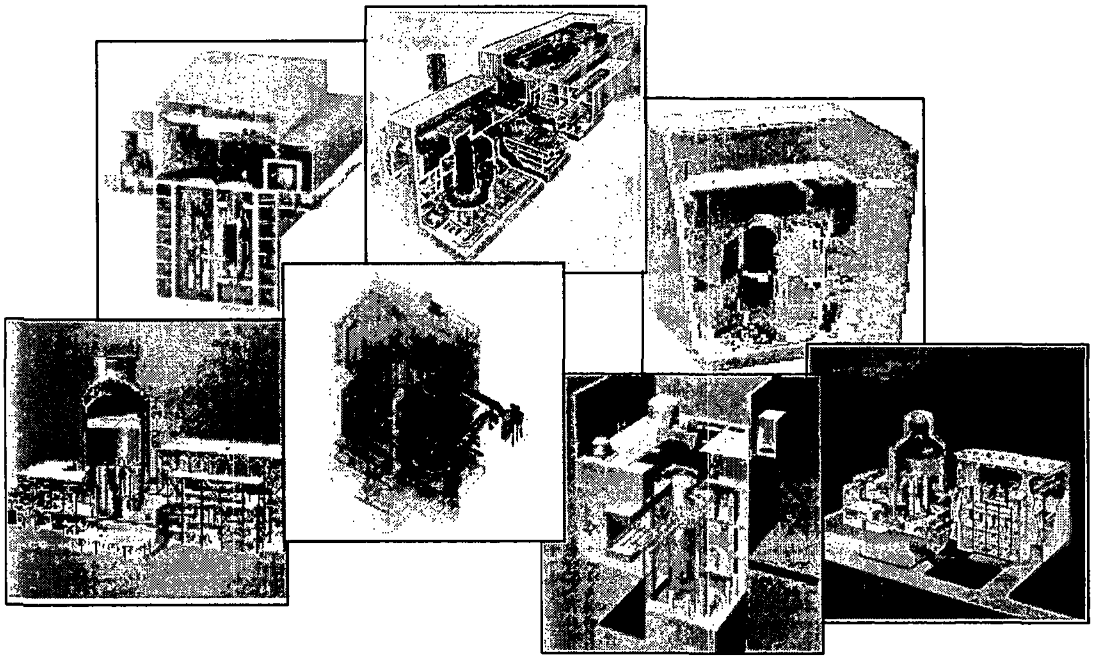
The NTDG recommendations discussed above address all of the key gaps identified in Section 2 of this report. The linkage between recommendations and gap closure is shown graphically as follows:

Recommendations		Gaps				
		Economic Competitiveness	Deregulated Marketplace	10CFR52 Implementation	Industry Infrastructure	National Nuclear Energy Strategy
1a	Phase 1: Regulatory Approvals	X		X		
1b	Phase 2: Design Completion	X		X		
1c	Phase 3: Plant Construction	X	X			
2.	Government Financial Incentives	X		X		
3.	Infrastructure Assessment		X		X	
4.	National Nuclear Energy Strategy	X	X	X	X	X

In each case, the symbol "X" indicates that the recommended action could address the identified gap in a meaningful way.

A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010

Volume II
Main Report



Prepared for the

United States Department of Energy
Office of Nuclear Energy, Science and Technology

and its

Nuclear Energy Research Advisory Committee
Subcommittee on Generation IV Technology Planning

October 31, 2001

Disclaimer

NEAR TERM DEPLOYMENT GROUP MEMBERSHIP

Tony McConnell (Co-Chairman)
Vice President Engineering Services
Duke Engineering & Services

Louis Long (Co-Chairman)
Vice President Technical Services
Southern Company

Eric Beckjord
Consultant

Jeffrey Binder
Argonne National Laboratory

Shem Blackley
Consultant

Chaim Braun
Altos Management Inc.

George Davis
Westinghouse

Edward Klevans
Pennsylvania State University

Malcolm LaBar
General Atomics

Atambir Rao
General Electric - Nuclear Energy

Thomas Roberts
Exelon Corporation

John Taylor
Nuclear Energy Research Advisory Committee

Gary Vine
Electric Power Research Institute

DOE POINT OF CONTACT

Tom Miller
Director, Advanced Research Programs
Office of Nuclear Energy, Science and Technology

GEN IV ROADMAP NERAC SUBCOMMITTEE (GRNS) REPRESENTATIVES

Bobby Abrams
Duke Engineering & Services

Doug Chapin
MPR Associates

GEN IV TECHNICAL WORKING GROUP (TWG) LIAISON

Jack DeVine (LWR TWG Chairman)
Polestar Inc.

Phil Hildebrandt (Gas-Cooled TWG Chairman)
EMT Inc.

NTDG SUPPORT

Marty Martinez
JUPITER Corporation

Raymond Reith
Idaho National Engineering Laboratory

Table of Contents

II-1: INTRODUCTION 1-1
Objective 1-1
Context and Scope 1-1
Current Situation 1-2
Roadmap Development and Interfaces 1-3
Roadmap Organization 1-5
II-2: BACKGROUND 2-1
Background Topics 2-1
U.S. Energy and Environmental Needs; Role of Nuclear Energy 2-1
Industry and DOE Nuclear Energy Initiatives 2-4
Readiness of Nuclear Energy to Contribute to New Generation 2-10
Background on Regulatory Processes 2-18
II-3: GENERIC GAP ANALYSIS 3-1
Key Near Term Deployment "Gaps" 3-1
Key Near Term Deployment "Issues" 3-7
Other Issues 3-10
Generic Gap Analyses 3-12
II-4: NTDG ECONOMIC ANALYSIS 4-1
Overview: The New Electricity Marketplace 4-1
Deregulated Electricity Supply – The New Marketplace 4-3
Nuclear Plant Realities 4-8
A Model for Nuclear Plant Competitiveness – Numerical Results 4-16
Key Factors Affecting Nuclear Plant Competitiveness 4-29
Special Cases 4-33
Summary 4-36
II-5: DESIGN OPTION EVALUATIONS 5-1
Introduction 5-1
GE/NE ABWR DESIGN 5-3
A. Criteria Evaluation 5-3
B. Gap Analysis 5-8
C. Overall Assessment 5-9
GE/NE ESBWR DESIGN 5-11
A. Criteria Evaluation 5-11
B. Gap Analysis 5-17
C. Overall Assessment 5-18
FRAMATOME ANP SWR-1000 DESIGN 5-21
A. Criteria Evaluation 5-21
B. Gap Analysis 5-28
C. Overall Assessment 5-29
WESTINGHOUSE AP1000/600 DESIGNS 5-32
A1. Criteria Evaluation: AP1000 5-33
A2. Criteria Evaluation: AP600 5-44
B. Gap Analysis for AP1000 and AP600 5-47

C. Overall Assessment: AP1000 and AP600 5-52
WESTINGHOUSE IRIS DESIGN 5-59
A. Criteria Evaluation 5-59
B. Gap Analysis 5-62
C. Overall Assessment 5-66
PBMR PTY. PBMR DESIGN 5-69
A. Criteria Evaluation 5-70
B. Gap Analysis 5-79
C. Overall Assessment 5-81
GENERAL ATOMICS GT-MHR DESIGN 5-84
A. Criteria Evaluation 5-84
B. Gap Analysis 5-94
C. Overall Assessment 5-97
II-6: Conclusions and RECOMMENDATIONS 6-1
Conclusions 6-1
Recommendations 6-1
Generic Gap Recommendations 6-2
Design-Specific Recommendations: Need for a Dual-Track Strategy 6-9
Recommendations for a Phased Action Plan 6-10
Public-Private Partnerships: Implementing a Market-Driven Approach 6-16
DESCRIPTION OF APPENDICES AND ATTACHMENTS 1
Appendix A: Design Description, Advanced Boiling Water Reactor (ABWR) A-1
Appendix B: Design Description, ESBWR B-1
Appendix C: Design Description, SWR 1000 .... C-1
Appendix D: Design Description, AP 1000 .... D-1
Appendix E: Design Description, AP 600 .... E-1
Appendix F: Design Description, International Reactor Innovative And Secure (IRIS) F-1
Appendix G: Design Description, Pebble Bed Modular Reactor (PBMR) G-1
Appendix H: Design Description, Gas Turbine Modular Helium Reactor (GT-MHR) H-1
Appendix I: Cost Sharing Rationale I-1
Appendix J: Near Term Deployment Roadmap Resource Needs J-1
Appendix K: Background And Source Documents K-1
Appendix L: References L-1
Appendix M: Acronyms M-1
Attachment 1: Mission of the Near-Term Deployment Group 1
Attachment 2: NTD Request For Information 1
Attachment 3: Nuclear Energy Institute's Vision 2020 1
Attachment 4: NEI's Integrated Plan for New Nuclear Plants 1

II-1: INTRODUCTION

OBJECTIVE

The objective of this document is to provide the Department of Energy (DOE) and the nuclear industry with the basis for a plan to ensure the availability of near-term nuclear energy options that can be in operation in the U.S. by 2010. This document identifies the technological, regulatory, and institutional gaps and issues that need to be addressed for new nuclear plants to be deployed in the U.S. in this timeframe. It also identifies specific designs that could be deployed by 2010, along with the actions and resource requirements that are needed to ensure their availability. This near-term roadmap will also serve as input for a longer term and broader scope Generation IV Nuclear Technology Roadmap being prepared by DOE, as discussed below.

In order to meet this objective, at least one competitive nuclear energy generation option, NRC-certified and/or ready to construct, must be available for order by late 2003. Further, this Roadmap presents a plan to make available by 2010 a range of competitive, NRC-certified and/or ready to construct nuclear energy generation options of a range of sizes to meet variations in market need, in order to have multiple new plants on line by the end of the decade.

CONTEXT AND SCOPE

DOE's Office of Nuclear Energy, Science and Technology with the advice of the Generation IV Roadmap Nuclear Energy Research Advisory Committee (NERAC) Subcommittee (GRNS), is developing a Nuclear Technology Roadmap for a long-term vision for nuclear energy for 2030 and beyond. The Generation IV Nuclear Technology Roadmap is focused on long-term, broad-scope objectives, including a wide range of technology options and applications and electricity generation missions. It is intended to engage and guide international cooperation in nuclear R&D, and will serve global as well as domestic markets.

In order to cope with near term needs for nuclear energy in the U.S., DOE has organized a Near Term Deployment Group (NTDG) (see Attachment 1, NTDG Mission). This group works cooperatively with the Generation IV program, and was tasked to develop a Near Term Deployment Roadmap ("NTD Roadmap") that will complement the longer term Generation IV Roadmap. The NTDG consists of 13 experts from the owner/operator, vendor, academic, and national laboratory communities, and reports directly to the DOE NTDG Manager and the GRNS. It maintains a dotted-line relationship with the Nuclear Energy Institute (NEI) Executive Task Force on New Nuclear Power Plants, assuring close cooperation with ongoing industry activities.

This NTD Roadmap proposes a strategy to enable deployment of new nuclear power plants by 2010 that could substantially resolve the growing energy supply deficit in the U.S. and provide for an appropriate and secure energy mix that will help achieve Clean Air Act requirements and reduce greenhouse gas production – without negatively impacting the U.S. economy. This Roadmap outlines the near term actions and resource requirements needed to support such a strategy. The scope of this Roadmap does not include consideration of the reactivation of old nuclear construction projects (i.e., completion of partially built plants), although it is recognized that such efforts, if found to be cost-effective, could provide additional nuclear generation and help reinvigorate various elements of nuclear industrial infrastructure.

CURRENT SITUATION

The U.S. depends on energy supply to maintain its economic strength and competitive position in the global economy. Americans have come to expect reliable, inexpensive, and environmentally friendly electricity. However, too little baseload capacity has been added over the last 1-2 decades, creating situations of inadequate supply (as in California) and the potential for escalating energy costs, which could seriously damage our economy. Addressing our strategic energy needs is an urgent matter, with clear and direct implications to our nation's security and economic strength, to our global competitiveness, and to worldwide environmental quality. Both aggressive conservation and new supplies must be pursued.

Existing nuclear plants are a major source of safe, clean, economical, and reliable electricity in the U.S and around the world. Nuclear energy provides this nation with 20 percent of its electricity, second only to coal, and provides 17 percent of the world's electricity. However, no new nuclear plant orders have been executed in the U.S. since 1979. Key factors that existed in the 1980s contributed to this situation:

- Coal and nuclear baseload generation construction in the 1970s and 1980s exceeded power needs. Over capacity reached 35 percent. The oil embargo and energy crises of the 1970s contributed to an economic downturn and high interest rates that drove up the construction costs of projects underway, and made new investment in major capital projects (e.g., coal and nuclear plants) prohibitive.
- An unstable licensing process at the NRC discouraged new plant construction.
- Institutional barriers related to lack of public support for expanded use of nuclear energy arose from reactions to the accident at TMI-2, and a lack of an assured means of disposing of spent nuclear fuel.
- Marginal performance by many operating nuclear plants caused extended shutdowns, low capacity factors, and rising operations and maintenance costs.

DOE and the industry saw a need in the 1980s for addressing performance issues at existing nuclear plants, and for maintaining the option to build new plants in the future. First and foremost, industry undertook a major and necessary effort to improve the performance of its current plants, assisted by the Institute of Nuclear Power Operations (INPO). That effort was vital to improved safety, NRC confidence in industry's capability and commitment, and the economic viability of nuclear utilities. It was a necessary prerequisite to building new plants.

DOE and industry then embarked on a joint program to enable a nuclear power option in the U.S. The Advanced Light Water Reactor (ALWR) Program ran from the mid 1980s to the late 1990s. It was funded on an industry/DOE cost-shared basis to conduct project specific engineering for four advanced designs, and addressed the institutional issues above. It placed a priority on standardization of designs and processes, and on establishing utility design requirements for future designs.

During this period, Congress and the Nuclear Regulatory Commission (NRC) improved the licensing process for new plants. They implemented a new regulation, 10 CFR Part 52, which provided an improved process for early site permitting, standardized design certification, and combined construction and operating license approval that increased public involvement in the early stages of the process, and improved the stability of the process as new plant projects approached completion. Ultimately, the NRC "certified" three standardized designs for construction in the U.S.: the General Electric Advanced Boiling Water Reactor (ABWR), the Combustion Engineering System 80+, and the Westinghouse AP600. (BNFL and Westinghouse have subsequently acquired Combustion Engineering.)

These three certified designs form an important foundation for near term deployment in the U.S. However, because of the deregulation of electricity generation in the late 1990s, and concurrent rapid growth in small natural gas-fired generating units that were well suited to this uncertain market environment, larger new baseload plants have not been built. Today, the need for new baseload plants (i.e., coal and nuclear plants) is becoming apparent. Both face economic challenges because of their size and cost. However, analyses by the Energy Information Agency (EIA) operated by DOE and by the industry show that nuclear energy could generate electricity at a competitive cost in the U.S.

DOE and industry agree that a parallel strategy is needed to address the need for new nuclear generation. This parallel strategy should consist of two elements:

1. Near term options with a demonstrable capability for deployment by 2010, consisting of certified ALWRs, enhanced ALWRs, and near term Generation IV options, and which can achieve clear economic competitiveness. This element is the subject of this Roadmap.
2. Longer term options that have the potential for major enhancements. These are under the purview of the DOE Generation IV Program.

This parallel strategy is embodied in both DOE's "Long Term Nuclear Technology R&D Plan" (June 2000) and EPRI's "Electricity Technology Roadmap, Volume II: Energy Supply" (January 1999). Both elements emphasize enhanced safety, reliability, standardization, and assured licensability, in addition to improved economics. Both elements will meet the regulatory requirements of the NRC and high-level goals set by industry for ALWRs in the early 1990s, and both are expected to substantially meet the new goals being established by the GRNS and DOE.

<u>The conclusions and recommendations of this report center on overcoming two primary obstacles to near term deployment: validating the new regulatory processes for approving the siting, construction, and operation of new plants, and assuring the economic competitiveness of deployable designs. Many other gaps and issues are addressed, but these two are paramount to success.</u>

<u>ROADMAP DEVELOPMENT AND INTERFACES</u>

The NTDG issued an interim work product in May 2001, to respond to an urgent need for an immediate assessment of near term (FY2002/2003) funding needs, prior to completion of the

NTD Roadmap. That report was made available to the Administration and Congress, and has been incorporated into this final NTD Roadmap.

In order to develop this Roadmap, the NTDG solicited and assessed non-proprietary design-specific information from potential suppliers and/or potential customers of reactor technologies that meet the screening criteria listed below. The NTDG issued a Request For Information (RFI) on 31 March 2001 (see Attachment 2), requesting information on how each candidate technology meets each of the noted criteria, what specific technological and institutional gaps exists which must be addressed to allow successful commercialization of the technology, and the cost, schedule and deliverables that would be required. Eight nuclear plant designs were submitted to the NTDG for assessment.

Screening Criteria

The NTD Roadmap evaluates eight designs against six specific screening criteria for near term deployment, as specified by the GRNS. These criteria are:

1. Credible plan for gaining regulatory acceptance - Candidate technologies must show how they will be able to receive either a construction permit for a demonstration plant or a design certification by the U.S. Nuclear Regulatory Commission (NRC) within the time frame required to permit plant operation by 2010 or earlier.
2. Existence of industrial infrastructure - Candidate technologies must be able to demonstrate that a credible set of component suppliers and engineering resources exist today, or a credible plan exists to assemble them, which would have the ability and the desire to supply the technology to a commercial market in the time frame leading to plant operation by 2010 or earlier.
3. Credible plan for commercialization - A credible plan must be prepared which clearly shows how the technology would be commercialized by 2010 or earlier, including market projections, supplier arrangements, fuel supply arrangements and industrial manufacturing capacity.
4. Cost sharing between industry and Government - Technology plans must include a clear delineation of the cost categories to be funded by Government and the categories to be funded by private industry. The private/government funding split for each of these categories must be shown along with rationale for the proposed split.
5. Demonstration of economic competitiveness - The economic competitiveness of candidate technologies must be clearly demonstrable. The expected all-in cost of power produced is to be determined and compared to existing competing technologies along with all relevant assumptions.
6. Reliance on existing fuel cycle industrial structure - Candidate technologies must show how they will operate within credible fuel cycle industrial structures, i.e., they must utilize a once-through fuel cycle with low enriched uranium (LEU) fuel and demonstrate the existence of, or a credible plan for, an industrial infrastructure to supply the fuel being proposed.

Coordination with Longer Range Generation IV Roadmap

Both the initial work product (FY2002/2003 Action Paper) and this NTD Roadmap have been coordinated with the longer term Generation IV Roadmap currently under development. These are complementary efforts. The NTD Roadmap has carefully limited its consideration to only those reactor design options that have clear potential to be operational by 2010. Equal discipline has been applied to the identification of technical and institutional gaps in these near-term design options, leaving longer-term issues (e.g., global sustainability, advanced fuel cycles, new technologies to enhance proliferation resistance and better manage nuclear waste), to the Generation IV Roadmap. Hence, this NTD Roadmap has not attempted to identify long-term research needs. It does identify short term R&D, as needed to close gaps, and related technical and programmatic resource needs (i.e., one-time costs) relevant to near term deployment that would be cost-shared between industry and Government.

The NTDG works closely with other Working Groups in the broader Generation IV program to share information, exchange information and conclusions; and to ensure NTDG work products are useful as an input to the longer-term Roadmap development.

Coordination with Industry

The NTDG coordinates its efforts with those of the Nuclear Energy Institute (NEI) Executive Task Force on New Nuclear Power Plants, assuring close cooperation with ongoing industry activities. This interaction has helped the NTDG develop a practical and appropriate plan for division of resources and responsibilities between DOE and industry. In general, most of the near term needs can be met through public/private partnership.

ROADMAP ORGANIZATION

This Roadmap consists of two parts, a "Summary Report" (Volume I) and this "NTD Roadmap" (Volume II). The NTD Roadmap is organized as follows:

Chapter II-1: Introduction
This Chapter provides the objective of this Roadmap, its context and scope as it relates to the current energy situation in the U.S., and a summary of the organization of the NTD Roadmap.

Chapter II-2: Background
Additional detail is given on the national energy situation, role of nuclear power, history of DOE and industry programs in support of new plants (including the ALWR program), and the Generation IV initiative. Detail is also provided on regulatory issues.

Chapter II-3: Generic Gap Evaluations
The generic gaps and issues are identified, along with solutions and resource requirements to close these gaps.

Chapter II-4: NTDG Economic Analysis
The conditions of the de-regulated electricity generation market are reviewed and the economics of future plants assessed.

Chapter II-5: Design Option Evaluations
Each design is evaluated including:

- Criteria assessments
- Design-specific gap and gap-closure analyses
- Overall assessment, including the timelines for deployment

Chapter II-6: Conclusions and Recommendations
This section provides an integrated/consolidated summary of key recommendations to close the design-specific and generic gaps. It also provides the basis for the recommendations in the Executive Summary of Volume I. This Chapter includes a separate set of strategic recommendations for accelerating new plant deployment via market-driven initiatives, primarily based on public-private partnerships. Finally, this section refers to recommendations for R&D and project-specific funding, based on a funding table (Appendix J), specifying all site-specific, generic, and design-specific funding requirements for all designs that NTDG judges should be candidates for industry-Government cost sharing for near term deployment.

Appendices:

A. Design Description, Advanced Boiling Water Reactor (ABWR)
B. Design Description, ESBWR
C. Design Description, SWR 1000
D. Design Description, AP 1000
E. Design Description, AP 600
F. Design Description, International Reactor Innovative and Secure (IRIS)
G. Design Description, Pebble Bed Modular Reactor (PBMR)
H. Design Description, Gas Turbine Modular Helium Reactor (GT-MHR)
I. Cost Sharing Rationale
J. Near Term Deployment Roadmap Resource Needs
K. Background and Source Documents
L. Reference List
M. Acronyms

Attachments:

1. Near Term Deployment Group Mission
2. Near Term Deployment Group Request for Information
3. NEI's "Vision 2020" – Strategic Objectives for Nuclear Energy's Future
4. NEI's "Integrated Plan for New Nuclear Plants"

II-2: BACKGROUND

BACKGROUND TOPICS

The purpose of this Background Chapter is to explain why a success oriented strategy for near term deployment of new nuclear energy plants is necessary and how it fits into a national energy policy. It will provide a perspective on the following four key issues:

1. The nation's energy and environmental needs that justifies this near term goal, and role of nuclear energy
2. The initiatives that DOE and industry have pursued to enable new nuclear plant orders in the U.S.
3. The readiness of nuclear energy to contribute to meeting the nation's energy supply needs
4. The key regulatory processes that are critical steps in the deployment of new nuclear plants

The authors of this report have concluded that a strong need exists for near term deployment of new nuclear power plants in the U.S. Hence, this Roadmap establishes a process and success-oriented strategy committed to reaching this goal. The NTDG has identified the technological and institutional gaps which must be addressed to allow successful commercialization of the near term deployment technologies, and the cost, schedule and deliverables that would be required. The NTDG has attempted to develop rather complete estimates of the resources (schedule and funding levels) required to close the gaps in time to meet the 2010 deployment goal. The intent of this effort has been to identify those actions and recommendations that are necessary and sufficient to deploying multiple nuclear power plants in the U.S. by the end of this decade.

U.S. ENERGY AND ENVIRONMENTAL NEEDS; ROLE OF NUCLEAR ENERGY

There is a growing consensus that the U.S. needs a balanced energy policy that both encourages conservation and adds new energy supply. Too little baseload capacity has been added over the last 1-2 decades, creating situations of inadequate supply (as in California) and the potential for escalating energy costs, which could seriously damage our economy. Further, fossil fuel price uncertainty and fossil fuel environmental impacts, including clean air considerations and the potential for global warming, are creating a renewed pressure to deploy alternative energy sources that are non-emitting, such as renewable energy and nuclear energy. Finally, recent events emphasize the need for stable and reliable domestic energy sources and for fuel diversity, so that dependence on imported energy can be reduced.

There are a total of 103 nuclear reactor units or plants operating at 65 sites in the U.S. today. Virtually all of these 103 U.S. nuclear plants will apply for a 20-year license renewal to help meet these energy demands. Increased environmental controls and potential fuel supply problems continue to put pressure on fossil energy costs. Renewable energy continues to find it difficult to make a sufficiently reliable and economic contribution to our national electricity supply. Hydropower can be relicensed in some situations, but significant growth in hydropower is unlikely. With energy demand growing and no easy answers, U.S. national energy policy must embrace a balanced portfolio of supply options that includes increased use of safe, reliable, and emission-free nuclear energy. Energy conservation is very important, but increasing demand cannot be met by conservation alone.

Power reliability is becoming an extremely important consideration in the digital economy, and is increasingly becoming a factor in deciding where to site new businesses that require extremely high reliability – upwards of "six nines." Reliable baseload generation is the foundation for high reliability, backed up by distributed sources and emergency generators.

Large amounts of bulk power are needed to power our major cities and industrial areas. Mass transit is necessary to mitigate air quality impacts, including increased greenhouse gas emissions, from carbon-based mobile sources. Other environmental protection systems, such as wastewater treatment and water purification, also require bulk electricity to serve the large, urban populations where 80 percent of Americans now live—not to mention to help meet electrical demands of a concentrated population. Nuclear plants offer an advantage to regions of the country with growing requirements for large amounts of bulk power.

Addressing our strategic energy needs has direct implications to our nation's security and economic strength, to our global competitiveness, and to worldwide environmental quality. The need to build new nuclear plants is being discussed in the U.S., as well as in other countries. However, bringing new nuclear plant technologies to the marketplace is challenging – there are significant uncertainties associated with the complex regulatory and financing processes, which impact cost and schedule.

Electricity Supply in the U.S. and Nuclear's Contribution

U.S. electricity demand grew by 2.2 percent a year on average during the 1990s, and increased by 2.6 percent in 2000. Even if demand grows by a modest 1.8 percent annually over the next two decades—as forecasted by the U.S. Energy Information Administration—the nation will need nearly 400,000 megawatts of new electric generating capacity, including replacement of power plants that will close during that time. This capacity is the equivalent of building about 800 new mid-size (500-megawatt) power plants—or 40 new plants every year for the next 20 years. At 2.5 percent annual growth, which is closer to the growth rates experienced during the 1990s, the United States will require an additional 564,000 megawatts to meet new electricity demand and replace aging power plants that have reached the end of their useful life.

In California, shortages of electric generating capacity and rising natural gas prices have contributed to skyrocketing consumer electricity rates, the bankruptcy of one major electric company, and blackouts affecting millions of people and thousands of businesses—all at a cost of billions of dollars. California provides a vivid example of the societal impacts of failing to add new generation and transmission capacity, as well as the societal impacts of fossil fuel price volatility when capacity margins are thin. Similar electricity shortages are forecasted for other regions of the country during the next few years.

An historic contributor to U.S. economic strength has been its abundant and diverse energy supplies, resulting primarily from ample domestic supplies of a mix of competing fuels for generating electricity. A healthy economy requires stable, low cost, and reliable electricity, and adequate reserve margins. These features are more difficult to achieve and maintain in a deregulated electricity marketplace. Federal and State Governments have concluded correctly that deregulation will benefit electricity consumers in the long run, but Government must assume greater responsibility, through market incentives, to ensure adequate reserve margins.

Nuclear energy is the second largest source of electricity in the United States, providing 20 percent of the nation's electricity, and our largest source of emission-free electricity generation, providing 70 percent of electricity in that category. License renewal of the nation's 103 operating nuclear plants is critical to maintaining this contribution to energy supply over the next two decades. But where will new capacity come from? Economic and environmental considerations will be key factors in new capacity decisions.

Environmental Issues and Nuclear Energy's Role in Emission Avoidance

Nuclear energy has been a major component of achieving domestic air quality goals for over three decades. Between 1973 and 1999, nuclear plants avoided the emission of 32 million tons of nitrogen oxide, 62 million tons of sulfur dioxide and 2.6 billion tons of carbon. During this period, making electricity in nuclear plants avoided more tons of nitrogen oxide (NOX) than were eliminated through fossil plant controls under the Clean Air Act. In 2000 alone, nuclear plants avoided more than 4 million tons of sulfur dioxide (SO_2), nearly 2 million tons of NOX, and 174 million metric tons of carbon equivalent. In the absence of current nuclear production, the difference between current U.S. greenhouse gas emission levels and our 1990 baseline established in the Framework Convention on Climate Change would double.

Future efforts to control greenhouse gases will require continued investment in emission-free technologies of all kinds, but particularly nuclear plants because of their sizable electric output, minimal environmental impact and siting capability near load demand. The vital role of emission avoidance is evident in the success of voluntary emission reduction programs to date. With approximately half the units reporting so far, nuclear plants are the single largest contributor to voluntary greenhouse gas emission reductions (40 percent of the program) under the Department of Energy's 1605(b) Program established under the 1992 Energy Policy Act.

Electric generating facilities have faced significant emission reduction requirements, especially because large, stationary sources of emissions are easier to regulate than small or mobile sources. But electric generating facilities that prevent air pollution to begin with—such as nuclear power plants—also have played a major role. For example, if the United States were to replace all its nuclear plants with pollution-emitting generation, our nation would have to take 135 million passenger cars off the road to keep carbon emissions from increasing.

Consider the importance of nuclear energy in three eastern states:

- In New Jersey, nuclear power plants accounted for 51 percent of total electricity generation in 1999. They also avoided substantial emissions: 80,000 tons of nitrogen oxide, 160,000 tons of sulfur dioxide and nearly seven million tons of carbon.

- Nuclear energy generated 47 percent of the electricity in Connecticut—avoiding the emission of 30,000 tons of nitrogen oxide, 70,000 tons of sulfur dioxide and nearly 3 million tons of carbon.
- Nuclear energy generated 26 percent of the electricity in New York, avoiding the emission of 110,000 tons of nitrogen oxide, 200,000 tons of sulfur dioxide and 8.5 million tons of carbon.

Many other states face the same issue to varying degrees. These states simply cannot meet the broad spectrum of clean air requirements unless they use nuclear energy for a substantial proportion of their electricity generation.

Also, the cost of NOX allowances – which electricity generators have to buy in order to run in California – increased dramatically through the summer months. Just the increase in the price of NOX allowances increased the price of electricity by $39 a megawatt-hour between May and September, for a typical combined cycle gas-fired plant. Analysis shows that about a fourth of all new gas-fired power plants across the country are proposed for areas that are already classified non-attainment for ozone. So buying NOX allowances is going to become an even more significant cost component nationally.

The benefits to society from emission free and highly reliable nuclear energy are huge. Nuclear energy reduces our dependence on foreign sources of energy fuels, and reduces the demand on precious natural gas resources so critical to transportation and residential sectors, and to a wide range of manufacturing applications. Nuclear energy is good for the overall economy because expanded nuclear capacity allows currently operating coal plants to continue to operate longer, many to end-of-life, within federally mandated emissions limits, giving time to rebuild and modernize the generation infrastructure at a pace that does not drag the economy down. Nuclear energy use in the electricity sector also gives more time to work on environmental and energy solutions in the transportation sector.

Industry and DOE Nuclear Energy Initiatives

In cooperation with DOE, the utility industry, with support from EPRI, initiated the Advanced Light Water Reactor Program in 1983, focused on addressing all the technical obstacles and shortcomings of existing reactor designs. A primary technical objective of the program was to develop designs for future LWRs that were safer, more reliable, easier to operate, and less expensive than existing designs. A vehicle to assure this outcome was the development of the ALWR Utility Requirements Document by senior, experienced utility personnel in the U.S. and overseas that incorporated the lessons learned from decades of worldwide operating experience with LWRs and specifically defined owner-operator needs in light of that experience. In 1990, the nuclear industry issued a "Strategic Plan for Building New Nuclear Power Plants" to guide implementation of the overall program, which was updated annually through the final Strategic Plan in 1998.

This Plan integrated the technical and project-oriented "building blocks" from the DOE-EPRI ALWR program with the institutional and licensing building blocks under the responsibility of NEI. It established an industry-wide commitment to a very high level of standardization of designs and plant processes for all future plants. Replacing this Strategic Plan in 1999 was NEI's "Strategic Direction for Nuclear Energy in the 21st Century", issued annually. One of the strategic "compass points" in this plan focuses on building the next generation of nuclear power plants.

DOE strategic planning documents have consistently supported maintaining a viable nuclear option. DOE-NE has a long history of supporting advanced reactor development. However, its programs to develop high temperature gas reactors and liquid metal reactors were terminated in 1994 and 1995 with much more work left to do. The ALWR program, jointly funded by DOE and industry, had its DOE funding terminated after 1997. Industry completed the unfinished ALWR work scope in 1998.

Despite funding limitations, these industry and DOE efforts resulted in major improvements in currently operating plant performance, an improved licensing process for new plants, and three advanced reactor designs, certified by the NRC in 1996-1998. These three standardized designs conform to U.S. utility requirements established in the early 1990s, and meet or exceed all U.S. safety regulations. They are simpler, safer and more robust designs, developed expressly to provide increased design margins, improved human factors, improved constructibility and maintainability, and improved economics over current plants.

The economic targets established for ALWRs, benchmarked against pulverized coal generating technology, did not account for the deregulation of electricity generation and for the major advances in the economy and performance of gas-fired combined cycle generation. As a result, even though currently operating nuclear plants are now the low cost producers of electricity across the country, ALWRs are currently only marginally economic. Deregulation has made large capital investment in new generating plants even more difficult.

Industry Willingness to Proceed in Partnership with DOE to Build New Plants

A number of factors are combining today to demand options for new nuclear energy plants in the U.S. These demands are both near-term and long-term in nature. Key factors are:

- Growing concerns over the environmental impacts of fossil fuels, including both clean air issues and greenhouse gas issues, resulting in the need for a rapid expansion of non-emitting generation technologies (i.e., nuclear and renewables).
- Continued growth in energy demand and increasing awareness of the need for highly reliable baseload generation to balance the recent over-emphasis on peaking and intermediate capacity in many parts of the country. Even with an economic downturn in the short term, retirements of older fossil plants will nevertheless create a demand for new nuclear plants.
- Volatile natural gas prices and backlogs in gas turbine plant fabrication and construction.
- The inability to date of renewable energy (the only expandable non-emitting generating technology option other than nuclear) to make significant market penetration, despite significant research and development investment.

Although standardized reactor designs developed in the early 1990s were certified recently by the U.S. Nuclear Regulatory Commission (NRC) under 10CFR52, they were designed to meet the needs of a regulated electricity market, in which costs had to be "prudent" and competitive with pulverized coal, the primary baseload alternative of the 1980s and 90s. For the deregulated markets of the new millennium, new nuclear plants must offer total life cycle generating costs (including financial risks) that are at least equal to those of any other alternative, including modern natural gas fired units.

The three certified reactor designs offer safety and reliability improvements over current technology, as well as improved life-cycle economic performance. Certified designs also have the advantage of being ready today – offering both construction schedule and regulatory certainty advantages. However, even with their superior production costs (as evidenced by current nuclear plant economic performance) future plants need to be made even more competitive in terms of their total costs (including capital costs) in order to penetrate all segments of today's deregulated markets. Relatively easy and cost effective steps should be taken to lower busbar costs for these certified designs, while at the same time pursuing additional promising options with near-term potential to achieve lower capital costs, so these designs can compete favorably in all deregulated electricity markets in this decade.

DOE Status and Available Resources

DOE programs and resources for advanced reactor development ramped down from ~$125M in 1992 to zero in 1998. Due largely to the timely 1997 report by the President's Committee of Advisors on Science and Technology (PCAST) on energy R&D needs, a consensus of energy policy makers emerged that nuclear energy supply R&D needed to be restored. In response to the PCAST report, DOE proposed and Congress funded two new nuclear energy R&D programs: the Nuclear Energy Research Initiative (NERI), initiated in FY 1999 to address longer-term issues facing nuclear energy, and the Nuclear Energy Plant Optimization (NEPO) program, initially funded in FY 2000 to focus on performance of currently operating nuclear plants. NEPO has been funded at $5M for FY2000 and FY2001.

NERI has expanded since inception and was funded at $35M for FY2001. The NERI encourages innovative scientific and engineering research at universities, national laboratories, and individual companies in such areas as advanced reactor and power conversion cycles, capital costs of future nuclear power plants, low output power and special purpose reactors, safety and proliferation resistance, and the continuing challenges associated with nuclear waste. Starting in FY2001, $7M of the total NERI funding has been earmarked for international projects. NERI is a useful source of funds to help make progress toward some of the goals of this Roadmap. However, because of its limited funding and specific programmatic nature (proposer-driven innovations), NERI is not amenable to supporting work that must be directed in a timely manner to meet the specific R&D needs of near term deployment (i.e., market-driven needs as identified in this Roadmap).

In October 1998, the Nuclear Energy Research Advisory Committee (NERAC) was chartered by DOE to advise the agency on nuclear R&D issues. One of the subcommittees under NERAC is the Subcommittee on Long-Term Planning for Nuclear Energy Research. That Subcommittee developed a "Long-Term Nuclear Technology R&D Plan," published in June 2000. It covered all aspects of DOE-NE's charter for R&D, including reactor development, medical isotopes, radiation sources, and space systems. Its section on Nuclear Power addressed R&D needs in:

- Advanced fuel cycles
- Plant operations and controls
- Modeling
- Probabilistic risk assessments
- Human factors
- Organizational performance
- Reactor technology and economics

The Long-Term R&D Plan recommended total annual funding at $240M in 2005, assuming a ramp-up from now to 2005 to reach that funding level. Of the $240M, about $100M was proposed for R&D in the nuclear power categories listed above. To date, some limited action has been taken on these recommendations, primarily via NERI, the Nuclear Engineering Educational Research (NEER) Program, and FY2001 programs discussed below.

The Long-Term R&D Plan recommended R&D objectives and tasks for both Generation III and Generation IV technologies. For Generation IV demonstration projects, this funding extended beyond 2010. Details have been factored into the R&D agenda contained in this Roadmap.

Another NERAC Subcommittee is the Subcommittee on Operating Nuclear Power Plant Research, Coordination, and Planning, with responsibility to advise DOE on the conduct of R&D, including criteria for prioritizing research for operating nuclear power plants, with a focus on NEPO. Although focused primarily on current plants, it does have advisory responsibility for any R&D that could benefit both current plants and near-term ALWR options.

In August 2000, another NERAC Subcommittee was established: the Generation IV Roadmap Subcommittee (GRNS). This Subcommittee's initial task was to reach consensus on a set of design goals for Generation IV reactors. In parallel, it has oversight over the development of a Generation IV Roadmap, authorized by Congress for FY2001. This effort is underway, and includes both Near Term Deployment and Generation IV planning.

Congress appropriated the following funds in FY2001 for advanced reactor development:

- Generation IV Technology Roadmap: $4.5M
  (To create a plant to develop and deploy advanced nuclear power plant technology.)
- Small and Modular Reactors: $1M
  (To provide a study to Congress regarding the viability of small reactors.)
- Commercial GT-MHR: $1M
  (To chart a path to leverage Pu-burning GT-MHR technology to create competitive commercial plants.)
- ALWR: $1M
  (To assess ways to make ALWRs more competitive and deployable in the U.S.)

Congress appropriated a total of $12M in FY2002 for advanced reactor development:

- $4,000,000 for completion of the Generation IV Technology Roadmap
- $3,000,000 for advanced reactor development consistent with the longer-term recommendations of the Generation IV Technology Roadmap and to continue research begun in FY2001 on small, modular nuclear reactors.
- $3,000,000 to share with industry the cost of new NRC licensing processes. (For these funds, Congress encouraged DOE to implement the recommendations of NERAC's NTD Group to support industry applications to the NRC for Early Site Permits, Combined Operating Licenses, and Design Certifications.)
- $2,000,000 for fuel testing, code verification and validation, and materials testing at national laboratories in support of license applications for new reactor designs.

DOE and industry have a long history of cooperation and joint funding of nuclear energy R&D, as discussed in the industry status below. In October 1999, DOE and EPRI updated their basis for joint R&D planning and cost sharing, via a Memorandum of Understanding (MOU) on Cooperation in Light Water Reactor Research Programs. The purpose of that MOU was to establish the guiding principles under which cooperative research programs between EPRI and DOE's Office of Nuclear Energy, Science, and Technology will be planned and conducted.

Industry Status and Available Resources

Industry funded about 2/3 of the $1B+ ALWR Program, over the course of its history from 1983 to 1998. These industry funds included about $165M utility contributions via EPRI, and about $480M to $600M reactor vendor contributions (depending on how one counts in-kind contributions from international partners in vendor ALWR programs). This jointly funded program with DOE resulted in three NRC-certified ALWR designs, the General Electric Advanced Boiling Water Reactor (ABWR), the Combustion-Engineering (now Westinghouse) System 80+, and the Westinghouse AP600. This last design is a passive-safety mid size plant (~600 MWe); ABWR and System 80+ are large, 1300 MWe evolutionary designs. Both of these evolutionary designs (with minor design changes) have been built overseas in Japan and Korea, respectively. Also, an ABWR is under construction in Taiwan. These construction projects have enabled further engineering details to be completed for these certified designs for potential construction in the U.S.

The U.S. reactor vendors, Westinghouse and General Electric, have continued to develop enhancements to their ALWR Program designs. Westinghouse has completed significant engineering work on an AP1000 design, which incorporates taller fuel assemblies, larger steam generators and turbine-generators and a few other selected components from currently operating designs into the AP600. This power uprate utilizes AP600 design features and safety analysis wherever possible. With an identical plant "footprint," the additional costs for the upgrade are small compared to the overall capital costs, allowing for a major overall capital cost reduction. The U.S. NRC has initiated design review of the AP1000.

General Electric developed a Simplified Boiling Water Reactor (SBWR), a mid-size passive safety design, under the ALWR program. However, this design was not carried to sufficient completion to obtain a U.S. NRC design certification. GE has continued SBWR development with European partners, with the objective of offering a larger plant and achieving similar cost reductions as are being identified for the AP1000. The resultant design, the ESBWR, incorporates the passive features of the SBWR into a 1380 MWe design that is essentially the same size as the ABWR and utilizes much of the ABWR's layout and balance of plant systems.

Other ALWR projects underway include the European Pressurized water Reactor (EPR) and the SWR-1000, both being developed by Framatome; and the Westinghouse BWR 90+ being developed with European partners, primarily in Finland and Sweden.

Significant progress on two commercial non-ALWR designs was achieved over the last decade, with most funding for this work coming from DOE: the General Electric PRISM reactor (a small, modular liquid metal-cooled reactor), and the General Atomics Gas-Turbine Modular Helium reactor (GT-MHR), a small, modular helium gas-cooled, direct cycle reactor.

During the last two years, U.S. interest has developed in another type of helium-cooled reactor, the Pebble-Bed Modular Reactor being developed by ESKOM, the South African national utility. The PBMR is smaller than the GT-MHR, but allows for on-line refueling and therefore very high projected availability. It is based on pebble-bed reactor technology developed in Germany in the 1970s and 1980s. One U.S. utility, Exelon, is investing in this development effort, and market interest is expected to grow.

Since the formal completion of the ALWR Program in 1998, EPRI funding for advanced reactor development has been limited to a small portion of EPRI-wide Strategic Science and Technology (SS&T) funding for longer-term R&D needs. Total advanced reactor development funding at EPRI since 1998 has averaged $2.5M/year. However, EPRI's senior nuclear utility advisory committee, the Nuclear Power Council, has indicated a desire to expand this effort using funds earmarked for long-term R&D. EPRI funds have been allocated to ALWR enhancements, including improved construction techniques and risk-informed regulation, and to helium reactor scoping studies.

Starting in 2001, the EPRI's Nuclear Power Council will have oversight over a larger strategic R&D budget (~$3.7M), much of which will be available to advanced reactor development. With the additional resources available, EPRI has committed to cover all the generic expenses of NEI's activities under its Executive Task Force on New Plants, primarily in the areas of Early Site Permit, regulatory framework, and Part 52 licensing issues. These EPRI funds will also be used to support the development and execution of the "Strategic Bridge Plan". In addition, EPRI funds may be available to assist in implementing some of the actions identified by this Roadmap, in cooperation with DOE, likely through cost-sharing arrangements.

However, EPRI's role, as a non-profit organization, is constrained by available resources to focus primarily on generic activities, in support of NEI, utilities and suppliers, where common solutions provide broad benefits. The primary source of private sector funding to accomplish the goals of this roadmap will come from reactor designers, investors, and nuclear generating companies who will purchase new plants. The one-time costs of these investments also need DOE cost-sharing.

READINESS OF NUCLEAR ENERGY TO CONTRIBUTE TO NEW GENERATION

Performance of Today's Plants

Nuclear energy has proven itself to be a safe, environmentally sound, economically competitive source of electricity for the United States and an indispensable component of our national energy mix. Nuclear energy plants in the U.S. lead the world in most categories of performance, and continue to improve.

In 2000, nuclear plants generated a record 754 billion kilowatt-hours of electricity, 25 billion kilowatt-hours more than the previous year and 178 billion kilowatt-hours more than in 1990. Last year's record performance capped the best decade in the industry's history. The average production cost of electricity generated by nuclear power plants during 1999 was the lowest of all fuel sources. For the industry as a whole, nuclear production costs (operations, maintenance, and fuel costs) in 1999 of 1.83 cents per kilowatt-hour were lower than production costs for coal (2.07 cents per kilowatt-hour), natural gas (3.52 cents per kilowatt hour, even prior to natural gas price spikes) or oil (3.18 cents per kilowatt-hour).

The dramatic increase in electricity generation by America's nuclear plants is also one of the most successful energy efficiency programs of the past decade. Output increases are equivalent to adding 22 1000-megawatt power plants to our nation's electricity grid, without the impacts that would have occurred if new facilities had been brought on line to meet these needs. Although the lack of new nuclear construction since the 1980s often is identified as a sign of industry stagnation, in fact, the more efficient operation of existing nuclear electric generating facilities has been an environmentally beneficial alternative for making additional electricity.

The growth in nuclear electricity production is primarily the result of two factors. The first is that nuclear plants are operating more efficiently. Refueling times have decreased and once common unscheduled shutdowns are significantly reduced. The second factor is that many nuclear plants have undergone equipment uprates, allowing them to produce more electricity than was initially planned.

The total cost of producing electricity from current, well-managed nuclear plants is less than 2.5 cents per kilowatt-hour (kWh). This cost compares favorably with combined cycle natural gas plants at 3.5 to 4.5 cents per kilowatt-hour (assuming a gas price of $3 to $4 per million BTUs). Natural gas prices paid by electricity generators have been volatile in the past year, more than doubling over many months and causing serious regional economic repercussions such as in California. In contrast, nuclear fuel costs have been substantially less volatile.

Plant uprates, improved maintenance, reduced outage times and safety improvements are expected to continue to provide higher operating efficiency and additional electricity output from existing power plants. But these increases are finite, limited to the maximum capacity of each reactor.

Nuclear Generation Essential to Protecting U.S. Air Quality

As discussed in the previous Chapter, the benefits to society from emission free and highly reliable nuclear energy are huge. As utilities, investors, and energy planners make decisions on future electricity generation technologies, they will need to consider the environmental impacts of their choices. Nuclear energy protects the environment. As discussed below, the nuclear fuel cycle is well managed, its environmental footprint is very small compared to alternatives, and its total costs are already "internalized," i.e., included in the cost of nuclear electricity.

A Safe Waste Management Record

Nuclear energy facilities, like other electricity sources, have waste streams and byproducts that must be managed safely. The environmental policies and practices at nuclear energy plants are unique in having avoided or prevented significant harmful impacts on the environment since the start of the commercial nuclear industry more than 40 years ago. Effective waste avoidance, minimization and management practices have successfully prevented or mitigated adverse impacts on water, land, habitat, species and air from releases or emissions in the production of nuclear electricity. Throughout the nuclear electricity production process, the small volumes of waste byproducts actually created are treated and released, or carefully contained, packaged and safely stored.

The safe handling and storage of used nuclear fuel is one of the most successful solid waste management programs in the industrial sector. Used fuel rods are stored in contained, steel-lined pools or in robust stainless steel containers at limited-access reactor sites.

As a result of improved process efficiencies, the average volume of waste generated at nuclear energy plants has decreased significantly in the past two decades. The high-level radioactive material in used fuel rods totals less than 20 metric tons per nuclear plant each year.

Although U.S. policy originally envisioned recycling reactor fuel to separate out the waste and reuse the remaining fuel, policy changes and high costs of recycle resulted in a plan to disposition the unseparated fuel in a deep geologic repository, leading to the site characterization project at Yucca Mountain. Research continues to develop improved processes for recycling used fuel—a long-term policy option that could provide strategic fuel reserves that can increase the future contribution of nuclear electricity to sustainable development. Whether or not that research is successful and is supported by a policy consensus, the fact remains that a federal spent fuel management program is necessary. Even if recycling of future spent fuel is implemented, nuclear wastes from today's plants will still exist and require safe storage.

A presidential decision is scheduled for this year on the suitability of a federal repository at Yucca Mountain, Nevada. The Yucca Mountain program is key to effective spent fuel management since cost-effective operation of nuclear plants calls for a centralized, permanent site to continue the environmentally preferable practice of isolated storage for used fuel. As a world leader in nuclear technology, the United States should also be a world leader in effective, long-term management of used fuel.

Deregulation and Industry Consolidation

Deregulation is allowing and accelerating the consolidation of the nuclear power industry that was already occurring and probably would have occurred anyway. Utilities with only one or two nuclear power plants have been realizing that it would be increasingly difficult to remain competitive without the resources and efficiencies of larger operators.

Consolidation in the nuclear industry is bringing many advantages that provide higher levels of safety and reliable performance at lower costs:

- A focused management is applied to plant operations
- Economics of scale through purchasing can be achieved.
- Financial risk can be spread over several plants.
- Talent and expertise in financial, technical and management areas can be pooled.
- Rapid response to a problem at one plant with highly qualified expertise.
- Bringing the best practices from all plants to each plant.

Ultimately, the cost of electricity from nuclear plants must be seen by investors as attractive with respect to return on investment, with reasonably low uncertainties, in order for nuclear to win in a competitive deregulated market investment decision. Nuclear designers and constructors have more work to do in making that case convincingly to likely owner/operators and investors. Recent activity in the industry suggests some reactor design options that can rise to this challenge in the next year or two.

Building New Nuclear Plants – Time to Market

More and more energy policy leaders are coming to the conclusion that nuclear energy must play an increasingly important role in a new National Energy Policy. Although nuclear energy is not ready to assume this role today, the prospects for nuclear assuming this role by the end of this decade are excellent. It will take a few years for nuclear plant orders and construction because of the following constraints:

- Nuclear energy plants take many years to site, license and construct – the average time to market for a design that is already certified is likely to be about 7-8 years. Some new designs discussed in this Roadmap (not yet certified) have the potential to shorten this "time to market," primarily through shortened construction times.
- No site permits and no regulatory approvals to construct a new plant exist today in the U.S. The processes to do this under new regulations have not been demonstrated.
- Although the economics of currently operating plants are excellent, the economics of new plants are more difficult, because of the relatively high capital costs of nuclear plants.

These obstacles can be overcome in sufficient time for new plants to be in operation by 2010. This Roadmap presents the actions and resources required.

Baseload Generation Economics

Depending on market conditions, project overnight capital cost (including engineering, procurement and construction (EPC) cost, owners cost, and contingencies) need be contained at about 1,500 $/KWe or less. Overnight capital costs of 1,200 $/KWe or less should secure broad market acceptance. Today's NRC-certified ALWR designs do not meet this low cost threshold. However, some near term deployment options (both water-cooled and gas-cooled) have the potential to meet this cost target, and should be certified as soon as possible. Further, options to significantly reduce the capital costs of currently certified designs also exist.

The appearance of first proposals to build new baseload coal-fired capacity is significant because it indicates several things. (1) a readiness to build new large plants with higher capital costs like nuclear plants, (2) a recognition that we are beginning to need large new baseload, not just mid-sized and peaking units, and (3) a recognition that we should reduce our reliance on natural gas in the future. Fuel diversity has long been the great strength of the American electric power industry. These realities should be factored in to national nuclear energy strategy (see Chapter II-6).

Like renewable energy, conventional coal-fired power plants and advanced "clean coal" technologies, nuclear power is a capital-intensive technology. Large new nuclear power plants could cost as much as $2 Billion each, and would thus represent a substantial investment risk for the company or companies that build them. Private companies would only undertake investments of this size if they were convinced that new nuclear power plants, once built, would be competitive with other sources of electricity.

In contrast to gas-fired electricity, a strength of our nation's nuclear energy program is the low cost of producing electricity at nuclear power plants and the stable forward pricing of electricity produced by nuclear power plants. The importance of this forward price stability was evident last year as sharp increases in natural gas prices resulted in significant increases in the price of electricity across the United States. The availability of a long-term, reliable and competitive fuel supply is a critical factor in achieving the excellent economic performance at nuclear power plants.

Carbon taxes to defray the costs of fossil fuel environmental mitigation (e.g., sequestration) would make nuclear energy the cost leader today, but it is not clear that an energy strategy based on such taxes will ever emerge, given their negative impact on the economy. Hence a generally accepted and conservative planning basis for near term deployment of nuclear energy plants by industry is that carbon taxes should not be assumed. Overall, the costs to bring nuclear energy into a competitively attractive market position without imposition of a carbon tax are much lower than the cost to the U.S. economy of imposing such a tax.

Clearly, no solution to our growing demand for new electricity generation is simple and inexpensive. Each option has its advantages and disadvantages. But on balance, nuclear energy's benefits cannot be ignored, and its potential to carry major responsibility for new capacity should be investigated.

Commitment to Standardization

One of the lessons learned from the early years of nuclear energy development in the U.S. was that a lack of standardization among nuclear plants contributed to industry complexity, and imposed barriers to cooperation and efficiency. These impacts either added costs or blocked efforts to reduce costs because most joint initiatives for improvements in design or operation had to be customized to each plant. In 1991, as part of the development of the Nuclear Energy Industry's Strategic Plan to Build New Nuclear Power Plants, a Standardization Policy was developed under the leadership of INPO and EPRI, and endorsed by the chief executives of all U.S. nuclear utilities. That policy called for "life-cycle standardization", starting with the Utility Requirements Document (URD) that specified user design requirements for all reactor designers, followed by standardized engineering and construction for each design, and standardized operational programs, as feasible. This policy would allow for construction of standardized nuclear plant designs at significantly reduced costs, and for common procedures, training, parts, and engineering solutions to emerging issues.

The concept behind the industry's standardization policy was not to restrict future nuclear plants to a single design, since this would eliminate the benefit of competition in the marketplace and ultimately not serve the interests of energy consumers. Rather, the concept was to seek to manage the diversity of design options to the minimum necessary to match variations in market need, and to then achieve a high degree of standardization for each design in use.

The Administration's National Energy Policy

The new National Energy Policy Report, issued in May 2001 by the National Energy Policy Development Group, led by Vice President Cheney, set out a comprehensive long-term strategy that uses leading edge technology to produce an integrated energy, environmental, and economic policy. It calls for improving conservation, modernizing our infrastructure, and increasing our energy supplies. It recognizes the vital role that nuclear energy must play, as the only large-scale energy supply option that does not produce greenhouse gasses or other harmful emissions.

With respect to nuclear energy, the report recommends that "the President support the expansion of nuclear energy in the United States as a major component of our national energy policy." Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.

- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price-Anderson Act.

The Report also includes two recommendations related to long-term goals in the development of advanced fuel cycles. These recommendations support longer-term objectives that are being examined by the Generation IV program.

The Nuclear Energy Institute's Vision 2020

One week after the National Energy Policy was issued to the American public, the Nuclear Energy Institute announced the nuclear energy industry's "Vision 2020": 50,000 megawatts of new nuclear generating capacity added to the U.S. grid by 2020. In addition, the industry vision also includes achieving another 10 percent in efficiency gains and power uprates at today's plants, equivalent to an additional 10,000 megawatts of additional nuclear generating capacity.

This commitment to building new nuclear plants – roughly 50 of them, assuming an average size of 1,000 MWe each – may seem small in the bigger picture of U.S. energy supply needs. The entire 50,000 megawatts, along with the 10,000 megawatts of enhanced capability at today's plants, is predicted to only slightly expand the total percentage of U.S. electricity generation from nuclear from about 20 percent to about 23 percent. However, from industry's perspective, this goal is a major challenge:

- Many segments of U.S. nuclear infrastructure have atrophied during the nuclear construction hiatus of last two decades, especially our nation's fabrication, manufacturing, and skilled human talent pool.
- Although three new advanced plant designs that incorporate significant safety enhancements have been certified by the U.S. NRC and are ready to build, the next steps in the new regulatory process, the Early Site Permit process and the Combined Construction and Operating License, are untested and open to wide interpretation.
- Although the economic performance of the current fleet of nuclear plants has been outstanding in recent years, the economic competitiveness of new nuclear plants, because of their relatively high capital costs, is less clear. In a deregulated electricity marketplace, any new plant must be economically competitive. Some of the nuclear options discussed in this Roadmap may be economically competitive, depending on assumptions made regarding natural gas prices, stability of regulatory processes during construction, and local economic conditions (see Chapter II-4). Importantly, there are things industry and DOE can do to improve the picture.

Additional information on the industry's Vision 2020 can be found in Attachment 3.

NEI's Integrated Plan for New Nuclear Plants

NEI has established an "Executive Task Force on New Nuclear Power Plants," comprised of industry leaders with a strong interest in forging ahead on efforts to enable new plant orders.

The Task Force members include utility executives from owner-operator companies committed to a long-term role for nuclear energy, executives from reactor vendors, architect-engineer firms, and EPRI. NEI and its Executive Task Force are focused on the business conditions and other factors impacting the economics of building new baseload generating plants in a deregulated electricity marketplace, such as tax and regulatory policy and investment strategies. NEI is developing a document to address these issues: an "Integrated Plan for New Nuclear Plants." The plan includes:

- A number of initiatives to improve the economics of new nuclear power plants;
- Programs to create a stable licensing regime and reduce regulatory uncertainties;
- A series of initiatives to build support for new nuclear power plants among policymakers, the media and local communities around prospective sites for new nuclear power plants.

For an electricity-generating company, new nuclear power capacity – if economical enough to enter the market – represents:

- A reliable source of electricity with low "going-forward" or "dispatch" costs
- A high level of forward price stability and protection against the fuel price volatility that impacts gas-fired power plants (e.g., as a result of fuel supply problems)
- Protection against possible escalation in environmental requirements imposed on fossil-fueled power plants. For companies already operating coal-fired or gas-fired power plants, new nuclear capacity reduces the cost of clean air compliance that might otherwise be imposed on that coal- and gas-fired capacity.

Additional information on NEI's Integrated Plan for New Plants can be found in Attachment 4.

<u>Availability of Suitable Near Term Nuclear Energy Options</u>

There are a number of excellent design options that could be deployed this decade. These options are examined in detail in Chapter II-5 of this Roadmap. In summary, potential near term options include, but are not limited to:

1. Two Advanced Light Water Reactor (ALWR) designs that have been certified recently by the U.S. Nuclear Regulatory Commission (NRC) for referencing in a Combined License (COL) application, which would authorize their construction and operation. (Note that three designs have been certified by NRC, but one [System 80+] was not submitted for consideration to the NTDG.)
2. Two 1000+ MWe passively cooled ALWRs that are power uprates of already certified designs (or from substantially complete passive ALWR designs), but that have not yet been certified.
3. Two modular direct cycle high temperature helium-cooled reactors that are under development.

Probabilistic Risk Assessment studies show that these designs have substantially lower core damage frequencies than existing plants that are already highly safe, and offer many advantages, in terms of additional reliability, simplicity-of-operation, and safety margin. Key to success of any near term option will be a clear indication of sufficient market interest to actually deploy it.

Plants in the first group of options above are designed for sixty years of operation, and some of them have already been constructed overseas. These plants are available for purchase today, but their competitiveness is significantly affected by very uncertain projections of long-term fossil fuel prices, particularly for natural gas. If natural gas prices returned to those of a year ago and prevailed long into the future, the cost of electricity from new nuclear plants could be higher than from gas-fired plants, making them less competitive. Further reductions in nuclear costs could overcome this fossil fuel price uncertainty. Since the primary cost factor for nuclear energy is its capital cost, substantial attention must be given to identifying cost-effective means to reduce these capital costs and construction schedules, and to improving process efficiencies, e.g., in procurement and construction management. In defining these improvements, it is essential that levels of safety and reliability be maintained, and that existing design certifications remain valid.

Plants in the second group of options above are power uprates of previously certified designs or substantially complete passive ALWR designs that have not yet been certified. These designs are expected to achieve substantially improved economics over the life of the plant (expected reductions on the order of 30 percent for life cycle generating costs), providing very promising cost competitiveness with fossil-fueled plants in the deregulated marketplace.

Plants in the third group of options above are helium-cooled and graphite moderated. They include small modular units in the 100-300 MWe range that differ primarily in their fuel forms and refueling design. They offer the potential for enhanced safety through reliance on TRISO-coated fuel particles that can sustain very high temperatures without damage. These designs are at a less complete stage of development than ALWRs and have a smaller operating experience basis to build on, but have potential to achieve low construction and life-cycle costs, equal to or better than ALWRs. One of these designs, the Pebble Bed Modular Reactor (PBMR) currently enjoys particular market interest from a large U.S. nuclear utility.

Nuclear Safety and Public Confidence

Safety at our nation's nuclear power plants has been achieved and remains at record high levels. There has not been any nuclear plant event that has jeopardized public health and safety due to the release of radiation in the United States. In 2000, the median number of unplanned reactor shutdowns industry wide was zero for the third straight year, and 59 percent of U.S. reactors had no automatic shutdowns. In addition, the number of significant events at U.S. nuclear power plants declined to an average of 0.03 in 2000, compared to 0.44 in 1990. Significant events include a degradation of important safety equipment, a reactor shutdown with complications, or operation of the plant outside technical specifications.

Today's energy shortfalls are increasing public support for building new nuclear power plants, according to public opinion surveys conducted in January and July 2001. The national survey of 1,000 adults found those in favor of "definitely building more nuclear energy plants in the future" increased from 42 percent in October 1999 to 63 percent in July 2001. The increase was largest in the West, where those in favor increased from 33 percent in October 1999 to 63 percent in July 2001.

Federal and state legislators and local government officials, as well as the national news media, also are re-examining nuclear energy, and many support an increased reliance on nuclear energy. A key reason for increased public support of nuclear energy is the public's growing appreciation of the environmental benefits of nuclear energy.

Surveys over the last decade have consistently shown that national leaders underestimate the level of public support for nuclear energy. National leaders generally support nuclear energy as much as their constituents do, but presume support among their constituents is much lower than it really is.

But perceptions are changing as energy and environmental policy rises in importance. Here are some recent quotes by national leaders regarding the role of nuclear energy:

Vice President Richard Cheney addressed the Nuclear Energy Assembly in May 2001 and said the following: "We think the [National Energy] policy provides a reliable, affordable and environmentally sound policy going forward with respect to our future. Part of that, obviously, we think also ought to involve nuclear energy. It's important that we focus on that in the future, just as we recognize that nuclear power is a very important part of our energy policy today in the United States. One out of five homes in America today runs on electricity generated by nuclear energy; that American electricity is already being provided through the nuclear industry efficiently, safely, and with no discharge of greenhouse gases or emissions, and we want, as a matter of national policy, to encourage continued advancements in this industry, improve safety and efficiency at nuclear plants, safe disposal of nuclear waste, and perhaps even technology that reduces the amount and toxicity of waste going forward."

Federal Reserve Chairman Alan Greenspan, in a speech before the Economic Club of Chicago in June, said that nuclear energy is "an obvious major alternative" for electricity production in the United States; and "Given the steps that have been taken over the years to make nuclear energy safer and the obvious environmental advantages it has in terms of reducing emissions, the time may have come to consider whether we can overcome the impediments to tapping the potential more fully."

BACKGROUND ON REGULATORY PROCESSES

Part 52 was introduced in the late 1980s since the existing system had become unpredictable and extremely inefficient because of the way the process was structured. The need to wait until construction of the plant was completed before an operating license was granted put the owners at enormous financial risk and offered intervenors broad opportunity to delay or thwart startup of the plant. In addition, the administrative, legal and procedural process was implemented in practice in a manner that focused the process on issues that had minimal public health and safety significance. Part 52 is intended to make the process of licensing a nuclear power plant more predictable, more efficient, and more objective. It focuses the process and attention on issues that are substantive and have public health and safety significance. The Part 52 process is also intended to get more information to the public at an earlier stage so that the public is better informed.

Early Site Permit Applications

Early Site Permits (ESPs) are the subject of Subpart A of 10CFR Part 52. An ESP issued by the NRC provides approval of a site for one or more nuclear power plants (NPPs), without actually applying for approval to build the NPP yet – which would require filing a separate application for a Construction Permit (CP) or a combined license for construction and operation. Approval of an ESP is advantageous in several ways to prospective NPP construction applicants. It permits planning of construction at the approved site in advance of a decision to construct. For construction on existing nuclear sites, advance approval and "banking" of ESPs allows for the flexibility to build new NPPs at the sites in areas of greatest energy demand. Since power suppliers typically "bank" sites for potential fossil-fueled projects that might be proposed in competitive bids to supply electricity, it is also important that potential nuclear projects have a number of banked sites to compete in such bids to supply power. In the case of an ESP for multiple units, it would allow construction of a later unit or units after undertaking the first. The latter case would be important for plants of standard design, and in particular, for plants of modular design for which 4 to 10 units might comprise the final full output of the multiple plant site. Subpart A identifies and sets forth conditions and requirements for such applications.

There is no experience or precedent for nuclear plant ESPs. In order to enable near term plants, it is necessary to initiate planning and to prepare actual ESP applications for review and approval by the NRC. Carrying the process through to conclusion, including the disposition of potential challenges by intervenors, will show the way to successful and expedited applications in the future. Further, there is a need to review the requirements of Part 52, Subpart A, to ensure they are up-to-date, anticipate applicant circumstances, and reflect other rule changes.

Combined Construction and Operating Licenses

The Combined Construction and Operating License (COL) for nuclear facilities is also provided for in Part 52. It is a concept that evolved from review of past experience and consideration of means for improvement, especially with respect to construction schedule. It allows for timely public access to relevant information, thorough review, and approval to build and operate before construction starts. In contrast, throughout the period of NPP construction in the U. S. in the 1960s-1980s, the Atomic Energy Acts required two applications, first an application for the CP, and, when construction was nearly complete, the application for a plant Operating License (OP). This two-step sequence was not a problem initially. As time and events moved on, however, it became a problem because of procedural and legal challenges requiring excessive time and effort to resolve. Delay of a production plant under construction increases finance charges, and defers revenue. The COL concept addresses this issue, by calling for review and resolution of all issues related to the plant design and intended operation, and a Commission decision on granting a COL, before construction begins. Applicants may reference a pre-approved design and a pre-approved site, thereby limiting the issues remaining to be resolved in the COL, thus offering an opportunity to applicants for a single, conclusive review with the benefit of greater certainty that the plant will start up on schedule. Of course, it is necessary to carry a project through the process in order to prove the value of the concept in practice.

There were reasons for the two-step process in the early days. Typically site preparation and construction began before completion of design, and the CP accommodated this process. One of the results was that a lot of information became available in the course of final design and construction that had received little or no attention in the review of the CP application. Not infrequently, reviews at the time of consideration of the OL application uncovered safety questions that required time and effort to answer. Frequently, major design changes and construction rework ensued. However, as the design process matured, it became apparent to the industry, the regulators, and Congress that the effect of this old CP/OL process was to postpone consideration of important issues and the making of key decisions too late in the project – decisions that could be dealt with much more effectively at the beginning. Further, from the standpoint of interested members of the public, a new process would allow for much better public participation early on, when it is useful and can be easily incorporated into the design and licensing process. In other words, beginning construction before completion of design created more problems than it solved. It was to everyone's advantage, including the public's, to take this new COL approach.

There is an important factor related to review of design and construction detail late in the project. Intervenors used the opportunity presented to cause further delays by questioning the regulatory review through litigation. These questions rarely surfaced any significant safety issues, but added major delays to the project, which added significantly to final plant construction costs.

The intent of the COL process is to require resolution of important site, design, construction, and operating issues at the beginning of the project, when the application is under consideration by the NRC. Another advantage is that public input and concerns are provided when they can be most effectively addressed – just prior to the granting of an ESP, DC, or COL – not after plant construction is complete when potential remedies are limited or prohibitively expensive. Stakeholders in the development of Part 52, including environmental groups, recognized that this shift in the timing of public interaction and applicant accountability was necessary and appropriate. The process does not allow waiting until the end of the project to raise new questions. In other words, the process is front-end loaded, instead of the reverse – as it was in the early days. There is, of course, a downside as discussed above, i.e., the need for major front-loaded investments, such as in design engineering, public education and interactions. These costs are formidable, but the benefits in terms of stability of the process and assurance that public concerns about safety are resolved prior to construction are preferable by comparison to the unpredictable delays that accompanied nuclear plant projects in the past. This front-end loaded characteristic is very compatible with the concept of standardized designs.

Since the COL process has not been tested, there are a number of related technical and process issues that are not resolved. Referencing a certified design in a COL application leaves some site-specific technical issues to be resolved (e.g., ultimate heat sink design) and a number of process and operational issues not addressed in the DC (e.g., construction inspection requirements, emergency planning requirements, security requirements). These issues need to be identified and resolved in a timely manner, generically, if possible, prior to the first COL application, or at least during that application. For issues that cannot be resolved generically for all future plants, a generic resolution applicable to a family of plants using a standardized design is highly preferable to applicant-by-applicant treatment.

In addition to concerns about the predictability and timeliness of these processes, other important questions have emerged recently regarding the sequencing of ESP, DC and COL applications and approvals. Part 52 allows for significant flexibility (e.g., the option of applying for a COL without a pre-existing ESP or a pre-existing DC, as long as the necessary information to review the design and the site are provided in the COL application). This option appears to be attractive to applicants who will need some type of prototype demonstration as part of their design approval. Also emerging as important questions are ones that relate to the ability and practical limits to overlapping these processes. For example, it now appears that the COL application for a given site could be submitted shortly after an ESP application is submitted, allowing for concurrent review and near-simultaneous approval by NRC. These options need more analysis.

Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC)

ITAAC are required by Part 52 as a key step in assuring that a design that is granted a combined license for construction and operation is actually constructed in accordance with the provisions in the design submittal (Safety Analysis Report) that was reviewed and approved by the NRC, and in accordance with the provisions in the design certification and COL. These ITAAC are verified by testing and analysis during construction but prior to the authorization to load fuel. ITAAC developed for the certified designs were subject to public comment in the design certification proceeding and will be incorporated in any COL that reference the certified design. A constructed plant can load fuel and go into commercial operation following a finding by NRC that all the ITAAC have been satisfactorily completed.

Development of a Risk-Informed, Performance-Based Regulatory Framework

Today's reactor regulatory process is based on the same concepts and principles as it was 35 years ago: deterministic design-basis events. As operating experience has increased new insights and information have been transformed into new prescriptive requirements. These new requirements have been layered on top of existing regulations without an overall comparison of the safety benefit against the resources required to implement the requirements.

The current regulations have provided for an adequate level of protection of public health and safety. Yet, operating experience and risk analyses insights have revealed that the process could be significantly enhanced by increasing regulatory focus and attention on some requirements, while other requirements could be significantly reduced or eliminated. The adoption of a complete risk-informed, performance-based approach would significantly enhance the protection of public health and safety through increased licensee and NRC attention and focus on safety significant matters.

In a competitive generating market, plant safety must continue to be of paramount importance. Nearly 30 years after PRAs were first used to evaluate reactor designs and operations, tools and processes are available that would allow the NRC to provide licensees additional flexibility in the manner in which they can implement the regulations, while at the same time improving the protection of public health and safety. A risk-informed, performance-based process will allow licensees to implement, and NRC staff to oversee, the regulations in a more efficient and effective manner, which will improve safety.

In 2001, the NRC completed its watershed transition to a risk-informed, performance-based oversight process for current plants. To further enhance efficiency and safety focus and ensure continuity between NRC oversight and underlying regulations, efforts are underway to risk-inform administrative, operational and technical regulations and the associated implementing guidance that govern the design and operation of nuclear plants. Progress to date on risk-informing regulations in 10 CFR Part 50 for existing plants has been sporadic, due to several factors:

- Current plants are already designed, built and have established operating programs that are difficult and costly to revise,
- The regulations are interwoven in a fashion that makes targeted changes difficult, and
- Many of the regulations have detailed, prescriptive requirements that do not allow alternative approaches or the consideration of improvements in technology.

In parallel with efforts aimed at current plants, work has begun on new, risk-informed, performance-based regulatory framework for future plants. To avoid the difficulties involved in risk-informing the existing regulations for current plants, an entirely separate regulatory framework is envisioned for future plants. In addition, unlike the existing regulations that are based on "light water reactor" technologies, the new framework will encompass varying reactor designs, reactor technologies, insights from 40+ years of reactor operating experience, and advances in analytical techniques and technologies.

Development of a risk-informed, performance-based regulatory framework is important for licensing, construction, and operation for future plants. Current regulations have been modified so many times that they are extremely complex and contain numerous outdated and extraneous requirements. A risk-informed, performance-based regulatory framework can incorporate decades of experience with licensing, design, construction, and operation of more than 100 plants in the U.S., emphasizing elements that are important to safety, removing requirements that do not affect or improve safety, and incorporating improvements in safety technology and analyses over the same period. The improvements include insights developed with more safety data and with probabilistic risk assessment, improvements in systems and component design and performance, and improved system configurations that have reduced core damage frequencies and produced engineered safety systems that are more reliable. The Design Basis Accident methods of regulatory evaluation that evolved in the early years of the industry, along with the regulations, guides, and directives, do not give full credit to the safety and performance advantages of new technologies. Key principles that should be embodied in a new risk-informed, performance-based regulatory framework include:

- The structure must support the NRC's mission of "adequate protection of public health and safety" and support the current safety goals.

- The framework must take advantage of the 30+ years of deterministic licensing experience as well as relatively new risk-informed insights, and build on the risk-informed regulatory activities that have been implemented.
- The new structure should focus on safety significant issues, processes, and equipment, and eliminate requirements in current regulations that do not address nuclear safety
- The framework should be flexible enough to accommodate new reactor designs as well as existing design certifications.
- The framework should improve predictability and stability of regulation, and result in a more efficient and effective regulatory review and approval of designs, license applications and regulatory oversight of plant operations consistent with the safety significance of the issue. This will set safety-focused priorities, make more effective use of resources, decrease new plant lead-times, and reduce financial exposure and risks attributable to regulatory uncertainty of the past.
- The framework should incorporate a defense-in-depth concept based on prevention and mitigation consistent with the degree of uncertainty with significant consequences to public health and safety.

It must be noted that new technical regulations should not impact existing Design Certifications or those designs obtaining certifications under the present regulations. This ensures the continued validity of these existing certifications for near term application.

Because a complete new regulatory framework will not be in place before 2005, the initial round of new plant licenses is likely to be based largely on existing regulations. However, to the degree that new risk-informed, performance based regulations are established at the time of a new plant licensing proceeding (e.g., DC, COL), the applicant may wish to take advantage of new regulations to improve the safety focus of an aspect of the design or relevant operational requirements. It is expected to be possible for new plants licensed before the new regulatory framework is fully in place to adopt portions of the framework (e.g., enhanced operational or administrative requirements) once they are established.

A new plant regulatory framework should provide a generic process and a set of regulations that specify safety objectives, but permit flexibility in how the objectives are achieved. This is important as the next generation of power reactors may include a variety of plant designs where the "one size fits all" prescriptive regulatory approach is not appropriate. Setting top tier safety performance objectives is a more efficient approach that avoids having to promulgate a different set of regulations tailored to each class of design.

Finally, within the scope of efforts toward an improved regulatory framework for new plants are a number of opportunities for incremental improvements that do not need to wait for completion of the new framework. Some of these could be applied to already certified designs, especially at the COL stage. These opportunities relate to taking advantage of progress on risk-informing the regulations for current plants using "Option 2" and "Option 3" of SECY-98-300, to the extent applicable to new plants.

Option 2 for risk-informing regulations relates to changes that could be made to "special treatment requirements" without modifying the underlying regulations. The term "special treatment requirements" refers to the regulations that govern structures, systems and components (SSCs) that are currently categorized as "safety related." Option 2 proposes to modernize these requirements through an improved categorization of SSCs in terms of their true safety significance, and then establishing specific risk-informed requirements for each new category. The NRC and the industry have made significant progress on this initiative, and agree on which equipment has high safety significance and on how to treat it. They also agree on appropriate treatment of equipment that is non-safety-related.

However, there has been disagreement about how to deal with equipment and systems categorized since the early years of the industry as safety-related, but which have been proven to have low safety significance. The industry believes that commercial industrial standards, not more stringent nuclear safety standards, should be applied to such equipment. Commercial industrial standards are widely used in the nuclear industry, as well as other industries with similar or higher potential impact on public health and safety.

The cost savings for replacement parts at reactors, and for initial construction for new reactors, is substantial. For example, an industrial-grade 10-horsepower electric motor could be purchased for $350. The same motor, purchased as a safety-related item, would cost 57 times that amount: $20,000. The two motors perform the same function; but the cost difference is huge.

Similarly, an industrial-grade electrical circuit card could be purchased for $1,160. The same circuit card, under nuclear standards, would cost $5,700—five times as much as the industrial-grade item. Either component could perform the function for which it is intended.

The main difference in cost is the extent of the process used to verify the component's performance capability. Commercial industrial standards are entirely satisfactory for many applications with low safety-significance in nuclear power plants. In fact, they already are widely used in nuclear plants, and their use could be expanded substantially. Improved categorization and treatment of SSCs has been shown to be achievable in a manner that does not compromise safety, but allows for significant cost savings.

Option 3 for risk-informing regulations relates to actual changes to the technical regulations. For current plants, an approach is being taken that focuses on selected regulations in greatest need of updating, instead of a top-down rewriting of the entire body of regulations. It is quite possible that some of the selected efforts under Option 3 (e.g., revising large break LOCA requirements, revising concurrent LOCA and Loss of Offsite Power requirements) could be applied to new plants.

II-3: GENERIC GAP ANALYSIS

This Chapter summarizes the gaps and issues that are generic to most or all NTD designs, and discusses solutions or required outcomes for each. Gaps and issues presented in this Chapter have resulted from both external inputs (from respondents to the NTD Request for Information (RFI) issued in April 2001, and internal deliberations among NTD Group members. All stakeholder inputs were carefully considered. The NTD Group then identified the high priority generic gaps for primary attention by industry and Government. The NTDG also identified some issues that were judged to be longer term in nature, and less critical to near term deployment.

The priority generic gaps focus on regulatory process issues that must be resolved promptly and demonstrated successfully to enable near term deployment of new designs, and on economic competitiveness, "time to market", cost management, and investor arrangements. The need for an integrated and results-oriented National Nuclear Energy Strategy is also discussed.

For the purposes of this Roadmap, the term "Gap" applies to situations where a problem is judged to be a significant technical, institutional, or economic obstacle to near term deployment – one that needs to be reasonably well resolved in some manner to permit near term deployment of new nuclear energy plants in the U.S. by 2010.

For the purposes of this Roadmap, the term "Issue" applies to a condition or circumstance that is judged to be an important generic factor to the longer-term effectiveness of nuclear power, but not necessarily an obstacle to near term deployment. Issues need to be monitored and managed, and progress should be made on each to allow nuclear energy to reach its full potential. Some issues could eventually become obstacles in the longer term, if adequate progress is not made or conditions worsen. In some cases, issues may have been perceived as gaps by some, while on closer examination these issues are actually being managed effectively today to prevent them from becoming gaps.

This Roadmap does not intend to draw a sharp distinction between "Gaps" and "Issues," since progress on all of them is important, and since 100 percent resolution is not required in any instance. Rather, this distinction is intended to suggest a qualitative difference in terms of priority, urgency, and resource allocation. As such, Chapter II-6 presents recommendations on the gaps identified below, but does not present recommendations on the Issues.

KEY NEAR TERM DEPLOYMENT "GAPS"

The following five priority generic "Gaps" have been identified to receive primary attention of industry and Government to enable near term deployment.

Gap 1: Nuclear Plant Economic Competitiveness

The primary disincentive to choose nuclear power for very near-term new U.S. electricity generating plants is that the plant designs certified by NRC in the '96-'99 timeframe, and thereby the ones immediately available, require higher capital investment than do natural-gas-fired plants, which then requires these higher capital costs to be offset by lower fuel, operating, and maintenance costs. Initially, while the return on and of the capital investment has to be included in the total cost of the electricity generated, these nuclear options would be more expensive than the natural-gas-fired alternative under today's financing arrangements. For the several decades of plant life remaining after the investment has been recovered, the nuclear option would be the much lower-cost option. This near-term/long-term trade-off is not currently marketable.

The life-cycle economic benefits of nuclear energy could become marketable as a result of potential government measures to address the carbon dioxide issue, measures such as a sequestration requirement or a tax on releases (or the converse, a tax credit for not releasing). Another possibility is substantial natural gas cost increases driven by rising demand, possibly aggravated by local delivery difficulties. Neither of these possibilities is likely in the near term, and the nuclear industry cannot and does not assume these outcomes in its planning process.

The responsible R&D approach is to identify this non-competitiveness during the investment recovery period as the prime hurdle the R&D should target to surmount, indeed eliminate. Then the external potentialities identified in the preceding paragraph and/or the long-term economic superiority of the nuclear option would constitute a strong deployment incentive.

This is primarily a "gap" that individual reactor designers must address for their own designs. Differing views exist among industry experts on the most likely way to get over this short-term economic hurdle. One view is that currently certified designs, with evolutionary cost improvements within the constraints of the certification, are the most likely path to near term success, especially if gas prices continue to increase. Another view is that a more innovative approach to defeating economies of scale with smaller plants must be undertaken, because smaller designs are more desirable choices in a deregulated business environment that works against large capital investment. These different views match, to a large degree, variations in deregulation across the country, and the expectation that small plants may fit better in states that have completed deregulation, while larger plants may fit better in states that have only partially implemented deregulation. These differing perspectives reinforce the need for choices – thus the imperative to pursue a dual track strategy that ensures both large and small plant options will be available. They reinforce the importance of this NTD Roadmap encompassing both tracks.

Critical to this market assessment is the overriding issue of "time to market" a major consideration in new capacity decisions in a deregulated electricity marketplace. Investors simply cannot afford the risk of ordering a plant that will not go on line for 8-10 years, by which time other investors may have added new capacity in that region. Time to market is of course dependent on plant construction times, which are essentially fixed by the technology and have already been the subject of significant optimization through new technology (e.g., modular construction techniques, time dependent 3-D plant modeling (computer-aided design + time dimension = "4-D modeling"). However, from the standpoint of uncertainty, investment risk, and opportunities for significant improvement, the most important dependency in "time to market" is the NRC licensing process.

Gap 2: Business Challenges of the Deregulated Electricity Marketplace

Better models for ownership and financing are needed to provide sufficient flexibility and risk sharing among investors and vendors to cover the relatively high construction costs of nuclear plants, despite their relatively low operating and fuel costs. This gap is primarily the responsibility of industry to solve. NEI has the lead for the industry in identifying the opportunities for improved business arrangements to facilitate new orders, and in working with the Administration and Congress to get administrative procedures and laws changed where necessary. Most of the issues that industry is discussing with Government relate to current provisions that unnecessarily increase the uncertainty and business risk associated with investing in a nuclear power plant in a deregulated marketplace. Some of these issues are discussed under "Other Issues" below.

Also important to closing this gap for near term deployment of new nuclear plants are means of informing and "conditioning" the marketplace to be more receptive to the longer term investment benefits of baseloaded nuclear plants. Benefits such as longer operating lives that allow more return on investment (ROI), low and predictable production costs (due primarily to low fuel costs), high reliability and availability, and other advantages typically go undervalued in short-term market investment decisions. Investment risks associated with longer construction times, capital intensiveness, and larger plants can be managed by reducing uncertainty and placing these short-term investment issues in perspective with longer-term investment value.

The industry needs to develop the business plans and models to facilitate the financing arrangements that will be required to build new plants in a deregulated electricity marketplace. This is a responsibility of industry, and NEI is facilitating this process through its development of a "Integrated Plan for New Nuclear Plants."

A key element of the industry plans to address this issue should be an effort to explore interest and build support for a consortium or consortia of owner/operators, vendors, architect/engineers, equipment suppliers and other investors, to share the risks and rewards of new plant ventures. The benefits of such consortia would be:

- Enhancing the technical and business expertise available through joint review of options and joint development of the generic aspects of an overall industry strategy and specific products of value to all participants (e.g., NEI guideline documents for ESP, COL, generic technology products)
- Leveraging resources, and enabling potential owner operators that are not ready to initiate an actual construction project to share resources with other owner operators who are ready for this step, thereby obtaining access to information that would help them later.

Enabling the formation of smaller and more focused consortia that would support the completion of engineering work and initial construction of specific designs, thereby creating the foundation for a "family of plants" infrastructure for specific designs.

Gap 3: Efficient Implementation of 10 CFR Part 52

10 CFR Part 52, created by the NRC in 1989 and affirmed by Congress in 1992 (EPACT), established three new licensing processes for future plants: Early Site Permit (ESP), Design Certification (DC), and Combined License (COL). These were judged as major improvements over the previous Construction Permit/Operating License process used for all existing U.S. plants. One of these processes has been demonstrated successfully: three standardized nuclear plant designs have been approved and "certified" for use in the U.S. However, these three certifications took 6-10 years each to complete, with many unanticipated process issues emerging to stall the process.

This gap has four key dimensions and solution objectives. The first three require essentially complete resolution to achieve near term deployment. The last one is not an obstacle to near term deployment, but deserves significant attention because of the opportunity it presents for major improvements toward more efficient and safety-focused regulation:

1. The DC process must be expedited to help resolve the "time to market" obstacle to nuclear plant orders in a deregulated market. In all instances of a design submittal that is complete and high quality, the DC process should take no more than three years, including the rulemaking phase. Experience gained from the first three DC rulemakings during the 1990s should provide a solid basis for achieving this goal. For DC applications that rely significantly on design information from a previously reviewed and/or certified design, the goal should be to complete the process in less than two years.
2. ESP and COL processes must be demonstrated successfully for new plants to be built. They must be shown to be stable and predictable processes that can be completed efficiently, in no more than 1-2 years each. Achieving this goal is equally important to resolving the "time to market" obstacle discussed above. The ESP process in particular allows companies to obtain pre-approval for numerous potential sites, reducing the time from project decision to commercial operation, should market forces determine the need for additional generating capacity. A strategic focus should be maintained in these application projects, beyond the minimum effort necessary to demonstrate the regulatory process. Industry and DOE should work to obtain multiple ESPs for nuclear projects, especially in areas of the U.S. with substantial projected power needs. With deregulation substantially in place, this means maintaining a sensitivity to market needs and using market incentives to get the right size plants built where the greatest needs are, from both an energy supply perspective and an emissions avoidance perspective.
3. Generic guidance needs to be developed to ensure efficient, safety-focused implementation of key Part 52 processes, including ESP, COL and ITAAC verification.
4. To increase investor confidence in predictable licensing and stable, efficient regulation, progress is needed toward a new regulatory framework for future plants. This effort would go beyond the ongoing efforts to risk-inform 10 CFR Part 50 for current plants, to establish a new regulatory framework that is fully risk-informed and performance-based. This effort promises to enhance the protection of the public health and safety by maximizing the safety focus and efficiency of future plant licensing and regulation. This will be a long term effort, with benefits accruing as various parts of the framework are completed and judged "ready for use" by applicants. Equally important is that progress

toward a new regulatory framework will increase the confidence of prospective applicants in the regulatory environment for new plants and encourage business decisions to proceed with new nuclear projects.

Gap 4: Nuclear Industry Infrastructure

Adequate industrial and human infrastructure exists today to build and operate a few new nuclear plants. But the ability of the industry to expand this infrastructure quickly enough to achieve the industry's new "Vision 2020" (50,000 MWe in new nuclear plant installed capacity) is not assured today.

In the area of human resources, the industry needs to begin to replace an aging workforce, and expand its employee base in the areas of skilled plant operators, maintenance technicians, engineers, project managers, and construction workers. With license renewal now a high probability for all of today's plants, the industry will need to train replacements in these areas for both currently operating plants and new plants. These new industry employees will be needed at both plant sites and manufacturing and engineering facilities.

The Federal Government will need new employees with nuclear skills as well. The NRC is facing an issue with an aging workforce that is at least as urgent as the industry's. The scientific and technical skills needed to license new nuclear power plants differ from those needed for oversight of today's nuclear plants—which has been the NRC's principal activity for the past 15 years—or in license renewal. To review applications for new licenses, the agency will need geologists, hydrologists, and other scientists. Current NRC staff may not have the appropriate expertise for this new function. To prepare for new nuclear power plant construction and operating license applications, the NRC should examine its staffing and determine how to fill any gaps in its expertise. Similarly, DOE, other federal agencies and national laboratories must ensure that they have the expertise and qualified staff for the development and staffing of future nuclear technologies.

Universities will need new faculty to conduct research and to educate future generations of nuclear professionals. Both DOE and industry support a multi-stakeholder effort to attract and retain top caliber nuclear talent, and have encouraged Congress to continue funding university programs in nuclear technologies, including continued support for their research reactors.

In order to retain and attract the top talent, it is imperative to create and sustain a favorable environment for nuclear energy that sends a clear message that nuclear professionals have expanding opportunities with bright futures. Industry and Government both have a part to play — through support of university programs involving nuclear technologies; through nuclear R&D funding; and through achievement of regulatory reform and investment in license renewal and new nuclear technologies. Each of these actions sends a message to young professionals who are making career decisions.

In the area of industrial infrastructure, the U.S. has lost much of its capacity for fabricating large long-lead nuclear components such as reactor vessels and steam generators, as well as specialized components for nuclear plants that must be manufactured and tested to special safety criteria. In almost all cases, the necessary capacity exists overseas, and will be used in the early stages of an expansion of nuclear plant construction in the U.S. For cost reasons, much of this infrastructure will have to be reconstituted here in the U.S. Also, for some components, the worldwide capacity may not be adequate to support such an expansion. This appears to be the case with the global industrial capacity for the forging of large nuclear plant components such as the reactor pressure vessel's bottom and top heads.

Gap 5: National Nuclear Energy Strategy

Until recently, the U.S. has not focused on a national energy policy and supporting strategy. The Administration and Congress are now working to develop and implement a strategy based on sound energy and environmental science, and supportive of our national economic objectives and limitations.

This presents an opportunity to establish a consensus for a national commitment to take advantage of nuclear energy's safety and environmental benefits, its low operating and fuel costs, its high reliability, and the U.S. position of technological leadership in advanced and even safer designs. Strategies for nuclear energy should be practical, results-oriented, and capable of implementation in the near term. To balance an urgent need to begin building new plants to meet our growing national need for emission-free electricity, a parallel effort should be undertaken to resolve longer term issues, especially ones related to the nuclear fuel cycle.

In a deregulated electricity marketplace, energy supply options should be able to compete fairly, without legal and financial obstacles (or special treatment provisions) erected for some technologies but not others. The nuclear industry has identified some circumstances where policies, statutory requirements, environmental regulations, R&D investments, and economic incentives regarding safety and environmental impacts may not be equivalent for nuclear energy and competing technologies. Both industry and Government should examine the various government policies, requirements, and funding programs, to correct areas of inequity. Also needing examination are areas of dual regulation, e.g., among NRC, EPA, FEMA, and OSHA.

Financing the development of new nuclear generation technology is difficult, since the wholesale power supply business is being deregulated and generation sources must compete in a highly competitive marketplace that is still evolving. Further, nuclear energy faces an untested licensing process that results in significant cost uncertainties. Virtually all of nuclear energy's environmental costs have been "internalized" by federal regulation (e.g., spent fuel disposal, cost of safety regulation, cost of routine emissions elimination), meaning that such costs are passed on to the electricity consumer in the case of nuclear energy, whereas comparable environmental costs for alternatives are carried by Government or deferred.

Federal R&D investments in the various alternative energy options are about an order of magnitude greater than nuclear energy supply R&D. It is highly appropriate for the Government to consider actions as part of the new National Energy Policy that recognize the need for a balanced investment strategy for new generation options that must compete in this new business environment. Such actions would encourage the deployment of new nuclear technologies – especially those offering improvements in licensability and economics. Although the industry will carry the primary burden of this investment, incentives should include significantly increased federal investment in R&D and demonstration, and the deferral or defrayal of federally mandated demonstration costs and regulatory review costs associated with new nuclear technologies and untested regulatory processes (e.g., ESP, COL).

KEY NEAR TERM DEPLOYMENT "ISSUES"

Based on the convention above, a number of "issues" have been identified that should receive appropriate attention by industry and/or Government to ensure progress and improved public understanding. These issues are already the subjects of significant attention and ongoing programs by both industry and Government, and thus no specific recommendations are provided in Chapter II-6 to address these issues. The following four key issues have received significant attention in RFI responses and/or the public arena:

- Nuclear Safety
- Spent Fuel Management
- Non-Proliferation
- Public Acceptance of Nuclear Energy

Nuclear Safety

It is important to note that safety is not considered a hurdle to expanded use of nuclear energy. Today's current plants are very safe and continue to improve. Challenges to safety systems have been reduced by a factor of three and safety significant events by a factor of ten. U.S. plants are ranked among the safest plants in the world by objective measures established by nuclear regulators and the World Association of Nuclear Operators (WANO). The certified "Generation III" designs have surpassed all regulatory and utility requirements for enhanced safety. Near Term Deployment options will continue to ensure high safety margins, because the superior reliability and performance standards demanded in the marketplace also ensure superior safety. It is also expected that various Generation IV options, many of which take fundamentally different approaches to achieving safety requirements, will match or exceed the levels of safety achieved by the already certified designs, if they can be deployed successfully.

The close scrutiny of the NRC and stringent licensing requirements requiring proof of safety through testing, analysis, and/or prototype demonstration, will ensure very high safety levels for all plants. Both NRC and industry engage in rigorous processes of identifying and resolving emerging safety issues, and will continue to do so for future plants. For example, the recent attack on the World Trade Center has raised concerns about the adequacy of sabotage protection at nuclear energy plants. Industry, NRC, and other responsible federal and state agencies are addressing this issue. A number of specific short-term actions have been taken, and longer-term options are under consideration. Near term deployment nuclear plants will benefit from this examination and will implement all actions deemed appropriate for existing plants. This and other experience with safety issues demonstrate that public concerns about safety need to be addressed by providing more accurate and timely information to the media regarding nuclear safety and how it is ensured and maintained.

Spent Fuel Management

In the NTD RFI, it was noted that spent fuel management is considered to be a longer term global fuel cycle issue, and that it is being addressed by the Generation IV Roadmap. The judgment of the NTDG in promulgating the RFI was that adequate response exists today, or adequate progress is being made on this issue to allow near term new plant construction in the U.S.; and that it is not an appropriate issue for near term deployment gap analysis. However, two RFI respondents nevertheless identified the spent fuel management issue as an important generic gap, reflecting a sense among many in the public that nuclear spent fuel management policy should be resolved prior to new plants being built.

The NTDG believes that spent fuel management is part of a larger long term issue of nuclear fuel cycle optimization, and that today's scientifically preferred solutions (centralized above-ground storage and deep geologic repository) may evolve, and other solutions, such as recycling spent fuel, may become preferred options in the future. In every scenario and solution to this issue under discussion, centralized storage is required, whether above or below ground, and whether permanent or retrievable. There is a consensus among experts that centralized aboveground storage and deep geological repository are adequate solutions, if phased and implemented properly. Hence, the continued progress toward satisfactory implementation of these solutions provides a basis for near term deployment, based on the following considerations:

- New plants are designed to use nuclear fuel more efficiently, achieving higher burnups than current plants. Some fuel cycle designs produce significantly less spent fuel volume.
- New plants are designed to safely store all nuclear fuel on-site for the life of the plant.
- Scientific consensus supports deep geological disposal as the best way to isolate spent nuclear fuel. In fact, the National Academy of Sciences concluded in a June 2001 report that "today's growing inventory of high-level waste requires attention by national decision-makers" and that "after four decades of study, geologic disposal remains the only scientifically and technically credible long-term solution."
- The U.S. Government has been studying the Yucca Mountain site in Nevada for permanent underground disposal of high level nuclear waste for over 15 years – an isolated site that scientific experts claim is one of the best geologic sites for the safe storage of nuclear waste on earth. Adequate progress is being made by DOE toward the goal of determining that site could be licensed as a spent fuel repository.
- Studies of Yucca Mountain have now yielded the scientific information necessary for a decision by the Secretary of Energy that there are no technical or scientific issues that will prevent Yucca Mountain from serving as a permanent repository, thereby providing the scientific basis to support a recommendation by Secretary Abraham to President Bush and to Congress to proceed on licensing a permanent repository at Yucca Mountain.
- Options for ultimate safe storage and disposition of spent fuel at a centralized repository are capable of significant expansion to accommodate increased spent fuel volumes, sufficient to support license renewal of current plants and near term deployment of new plants.

However, a major expansion of nuclear generation will inevitably focus much more attention to nuclear fuel supply consumption and spent fuel management – on a global basis. Each nation using nuclear energy will need to develop its own capability to properly manage spent fuel and/or collaborate on regional or global spent fuel management regimes that properly address health, safety, non-proliferation, and material control issues. These long-term issues, because of their international nature, will require many years to resolve, and efforts should begin soon to address them. The DOE's "Generation IV" program is doing that, by focusing on issues such as sustainability and nuclear fuel cycle optimization. These issues, however, should not have a detrimental effect on the near term deployment of new plants using current technology and regulations.

It is essential to the long-term future of nuclear power in the U.S. to complete the licensing and construction of a national repository for spent nuclear fuel and other government-generated high level wastes. No matter what nuclear technologies and fuel cycles are developed in the future to minimize the production of spent fuel, there will always remain a need for such storage capacity.

Also confirming this conclusion is a recent report by the Nuclear Energy Agency of the OECD: "nuclear waste management is fully consistent with the principles of sustainable development, and this issue should not be considered a barrier to the continued development of nuclear power."

Non-Proliferation

In the NTD RFI, it was noted that non-proliferation concerns are considered to be longer-term global fuel cycle issues, and are being addressed by the Generation IV Roadmap.

Extraction of weapons-usable material from spent commercial fuel is extremely difficult and more costly than other methods, and is not an issue in the U.S. for either current plants or new plants being considered for near term deployment in the U.S.

As discussed earlier under the spent fuel management issue, major expansion of nuclear generation will inevitably focus much more attention to nuclear fuel supply consumption, spent fuel management, and strict maintenance of the global non-proliferation regime maintained by the International Atomic Energy Agency (IAEA). Each nation using nuclear energy will need to develop its own capability, adhering to international standards, to properly manage spent fuel and/or collaborate on regional or global spent fuel management regimes that properly address both health and safety issues and material control/proliferation issues. These long-term issues, because of their international nature, will require many years to resolve, and efforts should begin soon to address them. The DOE's "Generation IV" program is doing that, by focusing on issues such as sustainability and nuclear fuel cycle optimization, as well as entering into international cooperative R&D through which international standards will evolve.

All of the design candidates considered for near term deployment utilize fuel cycles that do not recycle fuel. Therefore, they share the same strong proliferation resistance as existing reactors. As a result, these issues should not have a detrimental effect on the near term deployment of new plants using current technology and regulations.

Public Acceptance of Nuclear Energy

Many recent public opinion surveys show positive and growing public support for building new nuclear plants. "A new national survey finds that the dramatic increases in public support for nuclear energy have held at high levels, despite lower public concern about energy shortages. Almost two thirds of U.S. adults continue to support definitely building new nuclear power plants." [Bisconti, September 2001] Gallup, and other major media surveys are finding similar results. This support is particularly true in regions of the country where energy supply has not kept up with demand (e.g., California), and in regions of the country concerned about the environmental impacts of fossil fuels. However, public opinion surveys also reveal a general lack of understanding of nuclear technology, a rudimentary understanding of how nuclear power plants work and the nature of nuclear fuel; and a lack of appreciation for the clean-air benefits of nuclear power, the safety accomplishments achieved by currently operating plants, and the enhanced safety of new plants. Further, success in obtaining ESPs will require effective communications with the public living in the areas of potential sites.

OTHER ISSUES

There are a number of gaps and issues that have been raised by the nuclear industry that industry believes should be addressed by the Federal Government in the near term that have an impact on new nuclear plant deployment. These gaps and issues are primarily legislative or institutional in nature (e.g., amendments to existing laws, tax policies). No DOE-funded tasks have been identified in this Roadmap to support these items because they have not been examined in sufficient detail to offer recommendations, and because some of them are judged to be outside the NTD assigned scope.

NEI and other industry organizations are studying these gaps and issues in light of the need to assure equity in Federal energy laws and policies. The text below comes primarily from Congressional testimony by industry leaders, and does not currently represent a recommendation to either DOE or its advisors for any particular initiative. However, the NTDG believes that all of these matters warrant closer examination by the Administration, Congress, and industry, in order to determine which ones are critical to near term deployment.

Price-Anderson Act Renewal

The U.S. public has more than $9.5 billion of insurance protection if an accident were to occur at a commercial nuclear facility. This entire sum would be paid by the nuclear industry. The framework for this insurance coverage was established in 1957 by the Price-Anderson Act, which expires on August 1, 2002. The act requires each nuclear facility to have that insurance coverage to satisfy its statutory obligations. Neither taxpayers nor the Government pay for this coverage.

Like all the costs of electricity from nuclear power plants, the costs of Price-Anderson are internalized. That means the nuclear industry bears the cost of insurance, unlike the corresponding costs of some major power alternatives.

The Price-Anderson Act requires two levels of financial protection. The primary level provides liability insurance coverage of $200 million—insurance that is purchased by the utilities. If this amount is not sufficient to cover claims arising from an accident, a secondary level applies. For the second level, electric companies that own nuclear power plants must pay a retroactive premium equal to their proportionate share of the excess loss. That amount is $10 million per year, up to a maximum of $88.1 million per reactor. Currently, 106 nuclear reactors participate in the secondary financial protection program—103 operating reactors and three closed reactors that still handle used nuclear fuel.

Industry has recommended that Congress renew the act this year to ensure that Price-Anderson coverage will be available to companies that are considering building new nuclear power plants. Renewal also is important to Energy Department contractors, which are indemnified under the Price-Anderson Act. Nuclear power plants are grandfathered under the act; DOE contractors are not. The continued operation—and, where necessary, the cleanup—of federal sites depends on timely renewal of the Price-Anderson Act's provisions.

Changes to Atomic Energy Act

The industry has proposed several changes to the Atomic Energy Act to facilitate reform of the NRC and its regulatory processes to ensure the effective and efficient regulation of NRC licensees. Other changes are recommended by industry to remove unnecessary impediments that would inhibit the ability of nuclear power plant operators to make the transition from a cost-of-service market to a competitive market. The following actions recommended by industry to Congress for action could have a significant impact on near term deployment:

- Removing the requirement that the NRC conduct antitrust reviews. Other federal agencies conduct such reviews—notably the Securities and Exchange Commission, the Federal Trade Commission and the Federal Energy Regulatory Commission. Industry believes that an additional review by the NRC is unnecessary.
- Removing the restriction on foreign ownership of commercial nuclear facilities.
- Clarifying that the NRC has the discretion to determine the most appropriate form of hearing to hold in each circumstance and that the agency is not required to hold adjudicatory hearings for licensing proceedings unless it determines that such a proceeding is necessary.
- Clarifying that in the case of a combined construction and operating license for a nuclear power plant, the start of the operating license term is keyed to when operation begins, rather than when the license is initially issued.
- Clarifying that federal law preempts state insurance laws and constitutional provisions that would restrict insurers that satisfy NRC requirements from providing insurance to nuclear facilities.

Dual or Conflicting Regulation

Dual regulation of nuclear standards should be eliminated, particularly by NRC and EPA, who use widely divergent approaches to standards setting with frequently conflicting results. This situation creates significant uncertainties in projecting costs and schedules. These uncertainties adversely affect a wide range of decisions, including:

- Federal budgeting and site suitability for Yucca Mountain
- Mergers and acquisitions within the electric industry
- Expansion of nuclear energy through license renewal for today's plants and the licensing and building of new plants.

GENERIC GAP ANALYSES

The following are specific gap analyses addressing two of the five generic gaps listed above for which specific resource requirements are identified (Efficient Implementation of Part 52, and Economic Competitiveness). For each analysis, a short definition is provided for the gap, followed by a short description of the solution or outcome required. Then, projected resource requirements are identified to close the gap, listing the total resource needs, irrespective of source, estimated on an annual basis, from FY02 to FY10. For most of these gaps, the primary responsibility for addressing the problem lies with industry and the NRC. For the industry, NEI has the leadership role for both NRC interface and strategic policy matters. EPRI has primary responsibility for industry R&D on these generic issues, and works closely with NEI and NRC. Because of the strategic nature of these gaps, most frequently related to the challenges of dealing with complex federal requirements, DOE has an important role to play, via public-private partnerships, to help reduce federal obstacles unique to nuclear.

The resource requirements listed below are rolled up in summary form, along with design-specific resource requirements from Chapter II-5, in Appendix J to this Roadmap.

Generic Guidance for the ESP Process

Gap: Efficient Implementation of 10 CFR Part 52

Solution or outcome required: Develop generic guidance on all aspects of the ESP process, including application format and content, and a standard schedule of Applicant-NRC interactions. ESP generic guidance documents will include an update to the industry's Site Selection Criteria, and ESP guidance, to be approved by the NRC in advance of ESP filings, for preparation of an ESP Application Submittal.

Resource Requirements to close gap (G-1):

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	TOTAL
DOE										0
Industry	0.5	1	0.5							2
TOTAL	0.5	1	0.5							2

Note: All funding requirements in $M

Responsibility:
Lead: NEI, working with potential applicants; NRC
Supporting: EPRI. Note that at the current time, industry can probably close this gap without direct financial assistance from DOE. Industry should inform DOE if this assessment changes.

Early Site Permitting Demonstration

Gap: Efficient Implementation of 10 CFR Part 52

Solution or outcome required: Demonstrate NRC's ESP process for at least two "lead site" applications, and support up to two additional ESP applications (total of four) that demonstrate the ESP process for differing siting scenarios, e.g., existing nuclear sites, a possible "greenfield site," an existing non-nuclear industrial site or a site with an existing nuclear construction permit but no operating nuclear plant.

Resource requirements to close gap (S-1):

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	TOTAL
DOE	3	7	5							15
Industry	3	7	5							15
TOTAL	6	14	10							30

Note: All funding requirements in $M.

Note that the resource requirements listed above are difficult to judge at this point, because the full range of siting scenarios that could require a focused demonstration for licensing purposes is not fully appreciated. The NTDG recommends that DOE cost sharing of ESP demonstrations be limited to the total number clearly required to demonstrate the licensing process for the range of likely siting scenarios, thereby establishing "pilots" or "templates" for others to follow. Also, DOE has an interest in encouraging the banking of sites in regions of the country that could experience critical power shortages. For planning purposes, the funding levels above assume joint industry-DOE funding of ESPs for two existing sites, one green field site, and one non-nuclear or prior CP site. This probably represents an upper bound to the total number of sites and total funding required to close this gap.

Responsibility:
Lead: NEI, working with potential applicants; NRC
Supporting: DOE and EPRI.

Combined License (COL) Demonstration

Gap: Efficient Implementation of 10 CFR Part 52

Solution or outcome required: Demonstrate NRC's COL process for each NTD design option to be supported in Phases 2 and 3. This demonstration may reference a pre-existing ESP and/or DC, or may encompass one or both. Because of the unique nature of the technical issues involved in the COL application for each design, the COL process must be demonstrated separately for each NTD design that proceeds to deployment. DOE funding would only be required for those NTD designs that actually draw sufficient market interest to proceed with adequate industry resources to complete the COL process, assuming DOE cost share.

Resource Requirements to close gap (S-2):

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	TOTAL
DOE		5	10	10	5					30
Industry		5	10	10	5					30
TOTAL		10	20	20	10					60

Note: All funding requirements in $M.

For planning purposes, the assumptions used for these funding requirements are as follows:

- Total cost for a COL application and review for a certified design and approved site: $10M (assumes major industry and NRC effort (see below) to establish generic guidance to address application form and content, ITAAC verification)
- Total cost for a COL application and review for an un-certified design: $15M (COL scope only, not including design completion scope to support NRC's design approval. See Chapter II-5 for resource requirements for design completion.)
- For planning purposes, the assumed number of NTD designs that proceed with adequate industry resources to obtain matching DOE support is three certified designs and two uncertified designs.

These estimates could be low for total cost for each COL application, but are likely to represent an upper bound for total number of designs achieving adequate industry funding to proceed.

Responsibility:
Lead: NEI, working with potential applicants; NRC
Supporting: DOE and EPRI.

Generic Guidance for COL and ITAAC Processes

Gap: Efficient Implementation of 10 CFR Part 52

Solution or outcome required: Develop generic guidance on COL application form and content and processes for efficient, safety-focused COL review, construction inspection and ITAAC verification.

Resource Requirements to close gap (G-2):

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	TOTAL
DOE										0
Industry		1	1	1						3
TOTAL		1	1	1						3

Note: All funding requirements in $M.

Responsibility:
Lead: NEI, working with potential applicants; NRC
Supporting: EPRI. Note that at the current time, industry can probably close this gap without direct financial assistance from DOE. Industry should inform DOE if this assessment changes.

Risk-Informed Regulatory Framework for New Plants

Gap: Efficient Implementation of 10 CFR Part 52

Solution or outcome recommended: Develop risk-informed performance-based regulatory framework for future plants, to include both design and operational requirements applicable to all future plants.

Resource Requirements to close gap (G-3):

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	TOTAL
DOE			2	2						4
Industry	0.5	1	1	1	.5					4
TOTAL	0.5	1	3	3	.5					8

Note: All funding requirements in $M.

Responsibility:
Lead: NEI, working with potential applicants; NRC

Supporting: EPRI (initially); DOE (in FY04 and FY05). Note that at the current time, industry can probably complete all initial actions to close this gap without direct financial assistance from DOE. Cost-shared DOE assistance is envisioned to support detailed implementation (development of design-specific technical guidelines, as well as operational, programmatic and administrative guidelines). Industry should inform DOE if this assessment changes.

Advanced Information Management; Virtual Construction Technologies

Gap: Economic Competitiveness

Solution or outcome required: Develop advanced information management systems using open-architecture information technology, that can manage plant design, procurement, and operating data, and as-built conditions. Adapt advanced fabrication, modularization and construction technologies including time-sequenced virtual construction, to new plants. Integrate these information systems and apply them to future nuclear power plant construction and operation.

This solution develops the tools that will be used to reduce plant costs and time to market, described in more detail in the next task/solution.

Resource requirements to close gap (G-4):

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	TOTAL
DOE		1	2	2	1					6
Industry		1	2	2	1					6
TOTAL		2	4	4	2					12

Note: All funding requirements in $M

Responsibility: DOE and EPRI, working with applicants

Advanced Technologies to Reduce Design, Fabrication and Construction Time and Cost

Gap: Nuclear Plant Economic Competitiveness

Solution or outcome required: Although the primary responsibility for making sure new designs are economic resides with the individual reactor designer, there are a number of generic technologies that can be developed to assist designers achieve the goal, and to facilitate greater standardization in the industry. This solution would build on the advanced information management system and 4D plant model developed above and apply it to plans, programs and technologies that reduce plant cost by reducing the time required to design and construct the plant, including long lead component fabrication and component manufacture.

Adapt advanced modularization and construction technologies to establish applicability to future nuclear power plant construction. Comprehensive electronic modeling of the plant to be constructed, automation of information gathering and management, and automation of repetitive deductive conclusion-deriving functions are the essence of several advanced construction technology candidates currently emerging.

Develop standardized advanced man-machine interface systems for plant safety and control, including advanced sensors, programmable controllers, fiber optics, self-diagnostics, and human performance technologies.

Develop an integrated configuration control system for managing nuclear power plant programs that integrates with the design basis of the plant to provide continuity through the life cycle of a nuclear power plant. This system would implement collaborative engineering architectures, hand-off design information in a manner that preserves the integrity of design basis information, and thereby improve the confidence in expedited construction. The benefit of an integrated configuration control system is significant reductions to construction and operating costs as well as increased safety.

Systematically evaluate other opportunities (in addition to those above) to reduce plant construction time. Evaluate technologies, techniques, and human resource opportunities.

Resource requirements to close gap (G-5):

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	TOTAL
DOE		4	4	4	2					14
Industry	2	4	4	4	2					16
TOTAL	2	8	8	8	4					30

Note: All funding requirements in $M

Responsibility: DOE and EPRI, working with applicants

NOTE: The generic gaps associated with effective ownership and financing options for use in a deregulated marketplace, and industry infrastructure are viewed as industry responsibilities to address. NEI is responsible for these gaps and is working with utilities and suppliers to develop solutions.

II-4: NTDG ECONOMIC ANALYSIS

OVERVIEW: THE NEW ELECTRICITY MARKETPLACE

This chapter addresses the competitiveness of new nuclear power plants in the future deregulated electricity markets in the U.S. Under deregulation the basic definition of competitiveness has changed. New nuclear plant owners and developers have to consider not only economic superiority over other power generating technologies, but also meet the following deregulated market requirements:

- The ability to obtain over the mid- to the long-term market clearing prices that will cover not only the annual going forward (running) costs of the nuclear plant, but provide additional margin to return the initial investment and an adequate return on that investment.
- A short time to market, required both to respond to near-term market opportunities (high prices due to temporary supply shortage), and to reduce the risks and costs associated with long construction lead-times.
- Flexibility to adjust to the locational (nodal) nature of market prices and to the locational need for new plant projects. At each node the balance of local supply and local demand, as well as the availability of the electric transmission network to transmit power in or out of the region, will determine the nodal market prices and the need and timing for new capacity.
- Flexibility to adjust to time variations in market prices caused by the perception of availability of scarcity risks of fossil fuels to the marginal (price-setting) plants.
- The ability to satisfy the economics of the new plant as a cost and a profit center. New plants cannot depend on a parent utility to cover periods of financial shortfalls that may occur. Thus there exists a more pronounced need for a detailed risk analysis and for devising risk mitigation strategies before committing to a new plant project.
- The ability to meet the competition for new plant projects that is not just horizontal (between different types of power plants) but rather vertical (each plant competing individually against market prices). A utility or power developer will not only evaluate different generation options against each other to choose the least cost option, but will initially evaluate whether the projected regional and nodal forward market prices will provide adequate revenues to cover the full generation costs of each prospective plant.

Given the above market characteristics, how will new nuclear plants compete in the new deregulated markets? Nuclear plants have some advantageous and some negative attributes related to their role under the new market conditions.

- The capital investments in new nuclear plants are higher than required for most competing fossil-fired plants. This makes it more difficult to obtain the full funding package, under optimal financing terms, required for plant construction and startup.
- The construction lead-times for new nuclear plants are longer than the lead-times for fossil-fired plants. Nuclear plant lead-times in the U.S. are uncertain, in part since no new nuclear project has been initiated and completed in the U.S. for more than a decade. This uncertainty represents a risk to the potential investors who may require a premium

on the return they seek from their investments in prospective nuclear projects. The long lead-time implies that the economic conditions that justified project commitment may not be there when the plant reaches commercial operation.

- Nuclear power plants have very low marginal production costs and are called upon first to generate, thus assuring a constant revenue stream and generally large margins (between market prices and variable production costs) that are available to repay their initial investments.
- Nuclear production costs are very stable and are not subject to significant escalation pressures. Nuclear fuel costs are a small component of the production cost and are not influenced by market scarcity perceptions like fossil fuels. Thus nuclear production costs exhibit low time-dependent volatility, and are especially suitable for long-term stable bilateral contracts, which will be used increasingly in future electricity transactions.
- New nuclear plant vendors and prospective owners have embarked on programs aimed at controlling the investment costs in new plant projects, reducing construction lead-times to periods comparable with some fossil power plants, reducing the production costs below the best values achieved in currently operating nuclear plants, and assuring high annual capacity factors. These programs will improve the profitability and the attractiveness of future nuclear plants and will reduce the risks associated with committing to new plants.
- Under deregulation the assurance of safe operation has become a matter of first order economic necessity, rather than being an externally mandated regulatory requirement. The cost of regulatory-imposed reviews, shutdowns, and performance improvement programs in case of a safety breakdown has become prohibitive, to the point that safe operation, and strict compliance with regulations, are essential to guaranteeing a revenue stream and preventing corporate bankruptcy.
- The environmental liabilities (externalities) of nuclear power plants are relatively small portions of the production cost or total generation cost, and have been mostly internalized in their cost structure. The environmental liabilities of fossil-fired plants have only partially been internalized, resulting in uncertainty as to future emissions control and mitigation requirements and costs, and incremental risks related to uncertain total production and generation costs.

The decision to commit to a nuclear plant rather than a fossil plant will depend on the balance between the higher near-term economic risks associated with a nuclear plant, as compared with the higher lifetime economic risks associated with obtaining and burning fossil fuels. Nuclear plants represent greater front-end costs and risks, but are very attractive from a long-term operation perspective. Fossil-fired plants represent lower front-end risks but higher lifetime operating risks and reduced economic attractiveness over time. Short-term investors interested in relatively low risk projects of short duration may favor investing in fossil-fired plant projects. Longer-term investors, willing to absorb higher front-end risks for the sake of higher profit margins over longer periods later in the plant life, may consider nuclear plant projects, if the near-term disincentives can reasonably be mitigated.

DEREGULATED ELECTRICITY SUPPLY – THE NEW MARKETPLACE

The deregulation of the electric utility industry has brought significant changes to the way the new markets work, as compared with the regulated markets. The following discussion reviews how the newly deregulated markets work, and how prospective new owners make their plant commitment decisions.

The New Market Structure

The basic changes in the operation of the deregulated as compared with the previously regulated markets derive from three basic factors:

- The deregulated utilities are not limited to a fixed and contiguous service territory and are not operating under the obligation to serve their native load.
- The Equal Access provision of the Federal Energy Regulatory Commission (FERC) Orders 888 & 889 which have deregulated the electric transmission industry, require open access (for a fee) to the interconnected bulk transmission network to any generator serving any load.
- The regulated markets allowed a balance between investments in capital-intensive base load plants and in low front-end cost peaking plants, through a stable rate of return regulation. The deregulated markets are geared more to short-term low capital cost generation options, to compensate for price volatilities and mitigate investment risks.

The major impact of these trends has been the localization or the "nodalization" of the market and of the market clearing prices obtained at each node. Locational market clearing prices are determined by the balance between the electricity supply bids and the demand bids submitted within each location or node. These unconstrained market prices, however, are modified by the availability of low cost power that could be transmitted from outside the region. Market prices are increased if transmission constraints prevent the wheeling in of low cost power, or are decreased if abundant low cost power generated outside the region can be wheeled in, assuming transmission line availability, rather than relying on local higher cost generation. A specific node may be considered attractive if it is connected by adequate transmission capacity to an adjacent node (or region) where electricity supply is constrained and high market prices are available. A new plant can then dedicate a part of its output to supply its native load demand, and export the rest of its output to the adjacent region with high prices. The balance between generation for local demand and for exports will constantly vary, and will depend on the relative values of market prices in each node and the availability (and cost) of the interconnecting transmission capacity. From a new plant owner's perspective, the prices that count are the locational (constrained) market clearing prices, which take into account power transmission constraints and costs.

The market under deregulation is thus more complex than in regulated times. In order to understand the behavior of market prices, it is important to consider not just the generation nodes and the demand centers but also the transmission links connecting intra- and inter-regional supply and demand nodes. There is not much point in generating power without being able to ship it to market. It is quite possible that a plant will serve different demand nodes in different seasons of the year. Securing transmission rights on the regional network, leading to the different demand centers likely to be served, is a major consideration in choosing a new plant location. It may be that the owner may have to buy transmission rights on a line leading to a demand center during the months when demand is increasing, power prices are rising, and other suppliers may wish to capture that market.

The regulated markets operated as integrated markets at the power pool level. Participants in those markets were the local utilities with the obligation to serve the load within their service territories, and a wide assortment of local distribution companies, that purchased energy on the wholesale market for their customers. Utility generation costs were determined by the state Public Utility Commissions (PUCs), based on rate of return evaluation for each approved capital investment project. Fuel and Operating and Maintenance (O&M) expenses were directly passed through to the ratepayers, or reviewed through a Performance Based Regulatory (PBR) approach. The integrated utility, which also owned the transmission and distribution (T&D) regulated services, attached T&D charges covering its approved expenses in these areas to the generation costs, and these, with various other approved charges such as General and Administrative (G&A) public service research and development, conservation measures, and Qualified Facilities contract payments, formed the basis of the electric retail rates charged to the consumers.

In the deregulated world, the services performed previously by the regulated utilities have been disaggregated. The distribution network and customers billing services have remained with the utilities. The transmission system has been restructured but not deregulated. The transmission grids, though still under the ownership of the utilities, are operationally controlled by an Integrated System Operator (ISO) organization that functions at the state level, like the California ISO or the New York ISO, or as a Regional Transmission Organization (RTO), like the ISO New England, the PJM Interconnection, or the Midwest ISO. The various ISOs and RTOs are regulated by the FERC in Washington DC, and not by their State regulatory agencies. In its Order No. 2000 of December 1999, the FERC has mandated the formation of several large RTOs that will cover the entire U.S. transmission network. The Open Access requirement allows non-discriminatory access into the transmission grid, and all users must pay an equal and non-preferential charge, as determined by the ISO/RTO, for shipping power through the grid.

The regulated utilities have been freed from their obligation to serve, and have lost the monopoly position they have held within their service territory. The utilities' obligation to serve its ratepayers has metamorphosed into the State obligation to oversee the adequate supply of energy services to all its taxpayers - the citizens of that State. The State exercises this authority through its Energy Commission or its PUC, by monitoring supplies available from non-regulated generators both from within and from outside the State, by regulating the remaining commitments of the regulated utilities, and, in the last resort, by direct intervention in the markets. An example of such patterns has occurred in California during winter 2000/2001. During that energy shortage episode the State forbade the export of electric energy out of California during Emergency Notice periods, attempted to regulate availability factors and outage plans of all plants in California, and have used the California Department of Water Resources (DWR) as the State agent to purchase large amounts of long-term power supply contracts (at fixed prices), using the State General Fund as the revenue source.

The major change brought about by deregulation has been the restructuring of the generation system. New power plants can now be constructed by the utility companies, by Independent Power Producers (IPPs) seeking to sell their plant output through Power Purchase Agreements (PPAs), and by private developers willing to operate their plants as merchant plants relying on the short-term or spot energy markets to sell their output. A large number of new plant owners now exist, some owning a single or a part of a plant, others representing a large domestic diversified IPP such as Calpine, or a large domestic as well as international power developer/ producer such as AES. Both Calpine and AES represent a new type of private generating company with power plant assets spread over the entire country as well as abroad, and with total installed capacity (at 50,000 MWe or greater) larger than the largest formerly regulated utility in the U.S. The assorted older and new generators compete to sell their plants' output in the various energy markets developed in the deregulated world.

The Energy Markets – How They Work

Several types of electric markets now exist. The most stable market arrangements are the long-term bilateral contracts between power producers and large-sized end users. Such contracts specify the amount of energy delivered over each time period and the price for each block of power sold. Price escalation indices may be included in the PPAs, to account for unexpected rise in the seller's fuel cost or total generation costs. Following the instability in the California energy market of fall 2000 and winter 2000/2001, bilateral contracts are recognized as the preferable type of transaction between power generators and consumers. The role of bilateral contracts at stable prices in the future supply mix will likely increase. Nuclear power plants are especially well suited for such bilateral contracts due to their stable, and low-volatility production costs and total generation costs. Shorter term but also stable markets are the Block Forward Markets, in which power is sold in the forward markets for a fixed time period (a month) at a fixed price. Power consumers may solicit forward power contracts for a specified energy block at a given price range (not to exceed). Various power producers may offer a portion or all their available capacity for future delivery at a price range (no less than). The market maker matches requests and offers, and ensures that the physical delivery and the financial commitments of both parties are met. These types of energy markets are desirable due to their stable supply arrangements and low volatility prices. These market arrangements gained only limited acceptance in the U.S. due to imperfect market design problems, but have gained greater prominence after the energy supply problems of winter 2000-2001.

The more typical energy markets that came into being after the onset of deregulation are the single auction Day Ahead (DA) and Hour Ahead (HA) markets. In the single auction markets, for each time period, energy users submit bids for the capacity they wish to obtain at prices not to exceed, and the power producers submit bids for the amounts of power they are willing to generate at prices not less than. The market maker matches the supply and demand bids and determines the price that clears that market. This price is defined as the Market Clearing Price (MCP) and is the single price that all end-users pay all generators for power delivered during that time period. In the DA market, 24 hourly bids are submitted in one package for all hours of the next day and single price auctions are simultaneously held for each hour, resulting, when the process is completed, in twenty-four hourly MCPs for the next day. In the HA market, separate hourly auctions, for a small number of hours, are held about six hours prior to delivery. Market authorities try to channel a large portion of the demand into bilateral or block forward contracts. Most of the un-contracted demand is then met through the DA market and a small portion is provided through the HA market.

A special feature of the deregulated markets is the further modification of the single auction MCPs due to localized transmission network problems. In specific sub-regions within an ISO control area, which depend on power transmitted from other parts of the ISO, a supply-demand imbalance may occur, if due to line outages the grid cannot transmit in the power required to meet the localized demand. In that situation local higher cost plants might be called upon to generate to serve the local demand, while in other parts of the ISO territory, other plants, which normally would transmit power into the specific sub-region, will have to ramp down their capacity. The result is that localized MCPs in the affected sub-region may increase above the average single auction 'unconstrained' MCP, whereas in other parts of the ISO local MCPs may decline below the average MCP. Thus the transmission network can dynamically interact with the generation system to create regional or local MCPs, over some periods, which might vary from the unconstrained value. In the regulated world, the local utility, through its own reserve margin capacity, could resolve this problem. In the deregulated world, the coupling of the transmission and generation network is unique in its impact on local 'constrained' MCPs, and is the reason for the greater emphasis on transmission considerations in evaluating the prospects of investing in and constructing a new power plant. Under deregulation there is no obligation to provide reserve capacity, and such capacity is purchased as a separate service through a different auction process discussed below.

Due to the single auction price determination mechanism, those power producers with low production costs are likely to obtain, at least during peak demand hours, a large margin between the MCP received from the market and their own production costs. The accumulated price–cost margins provide the basis for the recovery of the fixed costs of the project, i.e., for the return of the initial investment an adequate return on that investment. Nuclear power plants, having inherently low production costs will accumulate the largest margins. The issue is whether the accumulated margins are large enough to provide returns of and on the initial investment, which is larger in a nuclear power project, as compared with a fossil-fired plant.

Both the DA and the HA markets represent forward energy markets. Other energy markets, which are essential for the proper matching of supply and demand, are the real-time energy markets. These markets have been developed to counter unexpected imbalances between the projected demand and available supplies. Such imbalances can occur due to unexpected or un-forecasted changes in the weather (a heat wave, a snow storm), due to forced outages in one or several generating plants that reduce the available supply, or due to transmission line outages, which constrain the inflow of required generation from outside the region. The real-time markets are cleared through the use of special pre-submitted 'adjustment' bids, through issuing generation orders to specially designated Regulation-Must-Run (RMR) plants, or through activating bids submitted in the various ancillary services (AS) markets.

Ancillary services represent the reserve energy markets, which in the regulated world were provided by the local utilities as a part of their overall obligation to serve the demand within their service territories at given reliability levels. With the removal of the obligation to serve, the local utilities were also released from having to provide reserve capacity for unexpected supply-demand imbalances. Providing reserve capacity is now the responsibility of the ISO, and is managed through the operation of the AS markets. Several such markets exist, each one for the provision of a specific reliability service. The highest quality service is the Regulation service, in which the participating plants operate under automated generation control (AGC) exercised by the regional ISO. The ISO operators from their centralized control room can issue electronic instructions to specific plants to ramp their capacity up or down, as required to meet local demand fluctuations. The regulation reserve service is further subdivided into 'regulation up' and 'regulation down' services. Only plants with very fast response time and ramp rates e.g., gas turbines or combined cycle plants qualify for this most valuable service.

Other ancillary services include the spinning reserve and the non-spinning reserve services, in which the plants are synchronized to the grid and can be called upon to generate within minutes of being notified. Nuclear plants qualify for these types of ancillary services and may dedicate a portion of their capacity to participate in these markets. A longer duration (thus less valuable) reliability service is the reserve service, in which a plant may be called upon to generate within an hour. This AS is reserved to older existing fossil units, which are maintained for peaking or reserve services by local utilities. Other reliability services include the provision of voltage control and black-start capability, both required to maintain the operation of the transmission network. The provision of ancillary services or the designation as a RMR unit qualifies the plant to receive capacity charges for every hour the plant is designated for that service, in addition to receiving market prices for every hour the plant is called upon to generate. The combined income from capacity charges and energy prices will improve the plant's margins and its prospects for capital recovery. Thus, participation in the AS markets, even for a portion of the plant output, may represent a good business opportunity in the deregulated markets.

Economic Considerations in New Plant Projects

Developers and investors in a specific power technology now consider the locational forward market clearing prices at several proposed plant sites, and analyze the adequacy of the price-cost margins likely to be obtained at those sites for capital recovery, as well as the adequacy of the transmission system for wheeling their output to high price demand centers. These are the real important considerations facing future nuclear plant owners.

Under deregulation, the new plant's only sources of revenues are its PPA, other merchant-type sales on the wholesale (spot) market, or sales of various ancillary services. The projection of these revenue streams is the first basic step in deciding on the advisability of building a new power plant, and what type of plant to construct. Such a projection will depend on analyzing the time-dependent energy supply and demand situations around the specific potential locations of the proposed power plant, and choosing the location, or node, where the highest sales revenue stream in relation to the local fuel prices and production costs can be identified. This differential between the nodal energy prices and fuel (production) costs, particularly in gas-fired generation, is termed the "spark-spread", and it represents one of the major decision-making criteria in choosing and locating a new power plant. A developer will seek to locate a new plant in regions with high price volatility and limited in-bound transmission capacity, conditions which should exist for several years and which should guarantee him large margins, though at higher risks.

Regions with many plants operating under long-term PPAs, and with adequate transmission interconnections, will exhibit relatively lower, stable, and less volatile energy prices. Such situations are beneficial to the regional ratepayers, though not necessarily to a new plant developer.

From a private sector developer's perspective, particularly in a new power plant project, there exist several mechanisms to control the risks inherent in the project:

- The developer may seek a plant with a low capital investment requirement and with a short construction lead-time. The recent trends in building gas-fired combustion turbines, micro-turbines, and wind power generators all testify to the investors desires to limit their exposure both with respect to total investment at risk, and regarding the time-at-risk, until a revenue stream is obtained.
- The developer may seek to reduce the equity portion of the total plant investment, increase the debt portion of the total up-front cost, and secure a high return on his investment, possibly including a risk premium, so as to compensate for the amount, and time of equity at risk.
- The developer may seek non-recourse (or, at worst, limited recourse) loan financing, in order to insulate his other projects from the project specific cost overruns or other non-performance events. In this type of loan arrangement the lenders have no recourse to other assets of the developer, outside of the project itself, in order to recover their loans.
- The most essential requirement for non- or limited recourse financing is a well-structured PPA, which specifies the amounts of power to be provided by the plant over the contract's period, and the obligation of the purchaser to take that power at the pre-determined contract price (a must-take contract). The sanctity of the PPA is the sole guarantee the developer has that his plant will produce a revenue stream from which to recover his own investment. A merchant plant developer not relying on PPAs will incur even greater risks on his investment, and will require stronger risk mitigation measures of the types mentioned above.
- The PPA can specify power prices equal to the projected locational MCPs at the plant site, or prices that are higher than market prices based on complex indexing formulae. The developer will evaluate the terms and conditions of the PPA, and his own expected production cost structure, in order to determine whether adequate margins will be generated from the future revenue stream, so as to allow the return of and on his investment.

NUCLEAR PLANT REALITIES

The new nuclear plants now being proposed for near-term deployment in the U.S. have specific characteristics that distinguish them from other base load power technologies available in the market. Some of those characteristics are advantageous for nuclear plant deployment, while others may represent risks that are acceptable to a limited number of utilities or developers. In general, nuclear plants, particularly in the U.S. where no new nuclear projects were initiated for several decades, may represent commitment and construction risks. On the other hand, when in operation, nuclear plants offer significant economic benefits. The decision to deploy a new nuclear plant will depend on the balance between the perceived short-term risks and the expected longer-term benefits. These issues are not just owner-specific but also depend on unique time-dependent local conditions, and on the way the project deal is finally structured among all the participants. The issues of nuclear-fossil competition, and competition against market prices were reviewed above. The specific issues related to the nuclear commitment decisions are addressed next, both qualitatively and with reference to representative numerical values.

Large Plant Size

Most new nuclear plants or coal-fired plants are designed for unit sizes of 1,000 MWe or larger. Gas-fired plant alternatives are now commercially offered at smaller unit sizes. The largest nuclear plant available for near-term deployment in the U.S. is 1,350 MWe, while a European vendor offers new plants for deployment in Europe in the capacity range of 1,550 –1,750 MWe. The larger size is required to obtain economy of scale benefits and to reduce the capital costs expressed in $/kWe units. Coal-fired plants are offered at unit sizes varying from 500 MWe to 1,300 MWe. Gas-fired combined cycle plants, which are the most widely used fossil generation technology now offered, are designed for a capacity range of 500-600 MWe. Gas-fired combustion turbines, used mostly for peaking applications, are offered in various equipment packages ranging in capacity from 100 MWe to 300 MWe.

The larger-sized nuclear plants, or coal-fired plants, while providing improved per kWe cost, have the drawback of exceeding demand growth in smaller-sized networks, or in slow load growth rate demand nodes. Large plants better fit fast expanding large-sized generation networks. In low growth markets, several years worth of demand growth are required before the need for large capacity addition materializes. In deregulated markets the addition of a large, low production cost, base load plant could significantly alter the marginal peaking plant that determines the locational or regional MCP. Thus the addition of a large nuclear or coal-fired plant may lower the MCPs and margins for all other plants participating in the regional single price auction market. These observations may change with the formation of the large RTOs mandated by FERC. These RTOs will represent very large electric systems and will require large capacity additions due to their size, even under low growth rate conditions. The impact of the large RTOs on locational MCPs is not yet clear. The formation of the RTOs will enhance the prospects for large base load plants that will likely operate under long-term PPAs. Both these trends will favor the commitments to large sized coal-fired or nuclear power plants.

Nuclear plant designers face the trade-off of increasing their plant size to obtain economy of scale benefits, or containing the growth of their plant capacity so as not to be locked out of smaller or slow growing markets. One way of finessing this dilemma is the development of modular nuclear plants based on the High Temperature Gas Reactor Technology (HTGR). The HTGR technology is amenable to smaller-sized modules of 110-285 MWe, which can be constructed, according to their developers, at unit costs similar to the unit costs of large Advanced Light Water Reactors (ALWRs). A large sized nuclear power station can be established from several small-sized modules constructed side by side, each operating as an independent plant. The smaller-sized modules may better match local load growth, and can be committed consecutively as the demand increases. Another benefit of the modular construction approach is the smaller total investment required for each module (compared with a large plant) that makes obtaining financing easier and reduces return on investment requirements. An additional benefit is that the early modules can start generating power and provide an early, though partial, revenue stream, even before the final and full station capacity is installed. While these expected benefits have been studied for decades, there exists little experience in the large-scale commercialization of the HTGR technology, and in achieving significant modularization benefits related to small-sized nuclear plants. Such benefits could be realized only when a significant number of modules have been constructed. These issues have been addressed with ALWR technology, although in a more limited way, by the design and development of the AP600. It is not clear yet how will RTO formation affects the prospects for the smaller modular HTGR type nuclear plants.

Capital Intensiveness

Nuclear plants, being large facilities and requiring massive radiation protection shielding and containment buildings, and heavy high pressure and corrosion resistant components, represent capital-intensive projects. A similar situation exists regarding coal-fired plants, which are also highly capital intensive, due to their large physical size, high pressure piping (particularly for supercritical units), and extensive pollution abatement equipment and facilities. Competing base load plant options such as gas-fired combined cycle plants having smaller sizes, being based on standard industrial components, and not requiring massive shielding, are less capital-intensive. Nuclear plants' engineering, procurement and construction (EPC) costs vary between 800 and 1,400 $/kWe. When project contingency and owners costs at 20 percent of the EPC cost are added, an overnight cost range of 1,000-1,600 $/kWe is estimated, excluding all time-related charges – escalation and interest during construction (IDC). At the high end of the range, for instance, assuming a capacity of 1,350 MWe and 1,600 $/kWe, a total overnight investment of 2.16 Billion Dollars is required, excluding time-related charges which could add 25-33 percent to the total project cost, depending on the project duration. At the lower end of the range at 1,090 MWe capacity and 1,000 $/kWe, an overnight cost of 1.09 Billion Dollars would be required.

Gas-fired combined cycle plants' EPC costs range between 450 and 650 $/kWe, with contingency and owners costs increment of 5 percent of the EPC cost. At an intermediate value range of a 500 MWe plant capacity and 600 $/kWe EPC cost, a total EPC cost of 0.30 Billion Dollars and an overnight cost of 0.32 Billion Dollars are computed. Combustion turbines require an even smaller up-front investment. At representative values for a 200 MWe plant with 300 $/kWe EPC cost and 5 percent contingency and owners cost increment, a total project overnight investment of 0.06 Billion dollars would be required.

The above representative numbers demonstrate the greater capital intensiveness of a nuclear plant, and, by inference, also of coal-fired plants, as compared with gas-fired power plant alternatives. The larger up-front investment is more difficult to raise, and results in a larger amount of value-at-risk throughout the construction period, until the plant starts generating power and providing an incoming revenue stream. In order to better control the risks associated with this large financing package, the lending institutions may require a greater portion of the total investment to be provided by equity financing, and the investors may require a higher return on investment (ROI) rate. Both factors tend to increase the time-related charges and the total project investment.

Modular HTGR type plants aim at alleviating the front-end nuclear financing hurdles by constructing smaller-sized modules, one at a time. Each module will require a lower up-front total investment. At a representative values set of 110 MWe module size, 1,250 $/kWe EPC cost and 20 percent contingency and owners cost increment, the total overnight cost is estimated at 0.16 Billion Dollars. This is significantly lower than the overnight investment requirement in a 1,000 MWe low cost nuclear plant or a 500 MWe combined cycle plant. This total investment is thus easier to arrange, and may require a lower ROI, even though the per kWe unit cost of the HTGR type module could be higher than the unit cost of the monolithic ALWR plant.

Longer Lead-Times – Slower to Market

Nuclear or coal-fired project lead-times are longer than gas-fired plants' lead-times due to the larger physical size of the nuclear or coal-fired project, the greater complexity of the design and the construction effort, and the need to demonstrate construction quality assurance and detailed paper trails of equipment purchases and of on-site construction practices, to the satisfaction of the regulatory agencies. Gas-fired plant lead-times are shorter than nuclear or coal-fired plant lead-times due to the smaller scope of the construction projects, the use of industrial quality equipment, and less regulatory-driven pre-approvals and quality assurance requirements.

In general, the overall project construction phase is divided into three time periods:

- The project startup period consists of three distinct activities. During this period, detailed site related permitting is completed; site preparation work is initiated based on a limited work authorization; and procurement of long lead-time components such as pressure vessels and steam generators in nuclear plants and gas turbines and boilers in fossil-fired plants is initiated.
- The project on-site construction period that involved three major activity phases, broadly defined as civil work, mechanical work and electrical work. Civil work includes excavation, foundation and base-mat concrete pour, and the erection of plant buildings. The mechanical work phase includes equipment installation, pipe connections and welding, and the completion of all plant facilities. The Electrical work phase includes all electrical cable laying and connections, installation of all measurement devices, construction and connection of the control room and electrical equipment, e.g., transformer installation.
- The project startup and acceptance testing period includes the testing of completed systems and their turn over from the construction crews to the operation staff; fuel loading and the operational testing of the entire plant; connection to the grid and the ramp up of generation to rated capacity; and the warranty testing activities required to ascertain that the completed plant and all related equipment perform to specifications for pre-determined time periods, and meet warranty conditions.

The advanced nuclear plant designs now proposed for near-term deployment in the U.S. require three to three and one half years for the on-site construction work phase, half year for startup and operational testing, and one year for the project development phase. This results in a total lead-time of sixty months or five years. (This does not include NRC regulatory approvals (i.e., ESP, DC, COL) which can add three or more years to total project lead-time.) Similar construction lead-times are projected for coal-fired plants. Combined cycle plants require shorter project lead-times consisting of one year for the up-front project development phase, and two years for on-site construction and startup. The total project requires thirty-six months or three years. Combustion turbines can be built with total lead-times of thirty months or two and one half years, consisting of one year for the project development phase, and one and one half years for on-site construction and startup.

The nuclear project lead-times mentioned here have been achieved and demonstrated abroad. There is no current experience of achieving such short lead-times in recent, and more modern, U.S. nuclear projects. Major nuclear industry programs, based on lessons learned in U.S. and foreign plant construction projects, are aimed at assuring the achievement of the projected short lead-times in future U.S. nuclear projects. The fossil plant lead-times discussed here have been demonstrated in several plants built in the U.S. and do represent real project experience. It should be mentioned that fossil plant lead-times in the U.S. have increased recently, due to longer project development phases than originally estimated, and longer wait periods for long lead-time equipment procurement due to shortage of manufacturing capacity.

Project lead-times have profound effects on total project capital investment requirements due to the accumulation of escalation charges and IDC throughout the construction period. Project lead-times also represent the major risk element in evaluating the prospects of committing to a new plant. Project risk is derived from three basic factors:

- The longer the plant is in construction before power is generated and a revenue stream is established, the longer the project financing is at risk, should the project fail. Thus longer construction projects require various mitigation strategies such as higher ROI on the equity portion of the investment and higher interest rate on the debt portion. The equity/debt ratio will be required to demonstrate higher equity fractions the longer the period that financing is at risk.
- The longer the project lead-time the more likely it is that the specific local conditions that gave rise to a project may change, thus reducing the economic justification for the project.
- In the deregulated markets the first plant that responds to a local need situation will reap the major economic benefit in terms of the highest, market price minus production cost, i.e., margin capture. That first plant, by virtue of its first entry into the market, will reduce the MCPs and margins for all follow-on other plants. This is the first-to-market syndrome.

It follows from the above discussion that nuclear plants or coal-fired plants with longer lead-times are at a disadvantage compared with gas-fired plants, due to the larger accumulation of time-related charges, due to potentially being late to market, and due to the risk of changing market conditions, on which the project profitability evaluation was originally made, before the project has reached commercial operation. Controlling and reducing project lead-time is an essential requirement for committing to a new nuclear or coal-fired plant. It remains to be seen whether the later in life economic benefits of nuclear projects make up for their greater up-front cost and risk. It is also unclear how RTO formation will impact first-to-market considerations.

Long Operating Lifetime

Nuclear and coal-fired plants' operating lifetimes are longer than gas-fired plant lifetimes. Currently operating nuclear plants are undertaking license renewal programs that will extend their operating license to sixty years, or beyond. Advanced nuclear plants proposed for near-term deployment are designed, from the start, for a sixty years operating period, though they will require license renewal beyond the forty year licensed term of operation. The plant designs are robust enough to support possible life extension beyond this nominal plant lifetime. The basis for these long plant lifetimes is the large margins designed into the plant equipment, the stringent quality assurance programs required to prevent equipment failure with potential radiological exposure consequences, the better choice and improved understanding of construction materials and alloys, the overall robust plant construction required as a radiation protection measure, and the high level of annual maintenance activities designed to prevent equipment deterioration or failure.

Gas-fired plants' operating lifetimes are much shorter. Little experience has yet been gained in the long-term operation of gas-fired combined cycle plants, and nominal plant lifetimes are not expected to exceed twenty-five years. Beyond the nominal value, plants' lifetime could be extended through major equipment replacement programs such as turbine rotor and blades replacement. The cost of such replacement program, as a fraction of the overall plant cost, is a much higher than the fraction of nuclear life extension programs is in relation to the initial plant investment. The reasons for the shorter lifetimes of gas-fired plants are that plant equipment is designed to industrial standards rather than to the more stringent (and more expensive) nuclear standards, the plants operate at much higher gas burning temperatures thus increasing metal fatigue and shortening lifetime, corrosive contaminants in the gas stream cause equipment corrosion, accelerated by the high temperature operating regime, and the plants are not as rigorously inspected and maintained on an annual basis as nuclear plants are. In order to conduct equal comparisons of nuclear and gas-fired plants it is necessary to carry out the analysis over a long time period, on the order of fifty years, and consider all major capital improvement programs throughout this period, properly discounted to a reference time-point. The economic performance of a gas-fired combined cycle plant will deteriorate if all periodic equipment replacement costs will have to be accounted for in the economic analysis.

The consequences of longer plant lifetimes are that nuclear plants have longer time periods over which to accumulate increasingly larger margins which will be used to repay the original plant investment, pay all equipment improvement and replacement programs, pay all fixed costs such as taxes and G&A, provide the required ROI, and generate net profit to the owners. While early in life the available margin is used to repay the construction loan and depreciation charges, once these expenses are retired after the first twenty years of life or earlier, a larger fraction of the available margin can be dedicated to provide ROI and net profits. In the deregulated world the construction and operation loan has to be returned, with interest, over a shorter time period than in the regulated world. Whereas in the regulated world the construction loan repayment period for a capital-intensive nuclear or coal-fired plant could be stretched over a 30 years period, in the deregulated world that loan is expected to be repaid over a 20 years period, or less. Gas-fired plant loans are expected to be repaid within ten years, or less. The longer the plant's lifetime, assuming no major equipment replacement needs, the more time exists, after the construction loan is repaid, to generate a return of and on the equity investment, and to further generate net profits.

A different situation exists with regard to a combined cycle plant. The construction loan is returned over a shorter time span, and the ROI is provided to the investors earlier in the plant's lifetime. Any additional funds generated have to be set aside against the need for a major equipment replacement program at the end of the nominally shorter lifetime. Investors who wish to obtain their expected ROI as soon as possible and move their capital to other projects would seek low capital-intensive power projects such as gas-fired power plants. Larger-sized investor organizations with longer capital recovery horizons can expect higher longer-term profits from nuclear power plants.

High Capacity Factors

Nuclear and coal-fired plants operate at higher capacity factors than gas-fired combined cycle plants. Peaking gas turbines are planned for operation at low capacity factors. The operating nuclear plants in the U.S. now consistently achieve fleet-average capacity factors in the 90 percent range. An increasing fraction of the plants achieve higher than 90 percent capacity factors over several consecutive years. This achievement is a testimony to the rigorous operating and maintenance programs implemented in all U.S. operating plants. The U.S. experience is now duplicated in many other countries that operate nuclear power plants, indicating that the U.S. experience is not unique but rather the norm, and that transfer of good practices and best-in-class benchmarking programs can improve the performance of nuclear plants worldwide. New nuclear plants proposed for near-term deployment are capitalizing on this accumulated experience, and the plants are designed, a priori, with best practices in mind, for lifetime operation at capacity factors of around 90 percent (87-93 percent range).

Gas-fired combined cycle plants have not yet achieved such high capacity factors, due in part, to the short period of experience in the operation of such plants in the U.S, and in part due to lack of standardization in equipment supplies. It is not anticipated that combined cycle plants will reach capacity factors as high as nuclear power plants, for the same reasons that affect their shorter operating lifetimes as compared with nuclear plant lifetimes. Current combined cycle plants now suffer from the same ownership and vendor and plant models balkanization problems that have negatively affected the earlier U.S. nuclear power program. It is expected that as the gas-fired generation industry matures and plant ownership is concentrated in several large operating companies, that performance improvement programs will be instituted, which will improve the future capacity factors. It is now assumed that gas-fired plants will achieve lifetime averaged capacity factors in the 80-85 percent range.

The achievement of high capacity factors is essential for plant profitability since each MWh generated results in incoming revenues. As each plant is its own profit center, the revenue and the margin bases for profitability depend on energy sales by the plant itself, rather than profits accumulated elsewhere by the parent owner. It follows that as each plant generates more energy it lays the basis for its own profitability. The longer the plant can operate on an annual and multi-year basis, the more profitable it will become, if properly managed.

Low and Predictable Production Costs

The major beneficial attribute of nuclear power plants is their low production costs. Nuclear production costs are not just low, but also are highly predictable, and exhibit low volatility over both the short and the long-term. The combination of low production costs, limited cost volatility, high capacity factors, and long operating lifetimes gives nuclear plants their distinctive economic advantage compared with fossil-fired plants over the long-term. Nuclear production costs for near term deployment plants are projected to be in the range of 10.0 $/MWh, compatible with the cost range of the best currently operating plants in the U.S. This cost is made up of 5.0 $/MWh O&M cost component and 5.0 $/MWh nuclear fuel cycle cost component. Nuclear fuel cycle costs include a 1.0 $/MWh contribution to the Federal Government for ultimate spent fuel disposal.

Gas-fired combined cycle plants exhibit higher production costs driven mostly by high natural gas prices. Combined cycle plant production costs are not very predictable due to the high volatility in natural gas prices, which was amply demonstrated in the fall 2000, winter 2000-2001 and spring 2001 seasons. Over that period natural gas prices first doubled from their historic values of 2.0 $/MMBTU to 4.0 $/MMBTU, then doubled and tripled again, and then exhibited shortage-related short-duration spot price peaks as high as 60 $/MMBTU in the Southern and Northern California energy markets. Finally, at the end of the Winter heating season, with the onset of the mild weather Spring and Summer 2001 seasons, natural gas prices have tumbled to the 3.0-4.0 $/MMBTU price range, depending on transmission costs and other local conditions. Gas prices are expected to increase again with the coming of the Winter 2001-2002 heating season, though this price increase may be moderated due to the economic downturn. Over the long run gas prices are expected to increase to the range of 3.5-5.5 $/MMBTU, reflecting the increased demand in the U.S. and the lower than expected reserves in the North American continent. This range will be compatible on a per BTU basis with oil prices at 20-32 $/Barrel, which seems to bracket the 25 $/Barrel long-range price target of the OPEC oil cartel.

It is necessary to multiply the per BTU fuel prices by the combined cycle plants' heat rate (in units of BTU/kWh) in order to convert the fuel cost to electric energy cost component expressed in $/MWh units. Depending on design and maturity, combined cycle plant heat rates vary between 7,500 and 6,000 BTU/kWh. For comparison purposes, assuming representative heat rate value of 7,000 BTU/kWh (multiply by a factor of 7.0), and further assuming a typical O&M cost figure of 2.0 $/MWh, a natural gas price range of 3.5-5.5 $/MMBTU will result in a combined cycle plant's production cost range of 26.5-40.5 $/MWh. When compared with the expected nuclear plant production cost of 10.0 $/MWh, the nuclear plant production cost advantage is significant.

Beyond the numerical production cost figures, which represent but current estimates, the more important observation is that combined cycle plants' production cost estimates are more volatile and prone to changes than nuclear production costs are. Based on the above representative values, at 3.5 $/MMBTU natural gas price, 24.5 out of 26.5 $/MWh, or 92 percent represent the fuel price component of the total production cost, which is less predictable and subject to changes. In nuclear production costs the fuel cost and the O&M cost components each represent about 50 percent of the total. Thus the volatile component of the nuclear production cost is both smaller, on an absolute basis, and represents a smaller percentage of the total, than the volatile component of the combined cycle plants' production costs. The nuclear plant production cost advantage is not just the lower numerical cost figure, but also the smaller volatile cost component; hence the lower production cost risk.

A MODEL FOR NUCLEAR PLANT COMPETITIVENESS – NUMERICAL RESULTS

This section deals with the numerical evaluation of the competitiveness of new nuclear plants, proposed for near term deployment, in the future energy markets. This section is divided into four parts. The first part reviews the methodology used in the economic analysis. The second part describes the computational model used. The third part reviews the base case results of the analysis, and the fourth part describes the sensitivity studies conducted around the base case.

Projection of the Competitive Playing Field

The approach taken in this study is to perform a parametric analysis of the range of economic competitiveness of advanced nuclear power plants in future market conditions. In order to do this, the total generation costs of future nuclear plants is compared against the total generation costs of gas-fired combined cycle plants, and gas-fired combustion turbines. A reasonable parameter range is defined as a base case, and then extensive sensitivity analyses are performed around the base case values. This analysis is not a definitive determination that could lead to a commitment decision for a specific plant at a specific location. Rather, a first order economic evaluation is performed that answers the question: "Is there a reasonable range of plant economic and performance parameters under which a future nuclear plant would be competitive in the market?" If, so then it makes sense for interested utilities or developers to perform detailed locational analyses of the competitiveness of specific plant designs, under specific deal terms. If not, then nuclear plants proponents will have to wait for different market conditions to evolve to the point that their designs will be competitive, or plant vendors will have to strive to modify their designs, so that they meet the economic conditions likely to prevail in the market.

The economic analyses performed here allow for three basic comparisons:

- A generation cost comparison between a nuclear plant and a combined cycle plant to indicate whether the nuclear plant represents an economical base load option on a lifetime generation cost basis.
- A base load cost-price comparison between market prices represented by the production cost of a combined cycle plant, and nuclear generation costs. The purpose of this analysis is to identify whether base load prices obtained cover nuclear production cost and provide a margin for the (partial) recovery of nuclear capital charges.
- A peak load cost-price comparison between market prices represented by the production cost of a combustion turbine, and nuclear generation costs. The purpose of this analysis is to indicate whether peak load prices, obtained mostly during the summer season, allow for full recovery of nuclear production cost, full recovery of nuclear capital charges during the peak prices period, and provide additional revenues to cover the portion of the

nuclear capital charges not recoverable from base load market prices during the remainder of the year.

In this stage of the analysis a reasonable parametric range is chosen that encompasses the specific plants data. Plant designers can interpolate among the base case and the sensitivity analysis computations, to identify the results most applicable to their own specific plant design data.

The Economic Analysis Model

The economic model used in this study was originally developed for the U.S. Council on Energy Awareness (USCEA), one of the predecessor organizations of the current Nuclear Energy Institute (NEI). This model was then transferred to Bechtel Power Corporation (BPC), where it was further developed and used for initial project profitability analysis. The model was then further extended by NEI and used in their economic evaluations related to advanced nuclear plant deployment. This model takes as an input a set of plant performance parameters and cost data, and a set of economic factors such as discount rate, inflation rate, cost of debt, return of equity, debt/equity fraction, interest during construction rate and debt repayment period.

The model can be exercised in either of two possible modes as follows:

- Generation cost calculator: The model computes annual fuel costs and annual fixed and variable O&M costs throughout the specified plant lifetime. The model computes annual fixed charges required to pay back the construction and operation loan as well as the interest on the loan, pay Federal and State taxes, and provide for plant depreciation and for decommissioning sinking fund, where appropriate. The model computes annual fixed charges required for the return of the equity investment in the plant, and using externally supplied ROI rate, the required annual return on equity. The model computes the year-by-year total generation costs i.e., the sum of the annual fuel costs, O&M costs, debt return charges, and equity repayment charges, throughout the plant's lifetime. The model then discounts and sums the stream of annual generation costs to yield levelized generation cost values.
- Profitability calculator: This is a reverse set of computations, which have been described earlier in this write-up. Given an externally supplied stream of annual market prices, the model peels off the computed annual fuel cost, annual O&M costs, annual debt return and tax related charges. For the remainder, the model then computes the internal rate of return (IRR), which will allow for the return of the equity portion of the plant investment, and provide a return on that investment. If the computed IRR is equal to or larger than the target ROI the utility or developer requires, the project could be considered profitable, on a first level of computations.

The model has been exercised in this study, mostly in the generation cost calculator mode, to provide generation costs of advanced nuclear power plants, gas-fired combined cycle plants and gas-fired combustion turbines, over a wide range of input parameter variations for each type of plant. The resulting sets of generation costs on an annual or lifetime-levelized basis were then compared, to yield conclusions regarding the prospective profitability of advanced nuclear plants under near-term market conditions.

Nuclear Plant Competitiveness – Base Case Results

A base case analysis comparing the generation costs of an ALWR, a gas-fired combined cycle plant and a gas-fired combustion turbine has been performed, using the NEI cost model. The basic assumptions of the analysis are reported in Tables 1 and 3. The results of the computations are reported in Tables 2 and 4, and shown in Figures 1 to 6. Some of the input variables used have been discussed above in the section on Nuclear Plant Realities. The more important variables that affect the relative competitiveness of the ALWR vs. the gas-fired plants are the natural gas price range, the ALWR capital cost range, and the returns required on the debt and the equity portions of the initial investment.

Future natural gas prices have been assumed in the range of 3.5 $/MMBTU to 5.5 $/MMBTU, increasing with inflation rate only (no real price escalation) throughout the plant lifetimes. A combined cycle plant heat rate of 7,000 BTU/kWh has been assumed, averaged over the 25 years of plant life. Gas turbine plant heat rate of 10,000 BTU/kWh has been assumed. The combined cycle plant is estimated to operate at a lifetime average capacity factor of 85 percent, and the gas turbine at an average peaking capacity factor of 30 percent.

In parallel with this gas-fired plants' cost/performance variability range, nuclear plant base capital costs were estimated to vary in between 1,000 and 1,200 $/kWe, with an additional 20 percent cost adder for contingency and owners costs. Thus, an overnight capital cost range of 1,200-1,440 $/kWe has been assumed here on a parametric basis. Nuclear plants are assumed to require an additional 30 Million Dollars cost increment for up-front licensing and project development activities, whereas the combined cycle plant and the gas turbine are expected to require only an additional 10 Million and 7 Million Dollars, respectively, for project development. The ALWR is assumed to have an improved heat rate of 9,600 BTU/kWh, to have a production cost of 10 $/MWh (equally distributed between fuel and O&M costs), and to operate at an annual average capacity factor of 90 percent over a conservatively estimated, forty year lifetime.

In terms of financial parameters, nuclear plants are assumed to require a 40 percent equity fraction of their total investment. The combined cycle plant, being a more mature technology, will require a 30 percent equity fraction, and the gas turbine will require 20 percent. The ALWR investors are assumed to require a 15 percent, before taxes, return on their equity, and the investors in the gas-fired plants are assumed to require a 13 percent ROI. The ALWR construction loan (Debt Fraction) is assumed to be returned over a 20 years period and carry an interest rate of 10 percent. The gas-fired plant debt is assumed to be retired over a ten-year period and to carry an interest rate of 9 percent. All three types of plants are assumed to reach commercial operation by January 1st 2010, and the project initiation dates are adjusted accordingly. ALWR total lead-time is estimated at five years, including one year of project development prior to construction start. The combined cycle plant's total lead-time is three years, and gas turbine plant's lead-time is two and one half years, both including one-year of up-front project development activities.

The basic conclusion derived from this analysis, given the sets of input data described above and shown in Tables 1 and 3, is that for the range of gas prices expected here, and for the combined cycle plant performance parameters listed, ALWRs with overnight capital costs in the range of 1,100 –1,500 $/kWe or higher, will represent a competitive base load generation option. Considering the production costs of the combined cycle plant to represent the market prices a nuclear plant will likely receive in the off-peak seasons of the year, and the production costs of the gas turbine as representative of market prices during the summer peak season, it is evident from the results shown in Tables 2 and 4, that ALWR will receive substantial margins above its production costs during the off-peak seasons, and high margins during the peak seasons. It is the accumulation of these margins that will be utilized to repay the plant investment and provide the required returns. The availability of adequate margins for capital cost repayment is the basis for nuclear plant profitability, and it accounts for the finding here of the ALWR being an economic option for base load generation.

First year generation costs for the ALWR and the two gas-fired plants are shown in Figure 1, for an ALWR with EPC cost of 1,000 $/kWe and natural gas price of 4.0 $/MMBTU, and in Figure 4 for an ALWR with EPC cost of 1,200 $/kWe and natural gas price of 5.0 $/MMBTU. First year costs are of importance, as they are higher than the levelized generation costs reported in Tables 2 and 4. Not only are the lifetime levelized costs higher than the corresponding ALWR costs, but the first year costs of the gas-fired combined cycle plant are higher than the corresponding ALWR costs. This is true for the range of natural gas prices and ALWR overnight capital cost cases evaluated in this section, even though the component makeup of the total generation costs are quite different. ALWR generation costs are capital charges dominated, while the combined cycle plant costs are fuel cost dominated, as seen in Figure 1. It is more difficult to receive market prices high enough to recover the full first year costs, or to cover the production costs and a significant fraction of the required capital charges. In time, as the annual generation costs decrease below the lifetime levelized values, adequate market prices can be obtained. It is, however, an issue as to how to operate the plant, with market prices below full cost recovery requirements during the first years of operation, and meet all the financial obligations to the debt holders and to the investors.

Two potential approaches to getting over the hurdle of the high first year's generation costs (in relation to market prices) include:

- Negotiating a PPA with higher than market price payments during the first years of the new plant's commercial operation, to be potentially repaid later in life.
- Levelizing the annual carrying charge payments over the new plant's lifetime, so that the high early in life investment repayments are reduced, and the low capital charges later in the plant's lifetime are increased. Such rescheduling of the annual carrying charges can be negotiated between the plant owners, investors, and the banks.

Options for resolving the price-cost mismatch early in life are discussed in a more quantitative way in the next section. The computations here indicate that this is as much of an issue for the gas-fired combined cycle plant as it is for the more capital-intensive nuclear plants.

Table 1 - Input Data - Generation Cost Comparison - ALWR, CCGT & GT
ALWR 1,000 $/KWe Base Cost, Natural Gas Price 4.0 $/MMBTU

Base case	1000 $/kw EPC	600 $/kw EPC	300 $/kw EPC
15 % IRR	40% Equity	Gas 4.0 $/MMBTU	Gas 4.0 $/MMBTU
6 months post construction hearings, startup	ALWR BaseCase	CCGT Base Case	GT Base Case
No production or mitigation credits		10 Years Debt Term	10 Years Debt Term
Project development start date	1-Jan-2005	1-Jan-2007	1-Jul-2007
Development time in months	12	12	12
Construction time in months or "manual"	42	24	18
Post-construction time in months	6		
Commercial operation date	1-Jan-10	1-Jan-10	1-Jan-10
Number of years before first capadd			
First capadd construction time in months			
Number of years before second capadd			
Second capadd construction time in months			
Escalation start date	1-Jan-2000	1-Jan-2000	1-Jan-2000
Inflation rate	2.0%	2.0%	2.0%
Project operating period in years	40	25	25
Discount rate	12.0%	12.0%	12.0%
Plant net electrical output in MWe	**1,000**	**500**	**200**
Net plant capacity factor (% or "detailed")	90.0%	85.0%	30.0%
Base EPC cost ($'000)	**1,000,000**	**300,000**	**60,000**
Construction schedule "manual" or "auto"	auto	auto	auto
Startup and mobilization ($'000)		5,000	5,000
First capital addition cost ($'000)			
Second capital addition cost ($'000)	-	-	-
Owner development costs & fee ($'000)	60,000	10,000	7,000
Owner costs & contingency (% TCB)	20.0%	5.0%	5.0%
Owner post-construction costs ($'000)			
Working capital: on or "off"	on	off	off
Equity share	40%	30%	20%
Term debt tenor (including any refinance)	20	10	10
Term debt interest rate	10.00%	9.00%	9.00%
Pre-refinance period			
Refinanced term debt rate			
Term debt repayment style (enter "M" or "P")	M	M	M
Closing costs ($'000)	1,000	500	500
Upfront fees (% debt)	-	1.0%	1.0%
Debt service reserve (months)	6	6	6
Equity during construction (%)	40%	30%	20%
Interest rate during construction (IDC)	10.0%	9.0%	9.0%
Commitment fee rate	0.75%	0.75%	0.75%
Fuel price in $ per MMBtu	-	**4.00**	**4.00**
Net heat rate in MMBtu per kWh	9,600	7,000	10,000
Fuel assemply rental costs ($'000 p.a.)	**39,420**		
Fuel escalation rate	2.00%	2.00%	2.00%
Total or variable O&M ($/MWh)	**5.00**	**2.03**	**1.00**
Custom periodic maintenance ("on" or off)	off	off	off
Fixed O&M and G&As ($'000 per annum)			
D&D sinking fund amount ($ million)	465		
Nuclear industry fees ($/MWh)	1.00		
Income tax rate	35%	35%	35%
Tax depreciation period (avg.)	15	15	15
Declining balance rate (avg.)	1.50	1.50	1.50
Investment tax credit rate	-	-	-
Tax carry forward in years	3	3	3
Property tax	1.0%	1.0%	1.0%
Project levered after-tax IRR (enter value or '?')	15.0%	13.0%	13.0%
Power price (enter $/MWh or 'detailed' or '?')	?	?	?
Power/fixed capacity escalation rate	1.0%	1.0%	1.0%
Carbon emissions credits in $/ton			
SO2 emission credits in $/ton			
Nox emission credits in $/ton			
Production sales credit in nominal $/MWh			
Production tax credit in nominal $/MWh			
Sales/tax credit validity period in years (if any)	5.0	5.0	5.0

Table 2 - Computational Results - Generation Costs Comparison - ALWR, CCGT & GT ALWR 1,000 $/KWe Base Cost, Natural Gas Price 4.0 $/MMBTU

		1000 $/kw EPC 40% Equity ALWR BaseCase	600 $/kw EPC Gas 4.0 $/MMBTU CCGT Base Case 10 Years Debt Term	300 $/kw EPC Gas 4.0 $/MMBTU GT Base Case 10 Years Debt Term
First year generation $ per MWh	Constant dollars	**44.9**	**45.8**	**64.2**
Capital cost		34.9	15.7	23.2
- of which : IRR		17.8	4.9	3.5
O&M cost		5.0	2.0	1.0
Fuel cost		5.0	28.0	40.0
Initial years production credit (if		-	-	-
Lifecycle generation $ per MWh		**41.6**	**42.7**	**59.9**
Capital cost		31.6	12.5	18.7
O&M cost		5.0	2.0	1.0
Fuel cost		5.0	28.2	40.3
First year generation $ per MWh	Nominal dollars	**55.2**	**56.3**	**79.1**
Capital cost		42.9	19.4	28.6
O&M cost		6.2	2.5	1.2
Fuel cost		6.2	34.5	49.2
Initial years production credit (if		-	-	-
Lifecycle generation $ per MWh		**60.0**	**61.6**	**86.4**
Capital cost		45.4	17.5	26.2
O&M cost		7.3	3.0	1.5
Fuel cost		7.3	41.1	58.8

Nuclear plants represent a less volatile generation cost option and, thus a more suitable choice for long-term bilateral contracting with large customers interested in stable energy prices. This is evident from the results shown in Figures 1 and 2, and other similar tables and figures derived from the computations performed in the course of this study. Figure 2 shows the year-by-year breakdown of the ALWR generation costs, at 1,000 $/kWe EPC cost. Figure 5 shows the year-by-year cost breakdown for a combined cycle plant burning natural gas at a price of 5.0 $/MMBTU. The equity and debt related cost components are the largest contributors to the lifecycle costs. At a natural gas price of 4.0 $/MMBTU, fuel costs represent 67 percent of the lifecycle generation cost of the combined cycle plant, as seen in Figure 3. O&M costs represent an additional 5 percent of the total cost. As gas prices increase to 5.0 $/MMBTU, fuel costs account for 72 percent of the total lifecycle cost, with O&M costs contributing an additional 4 percent, as seen in Figure 6. Thus the volatile component of the combined cycle plant's lifecycle cost represents 70 percent or more of the total cost, given the range of the likely natural gas prices assumed here. This volatile cost component increases with the increase in natural gas prices.

The volatile percentage of the ALWR lifecycle cost, at an overnight cost of 1,200 $/kWe, is computed as 24 percent, (12 percent fuel cost component and 12 percent due to O&M costs). Capital charges are determined at the commercial operation date, and the payment schedule established at that time is not subjected to change during the plant's lifetime. As nuclear

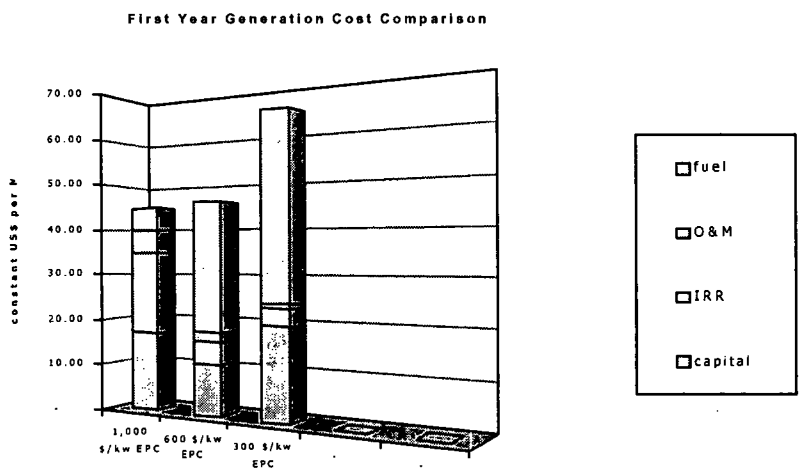
Table 3 - Input Data - Generation Cost Comparison - ALWR, CCGT & GT
ALWR 1,200 $/KWe Base Cost, Natural Gas Price 5.0 $/MMBTU

Base case	1,200 $/kw EPC	600 $/kw EPC	300 $/kw EPC
15 % IRR	40% Equity	Gas 5.0 $/MMBTU	Gas 5.0 $/MMBTU
6 months post construction hearings, startup	ALWR BaseCase	CCGT Base Case	GT Base Case
No production or mitigation credits		10 Years Debt Term	10 Years Debt Term
Project development start date	1-Jan-2005	1-Jan-2007	1-Jul-2007
Development time in months	12	12	12
Construction time in months or "manual"	42	24	18
Post-construction time in months	6		
Commercial operation date	1-Jan-10	1-Jan-10	1-Jan-10
Number of years before first capadd			
First capadd construction time in months			
Number of years before second capadd			
Second capadd construction time in months			
Escalation start date	1-Jan-2000	1-Jan-2000	1-Jan-2000
Inflation rate	2.0%	2.0%	2.0%
Project operating period in years	40	25	25
Discount rate	12.0%	12.0%	12.0%
Plant net electrical output in MWe	**1,000**	**500**	**200**
Net plant capacity factor (% or "detailed")	90.0%	85.0%	30.0%
Base EPC cost ($'000)	**1,200,000**	**300,000**	**60,000**
Construction schedule "manual" or "auto"	auto	auto	auto
Startup and mobilization ($'000)		5,000	5,000
First capital addition cost ($'000)			
Second capital addition cost ($'000)	-	-	-
Owner development costs & fee ($'000)	60,000	10,000	7,000
Owner costs & contingency (% TCB)	20.0%	5.0%	5.0%
Owner post-construction costs ($'000)			
Working capital: on or "off"	on	off	off
Equity share	40%	30%	20%
Term debt tenor (including any refinance)	20	10	10
Term debt interest rate	10.00%	9.00%	9.00%
Pre-refinance period			
Refinanced term debt rate			
Term debt repayment style (enter "M" or "P")	M	M	M
Closing costs ($'000)	1,000	500	500
Upfront fees (% debt)	-	1.0%	1.0%
Debt service reserve (months)	6	6	6
Equity during construction (%)	40%	30%	20%
Interest rate during construction (IDC)	10.0%	9.0%	9.0%
Commitment fee rate	0.75%	0.75%	0.75%
Fuel price in $ per MMBtu	-	**5.00**	**5.00**
Net heat rate in MMBtu per kWh	9,600	7,000	10,000
Fuel assemply rental costs ($'000 p.a.)	**39,420**		
Fuel escalation rate	2.00%	2.00%	2.00%
Total or variable O&M ($/MWh)	**5.00**	**2.03**	**1.00**
Custom periodic maintenance ("on" or off)	off	off	off
Fixed O&M and G&As ($'000 per annum)			
D&D sinking fund amount ($ million)	465		
Nuclear industry fees ($/MWh)	1.00		
Income tax rate	35%	35%	35%
Tax depreciation period (avg.)	15	15	15
Declining balance rate (avg.)	1.50	1.50	1.50
Investment tax credit rate	-	-	-
Tax carry forward in years	3	3	3
Property tax	1.0%	1.0%	1.0%
Project levered after-tax IRR (enter value or '?')	15.0%	13.0%	13.0%
Power price (enter $/MWh or 'detailed' or '?')	?	?	?
Power/fixed capacity escalation rate	1.0%	1.0%	1.0%
Carbon emissions credits in $/ton			
SO2 emission credits in $/ton			
Nox emission credits in $/ton			
Production sales credit in nominal $/MWh			
Production tax credit in nominal $/MWh			
Sales/tax credit validity period in years (if any)	5.0	5.0	5.0

Table 4 - Computational Results
Generation Costs Comparison - ALWR, CCGT & GT
ALWR 1,200 $/KWe Base Cost, Natural Gas Price 5.0 $/MMBTU

		1,200 $/kw EPC 40% Equity ALWR BaseCase	600 $/kw EPC Gas 5.0 $/MMBTU CCGT Base Case 10 Years Debt Term	300 $/kw EPC Gas 5.0 $/MMBTU GT Base Case 10 Years Debt Term
First year generation $ per MWh	Constant dollars	**50.9**	**53.4**	**75.0**
Capital cost		40.9	16.3	24.0
- of which : IRR		21.1	5.3	4.2
O&M cost		5.0	2.0	1.0
Fuel cost		5.0	35.0	50.0
Initial years production credit (if any		-	-	-
Lifecycle generation $ per MWh		**47.3**	**49.8**	**70.0**
Capital cost		37.3	12.5	18.6
O&M cost		5.0	2.0	1.0
Fuel cost		5.0	35.2	50.3
First year generation $ per MWh	Nominal dollars	**62.7**	**65.7**	**92.3**
Capital cost		50.4	20.1	29.5
O&M cost		6.2	2.5	1.2
Fuel cost		6.2	43.1	61.6
Initial years production credit (if any		-	-	-
Lifecycle generation $ per MWh		**68.2**	**71.8**	**100.8**
Capital cost		53.5	17.4	25.9
O&M cost		7.3	3.0	1.5
Fuel cost		7.3	51.4	73.4

Figure 1 - First Year Generation Costs Comparison -
ALWR, Gas-Fired Combined Cycle Plant & Gas Turbine
Natural Gas Price 4.0 $/MMBTU - Constant Year 2000 $/MWh



overnight capital costs increase to 1,440 \$/kWe, the volatile cost component decreases to 22 percent (half fuel cost contribution and half O&M cost contribution). Nuclear plant's lifecycle costs are thus estimated here to be only one third as susceptible to market impacts as are the combined cycle plant costs. Nuclear plants incur an up-front cost uncertainty and risk but provide lifecycle cost stability. Gas-fired plants incur lower up-front cost uncertainty and risk, but represent a greater economic risk over their lifetime, due to their greater exposure to fuel

Figure 2 - Year-by-Year Generation Cost Comparison - ALWR 1,000\$/KWe EPC Cost - Year 2000 Constant \$/MWh

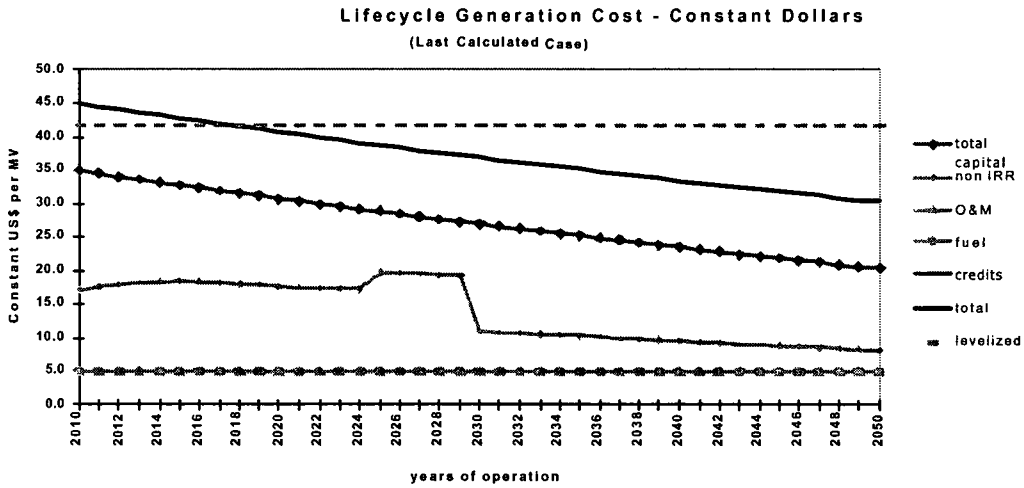
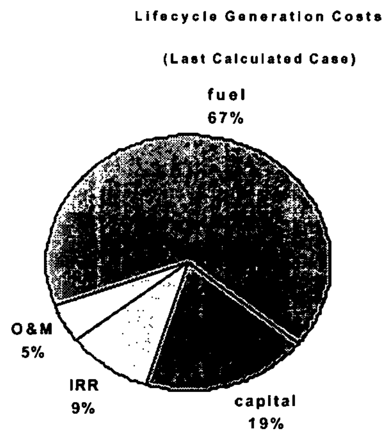


Figure 3 - Lifecycle Generation Costs Breakdown - Natural Gas Natural Gas Price - 4.0 \$/MMBTU - Constant Year 2000 Dollars



supply curtailments and market disruptions. This trade-off needs to be resolved by interested utilities and developers, depending on the overall corporate risk mitigation strategies, on specific locational factors, and on possible deal terms.

Figure 4 - First Year Generation Costs Comparison -
ALWR Gas-Fired Combined Cycle Plant & GasTurbine
ALWR EPC Cost - 1,200 $/KWe - Natural Gas Price 5.0 $/MMBTU
Constant Year 2000 Dollars

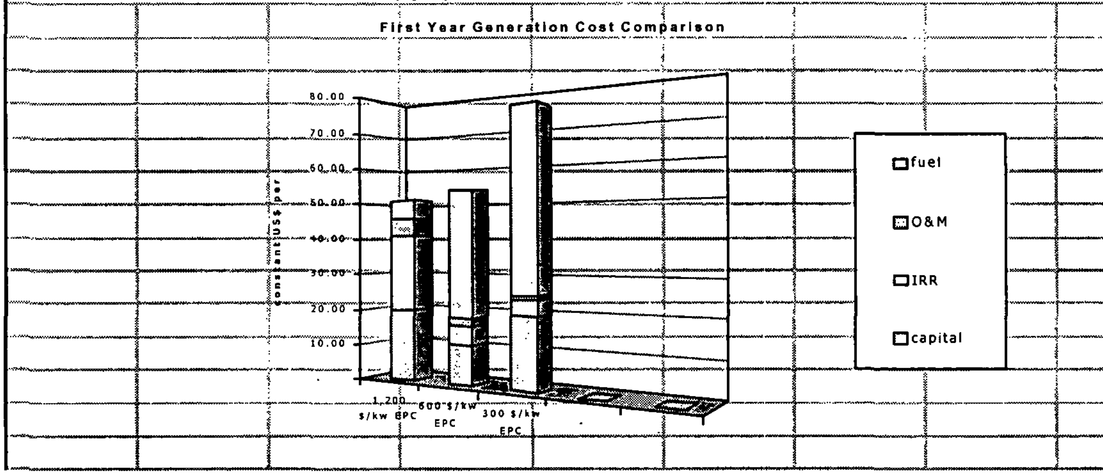


Figure 5 - Year-by-Year Generation Cost Breakdown - Gas-Fired Combined Cycle Plant
Gas Price 5.0 $/MMBTU - Constant Year 2000 Dollars

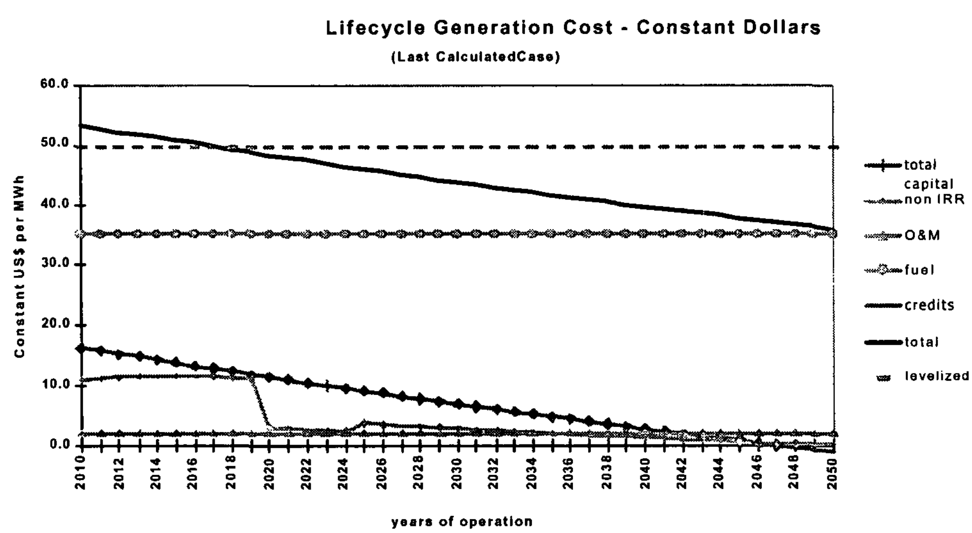
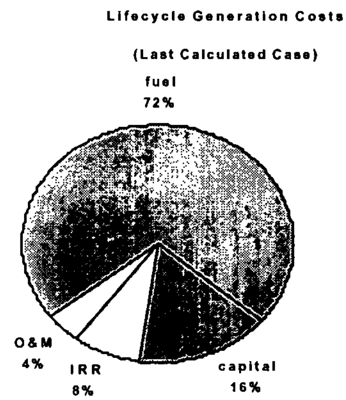


Figure 6 - Lifecycle Generation Cost Breakdown by Component
Combined Cycle Plant - Natural Gas Price - 5.0 $/MMBTU
Constant Year 2000 Dollars



Nuclear Plant Competitiveness – Sensitivity Analyses

The parameter range of the ALWR-gas-fired plants cost comparisons was extended in the Sensitivity Analysis part of this study, to investigate the envelope of nuclear plant competitiveness under various cost and performance conditions. The results of this section can be used for extrapolating of the range of nuclear competitiveness, identified in the previous section. Six input variables were changes parametrically, one at a time, and the generation costs of the appropriate plants were computed under the new assumptions. The results of these computations is the development of sensitivity values that indicate by how much will plant generation costs change, per unit change in an input variable. The input and output tables of the computer runs of the Economic Analysis Model are presented in a separate, stand alone version of this Chapter. The computational results are presented below, in decreasing order of sensitivity.

- Change in Nuclear Plant Overnight Capital Cost
  The Base (EPC) capital cost of a prospective ALWR was parametrically changed between 800 $/kWe and 1,600 $/kWe. An additional increment of 20 percent for contingency and owners costs was assumed in converting the EPC cost to an overnight capital cost. It is found that a change of plus/minus 100 $/kWe in the ALWR capital cost results in a change of plus/minus 2.8 $/MWh in the ALWR 40 years levelized generation cost. All other cost/performance characteristics of the ALWR are similar to the base case values shown in Tables 1 and 3.
- Change in Natural Gas Price to a Combined Cycle Plant
  Natural gas prices to a combined cycle plant were varied between 3.5 $/MMBTU and 5.5 $/MMBTU. The combined cycle plant's generation costs were computed, all other input

variables held similar to the values shown in Tables 1 and 3 above (7,000 BTU/kWh heat rate, 85 percent annual capacity factors). It is found that a change of plus/minus 1.0 $/MMBTU will result in a change of the levelized generation cost of a combined cycle plant by plus/minus 7.0 $/MWh.

- <u>Change in Natural Gas Price to a Gas Turbine</u>
  Natural gas prices to a gas turbine peaking plant were varied between 3.5 $/MMBTU and 5.5 $/MMBTU. The gas turbine plant's generation costs were computed, all other input variables held similar to the values shown in Tables 1 and 3 above (10,000 BTU/kWh heat rate, 30 percent annual capacity factors). It is found that a change of plus/minus 1.0 $/MMBTU will result in a change of the levelized generation cost of a combined cycle plant by plus/minus 10.0 $/MWh.
- <u>Change in Equity Investment Fraction in a Nuclear Plant</u>
  The equity fraction of the total investment in an ALWR is varied between 10 percent and 50 percent (nominal value of 40 percent). All other input variables were kept constant at the base case values of Tables 1 and 3. The sensitivity values are found to increase as nuclear plant's capital cost increases. It is found that at an EPC cost of 1,000 $/kWe, a change of plus/minus 10 percent in the ALWR equity investment fraction results in a change of plus/minus 2.4 $/MWh in the ALWR 40 years levelized generation cost. At an EPC cost of 1,400 $/kWe, a change of plus/minus 10 percent in the ALWR equity investment fraction results in a change of plus/minus 3.9 $/MWh in the ALWR 40 year levelized generation cost.
- <u>Change in ROI Requirements for a Nuclear Plant</u>
  The ROI rate required for the repayment of the equity investment in a nuclear plant has been varied parametrically between 12 percent and 17 percent (nominal value of 15 percent). All other input variables were kept constant at the base case values of Tables 1 and 3. The sensitivity values are found to increase as the nuclear plant's capital cost increases. It is found that at an EPC cost of 1,000 $/kWe, a change of plus/minus 1.0 percent in the ALWR ROI rate results in a change of plus/minus 2.0 $/MWh in the ALWR 40 year levelized generation cost. At an EPC cost of 1,400 $/kWe, a change of plus/minus 1.0 percent in the ALWR ROI rate results in a change of plus/minus 3.0 $/MWh in the ALWR 40 year levelized generation cost.
- <u>Change in the Debt Repayment Period for a Nuclear Plant</u>
  The repayment period of the debt fraction of the investment in an ALWR was varied between 10 years and 25 years. The nominal value is 20 years. All other input variables were kept constant at the base case values of Tables 1 and 3. The sensitivity values are found to increase the nuclear plant's capital cost increases. It is found that at an EPC cost of 1,000 $/kWe, a change of plus/minus 5 years in the ALWR debt repayment period results in a reverse change of minus/plus 1.4 $/MWh in the ALWR 40 year levelized generation cost. At an EPC cost of 1,400 $/kWe, a change of plus/minus 5 years in the ALWR debt repayment period results in a reverse change of minus/plus 1.9 $/MWh in the ALWR 40 year levelized generation cost.
- <u>Change in Interest Rate on Debt on a Nuclear Plant</u>
  The interest rate on the debt fraction of the investment in an ALWR was varied between 8.0 percent and 12.0 percent. The nominal value is 10.0 percent. All other input variables were kept constant at the base case values of Tables 1 and 3. The sensitivity values are found to increase as the nuclear plant's capital cost increases. It is found that

at an EPC cost of 1,000 \$/kWe, a change of plus/minus 1.0 percent in the ALWR debt rate results in a change of plus/minus 1.3 \$/MWh in the ALWR 40 year levelized generation cost. At an EPC cost of 1,400 \$/kWe, a change of plus/minus 1.0 percent in the ALWR debt rate results in a change of plus/minus 1.6 \$/MWh in the ALWR 40 year levelized generation cost.

- <u>Change in Debt Repayment Period for a Gas-Fired Combined Cycle Plant</u>
  The levelized generation costs of gas-fired combined cycle plants are found to be less sensitive to variations in the debt repayment period than do the generation costs of an ALWR. This is due to the smaller fraction of the capital charges in the combined cycle plant generation cost, as shown in Figure 1. The repayment period of the debt fraction of the investment in a combined cycle plant was varied between 5 years and 25 years. The nominal value is 10 years. All other input variables were kept constant at the base case values of Tables 1 and 3. It is found that a change of plus/minus 5 years in the combined cycle plant's debt repayment period results in a reverse change of minus/plus 1.0 \$/MWh in its levelized generation cost.
- <u>Change in Equity Investment Fraction of a Gas-Fired Combustion Turbine</u>
  The equity fraction of the total investment in a gas turbine was varied between 10 percent and 50 percent. The nominal value is 20 percent. All other input variables were kept constant at the base case values of Tables 1 and 3. It is found that a change of plus/minus 10 percent in the gas turbine equity investment fraction results in a change of plus/minus 0.8 \$/MWh in its levelized generation cost. The lower sensitivity value found here, in comparison with the ALWR, is caused by the lower contribution of the capital-related charges to the total generation costs of a gas turbine.

The sensitivity values computed here can be used to identify the boundaries of nuclear plant competitiveness under changing market conditions. Two examples of such use are:

- Natural gas prices have declined by 1.0 \$/MMBTU to 3.0 \$/MMBTU, averaged over the lifetime of a combined cycle plant. This results in a reduction of the lifetime levelized generation costs by 7.0 \$/MWh. If ALWRs are to maintain their economic competitiveness as base load generation options against gas-fired combined cycle plants, then ALWR EPC costs have to decline by 250 \$/kWe (7.0/2.8 x 100 \$/kWe) to 750 \$/kWe, from the nominal value of 1,000 \$/kWe, all other factors being constant at the base case values.
- A utility-developer consortium is formed to construct several nuclear plants. The new corporate structure will require only 30 percent equity investment fraction in the ALWR projects (nominal value of 40 percent), the remainder being provided by bank loans. The equity partners do however require 17.0 percent ROI, rather than the base case value of 15.0 percent. The average EPC cost of the ALWR projects is estimated at 1,000 \$/kWe. These changes will result an overall increase of the ALWRs' 40 year levelized generation costs of 1.6 \$/MWh (-2.4 + 2 x2.0 \$/MWh). Assuming that the generation costs of gas-fired combined cycle plants represent future market prices, likely to be received by the ALWR projects, then natural gas prices will have to increase by 0.23 \$/MMBTU (1.6/7.0 x 1.0 \$/MMBTU) above the nominal value of 4.0 \$/MMBTU over the plant lifetime, to sustain these ALWR funding structure changes.

Summary of the Sensitivity Analysis Studies

The general observation derived from the sensitivity analysis performed here is that a correspondence exists between natural gas prices, average market prices, and the acceptable ALWR capital costs that the MCPs could support, as follows:

- Gas price of 3.0 $/MMBTU will support ALWRs with overnight capital cost of 1,000 $/kWe.
- Gas price of 4.0 $/MMBTU will support ALWRs with overnight capital cost of 1,200 $/kWe.
- Gas Price of 5.0 $/MMBTU will support ALWRs with overnight capital cost of 1,440 $/kWe.

The above results are understated (higher nuclear capital costs could be supported) since no correction has been made here for periodic equipment replacement in the combined cycle plant and major replacements at the end of its nominal 25 years operating lifetime.

The issue of nuclear competitiveness and the acceptable, or break-even, nuclear capital costs, depend on one's perception of future natural gas prices, and by extension (equivalence on a per BTU basis) of all fossil fuel prices, and the MCPs determined by the fossil-fired marginal plants. If one believes in low and abundant long-term natural gas prices – a 3.0 $/MMBTU state of the world – this implies that competitive overnight nuclear capital costs should not exceed 1,000 $/kWe. If one assumes uncertain fossil fuel prices due to declining reserves, political instabilities, and difficulty in laying additional gas pipeline capacity, then gas prices ought to be higher, and the break-even nuclear capital costs will increase correspondingly. The best estimate of future natural gas prices is in the range of 3.5 to 5.5 $/MMBTU which will allow competitiveness with ALWRs with overnight capital costs in the range of 1,100 – 1,500 $/kWe or slightly higher. If project developers believe in a 3.0 $/MMBTU state of the world and build plants accordingly, then gas-fired electric capacity will increase significantly, thus increasing the demand for natural gas and driving gas prices higher, towards the 4.0 $/MMBTU range. The implication is that while a nuclear plant capital cost of 1,000 $/kWe is a worthy goal for the various design teams to shoot for, it is not clear that such cost will be required, given our understanding of the evolution of future fossil fuel prices. A more realistic range of acceptable nuclear overnight capital costs is 1,100 $/kWe to 1,500 $/kWe or slightly higher, depending on local market conditions.

KEY FACTORS AFFECTING NUCLEAR PLANT COMPETITIVENESS

In addition to the major factors affecting the relative competitiveness of nuclear and fossil power plants, which were discussed in the two previous sections, there are several nuclear specific parameters that affect the deployment of nuclear plants in the U.S. during this decade. These factors are discussed next.

Licensing Cost and Time

Project licensing and local permitting activities are part of the development activities undertaken after the commitment decision is made. The project owners are responsible for licensing at this stage. Following the commitment decision, the owners apply for a combined construction and operation license (COL), as well as seek other Federal and State environmental permits, and State determination of economic need. The cost to obtain these required licenses is assumed as 30 Million Dollars in our nuclear base case. This is a substantial sum, but relatively small compared with the EPC cost of an ALWR, which in many cases exceeds one Billion Dollars. The total licensing period of an ALWR prior to construction start is anticipated to be about three years, including both NRC licensing and local permitting. This is a significant time period (30-40 percent of total project lead-time), however its impact on the time-related charges is relatively small, since only a small amount of the EPC cost is expended during this period.

To test the sensitivity of nuclear generation costs to variations in project development cost and time, a set of parametric values of each of these input variables was run on the NEI Economic Analysis model. At all ALWR EPC values, a change of plus/minus 20 million Dollars will result in a plus/minus change of 0.5 $/MWh in the 40 year levelized generation costs. A change in the licensing and project development period is found not to affect the ALWR's 40 years levelized generation cost, since the licensing costs are small compared to EPC costs, and since they appear concentrated as one time payment at the end of the licensing period and the start of the construction period.

The variations in licensing period and costs, though found to have relatively small impact on the nuclear generation costs, do have a much greater qualitative impact on project uncertainties. Changes in licensing requirements affecting both cost and time, create up-front uncertainties regarding the viability of the proposed nuclear projects. In real life the effect of such up-front uncertainty could be the willingness of the prospective owners to abandon the project. This is particularly so, since only small sums of money have been expended during the project development period, so that the net loss to the owners, at this point, is small. Thus, even though licensing cost and time are relatively small compared with the overall EPC expenses, the impacts of licensing uncertainties on project commitment and viability could be significant.

Construction Cost and Time

The cost and time of the ALWR's construction (EPC) phase are the two variables that will have major impacts on its economic prospects, as compared with the only modest impacts found for changes in licensing cost and time. This is because the EPC costs represent the largest component of nuclear generation costs; thus changes to the EPC cost will have a direct linear impact on the plant lifetime costs. Changing the EPC period affect the accumulation of time-related charges - IDC and escalation - during the construction period. Since IDC and escalation accumulate exponentially rather than linearly, the longer the construction period, the more pronounced the increase in total capital requirements and in generation costs.

The economic impacts of changing the EPC cost and duration period have been investigated through a series of runs of the NEI Economic Analysis model, with separate parametric changes to each input variable. The impacts of changing the EPC cost on the ALWR generation costs were reported in the previous section. A sensitivity value of 2.8 $/MWh change in the ALWR's 40 year levelized generation cost was computed, per change of 100 $/MWe in the EPC cost. This is a linear impact related both to EPC cost increase or decrease.

A separate series of runs was performed, varying the EPC period above and below the nominal value of 42 months (3 ½ years). The impacts on generation costs are non -linear. Increasing the EPC period will increase total generation costs, more than a similar reduction in the EPC period will decrease generation costs. Thus, increasing the EPC period by one year (to 4 ½ years) will increase the ALWR 40 year levelized generation cost by 4.9 $/MWh. Reducing the EPC period by one year (to 2 ½ years) will decrease the levelized generation cost by 4.2 $/MWh. The effect is more pronounced the further we modify the EPC period away from the nominal values. Increasing the EPC period by 18 months (to 5 years) will increase generation costs by 7.0 $/MWh. Reducing the EPC period by 18 months (to 2 years) will decrease the levelized generation cost by only 5.2 $/MWh. Further increases in EPC periods will have significant impact on generation costs. A 6 years EPC period (total project lead-time of 7 ½ years), will increase the 40 years levelized generation cost by 11.8 $/MWh, above the nominal value of 47.3 $/MWh, and will elevate it to values higher than the prevailing or projected energy market prices.

More than the quantitative impact on generation costs, changes (or projected changes) to the EPC cost and execution period, signify greater project risks to the plant owners and investors. Higher construction costs and longer project durations were important factors in canceling nuclear plant projects in the U.S. over the last two decades. The perception of uncontrollable nuclear project period represents a major hurdle to new plant commitment, to this day. Investors and developers could plan and initiate mitigation measures against long lead-times, so long as those periods were stable and well understood. It is rather the concern for lack of control over the licensing and EPC periods, which worries prospective new plant owners or developers. Thus understanding the economic impacts of EPC cost and schedule changes is important. Stabilizing EPC cost and duration is essential.

Nuclear O&M Costs

Nuclear O&M costs significantly increased in the 1980s and early 1990s and became the dominant component of the production costs of the currently operating plants. Since the mid-1990s several joint industry programs have resulted in significant fleet-wide nuclear O&M cost reductions. These reductions were attributed to the improved nuclear capacity factors, to the incorporation of lessons learned from best-in-class plants, to O&M cost benchmarking programs, and to personnel reduction programs. Despite the significant improvement in nuclear O&M costs, the perception remains that these costs represent a major uncertainty factor affecting the prospects of future nuclear plants.

ALWRs were designed, from the start, for ease of maintenance, for equipment simplification and improved layout, and for optimized and lower plant personnel complement based on a from-the-ground-up functional analysis. These factors, coupled with the fact that the ALWRs are planned for lifetime operation at 90 percent or higher capacity factors, account for the low O&M costs

(5.0 \$/MWh) as compared with the current best values of about 8.0 \$/MWh. If it will be possible to achieve these low costs in near-term deployed plants, then O&M costs will become a relatively small contributor, accounting for less than 12 percent of total nuclear generation costs. The annual O&M budget at 5.0 \$/MWh is estimated at 39.42 Million Dollars, significantly less than the annual budgets of current plants, which vary between 80-100 Million Dollars. A sensitivity figure of 1.27 \$/MWh per change of 10 Million Dollars in the annual O&M budget of a future 1,000 MWe operated at 90 percent capacity factor, can be computed.

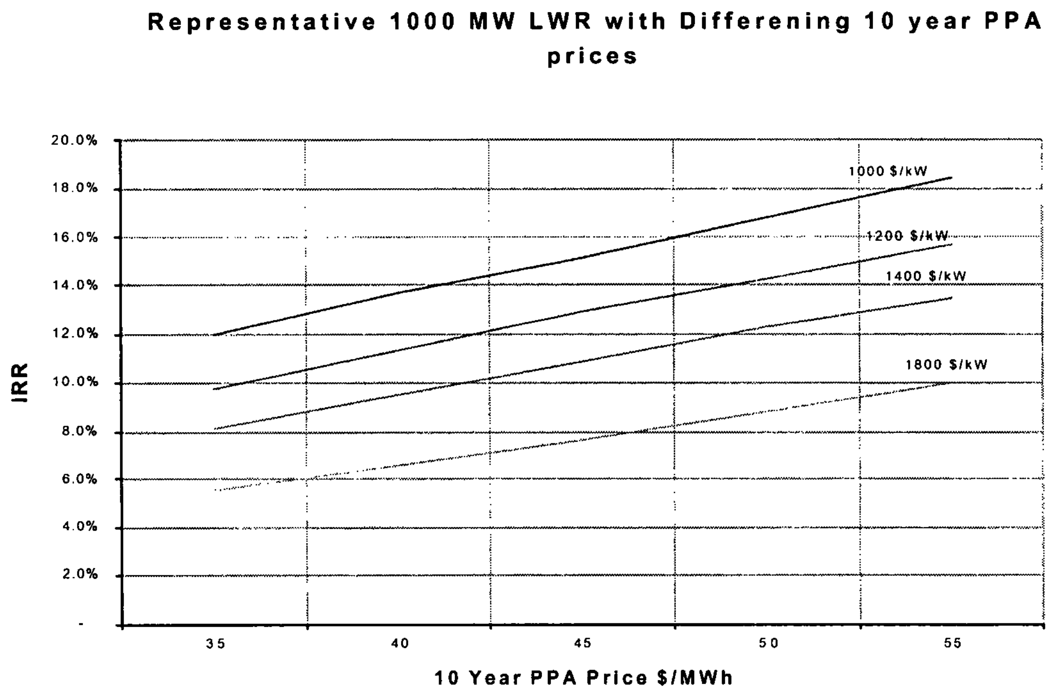
The low ALWR O&M cost estimates represent a risk, in that they have not yet been proven in a sustained manner in commercially operating plants in the U.S. Current U.S. LWR plant O&M costs have consistently declined since 1993, due to improvements in capacity factors, staff reductions, and more efficient operations. This experience is significant, but it covers a period of about ten years only, whereas ALWR plant lifetimes are projected to be sixty years. The optimized ALWR cost estimates have many margins eliminated from them. To that extent, the potential for cost increases due to less than optimal performance, over an extended period within the operating lifetime, cannot be ignored. On the other hand, future nuclear plants will likely be operated by large, well-experienced, nuclear utilities with several other plants under their management. Such utilities should be able to operate their plant fleets efficiently, and achieve low operating budgets.

Market Prices

The economic prospects of future nuclear plants depend on receiving adequate market prices to ultimately cover all their generation costs. While this can be accomplished over the plant's operating lifetime, a problem still exists regarding high generation cost requirements early in life that might exceed likely market prices. One potential solution to this problem may include obtaining power purchase agreements above market prices during the early years of operation, this price subsidy to be returned later in life when adequate price-cost margins have accumulated. Such PPAs can be issued by a state or a regional agency, interested in diversifying its energy supply technology mix. In principle, such a PPA was issued by the State of California, in order to assure adequate energy supplies to California ratepayers. The DWR, which is the California agency charged with purchasing power on behalf of the State, reported in July 2001 commitments to purchase power until 2010, with average annual prices of 65 \$/MWh, when spot prices during those periods are estimated by the DWR to average 50 \$/MWh. Other types of power purchasing arrangements are contemplated by New York State and by the State of Georgia. Thus there exists at least one precedent for the issuance of a higher-than-market price PPA, which serves to fill an importance social or economic policy goal of the issuing agency.

A study of such market prices strategy was performed in cooperation with NEI, using the NEI Economic Analysis model. The results of these computations are shown in Figure 7. The basic assumption of this evaluation is that new ALWRs will receive market prices of 40 \$/MWh, in constant year 2000 Dollars, through their operating lifetime, except for the first ten years of life when those plants will receive higher than market prices. Various price increments above 40 \$/MWh were assumed parametrically. For a range of ROI values required by the investors, assuming 40 percent equity fraction, the question is, "What ALWR overnight capital cost could be sustained by this schedule of market price payments to the plant?" A typical result, as shown in Figure 7, indicates that for a 1,200 $/kWe and a ROI requirement of 15.0 percent, a PPA with a price increment of 15 $/MWh will be required over the first ten years of life, in line with the California market price support. These PPA price increments can be returned by the ALWR owners later in the plant's life, after the construction loan has been returned and margin accumulation can be dedicated to equity repayment.

Figure 7 - Economic Competitiveness of an ALWR with PPA Above Market Prices in First Ten Years of Life



SPECIAL CASES

The analysis of advanced nuclear plants also involves a few special cases and considerations. Some of these cases are reviewed here. In particular, the case of modular plants is reviewed, as well as, special considerations related to First Time Engineering (FTE) costs, and the differences between first of a kind (FOAK) and Nth of a kind (NOAK) plants.

Economic Analysis of Modular Plants

Modular, small-sized, advanced nuclear plants based on the HTGR Helium gas-cooled design concept, are considered by proponents to be more suitable to the current market realities, and thus more likely to be ordered commercially, than the larger-sized ALWRs. The major advantages of the modular plants include:

- Smaller-size which better matches low load growth situations or small generation systems. Additional units can be added at each station when the demand grows. These plants are likely to cause smaller price depressions when introduced into the supply mix.
- Construction in shorter time periods than the larger ALWR, making them more responsive to specific market opportunities, and giving them a better chance of being first-to-market.
- Smaller up-front investments, so that financing may be easier to obtain. These plants may represent smaller risk to the investors, thus requiring lower ROIs.
- Commercial operation could be reached in shorter lead-times than could be achieved with the larger-sized ALWRs. Thus a revenue stream may be generated at the station earlier than could be obtained in an ALWR project.
- For a given capacity addition a larger number of smaller modules will have to be manufactured, thus creating opportunities for series production and module cost reduction through learning and economy of scale in manufacturing. Modules could be produced in a centralized facility and shipped to different sites, thus enjoying the benefits of factory manufacturing, rather than on-site construction.
- Higher thermal efficiency particularly for some HTGR concepts, resulting in lower cooling water requirements, smaller amount of spent fuel production per unit of electricity generation, and lower O&M costs.

On the other hand, there exist very limited actual plant operating data to support the projections for improved economics of the modular HTGR plants. Several issues should be raised:

- The modular plants could be more capital intensive than the larger sized, monolithic, ALWRs. This is due to two factors: economy of scale effects will increase the per kWe cost of the smaller-sized modules, and modular, graphite moderated, HTGR type plants require large-sized vessels, in order to provide low core densities. The GT-MHR plant at about 300 MWe capacity required a pressure vessel as large as that of a 1,100 MWe BWR; the HTGR plants require several large sized vessels – for the reactor system, for the energy conversion system, and for the gas compression system; most vessels will be partially, or completely, constructed below grade for safety purposes. This increases the excavation and civil works costs. The cost of the factory-manufactured modules will be higher than the cost of field construction due to the higher labor hourly rates in the factory than in the field (this is partially mitigated by higher factory labor productivity).
- An analysis performed by GE/NE has indicated that the footprint of a 110 MWe PBMR module will be about equal to the footprint of a 1,300 MWe ABWR. Plant capital costs are, in part, proportional to the facilities' footprint and volume. Thus the similar footprints for the PBMR and the ABWR could imply high PBMR per kWe capital cost.
- There exist little commercial experience in the U.S. in full-sized long-term operation of a vertically oriented energy conversion module. This is particularly true of the GT-MHR, where the functions of the energy conversion and the gas compression modules are combined on a single shaft and housed in a single large dimension vessel. The HTGR commercialization plans call for transition to commercial-sized plants with limited scale-up and performance/ endurance testing of the energy conversion modules. These modules represent performance and cost risks that may not be fully factored into the plant capital cost estimates.

- There exist very limited records of HTGR operation at high and sustained capacity factors. High capacity factors are required, particularly for capital-intensive plants, to reduce the per MWh unit energy costs. Projections of thirty years or longer levelized capacity factors are not based on real life experience.
- There exist limited data on achieving consistently low O&M costs over extended operating periods. The HTGR plants' low O&M cost projections are based on functional analysis and on limited operating records. There thus exist a significant risk that such projections may not materialize for the early HTGR- type plants built.
- The U-235 percent enrichment of the HTGR fuel is higher than the U-235 enrichment levels of the current LWRs and future ALWRs (8-9 percent vs. 4-6 percent, respectively). Under the current realities of the U.S. Enrichment Complex, HTGR type fuel cannot be enriched in the U.S., thus, gas-cooled plant owners will have to rely on foreign enrichment services providers, operating a special purpose cascade. This represents a potential fuel availability risk that may require keeping larger reload inventories on-site and paying higher fuel inventory charges, thus increasing overall fuel cycle costs.
- The impacts of large sized RTO formation on the need for small and modular plants has not yet been evaluated. It is possible that centralizing network expansion planning in large RTOs will favor the development of large monolithic plants, rather than small modular plants.

The economic analysis of modular HTGR plants is more complicated than the analysis of large-sized ALWR projects. Each module has to be analyzed as a separate plant, from commitment to commercial operation and throughout its operation. The costs, energy generation, and revenues streams from each module, each starting at a different time point, should be combined, discounted, and levelized to one reference point, to derive the total lifetime-averaged generation cost of the HTGR station. Each module should be evaluated separately though a margin analysis, considering that later modules will obtain different market prices, will represent lower costs due to learning experience, and will represent lower risk, thus requiring a different ROI. This analysis is complicated further by consideration of the modular stations' common facilities. Are these common facilities costs charged to the cost of the first module, or to the averaged cost of the first group of modules built on site, or to the station averaged cost? Evidently, more analysis work is required for a modular plant than for a monolithic plant, though the analytical principles are common. The difficulties emerge when several module-specific analyses have to be properly combined into a station-averaged evaluation.

First Time Engineering and Differences Between FOAK and NOAK Plants

First time engineering (FTE) is the generic design required to complete all detailed design drawings to the point of ready for procurement. FTE relates to the generic plant, not considering detailed adaptation to specific site conditions. The FTE effort for an ALWR-sized plant may require an expenditure of several hundred million Dollars, as demonstrated by the experience of the Advanced Boiling Water Reactor (ABWR), the only ALWR that has yet reached the FTE completion milestone by 2001. The advanced nuclear plant vendors all face the difficulty of securing financing for their FTE completion plans. Regardless of how funding is obtained, the vendors will have to recoup the cost of FTE completion from future plant sales.

This raises the issue of how to charge for the cost of FTE completion. Are all FTE costs to be charged to the first ALWR plant to be ordered, or to the first several plants, assigning a fixed FTE cost increment to each plant sold until all costs are recovered, or to a program of several orders issued by several prospective owners each paying his equal share of the total FTE cost whether he completes his plant construction or not? Different vendors will evolve different strategies for charging a portion of their FTE costs to new plant orders. This may create some equality in analysis issues. Some vendors will tend to assign most of the FTE cost to the first one or few plants sold. Other vendors may develop a multiple-plant-order strategy with each owner paying a fraction of the FTE cost. These strategies will thus affect the costs of the FOAK plants differently. Some prospective FOAK plants may be obligated with different fractions of the FTE costs than other plants. How do we evaluate different plant designs to be commercialized under different strategies on a common basis?

First-of-a-kind plants differ from Nth-of-a-kind plants in several ways:

- FOAK plants will get charged with portions of the design commercialization strategy expenses. NOAK plants represent mature plants unencumbered with commercialization costs.
- NOAK plants are expected to enjoy the benefits of a learning curve at the manufacturing plants, improved construction efficiency due to on-site replication, learning efficiencies between plants of the same owners, and multiple equipment order discounts. All these benefits will not apply to the FOAK plants.
- NOAK plants could be constructed with shorter lead-times than FOAK plants due to the accumulation of construction experience. Prospective investors will be better assured that the plant can be built, that it can be built on time, and that lead-times can be shortened further with experience. The shorter the plant lead-time, the smaller the time-related charges, the lower the total up-front capital investment and the levelized energy cost.
- NOAK plants will represent lower construction risks because of the overall experience gained in building all previous plants of the same design. Thus it is possible that obtaining project financing will be easier. This may result in potentially reduced equity fraction, lower ROI requirements, and lower interest rate on debt.

There are two sets of related problems discussed here: How to assign FTE costs (or fractions thereof) to FOAK plants, and how to distinguish between FOAK plant costs and NOAK plant costs. The resolution of these issues will affect the costs and prospects of the FOAK plants planned for early deployment in the U.S. and the prospects for new plant orders.

SUMMARY

This summary section reviews and comments on the results of the economic computations performed in this study using the vendor-specific cost data. It then comments on the attributes of a success path for a new nuclear power plant project.

Economic Competitiveness of Reactor Designs Based on Vendor-Specific Data

An economic analysis has been performed on the generation costs of several reactor designs, based on design-specific cost data provided by the vendors. The various cost components for each design were incorporated into the NEI Economic Analysis Model, and the Model computed the lifecycle costs for all designs. In general, designs closer to commercialization provided limited cost data, and designs early in their development process were willing to provide more detailed cost breakdowns. The submitted cost data relate to the NOAK plants, and are based on the assumption of success in the development, design and licensing activities of the various designs. The expectation of future market prices is the range of 35 $/MWh to 55 $/MWh. Inspection of the expected NOAK generation costs of the various reactor designs considered, versus the range of likely market prices indicates the following:

- The generation costs of all the reactor designs considered here are within the range of likely future market prices. Most of the generation costs fall within the more narrow range of market prices of 36 $/MWh to 46 $/MWh, or even below that range. Thus, nuclear plants are expected to be generally competitive on a total cost basis, with market prices likely to prevail in the U.S. in the future. As such, nuclear plants should be included as potential supply options in utility generation expansion studies.
- Should these lifecycle generation costs be achieved in future projects, nuclear plants will represent economic power supply options in specific market situations. More detailed and localized economic analyses will have to be performed to clarify whether a specific reactor design would prove to be a competitive choice in a local market under specific contracting arrangements.
- The deregulation of the energy markets did not price new nuclear plants out of the market. Given the low production costs of 10 $/MWh and the lower marginal costs of 5 $/MWh (fuel and variable O&M costs), adequate margins exist between nuclear production costs and market prices to allow an appropriate return on the investment. Nuclear designs currently under development, which will achieve the cost/performance data provided here, will be able to compete in the deregulated energy markets.
- Nuclear plants, at the low end of their lifecycle generation costs, present costs lower than the likely range of future market prices. Nuclear plants at the high end of the cost uncertainty range still fall within the band of likely market prices.
- The issue of costs in the early years of life should be evaluated further. It is possible that some reactor designs will be competitive in their specific markets from the first year of operation going forward. In other cases and based on local conditions, a specially structured PPA may have to be devised, to allow recovery of all costs in the early years of life.

Success Path for Future Nuclear Projects

The above conclusions are based on the assumption that the cost/performance data presented by the reactor vendors are achieved. What will, however, be required in order to guarantee that the target costs are realized? In other words, what is the success path for a future nuclear plant project? Evaluation of the computational results obtained in this study, allows the following observations to be made:

- Nuclear plant construction lead-times should be contained at four years or less, and total project lead-times should be constrained not to exceed five years. Being first to market is important in a deregulated energy system. Longer lead-times will reduce economic competitiveness, result in changing market conditions, and will increase project risk.
- Resolution of licensing issues before project commitment is essential to ensuring acceptably short lead-times. Resolving the issues of economic need for the project, site licensing and permitting, and NRC safety regulatory approval of the design will be required, to prevent an open-ended licensing process when the plant is under construction and interest during construction accumulates.
- For the general U.S. market, project overnight capital cost (including EPC cost, owners cost, and contingencies) need be contained at 1,100 \$/kWe to 1,500 \$/kWe, depending on the expectation of future fossil fuel prices. The lower the plant capital cost achieved within the above range, the greater the competitive position and the profitability of a future nuclear project. Overnight capital cost figures within the high end of this range could prove economic in specific situations, depending on locally high and sustained market prices, or on specially structured PPAs. Most 1,000 MWe and higher capacity nuclear plants will require a total as-spent investment, expressed in current year Dollars, of about two Billion Dollars. This poses strong competition from other lower front-end cost options for bringing a similar capacity power block to market.
- Nuclear plant production costs (fuel and O&M expenses) should be held to 10 \$/MWh or less. The major advantages of nuclear power plants are their low and stable running costs, which makes them ideal for long-term bilateral contracts. In order to allow competitively priced contracts, production costs should be kept as low as possible to provide adequate margins for capital cost recovery and profits.
- Nuclear plants lifetime capacity factors should be sustained at 85 percent or higher, in order to maximize incoming revenues and the potential for margin capture. The longer the plant operating life and the higher the annual capacity factors, the greater the return on the investment.
- Achieving high safety performance is essential to the economic well being of the plant. Regulatory-mandated shutdowns and inspections will reduce incoming revenues, increase capital outlays for recovery and reduce plant profitability.
- Nuclear project developers and owners should locate their plants in specific locations likely to experience high and sustained market clearing prices. In general, locations where market prices can be forecasted to remain above 40 \$/MWh for at least the first ten operating years would be preferable.
- Nuclear plant owners should strive to anchor their generation in long-term bilateral PPAs of 10 to 20 years duration, based on the prevailing local market prices (at or about 40 \$/MWh). The major selling point of an operating nuclear plant is the very low volatility of its annual prices. This should allow competitively priced PPAs, which will provide adequate margin capture.
- Nuclear plant developers should strive to obtain the best financing package possible, based on all of the above. Typical values could include containing the ROI requirements to 15 percent or less, allowing debt repayment periods as much longer than 10 years as feasible, and reducing equity financing to 40 percent or lower. These factors are all

mutually dependent, and the most advantageous package should be negotiated actively and aggressively.

The most important observation derived in this study is that the deregulation of the energy markets did not eliminate the prospects for capital-intensive base load generation options such as nuclear and coal-fired plants. New nuclear plant designs have adjusted to the requirements of the new energy markets. Should the cost/performance targets now expected be demonstrated in real projects, then the long-term role of nuclear power in the future energy markets could be sustained and enlarged.

II-5: DESIGN OPTION EVALUATIONS

INTRODUCTION

This Chapter provides a more detailed evaluation of each of the designs submitted in response to the Request for Information (RFI), relevant portions of which are provided as Attachment 2. As noted in the RFI all information provided by the respondents is viewed as non-proprietary and as such may be limited in its content. As a result of the RFI process the NTDG received and evaluated eight designs submitted by five organizations. The designs and the submitting organizations are summarized in Table 5.1 below.

TABLE 5.1 SUMMARY OF CANDIDATE DESIGNS

DESIGN	SUBMITTING ORGANIZATION
A. Advanced Boiling Water Reactor (ABWR)	General Electric Nuclear Energy
B. ESBWR	General Electric Nuclear Energy
C. SWR 1000	Framatome ANP
D. AP1000	Westinghouse Electric Company
E. AP600	Westinghouse Electric Company
F. International Reactor Innovative and Secure (IRIS)	Westinghouse Electric Company
G. Pebble Bed Modular Reactor (PBMR)	Exelon Generation
H. Gas Turbine Modular Helium Reactor (GT-MHR)	General Atomics

Each of the eight designs is briefly described in Appendices A through H as noted above, based on information provided by the submitting organizations. The key design features, plant layout, and operating characteristics are presented for each design.

In this Chapter, each design evaluation includes a brief summary of the respondent's reply on how their submitted design meets each the six NTDG criteria and the NTDG's assessment of that response, an analysis of the design specific gaps associated with the submitted design, and an overall assessment by the NTDG on the viability of each design to be deployable by 2010 based on the information provided. Each overall assessment includes a roadmap and timeline to deploy the particular design.

The NTDG acknowledges that this is not an all-inclusive list of currently available reactor designs. Other options exists that were either submitted late in response to the RFI and subsequently were not evaluated, or were not submitted at all by their respective vendors. These other options include:

- System 80+
- Westinghouse BWR 90+
- EPR
- CANDU Designs

It is possible that one or more of these designs would be deployable by 2010, and therefore need to be factored into the overall conclusions and recommendations of this Roadmap. Factors worth considering regarding some of these designs follow:

EPR

The European Pressurized water Reactor (EPR) is a very large (1545 MWe or 1750 MWe) design that was developed as a joint venture by French and German companies, Framatome and Siemens in the 1990s. The basic design was completed in 1997, working in collaboration with other European nations, and confofms to French and German laws and regulations. Significant cooperation took place during the 1990s between the European utilities developing user requirements for this design and the U.S. utilities leading the US ALWR Program and its Utility Requirements Document. The EPR was not submitted to the NTDG in time to support an assessment. Further, as with the SWR-1000, the designer, Framatome ANP, has not made a decision regarding entry into the U.S. nuclear market.

Systems 80+

The System 80+ is a 1350 MWe PWR design developed by ABB-CE (prior to that company's acquisition by Westinghouse), and is ready for deployment. It conforms to the ALWR Utility Requirements Document, and was certified by NRC in May 1997. Plants based on the System 80+ design have been built in Korea. However, as of this time Westinghouse has chosen not to market the System 80+ design in the U.S. If conditions change, it could be made available for order.

CANDU

Canada's CANDU reactor designs use multiple pressure tubes containing nuclear fuel assemblies in the active core region, which permit on-line refueling. Heavy water is pumped through the pressure tubes to remove heat and is also used to moderate neutrons in a low pressure vessel (the Calandra) that surrounds the pressure tube region. CANDU reactors have been deployed outside Canada (e.g., Romania, South Korea). Recent advances to this design use light water cooling but retain heavy water moderation in the Calandra. This approach holds significant promise for improved maintainability and economics. Most CANDU designs are in the medium (500-1000 MWe) size range.

It should also be noted that several of the options being evaluated as part of this near term deployment effort are also being evaluated separately as part of the Generation IV Reactor Roadmap initiative.

GE/NE ABWR DESIGN

A. CRITERIA EVALUATION

Criterion 1: Regulatory Acceptance

Summary of General Electric Response

The Advanced Boiling Water reactor (ABWR) was the first design reviewed and certified (on May 2, 1997) by the U.S. Nuclear Regulatory Commission (NRC) under the provisions of Title 10 of the Code of Federal Regulations Part 52 (10CFR52). The ABWR has been licensed to Japanese standards and continues to be reviewed by Japanese regulatory authorities as new ABWR plants are deployed in Japan. The first two ABWRs constructed, Kashiwazaki-Kariwa Units 6 and 7, are currently in their fifth cycle of operation and have met or exceeded operational and safety performance goals.

More recently, the ABWR received regulatory approval in Taiwan by the Atomic Energy Agency in the form of a Preliminary Safety Evaluation Report, issued in late 1998 and a construction permit for two ABWR units at the Lungmen site issued in March 1999. The plant construction project is about to resume in the fourth quarter of 2001, after having been suspended due to political problems in early 2001. The ABWR design has, by mid 2001, been reviewed by a team of European utilities, which have indicated that the ABWR is suitable for deployment in most of Europe, in terms of meeting European regulatory requirements.

NTDG Assessment

The ABWR has been licensed by the NRC to a full Design Certification status, and thus fully meets the requirements of Criterion 1. The ABWR has been licensed in two other countries, and found to be licensable in several European countries. Furthermore, the design has been completed and proven through the construction and operation of two units, and the construction of two other units (now ongoing). The NTDG judges that the ABWR meets the criterion of Regulatory Acceptance.

Criterion 2: Industrial Infrastructure

Summary of General Electric Response

The infrastructure is in place for the design, fabrication, and construction of two ABWR units in the Lungmen station in Taiwan. GE/NE has contracted with a global supplier network to deliver these ABWR units. Those countries that have a larger portion of the supply scope include Japan, U.S., Scotland, Germany, Spain, and the Czech Republic. Many of the suppliers are located in the U.S. The supplier chain is capable of supporting additional units in the U.S. and elsewhere.

ABWR mechanical components and hardware such as pumps, piping, valves, heat exchangers and tanks can be and are being produced in the U.S. for the current ABWRs under construction.

The same is true for the electrical components and instrumentation. The nuclear fuel, control rods and some reactor internals are also currently produced in the U.S. at GE/NE's nuclear fuel and components manufacturing facilities. Most components of the Turbine Island and balance-of-plant equipment can be produced in the U.S. The turbine generators for the two ABWRs built for Tokyo Electric Power Company (TEPCO) in Japan were manufactured by GE/NE at its turbine manufacturing facilities in Schenectady, New York. The reactor pressure vessel (RPV) and large internal components used for both the Japanese and Taiwanese ABWRs were fabricated by Japan Steel Works and other vendors, which have maintained their capacity and expertise for fabrication and machining of these large components. Some European suppliers could be used to meet a higher demand. GE/NE is seeking to develop other suppliers to shorten the RPV supply schedule.

Foreign suppliers can and do meet U.S. codes and regulations, when needed, since most foreign countries follow identical or similar Codes such as ASME Section III, IX and XI, as well as U.S. NRC imposed regulations and regulatory guides. For the Taiwanese ABWRs, full compliance with U.S. Codes and Federal regulations, including the ASME code, is contractually required by Taiwan Power Company. When the ABWR was first designed for Japan and certified in the U.S., the dual country codes and regulations were followed, to satisfy both national requirements. The U.S. Utility Requirements Document (URD) was used as a guideline for the U.S. design and was relied upon heavily by Taiwan Power Company for their bid specifications.

NTDG Assessment

A full-scope supply infrastructure now exists, capable of building a two-unit ABWR station in the U.S. or abroad for operation by 2010. This has been demonstrated by GE/NE and its Japanese partners, Toshiba and Hitachi as well as other suppliers, in actual construction projects in Japan and now in Taiwan. The ABWR has a proven track record of existing and well functioning supply infrastructure. GE/NE has indicated that it is working on creating options for expanding and diversifying its vendors supply network.

Future significant expansion of the supply infrastructure for the simultaneous construction of several ABWRs may require careful scrutiny by interested utilities, at that time.

A significant constraint now facing the expansion of the ABWR supply infrastructure, as well as that of all other designs, is the availability of industrial capacity for the forging of large-size nuclear plant components such as the RPV, and the pressure vessel's bottom and top heads. Currently only Japan Steel Company has maintained this manufacturing capability. GE/NE is working with other European and Asian large forging plants to remedy this potential constraint, should the demand require. This situation requires careful monitoring, as applied to future ABWRs or any other reactor concept proposed for deployment by 2010.

The NTDG judges that the ABWR meets the criterion of Industrial Infrastructure.

Criterion 3: Commercialization Plan

Summary of General Electric Response

The ABWR has already reached an advanced state of commercialization overseas. Several ABWRs to be constructed and operated by various Japanese utilities have been announced or are in the pre-project phase. The two Taiwanese units, expected to reach commercial operation in 2006 and 2007, are based on the ABWR design that has been licensed in the U.S. The ABWR is a contender for the proposed Fifth Nuclear Plant in Finland, which is expected to receive Government approval within the next 12 months and go into commercial operation around 2008.

The ABWR technology was developed and fully tested by GE, Hitachi, and Toshiba, and paid for by TEPCO in a multi-year program estimated to cost $500M. There are some small variations in the Japanese, U.S. and Finnish designs necessary to meet local requirements but the underlying technology is the same. The GE/NE approach to new plant projects is not based on a simultaneous multiple unit commitment contract, required to reduce the per-unit design completion cost. They rely on a single- or two-unit ABWR project contracts, each being negotiated separately with the prospective client, each benefiting from learning effects associated with previous contracts.

An important element of the ABWR commercialization plan is the willingness of the supplier team, led by GE/NE, to assume an acceptable portion of the project risks. For the projects in Japan and Taiwan, GE/NE has contracted for its scope of work providing the customer with a fixed price and schedule. GE/NE now claims to have the confidence to firm price its scope of supply and the associated delivery schedule, and require similar arrangements from other team members for future projects. GE/NE states that its approach to ABWR commercialization in the U.S. is to discuss firm scopes of supply with interested utilities or generators and other appropriate third parties on an individual basis.

NTDG Assessment

The ABWR team has the qualifications to prepare, present, and implement a successful commercialization plan. The ABWR has a completed design with all first time engineering already completed and all the generic design drawings available. The ABWR has a reference plant for construction and a reference plant for operation. GE/NE has a proven track record, albeit not under U.S. conditions, of leading a project team that can provide most of the scope of supply of a complete ABWR station in several fixed price and firm delivery schedule contracts.

GE/NE's characterization to the NTDG of market projections and supplier arrangements is very limited. GE/NE has stated that it has had detailed discussions with several U.S. utilities potentially interested in the ABWR, however the details are held confidential for commercial reasons. Due to the limited discussion of possible commercial project arrangements, we are unable to comment on the details of the GE/NE offerings, however we consider that the ABWR can meet the criterion of the Commercialization Plan.

Criterion 4: Cost Share Plan

Summary of General Electric Response

No funding has been requested and is needed for ABWR design specific activities. GE/NE states that an ABWR project in the U.S. could be considered as an "Nth of a kind" (NOAK) project. The first time engineering and detailed design have already been completed. Cost sharing with the U.S. Government for ABWR design completion is not required.

Cost sharing with the U.S. Government is recommended for early site permits (ESP) and for combined construction and operation license (COL) applications, related to ABWR projects. These are generic industry initiatives, discussed in a separate section of this Volume.

NTDG Assessment

The ABWR design team has not requested any U.S. Government cost share plan for Design Certification or for first time engineering completion. Its ABWR product is now fully licensed and engineered. ABWR project specific engineering will be included in the commercial discussions with the prospective customers. The NTDG agrees with GE/NE that no design specific activities are needed.

A cost share approach to cover the generic U.S. ESP/COL licensing process is recommended. The NTDG judges that the ABWR meets the criterion on Cost Sharing Plan.

Criterion 5: Economic Competitiveness

Summary of General Electric Response

The ABWR is the only plant for, which there is actual project design and construction experience to support high-confidence firm prices and schedules. In assessing economic competitiveness, prospective investors will consider economic factors such as cost and cost uncertainty to complete the remaining engineering, construction cost and schedule, programmatic and safety risks, plant lifetime and projected operating, maintenance and fuel costs, projections of market conditions and alternative system generation costs. The cost to build a new ABWR can be estimated with confidence, since the design is highly detailed and firm prices for a high percentage of the equipment, materials, and construction have been committed for existing projects. GE/NE has developed a cost database of more than 500,000 entries that defines in great detail the cost of an ABWR. This is a highly detailed cost database now available for a new ABWR project prior to the start of construction.

The construction cost of a new ABWR in the U.S. will depend on overseas cost experience, on U.S. project unique elements, and on the success of the industry in realizing improvements in regulatory and licensing initiatives. GE/NE expects that the current ABWR could be constructed in the U.S. in the range of $1400/KWe to $1600/KWe for overnight cost (including owners costs and contingency), depending on various assumptions and conditions.

The ABWR units in Japan have demonstrated that ABWRs can be built rapidly. From first concrete to commercial operation took 48.2 months at K-6 and 48.6 months at K-7. If U.S. constructors adopt some of the techniques and lessons learned from Japanese construction, GE/NE estimates that the first ABWRs in the U.S. could reasonably be built in 48 months (first concrete to commercial operation).

Given the current economic trends created by the growth in demand for natural gas and given the environmental prohibitions and costs related to development of coal burning plants, the ABWR could be an economic alternative for future major additions of generation capacity. The risks of generation cost increases, such as have recently occurred in California and elsewhere, for natural gas fired plants, are not applicable for the ABWR, or other nuclear plants.

NTDG Assessment

The ABWR cost estimates are based on a high degree of accuracy and real world experience. Future ABWR projects in the U.S. will demonstrate learning experience from previous overseas ABWR projects.

The NTDG agrees that economic competitiveness is a function of projected overnight capital costs, uncertainties and economic risk factors. The NTDG economic analysis, presented in Chapter II-4 of this Volume, indicates that the ABWR capital cost figures reported by GE/NE represent the high end of the economic competitiveness range, estimated as 1,000-1,400 $/kWe. We conclude that the ABWR could represent an economic generation option in specific market situations at some locations in the U.S. and thus the ABWR design can meet the criterion of Economic Competition.

Criterion 6: Fuel Cycle Infrastructure

Summary of General Electric Response

The ABWR is able to use the same fuel cycle industrial structure as conventional BWRs. The ABWR's fuel assembly design is the same as the fuel assembly design for the current BWRs. The ABWR can accept standard 8x8, 9x9 or 10x10 BWR fuel assemblies utilizing the once-through fuel cycle with low enriched uranium fuel. The ABWR could also accommodate mixed Uranium-Plutonium Oxide (MOX) fuel in the future if needed. The ABWR fuel design compliance with the fuel licensing acceptance criteria constitutes NRC acceptance and approval of the fuel design for initial core and core reload applications without further specific NRC review.

Currently, excess capacity exists worldwide to provide the fuel cycle services needed to fabricate BWR fuel. This situation will continue for the foreseeable future, assuming that capacity is not taken off line. Global Nuclear Fuels (GNF) has provided fuel fabrication for past and present overseas ABWR projects. General Electric Company (GE/NE) of America, and Hitachi, Ltd., and Toshiba Corporation of Japan, have established GNF, an integrated nuclear fuel joint venture with fabrication capabilities both in the U.S. and Japan. This organization has decades of experience supplying fuel under strict QA requirements for current BWRs. Other organizations capable of supplying BWR fuel include Empresa Nacional del Uranio SA (ENUSA) with facilities in Spain, Framatome ANP with facilities in Germany and the U.S., and Westinghouse Atom AB of the British Nuclear Fuel Ltd. (BNFL) Group with facilities in Sweden. Cogema (France, Belgium) has developed capability to supply BWR MOX fuel.

An extensive fuel performance experience base has been amassed by GE/NE and known failure mechanisms have been systematically eliminated. The Electric Power Research Institute (EPRI) goals for defect rates set in 1972, and again in 1990, have been achieved in practice with continuing decline in defects up to the present time.

The spent fuel pool in the ABWR reactor building can hold 10 years of discharged spent fuel plus one full core loading. Additional on-site storage of spent fuel can be added to the site layout if necessary, using wet or dry methods, without impacting the existing design.

NTDG Assessment

No gaps exist in the fuel cycle supply infrastructure that will prevent deployment of ABWR in the U.S. by the year 2010. All licensing issues related to ABWR fuel design have been resolved by the NRC through the Design Certification process in the U.S., and by the Japanese nuclear regulatory agencies for application to their operating and future ABWRs.

Adequate ABWR fuel-manufacturing capacity exists in the GE/NE and the Toshiba and Hitachi Corporations joint manufacturing venture. The BWR Owners Group tracks the BWR fuel supply situation, and will encourage GE/NE and its partners to increase and upgrade their manufacturing capacity, should an ABWR related need arise. The BWR Owners Group will likely also review GE/NE plans for on-site dry cask storage of spent ABWR fuel.

Based on all the above we do not find any gaps in the fuel cycle infrastructure area that may hinder ABWR deployment in the U.S. by 2010. We are reasonably assured that no such gaps will emerge in the near future. The ABWR meets the criterion of the Fuel Cycle Industrial Infrastructure.

B. Gap Analysis

The NTDG has identified no design-specific gap that may hinder ABWR deployment in the U.S. by 2010. There exists one area of concern related to the economic competitiveness of the ABWR, for all possible scenarios and regions of the U.S. The ABWR, like other designs, may be constrained by the current availability of only one RPV forging vendor worldwide, Japan Steel Works.

C. Overall Assessment

The NTDG judges the ABWR can be deployed in the U.S. by 2010. The ABWR has obtained a Design Certification in the U.S. and has been licensed for construction and for commercial operation in Taiwan and in Japan. Two ABWR units have been in commercial operation for more than four years in Japan and two units are under construction in Taiwan.

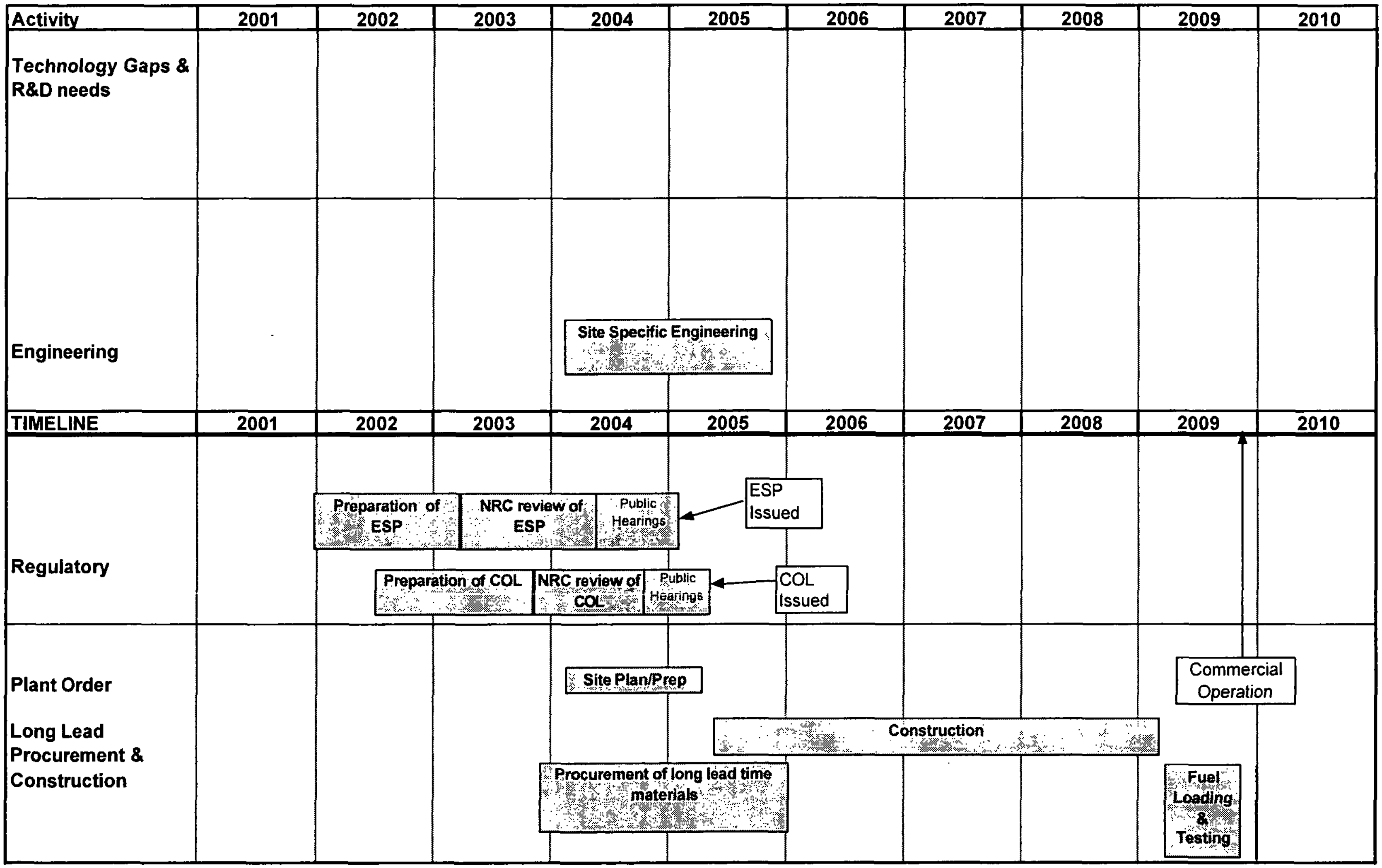
GE/NE has proven that it can lead an international vendors team in submitting lump-sum contracts for the full scope of supply of a two-unit ABWR station, though at an overseas location. They have further demonstrated that they have a worldwide supply infrastructure capable of providing on-time components supply to meet their construction contract obligations. A supply chain exists now to provide ABWR fuel, which is similar to current BWRs fuel, to several ABWR plants. GE/NE has completed the first time engineering of the ABWR and they have a complete set of design drawings. They claim to have already recovered the costs of their first time engineering effort. A future ABWR project will have a reference plant for construction and a reference plant for operation.

Future construction projects, should the demand for future nuclear plants revive, may be constrained by having only one worldwide vendor for RPV and other large component forgings. Other vendors may be qualified in time, however a potential supply constraint situation exists. The capital cost figures reported for the ABWR are very reliable, based on actual plant construction experience (though outside of the U.S.). These cost figures represent the high end of the competitive range, as estimated by the NTDG. The ABWR could represent a competitive base load generation option in specific market situations in the U.S.

Timeline for the ABWR

The timeline for the ABWR follows.

ABWR Near Term Deployment Roadmap



GE/NE ESBWR DESIGN

A. Criteria Evaluation

The ESBWR is a 4000 MWth (approximately 1380 MWe), Boiling Water Reactor (BWR), developed by GE/NE to improve the overall economics of the earlier 2000 MWth Simplified Boiling Water Reactor (SBWR). The ESBWR is derived from a long history of GE/NE BWRs, and incorporates many of the design features of the Advanced Boiling Water Reactor (ABWR) and the now discontinued SBWR design.

The ESBWR has been developed by industry in a systematic eight-year long stepwise process, which has addressed changing market conditions. The overall program had initial oversight from a group of European utilities, which were joined in the last few years by U.S. utilities and their representatives. The current design and technology team has partners from Europe and the U.S. and is led by GE.

Criterion 1: Regulatory Acceptance

Summary of General Electric Response

The following are the basic attributes of the ESBWR design:

- Advanced simplified design,
- Passive safety systems,
- Extensive use of components developed for the ABWR,
- Extensive plant optimization with utility inputs,
- Based on SBWR technology which was reviewed by US NRC,
- Can utilize the infrastructure in place for ABWR,
- Extensive investment by industry to develop the design and technology, and
- Developed by an international design team.

Some of these issues are discussed below.

The ESBWR uses the same basic passive technology and simplified design of its SBWR predecessor. By incorporating additional innovations, the design has been scaled to a higher power level – 1,380 MWe. The ESBWR also enjoys a strong synergism with the ABWR, using many of the fully developed technologies such as the Fine Motion Control Rod Drive (FMCRD), materials and water chemistry, multiplexing and fiber optic data transmission, and control room design. Because of this synergism, the detail design, analysis, and Certification resource requirements for the ESBWR have been greatly reduced. The ESBWR passive system innovations are supported by an extensive experimental database and rely on heat transfer mechanisms that are well understood and modeled. By using passive coolant circulation and passive safety systems, the ESBWR achieves significant simplification while still meeting the current international requirements for safety and reliability.

The ESBWR does not have a Design Certification by the U.S. Nuclear Regulatory Agency (NRC).

GE/NE believes that the time required to license the ESBWR in the U.S. ought to be less than three years, excluding public hearing and rulemaking. The reasons for the expected short review period are the following:

- Synergism with the ABWR, which is already certified,
- Basis for the Standard Safety Analysis Report (SSAR) is in place since the ESBWR can capitalize in a major way on the already written SBWR's SSAR which had been submitted to and partially reviewed by the NRC and which is, in turn, fifty percent identical to the ABWR's SSAR,
- Safety testing program has been completed, with extensive additional tests since the prior relevant testing within the SBWR program,
- Technology reports will all be completed in time for the NRC licensing review,
- The design is now completed to the point required for review by the NRC for issuing a Certification license, and
- The NRC is currently reviewing for generic approval the GE version of the Transient Reactor Analysis Code (TRACG), which will be an essential tool in its Certification review of the ESBWR.

GE/NE requested support from the DOE through a cost-sharing program to complete the Design Certification documentation, present the application to the NRC, and proceed with a licensing review.

NTDG Assessment

The licensing review period probably can be reduced to about three years for a relatively mature design such as the ESBWR. The three major points in favor of the shorter licensing period in the NTDG estimate are:

- The NRC is already partially familiar with the ESBWR given its earlier reviews of the ABWR and the SBWR,
- The extensive multi-year safety-testing program is already completed, and
- Some licensing documentation and design data at the level required for Certification are currently available.

Design Certification in time to allow ESBWR deployment in the U.S. by 2010 requires the following:

- A detailed licensing review plan that has been approved by the NRC. There is the need for NRC commitment to the target cost and timeline for a Design Certification review.
- Commitment by GE/NE to proceed with a Design Certification program, and
- Funding for the SSAR preparation, for a completed Certification application, and for a NRC licensing review.

Assuming that the commitments and financing gaps are resolved in a timely fashion, the NTDG considers that the ESBWR design can meet the criterion of Regulatory Acceptance.

Criterion 2: Industrial Infrastructure

Summary of General Electric Response

The ESBWR design team plans on utilizing the existing ABWR industrial infrastructure in commercializing the ESBWR. The ESBWR will use components that are identical to or similar to the ABWR: similar size vessel, fine motion control rod drives, pressure suppression containment, fuel designs, materials and chemistry. Since the supply infrastructure for the ABWR already exists, the ESBWR will rely on an existing network of suppliers in Europe, the U.S. and East Asia.

Similar to the ABWR, the ESBWR team expects a large fraction of the components in various plant systems to be provided by U.S. suppliers. In the Nuclear Island, U.S. manufacturers will likely provide valves, pumps, piping and heat exchangers. In the Turbine Island, the turbine generator, the condenser and various heat exchangers could be domestically manufactured. Plant instrumentation and controls will also be built in the U.S. The ESBWR, like the ABWR, will depend on Japanese vendors for the manufacturing of the Reactor Pressure Vessel (RPV) forging, large internals, and control rod drives. The ESBWR, like all other Advanced Reactors proposed for deployment in the U.S. by 2010, will depend a single Japanese vendor for RPV forging – Japan Steel Works. GE/NE has reported that it is exploring other RPV forging venues both in Europe and in Asia, which can be activated should the demand exceed the capacity of the current Japanese supplier.

NTDG Assessment

The NTDG agrees that the ABWR global supply infrastructure will likely provide the industrial base for the deployment of the ESBWR. The ESBWR like the ABWR and other Advanced Reactors planned for deployment by 2010 will all depend on a single supplier – worldwide –for the provision of RPV forging. Also, GE/NE's commercialization plans for the ESBWR call for the construction of several ABWRs before the deployment of the ESBWR commences. By the time the first ESBWR is committed, in the second half of this decade, additional ABWRs may then concurrently be under construction. The global ABWR/ESBWR supply chain may be constrained to meet an increased demand, and may have to be expanded on an accelerated basis.

In summary, the NTDG considers that the ESBWR meets the criterion of Industrial Infrastructure.

Criterion 3: Commercialization Plan

Summary of General Electric Response

The ESBWR program plan for the last eight years has been an industry funded and supported plan to develop a passive BWR plant that is economical and meets the utility needs for a reliable and safe plant. The overall plan presented –past and future – has several steps with decision points on whether to proceed to the next step. This plan includes the following steps:

- GE/NE will continue preparation of Design Certification documentation, and will present the completed application to the NRC review process when funding, through DOE cost-sharing program, is secured.
- Detailed engineering and any needed component testing will be initiated at the final stages of the Design Certification review. Funding sources and requests will depend on the then prevailing market conditions, and could include 50/50 cost share from DOE.
- GE/NE will keep informing its ESBWR utility review board of progress made in the Design Certification and engineering completion programs, and will solicit utility interest in developing the design.

The ESBWR team has completed the supporting technology programs and has completed the design in sufficient detail to conclude that it will meet the economic goals. GE/NE expects an ESBWR to be a commercially viable plant only if the First Of A Kind (FOAK) plant cost, including the ESBWR first time engineering costs, will be lower than the cost of a then fully commercialized Nth Of A Kind (NOAK) ABWR. They are not relying on multiple plant construction plans in order to amortize the engineering costs among several prospective clients.

The next steps in the plan are U.S. NRC design certification (2-4 years) followed by detailed design completion, commitment to a plant, plant specific licensing, and construction. The plans to offer a fully designed and economically competitive ESBWR product in the market has been a long, systematic and generally successful program and has been totally an industry effort, involving both European and U.S. utilities. Beyond Design Certification the plan relies on a robust nuclear marketplace, especially involving several ABWR's, to proceed to the next steps to commercialization. It relies on synergies with ABWR to keep first time engineering costs low and relies on the manpower and industrial infrastructure developed for ABWR.

NTDG Assessment

The NTDG notes that the general commercialization strategy presented for the ESBWR has been successful in bringing the design and technology to its current state. The strategy is a reasonable approach for commercializing a large-scale industrial product such as the ESBWR, under the circumstances of a limited market, and with minimum resources for developing a new product. While the overall thrust of the strategy seems feasible for orderly deployment, there are issues, which must be addressed and accelerated to deploy the ESBWR for operation in the U.S. by 2010. These issues are:

- Early commitment to a Certification program.
- Timely completion of Design Certification.
- Acceleration of the first time engineering effort.

With the exception of timing and/or funding first time engineering, no major commercial factor exists, which would impede deployment of the ESBWR in the U.S. by 2010, should GE/NE proceed with an accelerated commercialization approach. A number of commercial decisions and milestones will have to be met by all involved parties, to assure the ability to achieve deployment by the end of this decade.

GE/NE stepwise approach to commercialization depends on government cost-share for the Certification program, and will not initiate a detailed engineering and a component testing programs until the Certification review is almost completed, and until several ABWRs have been ordered. While this program minimizes reliance on U.S. Government funding support, it does not accelerate the commercialization schedule to allow deployment by 2010. The NTDG considers that should GE/NE proceed with the stepwise commercialization approach, it may not be able to deploy the ESBWR for operation in the U.S. by 2010, thus the criterion on the Commercialization Plan is not met.

Criterion 4: Cost Sharing Plan

Summary of General Electric Response

GE/NE has stated the need for U.S. Government funding to support a Design Certification application and review by the NRC. That funding would support the completion of an ESBWR SSAR, completion of technology reports, qualification of design analysis computer codes, preparation of application documents, and review by and interaction with the NRC's staff. The total cost of a Design Certification licensing program has been estimated by GE/NE to be 30 Million Dollars. GE/NE requests a 50/50 cost-share program with the U.S. Government. The period for this effort is estimated as 2-4 years.

GE/NE justifies U.S. Government cost sharing in its Certification application based on the fact that industry has taken the entire lead for the current eight-year program for designing a viable plant concept, technology development, and safety testing. GE/NE is also seeking government cost sharing for the completion of the ESBWR FTE detailed design.

NTDG Assessment

The NTDG agrees with GE/NE that it is justified in requesting U.S. Government support for its ESBWR Design Certification application, and that this cost share program is needed to support the deployment of the ESBWR in the U.S. The NTDG judges that careful attention must be given to assure that Design Certification and design completion are funded.

The limited U.S. Government funding requested is justified to develop this industry-funded design into a viable option, by minimizing the risk associated with U.S. Government mandated licensing approval.

A recent GE/NE decision to request U.S. Government cost-share for detailed engineering completion could shorten the ESBWR commercialization schedule to about 2010. The NTDG judges that the ESBWR meets the cost share criterion.

Criterion 5: Economic Competitiveness

Summary of General Electric Response

The approach of the ESBWR design team has been to reduce the number of systems and components in order minimize capital costs and annual operating expenses. The ESBWR nuclear island cost is estimated to be 50 percent of the cost of the nuclear island of its SBWR predecessor, and lower than the nuclear island cost of the ABWR. To keep the development costs low, systems components, processes, and technologies from the already developed and operating ABWRs are used extensively. This approach keeps first time design cost uncertainties low.

GE/NE did not provide any capital cost estimate figures for the ESBWR, however it claims that it has an internally generated cost estimate which support its claim for a lower cost for the ESBWR, compared with the ABWR. GE/NE has provided comparisons of several key ESBWR material quantities in relation to such requirements in other BWR designs. These comparisons provide evidence that the ESBWR is a simpler design than the ABWR and other BWR designs, and that it does not require some of the major components, such as the internal recirculation pumps, inherent in the ABWR design. These facts support GE/NE's assertions that the ESBWR should have a lower capital cost than the ABWR.

The ESBWR is being designed with the availability goal of 92 percent, concentrating on reducing the length of outages. Due to the simplicity of the systems and the reduction of components, the reliability, availability and maintainability should be improved over today's BWRs.

NTDG Assessment

The NTDG agrees with many of the qualitative assertions of GE/NE regarding the prospective economics of the ESBWR. Given the lack of any cost figures presented, and considering that the ESBWR design has not yet proceeded through FTE completion, it is premature to judge the overall economic competitiveness of the ESBWR. GE/NE has presented estimates of significant materials quantities reduction in the nuclear island of the ESBWR compared with the ABWR. It is not expected that similar large materials or cost savings can also be achieved in the turbine island and the balance of plant (BOP) area, which normally comprises about forty percent of the total plant cost. The ESBWR nuclear island cost advantage would be reduced by about forty percents when averaged over the entire plant.

There exists a reasonable qualitative basis for anticipating that the ESBWR can achieve a competitive position in the future U.S. nuclear market, and thus it can meet the criterion of Economic Competitiveness.

Criterion 6: Fuel Cycle Infrastructure

Summary of General Electric Response

The ESBWR fuel cycle uses standard BWR and ABWR fuel, with a slightly shorter configuration. No new fuel design demonstration and qualification program is required. The ESBWR could use the BWR/ABWR existing fuel manufacturing facilities, and the basic manufacturing capacity is already in place. The ESBWR design has allowed the reduction of the number of control blades and control rod drives (CRDs) as compared with its predecessor SBWR design. The use of a new core lattice design has further reduced the number of CRDs in the ESBWR.

The ESBWR is designed to effectively utilize the once-through uranium oxide fuel cycle. Longer cycle length and higher fuel burnup levels have been stressed in the core design development. The core support components and reactor vessel will allow for mixed oxide uranium-plutonium (MOX) fuel use, or the use of mixed fuel types such as uranium and thorium.

NTDG Assessment

Given reliance on standard BWR/ABWR fuel designs, there are no major developmental problems in the fuel area that may prevent deployment of the ESBWR in the U.S. by 2010. The use of wider control rod blades in the ESBWR core design, as compared with the ABWR control rods, will not require a redesign of the control rod drive mechanisms, nor will it impact their operation. The ESBWR meets the criterion of Fuel Cycle Industrial Infrastructure. No design-specific gap is identified.

B. GAP ANALYSIS

The NTDG has identified several design specific questions that need to be addressed for ESBWR deployment in the U.S. by 2010.

Design Certification of ESBWR

The NRC has not yet certified the ESBWR design. There remains some uncertainty as to how long it will take NRC to conduct any Design Certification review, and how long it will take the NRC specifically to review and approve the ESBWR license application. Another uncertainty is the timing of U.S. Government cost-share funding support for ESBWR Certification. If Certification funding is delayed to 2003, and GE/NE application is delayed accordingly, completion of the Certification process by 2005 may be delayed. A time breakdown of the proposed GE/NE request for 50/50 cost-share program is enclosed below.

Closure: Obtain Design Certification of the ESBWR from the NRC by the end of year 2005.

Estimated Cost: GE/NE estimates that the entire process through the granting of Certification will cost 30 Million Dollars and should require less than 3 years, given NRC's level of familiarity with the design, and GE/NE's level of preparations for design submittal to the NRC.

The Annual 50/50 government-industry cost-share budget request is provided below, in units of Million Dollars per year.

	FY02	FY03	FY04	FY05	FY06	FY07
Industry	*$0*	*$5M*	*$5M*	*$5M*		
DOE	*$0*	*$5M*	*$5M*	*$5M*		

The proposed justification for DOE funding is that the ESBWR eight-year design and testing effort has been entirely financed by private industry and has not involved the DOE, but the licensing issues are specific to the U.S. Government and going through them the first time is a development effort appropriate for shared cost.

Funding First Time Engineering

The ESBWR detailed first-time engineering (FTE) is incomplete. GE/NE recognizes that such funding will have to be provided from a variety of sources, in order to offer the ESBWR as a commercial product.

Closure: Complete FTE, including all detailed engineering not covered in other gaps/solutions, project development, vendor selection, and procurement specifications.

Estimated Cost: First time engineering effort for an Advanced Reactor like the ESBWR could cost several hundred million dollars, depending on the design concept, and on the percent engineering completion achieved by the time of the award of the Design Certification. No funding sources or schedule were identified by GE/NE in any level of detail. The decisions on how to close this gap will depend on progress on the earlier gap closures, on future ABWR sales, and on the development of the marketplace. Following is a rough estimate of anticipated FOAKE costs for ESBWR:

	FY04	FY05	FY06	FY07	FY08	FY09
Industry	*$10M*	*$40M*	*$50M*	*$40M*	*$10M*	
DOE	*$10M*	*$40M*	*$50M*	*$40M*	*$10M*	

C. Overall Assessment

The NTDG considers that the ESBWR possibly can be deployed in the U.S. by 2010. Its deployability by 2010 is limited by GE/NE plans to proceed with the commercialization of the design in a stepwise manner, as described above. GE/NE has requested a 50/50 cost-share funding for Design Certification and FOAKE. The large resources deployed by industry to develop the technology and design justifies the requested funding.

There exist several factors favorable to early deployment of the ESBWR in the U.S. market:

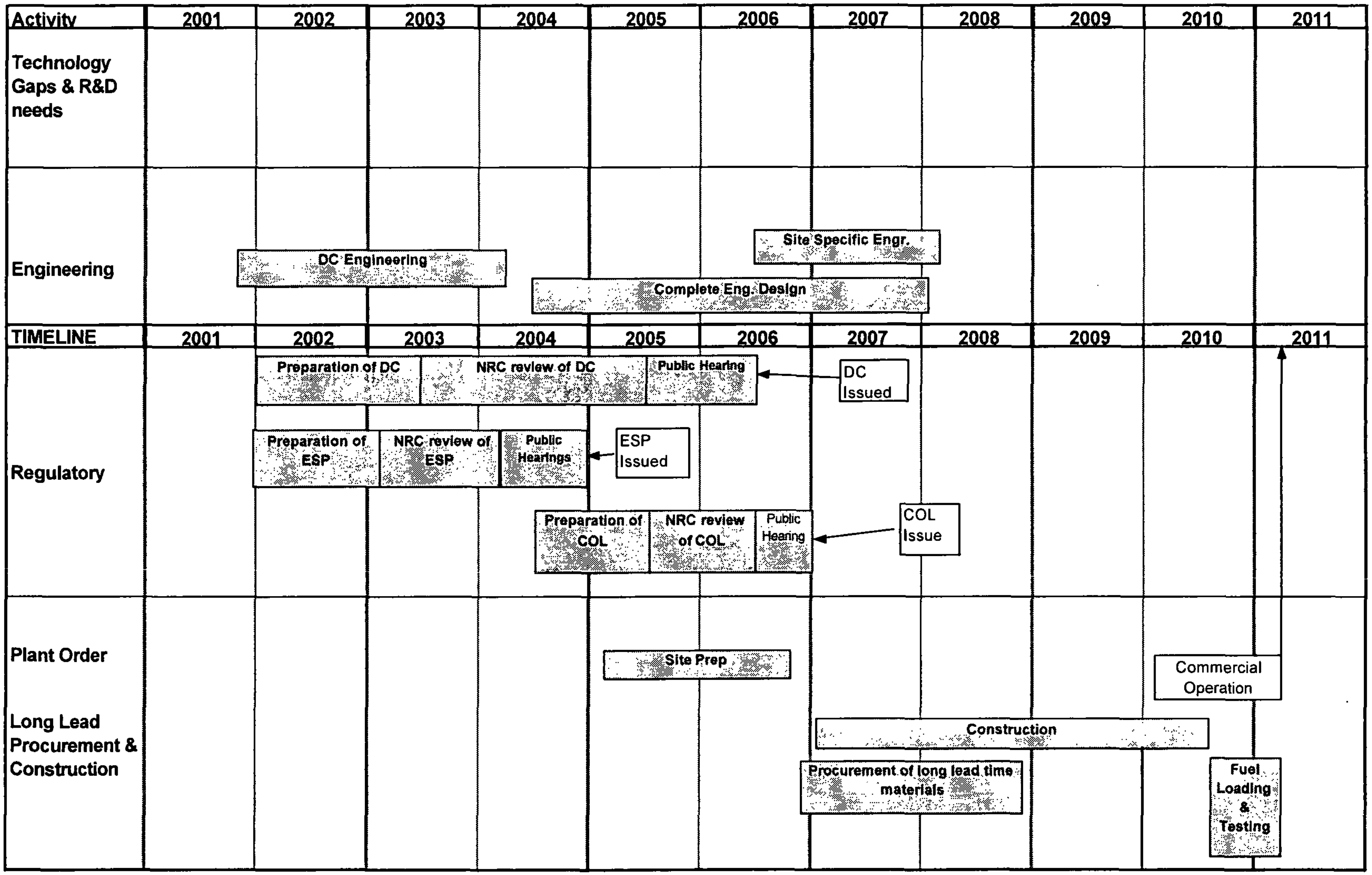
- The design is an extension of other GE/NE BWR product lines, and represents a simplification and optimization of the entire BWR reactor family. It capitalizes on the design, component specifications and commercialization experience of its predecessor BWRs and ABWRs.
- The design represents a passive safety plant concept at a capacity size of a mature, evolutionary, Advanced BWR. It could enjoy the benefits of improved public acceptance and improved economics, related to the elimination of active components such as the internal recirculation pumps, used in the ABWR design.
- The NRC is already familiar with the design, and GE/NE has completed an extensive list of safety testing to confirm it. A significant percentage of the Certification application reports and documents already exist.
- GE/NE has proven experience in commercializing the ABWR and in establishing a global supply network, capable of negotiating lump sum contracting, and meeting delivery schedules. This will prove useful for ESBWR commercialization.
- Commonality in equipment and component specifications, such as the use of similar fuel designs and assembly configurations, could reduce the FTE completion effort and cost and ease the licensing process.

The NTDG considers that additional work has to be completed on the ESBWR, before its potential, as highlighted above, could be realized. In particular, we note the need to secure GE/NE commitment to proceed expeditiously with ESBWR licensing, the need to obtain a Design Certification from the NRC, and the requirement of completing the first time engineering design. GE/NE has proposed funding support to complete the Design Certification licensing and FTE completion. However, GE/NE does not plan to initiate a FTE program until the certification program is nearing completion. These factors raise uncertainty as to the feasible deployment schedule of the ESBWR, should the stepwise commercialization approach be pursued and, as such, the ESBWR is judged to be in the "possibly can be deployed" category for deployment in the U.S. by 2010.

Timeline for the ESBWR

The timeline for the ESBWR follows.

ESBWR Near Term Deployment Roadmap



FRAMATOME ANP SWR-1000 DESIGN

A. CRITERIA EVALUATION

The SWR-1000 is a result of a long-term product development project of the Siemens KWU, part of the newly merged Framatome ANP (FANP). FANP has other product lines, such as the EPR, under consideration for potential introduction to the U.S. market.

Criterion 1: Regulatory Acceptance

Summary of Framatome Response

The SWR-1000 does not have a Design Certification from the U.S. Nuclear regulatory Commission (NRC). The design concept of the SWR-1000 was developed on behalf of German utilities that required that the design be licensable according to German law, and was reviewed by the experts of the German Government's Reactor Safety Commission (RSK). Framatome ANP is proposing to bid the SWR-1000 for Finland's fifth nuclear power plant. The concept was discussed with the Radiation and Nuclear Safety Authority (STUK) in Finland. STUK stated that the SWR-1000 is basically licensable according to Finnish codes and standards. An assessment, conducted by the European utilities (EDF of France, TVO of Finland as well as certain German utilities) concluded in 2001 that the SWR-1000 design concept complies with the requirements of the European Utility Requirements Document (EUR) for Light Water Reactor (LWR) Nuclear Power Plants. The results of this assessment will be published in January 2002 as Vol. III of the EUR. FANP has completed design and safety related documents relevant to licensing and is continuing work on the design in preparation for the Finland fifth nuclear plant proposal. FANP states that its significant European licensing experience will be used in support of NRC Design Certification.

FANP expects the following main issues to arise as part of a design certification by NRC:

- Assessment of the neutron-physics and thermal-hydraulic design of the core under normal operational conditions.
- Confirmation of the course of design accident events using the passive safety features of the SWR-1000 only.
- Confirmation of the capability of these safety features to control a postulated severe accident with core melts.
- Confirmation of compliance by the SWR-1000 design concept with US regulatory requirements.

In order for a first SWR-1000 plant to start operation in the U.S. in 2010, construction must commence (with first concrete pour) in 2006. FANP assumes that U.S. Certification would require two years, though it is the general industry assumption that this process may require at least three years, particularly for a foreign design developed to different codes and standards than the NRC is familiar with. This schedule requires that the application to NRC, with all the required documentation, must be submitted by 2003.

FANP has provided a detailed proposed timeline for design certification, starting in July 2001 and assuming the start of the NRC review by February 2002, leading to Design Certification, including public hearing and rulemaking by 2005. However, as of the date of this report there has been no contact between Framatome ANP and the NRC concerning certification of the SWR-1000.

NTDG Assessment

The NTDG concludes that there may be no serious technical hurdles that might prevent regulatory acceptance of the SWR-1000 in the U.S. There are, however, major schedule-related problems that unless expeditiously addressed, could make the licensing schedule proposed by FANP infeasible. These include:

- FANP has not yet committed to commercializing the SWR-1000 in the U.S. FANP has stated that they will not pursue Design Certification in the U.S. in a more proactive manner, until an internal corporate marketing study is completed in 2001.
- FANP did not yet have detailed interaction with the NRC to develop a Certification timeline. They have stated that they are only now in the process of studying 10CFR52 to determine what a realistic Certification schedule might be. FANP has not obtained any commitment from the NRC regarding the assignment of adequate licensing resources, or completion schedule.
- FANP has not yet committed corporate resources for SWR-1000 licensing review in the U.S. These resource requirements could be significant, considering that the German codes and standards used in the SWR-1000 design may have to be re-qualified and translated to NRC approved codes and requirements.

FANP provided limited information on the analytical tools and computer codes to be used to obtain NRC Certification. The SWR-1000 development, design, and safety work, have all been done in Europe. The development, qualification and approval of the safety analysis tools have traditionally taken the bulk of the effort required for NRC Certification of new designs. FANP will have to validate the computer safety codes used in the design of the SWR-1000 and their Quality Assurance standards, to fit the U.S. NRC's requirements. The effort required to convert all submissions and/or reanalyze to U.S. terms so that they can be evaluated using U.S. approved safety codes may be greater than FANP is estimating. Furthermore, given the current German Government policy on nuclear phase-out, future design development work on the SWR-1000 could be slowed down.

The NTDG concludes that with major resource commitment and expeditious schedule criterion 1- Regulatory Acceptance can be met. At this point in time it is too early to tell whether FANP would make such a commitment

Criterion 2: Industrial Infrastructure

Summary of Framatome Response

The development of the SWR-1000 has been based on experience gained from boiling water reactor (BWR) plants currently in operation, and incorporates the service-proven technology used at these plants. FANP anticipates no difficulty in finding suitably qualified and certified component manufacturers and suppliers. They believe this also applies to the new passive safety equipment to be used in the SWR-1000 (emergency condensers, containment cooling condensers and passive pressure pulse transmitters), which constitute relatively simple mechanical components (basically heat exchangers). Such components can be fabricated by certified manufacturers, qualified to the ASME Code, which are available in the U.S. and in Canada, Europe and Japan.

The state-of-the-art digital instrumentation and control (I&C) equipment to be used for the SWR-1000 will be manufactured by Siemens Corporation, which has already received approval from the U.S. NRC for its safety I&C platform TELEPERM XS.

FANP anticipates that with careful advanced planning and the timely placement of purchase orders to procure equipment, it should be possible to construct multiple units. For procurement of RPV, a suitable manufacturer still exists in Japan.

The largest nuclear-grade component with the longest lead-time is the RPV. The total time span involved in its manufacture is approximately 40 months and this will possibly require placing orders before ESP/COL is granted.

NTDG Assessment

FANP is relying on established industrial infrastructure in Europe for the building of BWRs, and that the worldwide nuclear capabilities of the FANP organization and its Framatome and Siemens subsidiaries are very substantial. A full-scope supply infrastructure exists, capable of building several BWRs in the U.S. or abroad for operation by 2010. However, FANP has not built a BWR in almost 15 years, so this particular infrastructure and the associated manpower may be unproven. Alternate sources of supply may be available to FANP, however no reliable information about that topic was provided.

In general, the potential gaps related to industrial infrastructure are judged to be resolvable for the deployment of an SWR-1000 in the U.S. by 2010. However, further significant expansion of the supply infrastructure for the simultaneous construction of several types of LWRs, may require careful scrutiny by interested parties, at that time. We consider that the SWR-1000 meets the criterion of Industrial infrastructure.

Criterion 3: Commercialization Plan

Summary of Framatome Response

FANP has begun to develop a commercialization plan for the SWR-1000. They believe the SWR-1000 can be ready for deployment in the U.S. by 2010, and will represent a nuclear energy option that is capable of generating power at a commercially attractive level.

Development of the SWR-1000 is based on three phases: a Conceptual Phase, a Basic Design Phase and a Detailed Design Phase. The Conceptual Phase started in 1992 and was completed in 1995. During that time the new concept of passive accident control was developed. In the subsequent Basic Design Phase, the SWR-1000 design was further developed and a preliminary safety analysis report (PSAR) was generated. This PSAR is now available. In the course of this development work new technical issues arose, and the Basic Design Phase was extended to 2002 in order to address these new issues. All development work performed during the Conceptual and the Basic Design Phases has been jointly financed by the German nuclear utilities and by Framatome ANP.

The third and final phase, the Detailed Design Phase, should result in the completion of all plant design details, such that the SWR-1000 design will be ready for construction. This phase is mainly oriented towards participation in the Finland fifth nuclear power plant bid. The detailed design will reach a point by the fall of 2002 when a proposal can be submitted for an SWR-1000 in Finland.

The SWR-1000 could be ready in the spring of 2003 for commercialization in the U.S. market. The period up to 2005 will be utilized for obtaining Design Certification from the U.S. NRC. Another 15 months are then anticipated as being necessary for contract award and acquisition of a construction permit, with construction starting in 2006. This would be followed by a construction period of 48 months.

Framatome ANP is capable of building the SWR-1000 either as a main contractor who supplies the entire plant on a turnkey basis, or as the head of a consortium. Construction of an SWR-1000 in the U.S. would be facilitated by the fact that FANP already has a national company operating here – Framatome ANP Inc. –, which would be available for project execution.

NTDG Assessment

The SWR-1000 is only a potential entrant into the U.S. market, at this time. FANP has begun to evaluate the U.S. market in the second quarter of 2001. Until FANP completes its marketing studies, planned before the end of 2001, and recognizes the opportunities and the challenges in the U.S. nuclear environment, it is not clear that they will launch a commercialization drive for the SWR-1000 in the U.S.

The FANP commercialization plan now concentrates on winning the Finnish fifth nuclear plant contract to provide resources for completing the detailed design. There is yet no identified U.S. utility interest, which could provide impetus for detailed design completion and Certification in the U.S. However, FANP has considerable resources and very close ties to U.S. utilities. The FANP statement that it will consider full scope turnkey contracts is considered a major positive element in gaining acceptance by U.S. utilities.

The NTDG judges the probability for successful SWR-1000 commercialization in the U.S. by 2010, and the likelihood of meeting the criterion of the Commercialization Plan, to be indeterminate, until a full commitment by FANP to commercializing the design is made.

Criterion 4: Cost Share Plan

Summary of Framatome Response

The SWR-1000 basic design has been developed in recent years on behalf of the German utilities. The majority of the development costs have been borne by these utilities and by FANP. The SWR-1000 incorporates passive safety systems, which are basically new, and which have been tested at large-scale test facilities to verify their functional capabilities and capacities. Most of the tests were funded with R&D funds from private industry as well as from the European Union (EU). Additional tests are currently underway to verify core melt retention inside the reactor pressure vessel in the event of a severe accident, and to test the functional capability of a passive boron shutdown system. These safety tests are funded by industry and by the EU.

U.S. Government funding is suggested by FANP for adaptation of the SWR-1000 design to U.S. regulatory requirements and to U.S. sites, as well as licensing in the U.S. – and the possible need for additional experimental or analytical design verification in U.S. laboratories, as a part of an NRC Design Certification program. FANP may, in the future, seek U.S. Government cost sharing for Design Certification Licensing and for ESP/COL application.

FANP further identifies the need for funding of future activities associated with the Detailed Design Phase of the SWR-1000 and experimental design verification. No specific request for U.S. Government cost sharing for these activities has been made.

NTDG Assessment

FANP has stated that they would initiate a U.S. Design Certification program by themselves, but would look for cost share in parity with past Design Certification submittals. They have not yet defined these needs for U.S. Government cost-share. FANP did not submit a total cost-share budget request, or an annual breakdown of that request. This lack of detail seems indicative of the preliminary status of FANP's licensing and commercialization plan.

The NTDG considers that it is indeterminate as to whether FANP meets the criterion of the Cost-Share Plan for the SWR-1000, pending FANP's commitment to commercialize.

Criterion 5: Economic Competitiveness

Summary of Framatome Response

Achieving a reduction in capital and power-generating costs was, in addition to increasing plant safety, one of the two main goals pursued in developing the SWR-1000. The following design features for SWR-1000 account for the projected lowers costs:

- Simplifications in system and component design and the short construction period of 48 months enable the specific capital cost to be lower by 30 percent compared with the capital costs of existing LWR plants of the same capacity
- Simplifications in plant design leads to lower maintenance cost since there are fewer components to be inspected, maintained, and repaired. The smaller number of ATRIUM 12 fuel assemblies may enable shorter refueling outages and higher plant availability. A study conducted by EDF predicted a long-term availability rating of 91.3 percent for the SWR-1000.
- Fuel cycle costs are reduced due to the use of larger fuel assemblies and due to the higher core design burnup of up to 65 GWd/tU.

Based on a first-of-a-kind (FOAK) plant built at a coastal (seawater) site without a cooling tower, the plant specific capital cost is estimated to be within the range of 1,150 – 1,270 $/kWe. Cost data were reported in year 2000 U.S. Dollars. The smaller value is considered by FANP to be a realistic value, while the larger value is regarded as conservative. Cost savings attainable for a subsequent Nth-of-a-kind (NOAK) plant compared to those of the first-of-a-kind (FOAK) plant were estimated to be in the range of 15 to 20 percent.

NTDG Assessment

FANP was very responsive to the RFI regarding the cost and economic information for SWR-1000. However, it is unclear whether some of the data are appropriate to U.S. conditions. The data presented indicate that SWR-1000 could realize excellent economics, but they are based on limited recent construction experience, in the European context. The SWR-1000 could realize these favorable projected economics through major design simplification and equipment elimination programs. Until more design information is developed and the FTE is completed, and until the licensing status of, and the requirements for, the SWR-1000 in the U.S. are established, the economic projections under U.S. conditions cannot be considered definitive. Among other uncertainties, it is also not clear whether the cost of detailed design is factored into the initial U.S. FOAK plant's cost.

The low capital cost figures provided by FANP fall within the range of economic competitiveness of 1,000 – 1,400 $/kWe, as estimated by the NTDG. The FANP cost projections for the SWR-1000 design can meet the Criterion for Economic Competitiveness. However, there exist many uncertainties in translating a German design into an economic plant under U.S. conditions.

Criterion 6: Fuel Cycle Infrastructure

Summary of Framatome Response

The type of fuel that will be used for the SWR-1000 is similar to fuel used in BWRs operating today. Although advanced assembly geometry has been developed which features a 12 x 12 fuel rod lattice, all fuel assembly materials and components correspond to those employed in existing BWRs.

The current BWR fuel fabrication facilities are suitable for manufacturing future SWR-1000 fuel. Enrichment services for SWR-1000 fuel can be provided by the same enrichment plants that enrich uranium to concentrations required in today's BWRs. Conversion from UF6 to UO2 can be accomplished in the conversion plants used today, including FANP's advanced dry conversion facilities. Pellet fabrication and fuel assembly manufacturing can also be done in other existing fabrication facilities, including FANP's facilities in the U.S. and Europe. The fuel produced for the SWR-1000 should have the high reliability levels that are typical for today's BWR fuel.

The U.S. and the European nuclear fuel industry are expected to have reserve capacity to fabricate and supply the required SWR-1000 fuel. There exists considerable flexibility in the reliable supply of fuel for the SWR-1000.

It is anticipated that almost all components used in the SWR-1000 fuel assembly will be proven from previous insertion in BWR cores. Although some components, such as the fuel channel and spacers will have different dimensions due to the transition to the 12 x 12 lattice, the design features and materials will be the same as in current BWR reload fuel design. It will not be possible to irradiate lead test assemblies (LTAs) of the SWR-1000 design in current BWRs due to the different ATRIUM 12 assembly dimensions. FANP expects, however, that there will be no need to develop a special qualification and licensing strategy for the SWR-1000 fuel, since its design features and components resemble those of familiar BWR reload fuel, and the licensing procedure is expected to resemble that for familiar BWR reload fuel.

The SWR-1000 fuel assembly uses Low Enriched Uranium (LEU) and is suitable for the once-through fuel cycle as well as for reprocessing and recycling. Extensive experience is available regarding the on-site storage of LWR spent fuel assemblies. This experience is applicable to SWR-1000 fuel assemblies. FANP will optimize the scope of on-site storage of SWR-1000 fuel assemblies based on the requirements specified by its customers. This applies also to the type of storage, e.g. compact storage in the storage pool, or dry storage. From the experience available today with on-site storage of BWR spent fuel assemblies, FANP concludes that no conceptual engineering problem has been identified or is anticipated.

NTDG Assessment

There exist no technical problems in the fuel cycle supply infrastructure, which cannot be closed in time for deployment of SWR-1000 in the U.S. by 2010. SWR-1000 will use a non-standard new fuel assembly design. It will not be possible to perform irradiation testing of a LTA in an actual reactor, as is the current practice in the U.S. This is likely to present a licensing challenge, possibly requiring testing in an ATR type reactor, although FANP's position is that only thermal hydraulic testing will be needed.

In summary, the unique 12x12 ATRIUM fuel design could pose difficult problems to licensing that fuel for insertion in U.S. reactors. FANP, given its considerable fuel cycle resources, should be able to resolve these problems in time for reactor deployment in the U.S. by 2010. We consider that FANP can meet the criterion of Fuel Cycle Infrastructure.

B. GAP ANALYSIS

Overview

FANP did not identify specific gaps but generally recognized the need for closure of several issues related to certification and detailed design completion.

Design Certification

The SWR-1000 has not been submitted to the U.S. NRC for any review, nor does it have a Design Certification. This constitutes a gap that needs to be resolved in order to allow deployment. The existing design and licensing information has been developed for the European regulatory system, in particular for Germany. A major question arises as to the extent to which the existing SWR-1000 licensing information, safety testing, and non-US certified codes are applicable and useful for NRC Design Certification.

Closure: Apply for and Obtain Design Certification of the SWR-1000 from the NRC.

Estimated Cost: No cost figures were provided by FANP on a total funding request or an annual budget breakdown. FANP indicated it would seek parity with previous U.S. Design Certification programs, however no specific numbers were yet provided.

Completion of First-Time Engineering

The SWR-1000 detailed first-time engineering (FTE) is incomplete. In general, FTE results in about 70 percent design completion and may cost upwards of 500 Million U.S. Dollars (The ABWR design team estimates the total FTE cost of the ABWR as 500 Million Dollars).

The SWR-1000 has already been partially designed, to a completion level higher than required for an U.S. Design Certification. FANP estimates design completion level of 40 percent, which would bring the SWR-1000 design completion effort to similar levels as have been achieved during the U.S. First-Of-A-Kind-Engineering (FOAKE) Program.

Closure: Complete FTE, including all detailed engineering, modify design documentation for U.S. codes and standards; incorporate all changes required by NRC in Certification Process.

Estimated Cost: No cost figures were provided by FANP. The level of effort required will depend on the effort expended on the Finland Fifth Nuclear Plant program. FANP has not yet indicated whether it will seek U.S. cost-share funding for this program.

Lead Assembly Testing In a Reactor Environment

The fuel cycle specific gap related to the SWR-1000 deployment is the irradiation testing, in a reactor environment, of a Lead Test Assembly (LTA) of the new ATRIUM 12 fuel. Core testing under realistic neutron flux conditions may be required for the licensing of a new assembly design. FANP's position is that only thermal hydraulic testing will be required, but FANP has not yet interacted with the NRC on this issue. The testing required may need a focused program in an ATR type test reactor, since a LTA could not be tested in an existing commercial reactor given the incompatible dimensions of the ATRIUM 12 assembly.

Closure: Develop and carry out a LTA test program, possibly requiring a high flux U.S. or European test reactor, in a coordinated program with the licensing authorities.

Estimated Costs: No cost figures for this activity were provided by FANP.

C. OVERALL ASSESSMENT

The requirements for the SWR-1000 design deployment in the U.S. include: FANP early commitment to commercializing in the U.S. market, expanding of the required resources to do so on an accelerated schedule, and overcoming the identified design-specific, as well as the generic gaps. At this time, however, FANP has not provided information on its decision to commit to commercialize the SWR-1000 in the U.S. or details of its commercialization plans. Thus there exists significant uncertainty as to whether the SWR-1000 can be deployed in the U.S. by 2010.

Closure of the design specific gaps will require a concentrated effort in the following areas:

- Design certification by the U.S. NRC – this requires a major effort of code development, qualification and testing. A more comprehensive licensing and cost share plan for this effort is also needed.
- Completion of the detailed design by FANP, which could depend on winning the Finnish fifth nuclear plant order and/or significant U.S. utility interest and demonstrated U.S. market potential.
- A focused effort to resolve the potential fuel licensing issues for the ATRIUM 12 fuel.

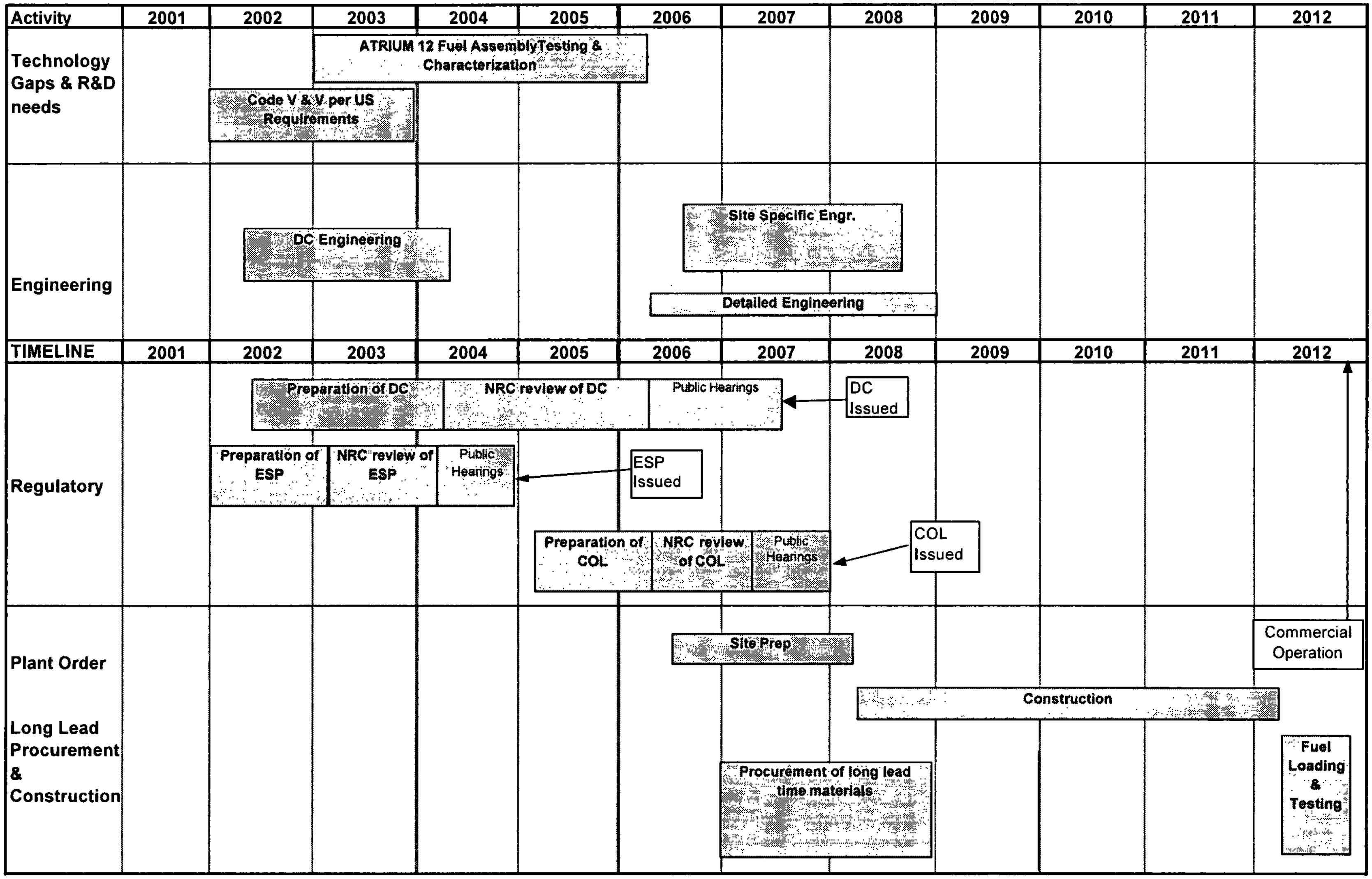
Beyond these gap resolution issues remains a basic concern with the FANP commercialization plan. FANP is only now developing its commercialization plan for the U.S. market, to be completed by the end of 2001. It is not clear, at this point, that the SWR-1000 will be chosen as their preferred nuclear technology to be commercialized in the U.S. This decision will also be influenced by FANP analysis of the prospects of the SWR-1000 winning the bid for the Finland fifth nuclear plant.

Commercialization of any foreign nuclear reactor design in the U.S. will require a major commitment of financial and engineering resources. A large global nuclear corporation such as FANP, with several large subsidiaries in the U.S., and with good exposure to U.S. nuclear utilities, could undertake such commitments, when it determines to do so. Considering the challenges in adopting the design to meet U.S. requirements, and in developing an expedited commercialization strategy, it is judged, at this point, that the SWR-1000 is in the "possibly can be deployed in the U.S. by 2010" category.

Timeline for the SWR-1000

The timeline for the SWR-1000 follows:

SWR1000 Near Term Deployment Roadmap



WESTINGHOUSE AP1000/600 DESIGNS

Westinghouse has submitted two plant designs, the AP600 and the AP1000 for evaluation as near term deployment candidates in the U.S.

The AP600 is a two-loop, 600 MWe pressurized water reactor (PWR) with passive safety features and extensive plant simplifications to enhance construction, operation, and maintenance. The AP600 design received Design Certification in December 1999.

The approach in uprating the AP600 to the AP1000 was to increase the power capability of the plant within the space constraints of the AP600, while retaining the credibility of proven components and substantial safety margins. The AP1000 power uprating results in 30 percent generating cost reduction relative to AP600 because the increased power is achieved with a small increment in capital cost and without significant loss of design detail. The AP1000 passive safety systems are the same as those for the AP600, except for some changes in component capacities.

The NRC is performing a pre-application review of the AP1000 during 2001. AP1000 Design Certification is expected to be completed by the end of 2004.

The AP1000 and AP600 are both PWR systems whose power trains use technology proven over decades of extensive operating experience in both commercial electricity generation and naval nuclear propulsion. The core, reactor vessel, internals, and fuel are essentially the same design as for present operating Westinghouse PWRs. Canned rotor primary pumps, proven in the naval program and in fossil boiler circulation systems, have been adopted to improve reliability and maintenance requirements. The pressurizer is a conventional design except that it has a larger volume to minimize the need for relief valve actuation. Providing larger design margins has reduced the burden on the components and systems.

The innovative aspect of the design is the use of passive features for emergency cooling of the reactor and containment. The cooling is provided by natural forces such as gravity, natural circulation, convection, evaporation, and condensation rather than on AC power supplies and motor-driven components. All safety-related electrical power requirements are met by Class 1E batteries, eliminating the need for safety grade on-site AC power sources and greatly reducing dependence on off-site power.

The passive emergency core cooling system provides core residual heat removal, safety injection, and depressurization. It includes a 100 percent capacity passive residual heat removal heat exchanger that satisfies the safety criteria for loss of feedwater, feedwater line breaks and steam line breaks. The entire system is located within the containment building, requiring no circulation of reactor coolant outside the containment boundary. The system consists of a combination of cooling water sources: gravity drain of water from two core makeup tanks and a large refueling water storage tank suspended above the level of the core as well as water injected from two accumulator tanks under nitrogen pressure.

The passive containment cooling system provides the safety-related ultimate heat sink for the plant. In a loss of cooling accident, the natural circulation air-cooling of containment is supplemented by evaporation of water flowing by gravity from a tank located on top of the containment building shield. Heat is removed from the containment vessel by the continuous, natural circulation of air so that design pressure is not exceeded and pressure is rapidly reduced.

The use of passive emergency cooling permits substantial simplification of the plant: 60 percent fewer valves, 75 percent less piping, 80 percent less control cabling; 35 percent fewer pumps and 50 percent less seismic building volume as compared to present operational PWRs. Extensive testing of the AP600 passive cooling systems has been completed and supported by independent confirmatory testing by NRC to verify the design and analyses of the passive emergency cooling features.

A1. Criteria Evaluation: AP1000

Criterion 1: Regulatory Acceptance

Summary of Westinghouse Response

The AP1000 is based largely on the AP600 design that has received design certification (DC) from the U.S. NRC. AP1000 is being designed to meet current U.S. regulations in the same manner as the AP600. The AP1000 safety systems are the same as those for the AP600, except for some changes in component capacities. Westinghouse expresses little doubt that the AP1000 can meet current regulatory requirements.

Significant licensing issues are expected in the NRC review, many of which have already been addressed to some degree by the AP600 DC. These include:

- 20 percent of the AP600 sections of the SSAR will require change.
- The test results and analysis codes accepted by NRC for the AP 600 will be used in support of AP1000 Design Certification application. No additional testing is expected to be required to support AP1000 licensing.
- Applicability of the AP600 safety analysis codes to the AP1000 must be demonstrated. The AP1000 Code Applicability Report was submitted to NRC in justification.
- Applicability of the AP600 PRA to the AP1000 PRA must be demonstrated. The AP1000 is designed to maintain large safety margins for postulated accidents; low risk associated with the AP600 design will be reflected in AP1000 results.
- Acceptance criteria for the AP1000 design (not needed for DC of the AP600) will be based on the same ITAAC Design Acceptance Criteria (DAC) process used for the evolutionary ALWRs.
- Applicability of exemptions granted to AP600 must be extended to the AP1000.

Examples of the more significant safety margins estimated for the AP1000 design are shown in Table I. These and some other margins are lower than AP600 but they still meet NRC's regulatory requirements and, in no case does a particular margin drop below a value that has already been successfully licensed in a currently operating plant. The most significant margin that is decreased from the AP600 value is the large break LOCA peak clad temperature. As part of its pre-application submittals to NRC, Westinghouse has provided an extensive discussion comparing safety margins between AP600 and AP1000 and expects to identify NRC concerns, if any, prior to beginning the review of its formal application.

TABLE I: Examples of AP1000 Safety Margins (1)

	Typical Plant	AP600	AP1000
Loss of flow margin to DNBR limit	1-5 percent	15.8 percent	13.6 percent
Feed water line break sub-cooling margin	Greater than 0° F	170° F	140° F
Steam Generator Tube Rupture	Operator action required in 10 minutes	Operator Action not required	Operator Action not required
Large Pipe Break	2000-2200° F	1644° F	1940° F

(1) Based on preliminary AP1000 T&H analyses using AP600 SSAR computer codes

To avoid opening new policy issues, AP1000 will follow the past precedents set by the AP600 review. This should avoid opportunities for delay in the NRC review schedule, since it will limit the ability of NRC reviewers to re-open issues already settled in the AP600 Design Certification.

The AP1000 Design Certification will likely be off the critical path for deployment because projected ESP and COL licensing schedules appear today to extend to 2005.

NTDG Assessment

The AP1000 has a good regulatory position. There is little doubt that the AP1000 can meet the current regulatory requirements and that a design certification will be obtained. The uncertainty resides in the time it will take, including the necessary public hearings. This uncertainty is ameliorated because AP1000 licensing relies heavily on precedents already established by NRC in their AP600 review, and because it appears that DC is not presently on the AP1000 critical path to deployment. Presently it appears that ESP and COL may be on the AP1000 critical path.

The up-front effort to address the key issues of applicability of the AP600 licensing determinations is an appropriate strategy. The timely resolution of the applicability issues identified through the pre-application review of the AP1000 with the NRC are key to confirming that the design certification schedule will meet the near term deployment criteria.

It is reassuring that Westinghouse preliminary estimates indicate that adequate safety margins remain in the AP1000 design and, in almost all cases, are significantly larger than in present operating plants. But, the magnitude of the regulatory acceptance gap depends strongly on the magnitude of changes in safety margin from the AP600 to the AP1000. Significant safety margin decreases could reopen issues that are thought to be settled. This could delay the process, particularly if the NRC requires additional tests and code modifications. PCT (Peak Clad Temperature) is important because it is a measure of core-cooling effectiveness in loss-of-coolant accidents. A 300 ^{0}F increase makes the ECCS significantly less effective than in AP600. However, the result does not appear to be a fundamental design issue, but one that could be optimized if need be. NRC can be expected to look at this closely.

A significant hedge against the possible need for further testing is the Oregon State facility that was used for AP600 testing and is now being funded under NERI to perform confirmatory testing related to AP1000 plant safety system performance.

The AP1000 can meet Criterion 1. AP1000 is not yet certified, but the pre-application review is in progress. Its licensing position is based on AP600.

Criterion 2: Industrial Infrastructure

Summary of Westinghouse Response

The U.S. nuclear power plant industrial base has been in place for over 40 years. It was developed specifically for light water plant designs and has maintained most of its capability by participation in the international new plant market and by meeting domestic fuel and services supply requirements. Standardized, pre-licensed plants are expected to reduce significantly the complexity of the industrial infrastructure necessary to build new plants.

Plant Design: Westinghouse has successfully used integrated industry resources to design many of the existing commercial PWRs and more recently the AP600. Design support has come from numerous sources. Plant design for more than one plant should be easily facilitated by use of standard designs that are nearly complete.

Equipment Supply: The AP1000 safety systems have fewer pumps, valves, and associated piping in comparison with current or evolutionary plants. Substantial major equipment supplier capability exists worldwide, including many qualified suppliers with the capability to manufacture the major nuclear grade components needed for new plant construction. Westinghouse has identified a long list of domestic and international suppliers of major nuclear equipment. Standardization can provide the buying power to enable build up of domestic equipment supplier capability.

Nuclear (ASME) certification is a key issue with suppliers of smaller components, especially for steel mill piping, and possible Section III heat exchangers and filters. No small U.S. supplier has maintained this certification. Re-establishing supplier capability is straightforward, but depends on determination by the suppliers whether or not the new market can support the expense of re-qualification.

The list of nuclear-ASME-qualified suppliers would grow considerably for highly reliable equipment not requiring a nuclear pedigree. The design of the AP1000 is unique in this respect because the U.S. NRC has accepted control functions, including components, as non-safety, that do not need to meet nuclear-grade requirements. Also, the AP1000 safety systems have less equipment when compared to current or evolutionary plants, reducing qualified supplier capability requirements.

Architect Engineering: A significant A/E capability still exists in the U.S. and elsewhere, and is available for new plant projects. The capability is more than adequate to support engineering of the site interface for a new plant or multiple plants due to the reduced effort required for standardized designs.

Project Management: Assembling a new plant project management team with nuclear experience will be challenging. More than one organization may be needed to provide the talent for a complete project team. Westinghouse anticipates it will need a project team of 100 to 150 people, including site management above the craft labor supervisor level.

Construction Companies: The size and complexity of a large new nuclear plant project will be challenging, and finding capability is a significant issue. The recent experience of building combined cycle power plants and other process plants is applicable, with the exception of the particular QA and QC challenges of nuclear construction. The AP1000 benefits because large portions of the on-site construction capability required for current plant construction, will not be required because of structural and systems modules to be built in manufacturing facilities. An estimated 40 percent of field labor hours will be moved to shops. Also if needed, overseas construction companies could probably be used to fill any gaps.

Long Lead Procurement: Long lead items, such as reactor vessels, steam generators, reactor coolant pumps, integrated head package, turbine generators, certain heat exchangers, and the plant simulator need to be ordered approximately 30 to 36 months in advance of installation.

NTDG Assessment

The reactivation of the nuclear power plant design and construction industry called for by Westinghouse will require firm commitments on the part of many companies to meet near-term deployment schedules. This can be done for one or several new plants, but would probably present difficulties for a larger number of plant starts because of supply limitations. Standard plant designs are a necessary ingredient for success. The standardization policy established in the ALWR Program is being followed.

Equipment supply, given the loss of small U. S. suppliers with ASME Nuclear certification is clearly a problem, but is probably manageable for near-term deployment. One reason is that there are still ASME-qualified suppliers for the major components. Another is that the Westinghouse passive design eliminates many of the active systems and protective functions required in earlier plant designs, with the result that fewer suppliers of small components will be needed. Also regulatory acceptance of some components, formerly safety-grade, as non-safety grade would be helpful, if the NRC implements Option 2 of SECY –98-300. Nuclear safety qualification of off-the shelf equipment is of potential use. Some use of foreign suppliers will also be helpful.

Project management is a critical skill, and recruiting the 100-150 people will be a challenge. An issue generic to all NTDG plants is the need for a national effort to educate and train the human resource infrastructure to sustain and expand nuclear energy activities.

Obtaining construction capability will also be a challenge, and use of some foreign construction companies may be needed.

The AP1000 meets Criterion 2. Strong international infrastructure is in place. No gaps are unique to AP1000.

Criterion 3: Commercialization Plan

Summary of Westinghouse Response

The key to successful commercialization of new nuclear generation by 2010 is readiness in several different areas. The main areas requiring progress to meet one or more stages of completion are (1) plant design completion, (2) regulatory approvals of the plant design, to the design certification stage, and construction sites, (3) a project implementation plan including detailed scheduling, (4) reliable project cost projections leading to competitive electrical generation, (5) project participants with defined and integrated scopes of supply who are committed to meeting objectives and estimated costs, (6) reliable supplier chain, (7) adequate experienced engineering , project management and construction workforce, and (8) reliable financing at competitive rates. No one company or institution can satisfy all of the needs generated by the above list. Westinghouse identified areas within its domain of expertise and influence.

Market Opportunities: For the past 25 years the only market opportunities for new plant sales were international customers, including Korea, Japan, and China, with plant offerings in smaller markets in Finland and South Africa. Due to plans to retire their Magnox and gas-cooled reactors over the next 20 years and commitment to reducing greenhouse gases, the United Kingdom could be one of the largest markets for 1000 MWe plants in the next 20 years. A significant small plant market (<700 MWe) will become active after 2005.

The U.S. is just awakening to the future potential of nuclear power and it is difficult to predict the size of the market in the next ten years. The focus will be on generation costs, plant performance, and new and simpler designs. AP1000 meets these objectives. When the first advanced passive plant is deployed, it is possible that many more units will follow.

Plant Design Completion: this is critically important. Emphasis will be on 1) developing a reliable project schedule, 2) generating a complete lowest cost price, 3) gaining NRC acceptance of the plant design, and 4) establishing well-defined boundaries and responsibilities between project participants.

The effort required for AP1000 design completion can be estimated with confidence with reference to AP600, for which the plant design has been completed such that detailed project schedules and substantive vendor quotes can be and have been generated. Completed design detail includes equipment specifications down to the sub-component level, detailed final equipment drawings on all major components, piping and instrumentation drawings for all nuclear and turbine island areas, and detailed module descriptions available for bidding by large systems fabricators.

Approximately 80 percent of the AP600 design drawings apply directly to the AP1000 plant. This high percentage was accomplished by minimizing component and systems design changes to achieve 1000 MWe. This approach has led to an AP1000 footprint that is identical to that of the AP600. Component changes for the AP1000 were accomplished using existing equipment design features most of which have had field duty such as the steam generators, nuclear fuel, reactor vessel and control rod drive mechanisms. For those changes made in the AP1000 plant, new costs were established by utilizing existing quotes or obtaining new ones. Minor changes in pipe sizes, valve flow rates and heat exchanger requirements were also considered in the revised cost estimate. Therefore, as is the case for the AP600, there is a high degree of confidence in the cost estimate for the AP1000.

Regulatory Approvals: A critical factor in the Commercialization Plan is the presumed completion of all regulatory approvals required to initiate construction of the plant at an acceptable site. Three necessary approvals are the Design Certification, the Early Site Permit (ESP) and the Combined License (COL). ESP and COL require owner actions with the NRC. Potential owners are currently exploring the possibility of pursuing ESPs and COLs.

Detailed Construction Scheduling: An extremely detailed project schedule that includes three years from the pour of first concrete to fuel load has been generated for the AP600. Only minor changes are required to make the schedule applicable to the AP1000, with the most significant being the installation of an additional containment ring, which is off the critical path.

Project Planning: Many questions on planning require answers: supply chain capability (addressed in Criterion 2), project costs (addressed in Criteria 4 and 5), and adequate engineering, construction and operations resources, and financing.

Project Financing: This is a critical part of commercialization. The focus will be on the owners, but strong support is needed from the suppliers, the A/Es and the U.S. Government to assure the lending institutions that the project is viable. Needed support includes project risk allocation, project costs and schedule, design completion, project payment structure, experience in new projects and working together. The owners need to address the issues of experienced operations, reliable maintenance, the fuel cycle, waste disposal and decommissioning.

U.S. Government: The U.S. Government has a role in at least three areas: 1) providing timely regulatory review of the plant and site submittals to the NRC, 2) assuring the implementation of waste disposal and spent fuel storage/disposition, and 3) helping develop confidence in lending institutions by addressing and removing uncertainties associated with long-term government actions.

Introduction of New Technologies: New technologies, especially computer-aided drafting and advanced management information systems, are being applied in other industries and can be applied to design, procurement and construction of AP600 and AP1000 units. New processes and tools can integrate and coordinate the entire team of owner, designer, constructor, fabricators, and suppliers into a cohesive, quick turnaround whole.

Teaming Arrangements: Westinghouse endorses an approach that would bring power companies together to share certain costs of new construction, e.g., first time engineering, procedures development and training, so the first plant buyer would not have to cover all of the first time costs alone. A teaming approach for the designers and constructors can provide the close working relationships needed to minimize costs and resolve problem areas.

NTDG Assessment

NTDG agrees that readiness is required in the list of 8 main areas requiring progress that is shown above. Westinghouse has identified its areas of expertise, but a substantial cooperative effort by other players in the industry is needed as well. Market opportunity is the most critical in this category.

The approach of minimizing change between the AP600 and AP1000 designs is important to achieving timely design completion, but construction planning and schedule uncertainty is introduced because of the AP1000 design differences. Westinghouse has minimized those differences by keeping the footprint and layout of the two designs the same. Although larger components are used in the AP1000 design, these components are based upon designs that have been used in operating plants. Use of virtual construction technology to compare the two designs would improve the understanding of the impact of those differences.

The Westinghouse commercialization plan shared with the NTDG is not as complete as one would expect of an internal strategic action plan that sets forth goals, describes the actions that must be carried out and the activities that are needed to make sales and get underway for timely completion. This is not surprising, because companies do not normally tell their competitors how they plan to do the job.

Westinghouse introduces the possibility of a cooperative effort among power companies, suppliers and constructors but does not seem to weight it heavily in their commercialization plan. A consortium is a well-known concept to reduce individual company risk, which is a very important factor in deciding to build a nuclear plant. NTDG believes that the consortium idea should receive more attention as a possible route to near-term deployment. The consortium idea could also apply on the supplier side, as a way to bring together all of the capabilities needed for plant design, for component fabrication, and for plant construction. It is also possible that a consortium could link together the power producers, the plant suppliers, and long-term electricity supply contracts. An encouraging move in this direction has recently been announced publicly by Mitsubishi Heavy Industries. MHI has agreed to participate and contribute toward completing the AP1000 and would be a participant in actually deploying units. EDF and BNFL are also involved and Westinghouse states that they plan to add a number of other companies over the next year or so.

The AP1000 can meet Criterion 3. It is a mature design but will require substantial financial investment to bring to market.

Criterion 4: Cost Sharing Plan

Summary of Westinghouse Response

Westinghouse proposes that DOE cost share generic and plant-specific activities up to a point in time where construction of a new plant can be committed. During this period, a project to deploy a new plant is speculative, and government cost share will be important to attracting potential owners to participate in bringing plant options to market and investing their own funds. This period also involves significant FOAK costs that are nonrecurring. For a new plant design to be competitive, these costs will need to be spread over multiple units in addition to being shared with the Government.

Benefits from stimulating the deployment of new nuclear plants would include royalty income for DOE, based on its prior investments in the ALWR program. It would also assist in making nuclear power a greater contributor to meeting U.S. energy needs, thereby lessening reliance on new fossil units, with their associated pollution and resulting costs to consumers.

Westinghouse is willing to cost share such efforts as it did in the successful ALWR program – including royalty payments for any future funding. Support for current AP1000 design, development, and NRC review activities is being provided by industry (Westinghouse Electric Company, British Nuclear Fuels Limited, EPRI, Mitsubishi Heavy Industries, Electricite de France, and several other European utilities) and by the U.S. Government through a DOE NERI grant.

The proposed cost sharing is 50 percent by industry and 50 percent by Government. The one exception is the NRC fees for performing the federally mandated reviews associated with ESPs, COLs, and design certifications, where it is proposed that these fees be fully funded by the Government. The industry cost share would be carried in part by Westinghouse and in part by its partners/suppliers.

The total cost estimated by Westinghouse to complete the AP1000 design, identified in their design specific gap analysis, is $303M. Westinghouse proposes that $155M be paid by the Government and $148M by industry. The identified funding is based on an approach that the plant specific detailed design and engineering efforts will be carried out on either (but not both) AP600 or AP1000, depending on Westinghouse reviews with potential plant owners.

NTDG Assessment

The Westinghouse cost-sharing plan includes a clear statement of costs to be shared by Government and by industry, as well as a rationale for the proposed split. The funding proposed to be shared by DOE and other industrial partners is very large and will be difficult to come by.

It is not clear whether the Federal Government will be willing to provide the substantial amount of cost-share that Westinghouse has proposed. To be successful, Westinghouse will need to be flexible in its cost-sharing approach and should also consider other options, e.g., (1) convince industry to provide more than 50 percent cost share, (2) enlist support of the power companies to help demonstrate a wider industry interest in going forward with the design, and/or (3) develop an alternate commercialization approach that allows some of the design completion steps and their funding to be phased, consistent with key milestones. This approach is further elaborated under the design specific gap analyses, and a conclusion reached that a revised cost-sharing (Table V) of 41 percent Government and 59 percent by industry is more appropriate.

AP1000 meets Criterion 4, since the cost-sharing is altered to increase industry participation, relative to government contribution.

Criterion 5: Economic Competitiveness

Summary of Westinghouse Response

Construction Schedule: The construction schedule is important because the interest during construction and the construction overheads add significantly to the cost of power and will to a considerable extent be determined by the time between expending funds for fabrication and construction and the time the plant begins to operate. The standard AP1000 schedule for an Nth plant is 5 years from order placement and 3 years from first concrete pour to fuel load. Having the Design Certification in hand and the simplified AP1000 design will make this schedule possible. The cost estimates (in $ millions) provided by Westinghouse for the AP1000, rated at 1090 MWe, are shown in Table II.

The overnight capital cost for the first unit is estimated to be $1.49 billion (or 1,365 $/kWe). This assumes that the first unit is ordered as part of a pair of units and the costs include procurement costs, construction costs, post-construction costs, contingency, owner's costs, and the first time engineering. If it is assumed that the first time engineering costs are recovered before the first project (e.g., through a cost-shared Government/industry program), then the overnight capital cost for the first unit would drop to $1.32 billion (or 1,210 $/kWe). For the Nth-of-a-Kind plant, the learning curve would reduce the overnight capital costs to $1.13 billion (or 1,040 $/kWe). The cost estimate is based on quotes and estimates from vendors and standard labor rates for Kenosha, Wisconsin. The production cost (O&M, fuel, and decommissioning) is 1.1 cents/kWh. The total generation cost for an Nth-of-a-Kind unit is estimated to be 3.2 cents/kWh. All costs are in year 2000 dollars.

Table II: AP1000 Cost Estimates

Procurement	676
Construction	406
Post construction	9
Contingency	78
Plant Engineering	338
Owner's cost	150
Sum of first 6 rows	1657
Less ½ of Plant engineering	-169
FOAK overnight cost (FOAK $/kWe)	1488 (1365 $/kWe)
Less ½ of Plant engineering	-169
Less Nth plant reduction	-185
Nth plant overnight cost (Nth plant $/kWe)	1134 (1040 $/kWe)

Notes:

- FOAK overnight cost is based on the assumption that the plant engineering cost would be charged to the first two units, each unit bearing half the cost since units would be ordered in pairs.
- Nth plant overnight cost assumes that the plant engineering cost is charged to the first two units; the Nth plant reduction is derived from the learning experience on earlier plants.

NTDG Assessment

The Westinghouse financial projections show that AP1000 has lower capital and operating costs than AP600, estimating a total generation cost of 3.2 cents/kWh for AP1000. This is a substantial reduction (about 37 percent) that results from treating the changes as a power up-rate of the AP600 design rather than simply scaling up all of the design features in the plant.

A comparison of the projected generation cost of AP1000 with a new natural gas fired plant shows that AP1000 is competitive in the present market with gas-fired and coal-fired plants. This assumes a natural gas price in the range of $3 to $4 million BTU, which has prevailed until increases (which may be temporary) were caused by increased demand for natural gas and inadequate new production and transmission line capabilities electricity shortages in some regions of the U.S. If gas prices rise in excess of normal inflation, the profit margins could be even more substantial.

The key to assuring an adequate return on investment is plant reliability. There is strong assurance of AP1000 operational reliability because the plant design utilizes proven technology, and incorporates the lessons learned from decades of operating experience at U.S. nuclear plants.

The primary uncertainty is in the ability to achieve the capital cost target and to complete construction (from the first concrete pour to commercial operation) in the three years planned. It is recommended that a contingency of 6 months be added to the scheduled construction time for the first unit. The overall time-line can be kept the same by scheduling the total time to obtain a COL at 18 months rather than 24 months and starting site and construction preparations 6 months earlier. Investor confidence has to be gained that the plant will be built on that schedule and within budget. A contribution to building that confidence can be to utilize virtual construction (3D+ time digital portrayals of the construction process) to provide detailed planning and schedule recovery capability as well as to demonstrate the validity of the schedule.

Based on Westinghouse projected costs, AP1000 can meet Criterion 5.

Criterion 6: Fuel Cycle Industrial Structure

Summary of Westinghouse Response

Production: All of the facilities necessary for fuel production supporting the operation of the Westinghouse AP1000 plant are currently in commercial operation and are supplying fuel for the existing PWR operating plants that is the same as needed in the AP1000.

The enriched uranium supply chain (consisting of uranium ore extraction and refining, UF_6 conversion and enrichment) is characterized worldwide by significant over-capacity from both the conventional sources as well as the sources resulting from nuclear weapons dismantling.

The fuel fabrication portion of fuel supply has excess capacity both within the U.S. and from international sources. Westinghouse has significant available capacity that is currently in lay-up but could be re-activated in a relatively short period of time. The capacity needed to support new plant orders could easily be put into commercial service within the new power plant construction period.

Fuel Qualification & Licensing: No fuel qualification or licensing will be required for the Westinghouse AP1000 plant design, since it uses fuel that is currently licensed and in commercial service.

Fuel Reliability: The fuel required for the Westinghouse AP1000 design is currently in service and is exceeding the industry fuel reliability requirements.

On-Site Spent Fuel Storage: The Westinghouse AP1000 plant design provides for on-site wet spent fuel storage to accommodate the spent fuel resulting from at least 10 years of operation without shipment of spent fuel or fuel consolidation, while maintaining the ability for a full core offload. In addition, on-site dry storage is a clearly demonstrated and feasible option for the interim storage of spent fuel.

NTDG Assessment

NTDG agrees with the Westinghouse response. There is no problem in the fuel cycle industrial structure that would hamper deployment of the AP1000. Although there is a plentiful supply of enrichment services worldwide, a generic issue exists in that domestic supply is limited to one relatively old plant. In the longer term, a more robust domestic enrichment supply would be prudent

AP1000 meets Criterion 6. It will utilize conventional fuel.

A2. CRITERIA EVALUATION: AP600

Criterion 1: Regulatory Acceptance

Summary of Westinghouse Response

The AP600 received Design Certification from the U.S. NRC in December 1999. This resulted from a seven year review of the AP600 standard plant design review including:

- AP600 Standard Safety Analysis Report (SSAR)
- Probabilistic Risk Assessment
- Inspections Tests Analyses and Acceptance Criteria (ITAAC)
- AP 600 Test Program and Safety Analysis Codes

The test program results were used to validate the safety analysis codes. The purpose of these codes is to predict the performance of the passive safety features in response to transients and accidents. First-of-a-kind (FOAK) engineering totaled approximately $190 million and produced over 12,000 design documents and a 3-D computer model of the entire plant that is integrated with both the plant engineering database and detailed 36-month construction schedule. The FOAK work was helpful in assuring NRC that the balance-of-plant safety issues had been adequately addressed.

Westinghouse also identified the need for the Early Site Permit (ESP) and the Combined License (COL), which have not been completed yet. Both require plant owner actions with the NRC.

NTDG Assessment

Because the NRC has accepted the AP600 test and analysis codes, and granted AP600 Design Certification, the AP600 has a strong regulatory position. NTDG concurs with Westinghouse that an ESP and a COL are necessary for near-term deployment. Some additional work is needed for Westinghouse to reach agreement with the NRC on details of the ITAAC process. However this is a generic issue that applied to all certified designs that are referenced in a COL. It is reasonable to expect that these needs can be met in time for deployment by 2010.

The AP600 meets Criterion 1; the design is certified.

Criterion 2: Industrial Infrastructure

The summary of the Westinghouse response and the NTDG evaluation for the AP600 are essentially identical to the AP1000 and thus are stated under the AP1000 criteria evaluations.

The AP600 meets Criterion 2, with the same comments provided for AP1000.

Criterion 3: Commercialization Plan

The summary of the Westinghouse response and the NTDG evaluation for the AP600 are essentially identical to the AP1000 and thus are stated under the AP1000 criteria evaluations.

The AP600 can meet Criterion 3. It is a mature design but will require substantial financial investment to bring to market. Because it is already certified, AP600 design completion costs are incrementally (~10 percent) lower than AP1000.

Criterion 4: Cost Sharing Plan

The summary of the Westinghouse response and the NTDG evaluation for the AP600 are essentially identical to the AP1000 except that the design certification effort, (identified at a total cost of $30 million versus an $18.7 million government cost-share). Thus the AP1000 criteria evaluations are given under AP1000 Criterion 4.

The AP600 meets Criterion 4. It is recommended that the Westinghouse plan be altered to increase industry participation, relative to government contribution

Criterion 5: Economic Competitiveness

Summary of Westinghouse Response

Construction Schedule: The construction schedule is important because the cost of power from any plant will, to a considerable extent, be determined by the time between committing funds for fabrication and construction and the time the plant begins to operate. Because the AP1000 follows the design footprint of the AP600, their overall schedules are identical. The standard AP600 schedule for an Nth plant is 5 years from order placement to commercial operation. Having the Design Certification in hand makes this schedule possible. The Westinghouse cost estimates (in $ million) for the AP600, rated at 610 MWe, are shown in Table III.

TABLE III: AP600 COST ESTIMATES

Procurement	614
Construction	352
Post construction	8
Contingency	69
Plant Engineering	268
Owner's cost	150
Sum of first 6 rows	1461
Less ½ of Plant engineering	-134
FOAK overnight cost (FOAK $/kWe)	1327 (2175 $/kWe)
Less ½ of Plant engineering	-134
Less Nth plant reduction	-182
Nth plant overnight cost (Nth plant $/kWe)	1011 (1657 $/kWe)

Notes:

- FOAK overnight cost is based on assumption that the plant engineering cost would be charged to the first two units), with each unit bearing half the cost, since units would be ordered in pairs.
- Nth plant overnight cost assumes that the plant engineering cost is charged to the first two units; the Nth plant reduction is derived from the learning experience on earlier plants.

The overnight capital costs for the first unit are estimated to be $1.33 billion (or 2,175$/kwe). This assumes that the first unit is ordered as part of a pair of units and the costs include procurement costs, construction costs, post-construction costs, contingency, owner's costs, and the first time engineering. If it is assumed that the first time engineering costs are recovered before the first project (e.g., through a cost-shared Government/industry program), then the overnight capital cost for the first unit would drop to $1.19 billion (or 1,956 $/kWe). For the Nth-of-a-Kind plant, the learning curve would reduce the overnight costs to $1.01 billion (or 1,657 $/kWe). The cost estimate is based on quotes and estimates from vendors and standard labor rates for Kenosha, Wisconsin. The production cost (O&M, fuel, and decommissioning) is 1.4 cents/kWh. The total generation cost for an nth-of-a-kind unit is estimated to be 4.7 cents/kWh. All costs are in year 2000 dollars.

NTDG Assessment

The Westinghouse financial data show that AP600 has higher capital and higher operating costs than AP1000, citing a total generation cost of 4.7 cents/kWh for AP600 (and 3.22 cents/kWh for AP1000). AP600 has the important advantage of Design Certification, which AP1000 does not yet have, and will not have for several years. Since the projected schedule is the same for the two plants, i.e., 2010, an AP600 order would essentially be a hedge against possible delay of Design Certification of AP1000, assuming that the plant output is not an issue.

A comparison of the generation cost of AP600 with a new natural gas fired plant shows that AP600 is competitive at a price of natural gas between $5 and $6 per million BTU with a combined cycle natural gas plant. The conclusion is that AP600 would be competitive with new natural gas power plants if natural gas prices remain at levels of this past winter. If gas prices fall to average levels of the 1990s, AP600 would be unlikely to be competitive.

The key to assuring an adequate return on investment is plant reliability. There is strong assurance of AP1000 operational reliability because the plant design utilizes proven technology, bolstered by infusion of decades of operating experience, that is already being achieved by most of the present U.S. nuclear plants.

The primary uncertainty is in the ability to achieve the capital cost target and to complete construction (from the first concrete pour to commercial operation) in the three years planned. It is recommended that a contingency of 6 months be added to the scheduled construction time for the first unit. The overall time-line can be kept the same by scheduling the total time to obtain a COL at 18 months rather than 24 months and starting site and construction preparations 6 months earlier. Investor confidence has to be gained that the plant will be built on that schedule and within budget. A contribution to building that confidence can be to utilize virtual construction (3D+ time digital portrayals of the construction process) to provide detailed planning and schedule recovery capability as well as to demonstrate the validity of the schedule.

AP1000 can meet Criterion 5. Based on Westinghouse projected costs, AP1000 would be competitive in today's market. The AP600 can meet Criterion 5. The AP600 may be competitive in some U.S. market scenarios.

Criterion 6: Fuel Cycle Industrial Structure

The summary of the Westinghouse response and the NTDG evaluation for the AP600 are essentially identical to the AP1000 and thus are stated under the AP1000 criteria evaluations.

AP600 meets Criterion 6. It uses conventional fuel.

B. Gap Analysis for AP1000 and AP600

The design specific gaps are the tasks to be done by Westinghouse relating to completion of design, licensing, and component tests that are necessary to assure near term deployment of the AP1000 and AP600. The gaps, the needed closure actions, and the costs (in $ million) estimated to achieve closure are summarized in the tables below. 50-50 cost-sharing between industry and DOE is proposed. The gaps are identical for both the AP1000 and AP600 except that there is no gap for design certification for the AP600.

Design Certification of AP1000

Gap: The AP1000 design offers superior economics, but it is not yet certified.

Closure: Obtain Design Certification of the AP1000 from the NRC by the end of year 2004.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE	$3M	$6M	$6M	$3.7M						$18.7M
Industry	$6M	$3M	$2M	$0.3M						$11.3M
Total	$9M	$9M	$8M	$4M						$30.0M

COL Items Called for in AP1000/600 Design Certification

Gap: AP600 and AP1000 specific COL items are needed by COL applicants.

Closure: Develop AP600 and AP1000 specific COL items that are not addressed by other gap solutions.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$2M	$2M							$4M
Industry		$2M	$2M							$4M
Total		$4M	$4M							$8M

First Time Engineering

Gap: AP600 and AP1000 detailed first-time engineering (FTE) are incomplete.

Closure: Complete FTE, including all detailed engineering not covered in other gaps/solutions, project development, vendor selection, and procurement specifications.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE			$14.5M	$16.5M	$19M					$50M
Industry			$14.5M	$16.5M	$19M					$50M
Total			$29M	$33M	$38M					$100M

Reactor Coolant Pump Prototype Testing

Gap: AP600 and AP1000 reactor coolant pump (RCP) detailed design and prototype development and testing are needed.

Closure: Develop and test RCP prototype.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$4.0M	$4.0M	$2.5M	$2.0M					$12.5M
Industry		$4.0M	$4.0M	$2.5M	$2.0M					$12.5M
Total		$8.0M	$8.0M	$5.0M	$4.0M					$25.0M

Human Factors and Plant Simulator

Gap: Human factors engineering and a plant simulator are needed for AP600 and AP1000.

Closure: Complete human factor engineering consistent with approved processes identified in the AP600 SSAR and develop plant simulator. (These steps are also required to support the digital control room gap/solution.)

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$5M	$6M	$5M	$4M					$20M
Industry		$5M	$6M	$5M	$4M					$20M
Total		$10M	$12M	$10M	$8M					$40M

Control Room Design

Gap: Detailed design of a digital control room is needed for AP600 and AP1000 deployment.

Closure: Complete design of the digital control room consistent with the NRC approved requirements in the AP600 SSAR. (The AP1000 design will be the same. Support for this solution is required from the human factors gap solution.)

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE			$5M	$5M	$5M					$15M
Industry			$5M	$5M	$5M					$15M
Total			$10M	$10M	$10M					$30M

Squib Valve Development & Testing

Gap: Certain squib valves used in the passive safety systems of AP600 and AP1000 plants require development and testing of prototypes for deployment.

Closure: Complete development and testing of AP600 and AP1000 prototype squib valves.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE			$1M	$1M	$0.5M					$2.5M
Industry			$1M	$1M	$0.5M					$2.5M
Total			$2M	$2M	$1M					$5.0M

Environmental Qualification of Selected Equipment

Gap: Certain safety related equipment used in AP600 and AP1000 plants requires qualifications to be extended for in-containment environs consistent with NRC regulations.

Closure: complete qualification of AP600 and AP1000 safety related equipment.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE			$5M	$5M	$2.5M					$12.5M
Industry			$5M	$5M	$2.5M					$12.5M
Total			$10M	$10M	$5M					$25.0M

Piping & Module Design

Gap: Detailed design of AP600 and AP1000 piping and modules is needed for NTD.

Closure: Complete detailed design of AP600 and AP1000 piping and modules.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE			$1.5M	$3.5M	$5M					$10M
Industry			$1.5M	$3.5M	$5M					$10M
Total			$3M	$7M	$10M					$20M

Standardization

Gap: Standardization of AP600 and AP1000 plant equipment and commodities is needed for cost effective deployment.

Closure: Complete standardization of AP600 and AP1000 plant equipment and commodities.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE			$2.5M	$5M	$2.5M					$10M
Industry			$2.5M	$5M	$2.5M					$10M
Total			$5M	$10M	$5M					$20M

Summary of Gap Analyses

TABLE IV: Total Resources Required for All Gaps

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE	$3M	$17M	$47.5M	$47.2M	$40.5M					$155.2M
Industry	$6M	$14M	$43.5M	$43.8M	$40.5M					$147.8M
Total	$9M	$31M	$91M	$91M	$81.0M					$303M

Design Completion Cost Sharing Evaluation

As stated in the NTDG Cost Sharing Evaluation, the proposed sharing between DOE and industry may not be achievable and therefore an alternative has been developed that relies on more funds from industry in its cost-sharing approach. The alternate cost-sharing approach is based on the following principles:

- Activities necessary to obtain regulatory approval should be cost-shared 50/50 between industry and Government.
- Activities necessary to further the design should be cost-shared in the range of 60/40 between industry and Government, respectively.

There is substantial precedent and justification for Government to provide 50/50 cost-share on activities necessary to obtain regulatory approval. Substantial government cost-share is justified at this stage of a program because NRC licensing is a major hurdle for introducing new technologies and is unique to the nuclear industry. It is in the public interest to encourage industry to bring new, safer technologies before the NRC and assure that a thorough and timely review is supported by the applicant. In addition, regulatory review usually occurs before a potential buyer has placed an order.

In continuing the design of a plant, however, there is a logical basis for assuming that some degree of interest in the design must be provided by potential buyers before proceeding very far into the detailed design effort. A possible vehicle for this could be to absorb all or some of the

$100 million of the total design completion costs identified to FOAKE among 3 to 5 plants rather than carrying all the cost on the 1st plant. AP1000 has the advantage of significantly lower capital cost in $/kWe compared to AP600.

On the other hand, potential buyers in the deregulated marketplace may not be able to provide a 100 percent commitment to construct a plant until after all of the regulatory approvals and design details are completed. Therefore, it would be appropriate to require greater industry cost-share at this stage of a particular program.

This revised approach is shown in Table V, reflecting 62 percent DOE/38 percent industry cost-sharing on the Design Certification gap and 40 percent DOE/60 percent industry cost-sharing on all other gap closures activities, for an overall cost-sharing of 42 percent by Government and 58 percent by industry.

TABLE V: Revised Cost Sharing Scenario for AP1000

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE	$3M	$15M	$37M	$40M	$33M					$128M
Industry	$6M	$15M	$52M	$52M	$50M					$175M
Total	$9M	$30M	$89M	$92M	$83M					$303.0M

Since the $30 million for design certification is not needed for the AP600, the cost-sharing pattern would change to show no expenditure in FY 2002 and only $12 million in FY 2003. The pattern would remain the same as for AP1000 in the subsequent years. The decisions on which of the AP1000 and AP600 designs will be successful will be determined by progress on the early gap closures as well as the marketplace.

C. Overall Assessment: AP1000 and AP600

The Westinghouse AP600 is based on proven pressurized water reactor technology. Its power train is identical in basic design to the conventional design but with many detailed improvements coming from the extensive operational experience gained worldwide on this system. A key and innovative feature of the AP600 safety systems is the utilization of natural phenomena, such as gravity and compressed gas releases, to assure the availability of cooling water in the case of a loss of coolant accident. These features assure that the cooling water level will not fall below the top of the core in the event of a severe accident and that no operator action is needed in such emergency conditions for three days. The natural (or passive) emergency cooling systems also have effected a major simplification in the plant by the elimination of the power driven pumps and their associated lines, valves, and controls.

The AP600 was developed by a coalition of industry (domestic and international utilities through EPRI), Westinghouse, and DOE, all of who cost-shared the major effort involved. Highly qualified consultants and university experts made important contributions. The utilities developed a set of owner-operator requirements to guide the design development and assure safety, reliability, and maintainability to an even higher level than is being achieved today.

Validation of the design of the passive safety features has been obtained by extensive testing by the industry in the U. S. and overseas. NRC has carried out independent testing that has confirmed the Westinghouse safety design of the AP600.

With the onset of low natural gas prices and the rate de-regulation of electricity generation, the AP600 economic competitiveness has been weakened. Westinghouse has thus turned to economy of scale to improve its economics by raising its nominal 600 MWe output to 1000 MWe. The AP1000 is basically the same design as the AP600 and follows on the Westinghouse experience in developing its conventional set of standardized nuclear steam supply systems at the 600, 900, and 1200 MWe nominal levels.

The gaps that need to be closed in the time frame to achieve deployment of AP1000 or AP600 by 2010 encompass three major efforts: regulatory, detailed design completion, and market acceptance. The issues that have to be addressed to close the gaps are summarized for each effort.

Regulatory: The prime regulatory gap closure needed for the AP1000 is obtaining design certification (DC) from the NRC. Because the design is so firmly based on the already certified AP600, there is little uncertainty that the DC can be obtained. The NTDG has less confidence in the optimistic DC schedule projected by Westinghouse, but notes that this may not be a determining factor in the overall schedule since an early site permit is on the critical path.

There is no gap for AP600 design certification since it has already been granted.

Additional key gap closures in this effort, applicable to both AP1000 and AP600 as well as all designs that choose to seek a COL, is to obtain from the NRC one or more early site permits, a finalized practicable ITAAC process, and a combined construction-operating license (COL). The completed safety design, along with the experience gained to date with the NRC in defining an ITAAC approach related to LWRs, should help to accelerate this gap closure for the AP1000 and AP600.

Detailed Design Completion: Completion of the detailed designs on schedule for both the AP1000 and AP600 is fairly assured, assuming the availability of the needed funds, because of the AP600 design work that has been completed to date and its acceptance by NRC through the DC. There is somewhat more uncertainty for the AP1000 because of possible changes in the license-related design completion arising from the design certification review. Completing the remaining design work for both AP1000 and AP600 is straightforward.

The primary gap in this effort is obtaining the large funding ($303 million for the AP1000 and $273 million for the AP600) necessary to complete the design to a high degree (of the order of 90 percent), so as to assure efficient and rapid plant construction. Early investor and sub-supplier interest will be key to obtaining the requisite industry cost sharing. A significant change in political support will be essential to obtain the proposed government cost sharing. An important way of fostering industry and government investment is to focus resources in each phase on closing the gaps, which will best build confidence among the prospective investors.

Market Acceptance: Market acceptance will require that the nuclear plant being offered: (1) is economically competitive and highly reliable so as to produce the income to gain the expected return on investment (ROI) and (2) has investor confidence that it will be built on schedule and within budget.

On the first requirement, the fundamental merit of the AP1000's near-term deployment candidacy is its economic competitiveness under the conservative assumption that gas price increases will remain within the bounds of normal inflation. There appears to be adequate margin in the projected bus-bar generation costs to provide an ROI premium to compensate for the longer time to achieve the ROI as compared to gas-fired units. If gas prices rise in excess of normal inflation, the profit margins will be even more substantial.

The ability of the AP600 to compete broadly in the marketplace depends on a continuation of the high natural gas prices in the range experienced in 2001-2.

There is strong assurance of high operational reliability for both the AP1000 and AP600 because the plant designs utilize the proven technology, bolstered by infusion of decades of operating experience, that is already being achieved by most of the present U.S. nuclear plants.

The second requirement is an important gap to be closed in this effort and applies to both AP1000 and AP600. Obtaining an early site permit(s), a COL, and a practical ITAAC process, as identified under the regulatory phase, is an essential element in gaining investor confidence. Assurance of completion of design to construction-readiness is another key element that can be re-enforced by utilizing virtual construction of the construction process to provide detailed planning and schedule recovery capability as well as to demonstrate the validity of the schedule. The content, skills, and quality assurance requirements to build the plant have been fully developed over the past several decades in building the present fleet of plants. The AP1000 and AP600 can meet the evaluation criteria and close the gaps necessary for deployment.

The NTDG concludes that the gaps in the above three efforts can be closed on a schedule consistent with the near term deployment goal and therefore both the AP1000 and AP600 can probably be deployed in the U.S. by 2010. NTDG does not expect that there will be sufficient resources available to carry both APs to deployment in the 2010 time frame, but that the level of progress in closing the gaps, as well as market considerations, will determine the choice among them at a sufficiently early stage to permit focusing resources on one of them. In any event, Westinghouse has stated that it only intends to pursue one or the other of them, but not both designs.

Timelines for the AP1000 and/or AP600

The AP1000 Roadmap and associated timelines are given in Chart 1 and 2, below. The schedule and relationship of the other main lines of effort, i.e., Early Site Permits, Combined Licenses, Construction & Startup, Engineering and Procurement, and Key Decision Points, are shown in the following lines.

With the exception of Design Certification, which has already been accomplished for the AP600, this Roadmap applies to AP600. The schedule and relationship of the other main lines of effort are the same as those for AP1000. For deployment by 2010, Early Site Permits and Combined Licenses are on the critical path for both AP1000 and AP600, as is completion of first time engineering

This Roadmap is a broad overall summary of a complex industrial campaign to assemble all the necessary human and material resources, and to focus them on the final goal of building a power plant and putting it into operation at the end of 10 years.

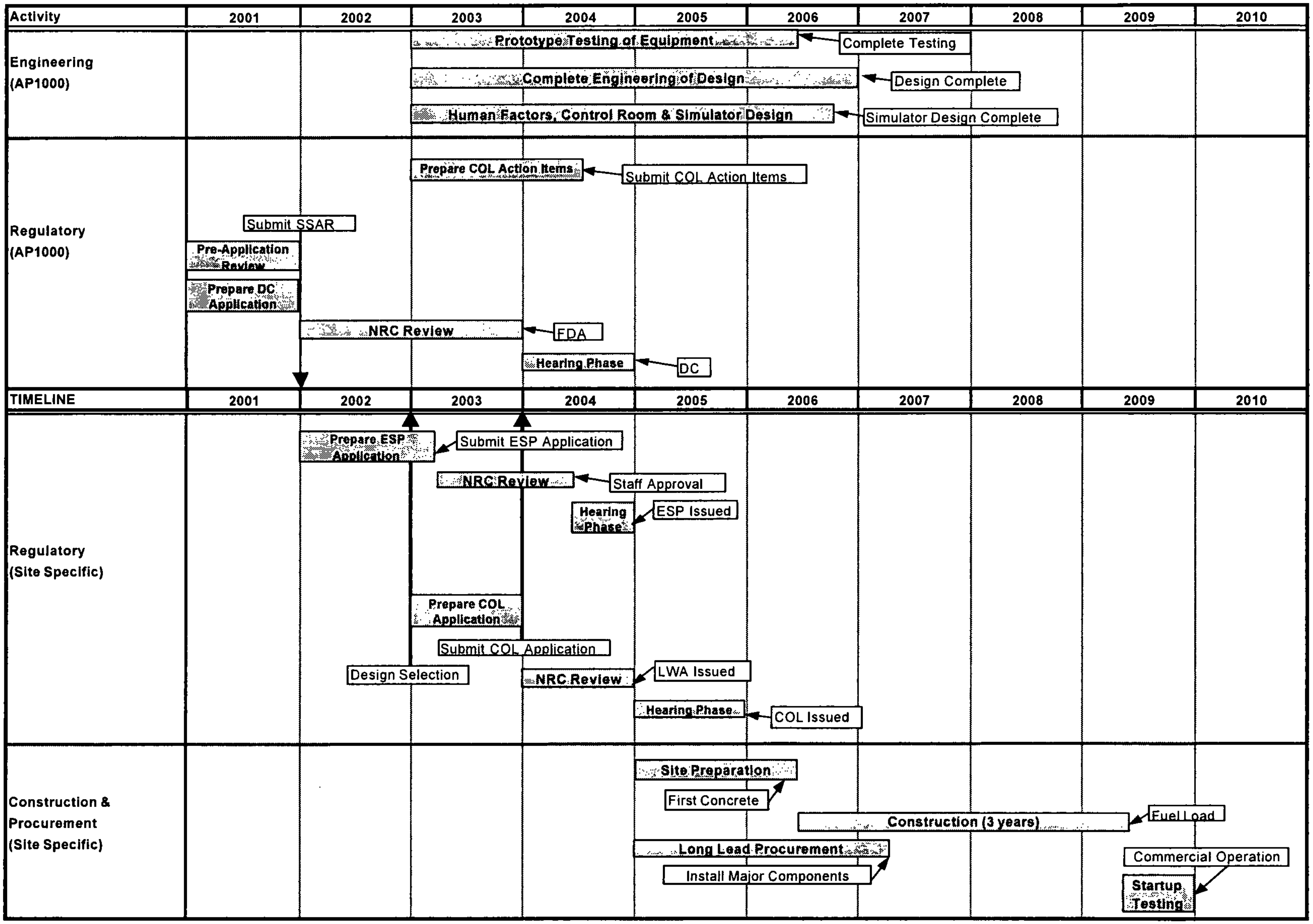
Of the four top level lines that represent the major project activities the first two, Early Site Permits, and Combined Operating Licenses, are normally plant owner responsibilities, with some tasks delegated to the reactor vendor, particularly those that require reactor and plant engineering information to carry out. The next main lines are Construction/Startup, and Engineering/Procurement. The plant owner, reactor vendor, architect-engineer, constructor, component and equipment suppliers, and various consultants are involved in these activities, with their responsibilities defined by contract. At the bottom of the page, under Engineering and Procurement the key decision points are shown: Design Selection, Order Placement, and Construction Commitment. The second page shows a line for the plant buyer/owner's responsibilities, and amendments to Design Certification that incorporate any changes made in the course of final design. A considerable part of the responsibility for this would probably be delegated to the reactor and plant vendor.

The following charts and the top level lines shown thereon, along with some additional information, make up the big picture roadmap of the projects. It is clear that the main lines are not independent of each other. All work on them must be completed on the dates shown in order to complete the project and operate the plant. The lines in fact are strongly interdependent, because of the relationship of each of the lines to the others, i.e., Engineering to the ESP and the COL, and to Construction. Procurement and Construction will in turn affect Engineering when changes occur. These must be recorded and reviewed to make sure that the licenses are not affected by the changes; or, if they are, so that appropriate changes can be initiated.

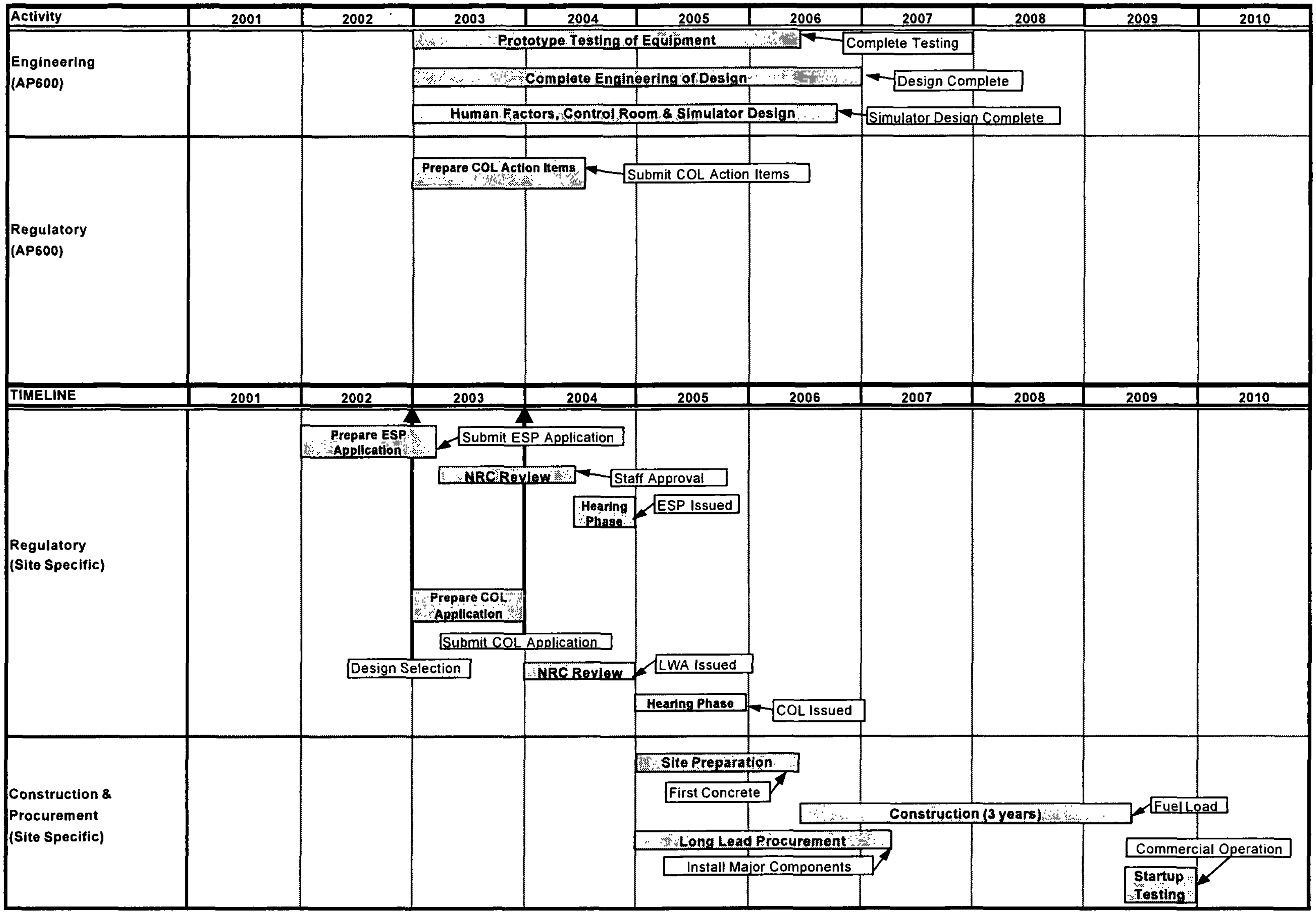
Generic and specific design gap closures have strong connections with the top-level project lines. Closure of Gaps has the greatest impact on obtaining the ESP and COL, and on Engineering and Procurement. The schedule of Generic Gap ESP work ties directly into the top level ESP schedule, as does design specific work required to complete the ESP application. Likewise the mostly design specific COL work ties directly into the COL top level timeline. Similarly design specific Gaps 3-10 in the information supplied by Westinghouse tie into the Engineering and Procurement top level timeline.

The charts below, with the gap information tied into it, are roadmaps for the AP1000 and for AP600, with the exception of Design Certification as noted. It is not sufficient, however, for project management and control. Attention to project management detail is absolutely necessary to successful project completion and operation of the plant at the appointed date.

AP 1000 Near Term Deployment Roadmap



AP 600 Near Term Deployment Roadmap



WESTINGHOUSE IRIS DESIGN

IRIS is an innovative small (100-300MWe) pressurized water reactor design featuring an integrated primary system – that is, all primary system components, including the steam generators, coolant pumps and pressurizer are housed along with the nuclear fuel in a single, large pressure vessel. As such, IRIS offers potential safety advantages, primarily related to the elimination of large-break loss of coolant accident potential. Its small size and modular design may simplify on-site construction and be deployable in areas not suitable for large, monolithic nuclear plants. Evaluation of the IRIS proposal follows:

A. CRITERIA EVALUATION

Criterion 1: Regulatory Acceptance

Summary of Westinghouse Response

a. Licensing is straightforward because IRIS is firmly based on LWR technology, and will comply with current regulatory requirements. Several categories of accidents are not credible. Fuel design is relatively conventional for the Category I plants (i.e., those that would be considered for near-term deployment).
b. A prototype is not needed. The first IRIS deployment will be the first-of-a-kind (FOAK) plant. Primary reliance will be placed on focused testing.
c. Risks are primarily institutional, not technical, and hinge on a consortium decision to commit in 2003 (anticipated).
d. The proposed schedule is to obtain design certification by the end of 2007, with operation commencing in 2010.
e. There has been preliminary interaction with NRC Commissioners and staff.

NTDG Assessment

a. The submittal overstates the degree to which IRIS is based on proven technology, and it understates the development required to build a practical, cost-competitive IRIS. In principle, IRIS is a conventional PWR and much of LWR/PWR operating experience is applicable, but the IRIS design details are vastly different from all US commercial operating experience with respect to steam generators, pressurizer, reactor shutdown, and in-reactor I&C, to name some particularly important areas. IRIS, with its in-reactor configuration, may require revision of the General Design Criteria.
b. The first IRIS will be a prototype, whatever else it may be called. The testing is extremely important and will have to be very lengthy and carried out under a variety of non-normal operating conditions to verify the key issues of the reliability and maintainability of the major non-core components within the reactor vessel. Development of practical remote maintenance tooling will be needed.
c. The risks of achieving success in deployment are identified under Criterion 1 by Westinghouse as primarily institutional not technical. This is a commercial viability issue, not a regulatory acceptance one.

d. The design needs further development and safety review before one can project a design certification schedule with confidence. The proposed operation schedule (3 years after certification) is not credible.
e. Preliminary interaction with the NRC is of very limited value, based on ALWR experience

IRIS does not meet Criterion 1. Design certification in the time frame needed to support 2010 deployment is very unlikely, because of the extensive analysis and testing required.

Criterion 2: Industrial Infrastructure

Summary of Westinghouse Response

Very well qualified, diverse IRIS team:

- Westinghouse / BNFL
- Bechtel
- MHI-Ansaldo / ENSA / NUCLEP

NTDG Assessment

It is judged that the LWR-based industrial infrastructure is suitable for the IRIS. I&C sensors and transmitters are a possible exception.

IRIS can meet Criterion 2. The international IRIS team, which includes manufacturing capability, has been assembled.

Criterion 3: Commercialization Plan

Summary of Westinghouse Response

a. IRIS is based on proven technology LWR technology and therefore the time scale of the FOAK work is reasonable. The IRIS consortium member capability is restated.
b. There is renewed worldwide interest in nuclear plants, combined with projected very high demand for electricity. Future investment can be expected in new nuclear plants.

NTDG Assessment

The IRIS concept proposed by Westinghouse is a major innovation of systems and component design that places the steam generator, pressurizer, and vital elements of control and protection systems within the reactor vessel, for which there is little basis in proven PWR technology. Therefore the time scale of work is not reasonable, because of the R&D that will be required to prove safety in both normal operation and under accident conditions, including completion of testing programs before the design can be made final. The testing program schedule itself is overly optimistic. Given the extent of IRIS innovations, it is quite possible that operational experience on an IRIS test reactor would be required to produce and confirm a final design. These points apply directly to Criterion 2.

IRIS does not meet Criterion 3. The commercialization plan (in time to support 2010 deployment) is unrealistic.

Criterion 4: Cost Sharing Plan

Summary of Westinghouse Response

Through 12/2002, existing government cost sharing (via NERI) is in place. An additional $5M for focused testing is suggested. After 1/2003, (presuming the consortium elects to proceed), government funding will be needed. Cost sharing of 30/55/15 percent (U.S. Government/IRIS consortium partners/foreign Government/organizations) is proposed.

NTDG Assessment

The cost sharing proposal of 70 percent industry, 30 percent Government appears reasonable although the overall cost estimate is subject to uncertainty because of the innovative features of the design.

IRIS meets Criterion 4. Identified cost sharing would support IRIS engineering, testing, and licensing.

Criterion 5: Economic Competitiveness

Summary of Westinghouse Response

The Westinghouse cost estimates for the FOAK and Nth of-a-kind cases are given in the Table below:

IRIS CAPITAL COST ESTIMATES ($/kWe)

	Low	Nominal	High	percent from Nominal
NOAK	687	836	1224	-18 percent, +46 percent
FOAK	746	925	1343	-19 percent, +45 percent

The plant availability factors are estimated to range from 85 percent to 98 percent for the FOAK plant and between 90 percent and 99 percent for the NOAK plant, resulting in a nominal production cost of 10.9 $/MWh. The nominal total cost of electricity for the NOAK plant is stated to be 23.5 $/MWh.

NTDG Assessment

Cost estimates need thorough assessment, particularly capital costs because of the loss of economy of scale and operating costs and because of the maintenance issue for in-reactor vessel components. One should not have high confidence in cost estimates until design and regulatory review are further along, and the IRIS safety basis better established.

It is indeterminable as to whether IRIS meets Criterion 5. Westinghouse projections on IRIS costs are highly conjectural; if true, IRIS would be economically competitive, but there is not yet sufficient basis for confidence in the projections.

Criterion 6: Fuel Cycle Industrial Structure

Summary of Westinghouse Response

Initial core loads (Category I operation) are largely conventional (see gap analysis). No development will be required for manufacture of the higher enriched fuel.

NTDG Assessment

It is agreed that the initial core loads (Category I) are conventional but the subsequent Category II core loads (at ~9 percent enrichment, high burn-up, extended cycle) are well beyond current practice and US licensed manufacture (see Gap analysis). The degree of required development seems understated.

IRIS meets Criterion 6 for initial fuel loads. More highly enriched fuel loads, proposed to be used in later years, would require new manufacturing capability

B. GAP ANALYSIS

The design specific gaps are the tasks to be done by Westinghouse relating to completion of design, licensing, and component tests that are necessary to assure deployment. The gaps, the needed closure actions, and the costs (in $ million) estimated to achieve closure are summarized below.

Safety By Design

To confirm that the IRIS design provides the high level of safety claimed, correctly simulated testing, using a mockup of the IRIS vessel / containment and associated safety systems, must be carried out. The scope of the testing program is as yet undefined, but the overall magnitude, given needed R&D, looks low.

Year / Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$5M	$5M	$5M	$3M	$1M				$21M
Industry	$4M	$3M	$4M	$3M	$5M	$4M				$21M
Total	$4M	$8M	$9M	$8M	$8M	$5M				$42M

Integral Steam Generator

An extensive test program is needed to demonstrate steam generator (SG) normal operation performance and reliability, and safety functions, (using "reasonably" sized SG module); and the same for in-reactor I&C sensors and transmitters. It may also be advisable to perform integral RV/containment/SG/ emergency HX tests. This test work is central to IRIS feasibility. A very high standard for successful completion is required, given the integral nature of the design (i.e., not much flexibility for later design adjustments, if there are performance problems). The tests could take longer, and be more costly than projected.

Year / Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$1M	$1M	$4M	$3M	$1M				$10M
Industry	$4M	$4M	$7M	$4M	$3M	$2M				$24M
Total	$4M	$5M	$8M	$8M	$6M	$3M				$34M

Maintenance Optimization

Extended (4 year) maintenance shutdown intervals demands extensive evaluation and "multiple solutions", related to equipment design (to allow ease of inspection), diagnostics, regulatory changes (presumably re in-service inspection), to provide optimized maintenance. Substantial funding ($26.5M) is projected. This is another area central to IRIS success. It is not just "optimization" – it is more correctly "feasibility".

The Westinghouse submittal suggests that some part of the solution will be to relax requirements. Caution should be exercised here: the real issue is whole plant reliability, not just safety system reliability or regulatory compliance. A large funding allocation is appropriate but the adequacy of the testing cost projection is uncertain.

Year / Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$1.5M	$2M	$2M	$2M	$0.5M				$8 M
Industry	$1.5M	$3M	$5M	$5M	$3M	$1M				$18.5M
Total	$1.5M	$4.5M	$7M	$7M	$5M	$1.5M				$26.5M

Steam Generator Inspection Procedure

SG inspection procedures need to be revised to reflect different functions, configuration, and failure modes of the IRIS SG tubes. There are fundamental design differences from present experience with PWR plants (primary circuit is external to the tubes; tubes in compression, not tension). This is an important issue, and is related to the second gap above. SG inspection requirements and methods will, in fact, have to be changed, but the broader issues of materials, SG design details, and SG accessibility for inspection and maintenance need to be addressed. The projected testing cost may be low.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$0.3M	$0.3M	$0.5M	$0.2M	$0.2M				$1.5M
Industry	$0.4M	$0.3M	$0.3M	$0.5M	$1M	$0.7M	$0.5M			$3.7 M
Total	$0.4M	$0.6M	$0.6M	$1M	$1.2M	$0.9M	$0.5M			$5.2M

System Performance Modeling

The IRIS integral vessel/coupled small containment requires modeling of system performance under normal and abnormal conditions, as input to the IRIS control system. The plan is to "model the IRIS system response and interaction of different subsystems..." This is a computer-based analytical model, which will require using test data from testing in the first gap. The projected testing cost is subject to uncertainty. Pressurizer faults and control under normal and accident conditions should be carefully studied to determine adequacy of the current concept, functional and design specifications, but this work is not included in the cost estimates.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$1M	$2M	$1M	$0.5M					$4.5M
Industry	$1.2M	$2M	$1.5M	$0.5M	$0.5M					$5.7M
Total	$1.2M	$3M	$3.5M	$1.5M	$1M					$10.2M

Internal Control Rod Drive Mechanisms

The IRIS reactor vessel (RV) configuration causes very long internal control rod drive mechanism (CRDM) drive lines and more CRDMs than a conventional LWR. The plan is to develop and apply, if feasible, an internal electromagnetic or hydraulic CRDM system. This would eliminate the long drive lines and also eliminate RV penetrations, which are possible loss of coolant accident sites). It is not clear whether the long drive lines are an IRIS "technical gap", or that the designers simply view the internal CRDM as a potentially attractive design improvement. It is also not clear how this relates to Category I vs. II, in that it is not directly related to operating cycle time. The internal CRDMs are not proven technology, and that configuration places a vital safety component in a relatively inaccessible location (i.e., inside the RV).

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$2M	$3M	$3M	$2M	$2M	($2M	$1M	$1M)	$13 ($16.M)
Industry	$2.0M	$2M	$5M	$5M	$3M	$2M	($2M	$2M	$2M)	$19M ($24.5M)
Total	$2M	$4M	$8M	$8M	$5M	$4M	($4M	$3M	$3M)	$31M($41M)

( ) indicate additional development – Category II – if necessary

Extended Cycle Fuel Operation

IRIS fuel assemblies will be operating on a 4-5 year cycle (Category I), and later on an 8-10 year cycle (Category II). Design and qualification testing are needed for the cladding, grids and assembly structures. Material testing and post-irradiation exams are needed to confirm adequacy of materials, design and licensing data. No testing is planned to support Category I, but is not clear that no testing is required.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE				$0.3 M	$0.3 M	$0.3 M	$0.1 M	$0.1 M	$0.1 M	$1.2M
Industry		$0.5M	$0.5 M	$0.7 M	$0.7 M	$0.7 M	$0.4 M	$0.4 M	$0.4 M	$4.2 M
Total		$0.5 M	$0.5 M	$1 M	$1 M	$1 M	$0.5 M	$0.5 M	$0.5 M	$5.4 M

Licensing of Higher Enrichment Fuel

Reload cores will use up to 9 percent enriched fuel, above the level currently allowed for US facilities. Thus, licensing requirement changes will have to be reviewed and approved by NRC and the license production line will have to be designed or modified. This is clearly a Category II gap; not central to IRIS success unless overall IRIS economic success dictates the shift to Category II fuel loads.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$0.4M	$1M	$1M	$1M	$1M	$1M	$1M	$1M	$7.4M
Industry			$0.8M	$1.5M	$1.5M	$1.5M	$3M	$3M	$1M	$12.3M
Total		$0.4M	$1.8M	$2.5M	$2.5M	$2.5M	$4M	$4M	$2M	$19.7M

High Burnup Fuel Demonstration

High burn-up of Category II IRIS fuel needs to be demonstrated, via prototypical testing. This is clearly a Category II gap; not central to IRIS success unless overall IRIS economic success dictates the shift to Category II fuel loads.

Year Source	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09	FY10	Total
DOE		$1M	$1M	$1.5M	$1.5M	$1.5M	$0.5M			$8M
Industry		$0.5M	$2M	$2M	$3M	$3M	$0.5M	$0.5M	$2M	$13.5M
Total		$1.5M	$3M	$3.5M	$4.5M	$4.5M	$1M	$0.5M	$2M	$21.5M

Because of very congested "integral" configuration of IRIS, thorough assessment of RV / internals disassembly, lay-down, fuel removal, inspections, etc is needed, followed by design refinement as called for. This is not included in the cost estimates.

C. OVERALL ASSESSMENT

Along with its potential advantages, the integral primary system configuration introduces significant design and licensing challenges that may be difficult to overcome, particularly in the relatively short time frame established for this near term deployment assessment. In key design details, IRIS is fundamentally different from any reactor licensed and operating in the United States or anywhere in the world. Extensive analysis and testing will undoubtedly be needed as a prerequisite to NRC licensing and commercial deployment in the U.S.

For those reasons, the evaluation team concludes that the IRIS design is not deployable by 2010. This designation does not suggest that the potential advantages of the IRIS concept are unimportant or unachievable – rather, it reflects the daunting challenge of design and licensing of an innovative and unfamiliar reactor configuration in the near term. In that respect, the team also recommends that further consideration of the IRIS concept be assigned to the Generation IV Water Reactor Technical Working Group (TWG).

The following is a brief summary of the NTDG's assessment of IRIS compliance with the NTD criteria and of identified gaps.

NTDG Criteria Compliance: With respect to Criterion 1, Regulatory Acceptance, it is the NTDG's view that because of the substantive differences between IRIS and currently licensed reactors, a great deal of analysis and test work will be required to support a successful design certification submittal. The necessary test work will undoubtedly involve extensive computer and large-scale physical modeling, as proposed by Westinghouse. However, the review team believes that full prototype testing, in some fashion, will also be needed. It is the team's view that the extent, cost and duration of the testing needed to secure regulatory acceptance is significantly greater than predicted by Westinghouse.

The current plans regarding NTDG Criteria 2 and 3 (Industrial Infrastructure and Commercialization Plan) are vague. Because much of the IRIS design utilizes LWR technology, the LWR industrial infrastructure would appear to provide the requisite support except possibly for the special inspection and maintenance features needed in the integral design. The commercialization plan to achieve deployment by 2010 is unrealistic.

Criterion 4, Cost Sharing Plan may have to be adjusted to reflect the increased amount of testing needed compared to the Westinghouse projection. In addition to the lengthier testing required for regulatory acceptance, extensive testing will be needed to satisfy potential investors that the reliability and maintainability of the system will meet present industry performance.

Compliance with Criterion 5, Economic Competitiveness cannot be determined with confidence at this time because of the relative immaturity of the design, and because of the economic importance of the plant maintainability, a key design issue (see the Gap Analysis) for IRIS.

The IRIS Criterion 6, Fuel Cycle Industrial Infrastructure is satisfactory for the Category I fuel load. However, the potential fuel design for subsequent loads (called Category II) will involve higher enrichment and higher burn-up than current fuel designs, and will require substantial development work.

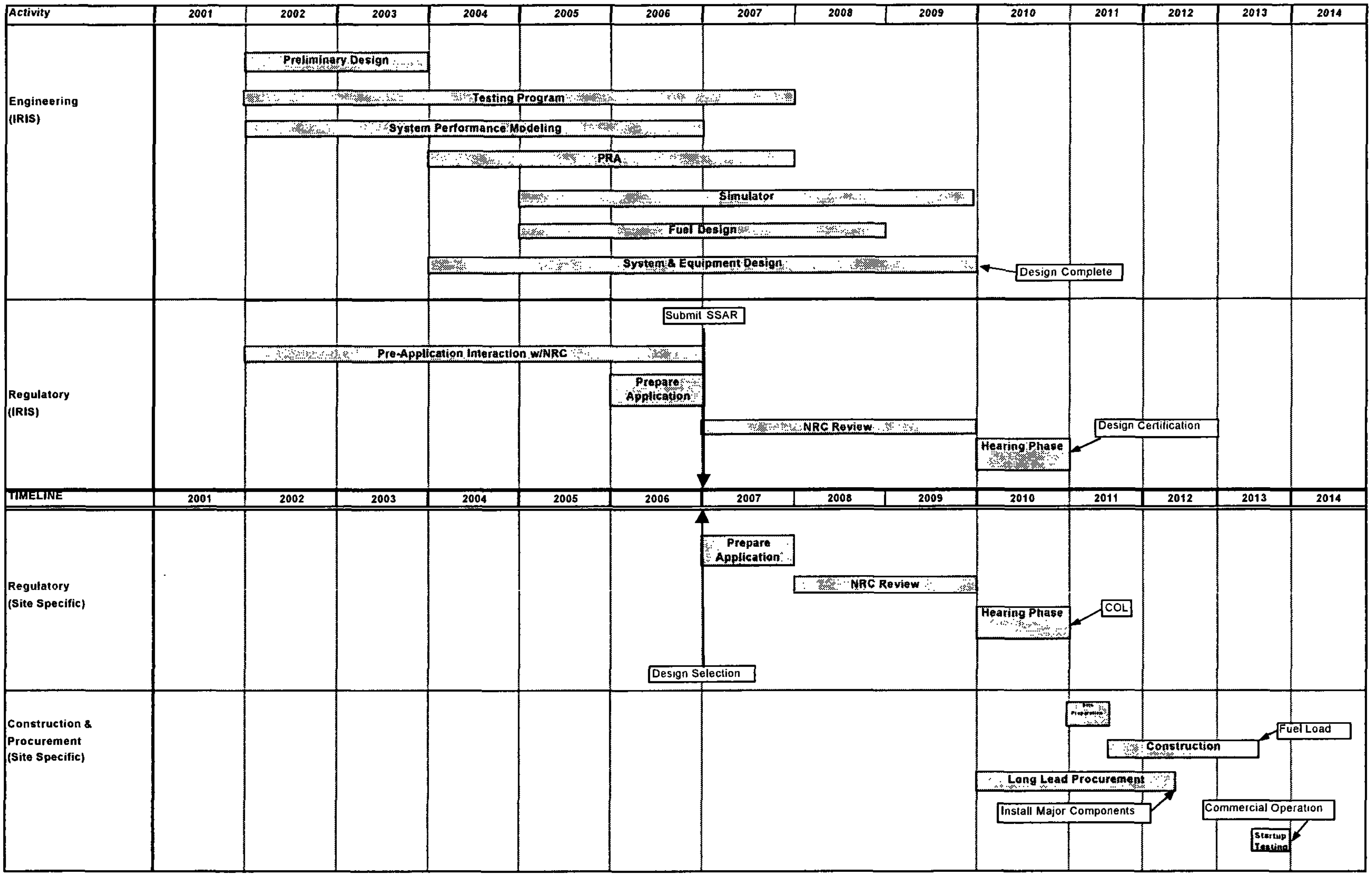
Gap Assessment: Westinghouse identified six gaps applicable to the IRIS "Category I" design, that is the version of the IRIS concept which utilizes nuclear fuel with conventional enrichment levels. These gaps all relate to the needs for development and testing referred to above. They are:

- The IRIS "Safety by Design" concept of integrated primary components, requiring mockup testing and analysis of safety system performance.
- Integral Steam Generator and Steam Generator Inspection Procedure: The IRIS steam generator concept presents very significant technical challenges in operation, maintenance and safety, requiring extensive analytical and mock-up testing. The difficulty of inspecting steam generators of novel design and housed within the reactor vessel must also be addressed through analysis and testing.
- Maintenance Optimization: The IRIS integrated primary system configuration, in combination with the planned four-year refueling cycle, demands extensive evaluation and development of inspection, diagnostic and maintenance methods.
- System Performance: Modeling and /or testing of the integrated reactor vessel and containment are required. In-reactor I&C must also be extensively analyzed and tested.
- Internal CRDM: This gap addresses the objective of considering internal CRDMs as a means of avoiding the very long CRDM drives necessitated by the very tall IRIS reactor vessel. This is a novel design for an important plant control and safety feature, and will require significant development and testing.

Three additional gaps identified by Westinghouse relate to the Category II IRIS utilization of higher enriched, longer life cores. These also present significant difficulty and would require extensive testing, but they are not relevant to near-term deployment considerations.

In summary, the NTDG considers the Westinghouse gap assessment to be a reasonably complete identification of major challenges facing the IRIS designers. In some cases, the NTDG believes that the cost to resolve these issues conclusively will exceed the Westinghouse projection. But regardless of cost, the NTDG does not consider it realistic to project resolution of these gaps, successful IRIS licensing and construction of the first unit in the near term. On that basis, IRIS is not deployable by 2010.

IRIS Near Term Deployment Roadmap



PBMR PTY. PBMR DESIGN

The Pebble Bed Modular Reactor (PBMR) is a graphite moderated helium-cooled reactor. Heat generated by nuclear fission in the reactor is transferred to the coolant gas (helium), and converted into electrical energy in a gas turbo-generator via a Brayton direct cycle. The PBMR core is based on the German high temperature gas cooled technology and uses spherical fuel elements.

The PBMR core consists of a cylindrical array of 6 cm diameter, spherical elements. The core array is 3.5 m in diameter and 8.5 m high and produces about 268 MWth. The center of the array contains approximately 100,000 unfueled graphite spheres. The outer part of the core contains about 300,000 fuel elements, each containing about 9 grams of fuel, in the form of 9 percent enriched uranium dioxide. The core geometry is established by a graphite reflector, which in turn is contained in a steel reactor vessel. The reactor is refueled continuously by withdrawing fuel spheres from the bottom of the core and returning them to the top. Fuel elements pass through the core from 5 to 10 times during their useful life. Each time an element is removed from the core, burnup and other fuel element characteristics can be measured, and spent fuel can be diverted to on-site, long-term storage.

The fundamental concept of the design of the PBMR is aimed at achieving a plant that has no physical process that could cause a radiation hazard beyond the site boundary. This is principally to be achieved in the PBMR by demonstrating that the integrated heat loss from the reactor vessel exceeds the decay heat production in the post accident condition, and that the peak temperature reached in the core during the transient is below the demonstrated fuel degradation point and far below the temperature at which the physical structure is affected. This effectively would preclude the possibility of a core melt accident. Heat removal from the vessel is achieved by passive means.

The containment concept for high temperature gas reactors (both GT-MHR and PBMR) is distinctly different from the high-pressure containment of light water reactors. For HTGRs there is an additional level of radionuclide containment in the TRISO coated fuel particles used in these reactors. This containment is provided by a SiC coating that is presumed to contain the fission radionuclides during normal operation and during all accident scenarios. A primary system boundary rupture during operation would lead to an initial pressure buildup. The building containment design allows this pressure to be released through filtered vents, which would then close. Analyses suggest that release of radioactivity for any accident scenario is sufficiently small that the emergency planning zone (EPZ) could be set at the site boundary.

The PBMR module is the smallest stand-alone component of the PBMR power generation system. The module is a power station that can produce approximately 110 MW (or more) of electrical power with an overall thermodynamic efficiency of about 40 percent. This module can be used to generate power in a stand-alone mode or as part of a power plant that consists of up to 10 units.