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Advanced Fuel Cycle Cost Basis – 2017 Edition

Nuclear Technology Research and Development

Prepared for
U.S. Department of Energy
Fuel Cycle Options Campaign

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ABSTRACT

This report, commissioned by the U.S. Department of Energy (DOE) Office of Nuclear Energy (NE), provides a comprehensive set of cost data supporting a cost analysis for the relative economic comparison of options for use in the DOE Nuclear Technology Research and Development (NTRD) Program (previously the Fuel Cycle Research and Development (FCRD) and the Advanced Fuel Cycle Initiative (AFCI)). The report describes the NTRD cost basis development process, reference information on NTRD cost modules, a procedure for estimating fuel cycle costs, economic evaluation guidelines, and a discussion on the integration of cost data into economic computer models. This report contains reference cost data for numerous fuel cycle cost modules (modules A-O) as well as cost modules for a number of reactor types (R modules). The fuel cycle cost modules were developed in the areas of natural uranium mining and milling, thorium mining and milling, conversion, enrichment, depleted uranium disposition, fuel fabrication, interim spent fuel storage, reprocessing, waste conditioning, spent nuclear fuel (SNF) packaging, long-term monitored retrievable storage, managed decay storage, recycled product storage, near surface disposal of low-level waste (LLW), geologic repository and other disposal concepts, and transportation processes for nuclear fuel, LLW, SNF, transuranic, and high-level waste.

Since its inception, this report has been periodically updated. The last such internal document was published in August 2015 while the last external edition was published in December of 2009 as INL/EXT-07-12107 and is available on the Web at URL: www.inl.gov/technicalpublications/Documents/4536700.pdf.

This current report (Sept 2017) is planned to be reviewed for external release, at which time it will replace the 2009 report as an external publication. This information is used in the ongoing evaluation of nuclear fuel cycles by the NE NTRD program.

PREFACE

In 2003 the U.S. Department of Energy-Nuclear Energy (DOE-NE) Advanced Fuel Cycle Initiative (AFCI) program established an Economics Working Group for the purpose of assessing the projected life cycle costs of new fuel cycles being examined as part of the ongoing fuels-related DOE-NE research and development (R&D) program. The group was formed of several individuals from multiple DOE National Laboratories and NNSA Facility Sites. Being that complete fuel cycles, including the nuclear reactors or other transmutation systems, consist of multiple process or service steps, there is a need to understand the life cycle costs associated with each. As an example today's "once-through" light water reactor (LWR) fuel cycle consists of mining & milling, conversion, uranium enrichment, fuel fabrication, fuel irradiation (reactor), spent fuel storage, and geologic repository steps. Fuel cycles for advanced reactors may consist of considerably different and/or additional steps for which there is little or no operational experience or cost data. This is especially true of those systems for which spent fuel is "recycled" and useful products recovered along with the production of separated wastes for disposal.

It was decided that the AFCI Economic Working group would begin the preparation and occasional updating of an economic data base for all of the steps of the nuclear fuel cycle. Emphasis would be on the unit cost ($/unit of mass or service) for each step. Acquisition of the data would be from public reports, the trade press, other fuel cycle studies, discussion with private industry, and for many steps life cycle cost calculations made by this group for hypothetical new facilities. Each possible step was assigned a "module designator" and a "tab" or chapter in the AFC Cost Basis Report (AFC-CBR). In addition to suggested unit cost ranges for each module, there is a comprehensive description of the step, including process diagrams, historical information, module interface consideration, existing facility data, and discussion of data limitations. By providing "what-it-takes", "low", "mode" (most likely), "mean" (average) and "high" values (or a low to high range), for each unit cost, along with suggested probability distribution types, a useful self-consistent set of data is provided for those who wish to assess the economics of entire fuel cycles. How such overall fuel cycle assessment is conducted is discussed in the AFCI document *Advanced Fuel Cycle Economic Tools, Algorithms, and Methodology*; May 2009; INL/EXT-09-15483. The body of the AFC_CBR also discusses a number of related cost analysis topics.

AFC-CBR documents were prepared nearly every year 2004 through 2009 and grew from around 250 pages to over 600 in the 2009 version. As the size of the document grew, so too did the effort involved with the updates. A decision was made move to less frequent updates and a 370 page addendum to the 2009 report was issued in 2012 (FCRD 2012). This 2017 edition is the second full update since 2009, following a 2015 edition that incorporates the 2012 addendum. This edition also incorporates material from a 2016 status report.

As successive new AFC-CBR documents have been prepared, each has maintained much of the original text from the first time a fuel cycle module was introduced. The following also appear in any newer volume:

- New cost analysis topics in the main report

- New data and the references supporting it in the cost modules
- Additional reactor types (R-modules)
- Additional sub-modules that address different topics within the main module (e.g. fabrication of different types of fuels)
- Placeholders for any modules or submodules which have been superseded or rearranged in subsequent updates.

This edition follows the same format as preceding editions. Front material in each module summarizes the main changes since the last full report. At the front of this report there is also a Table which lists all the module unit cost ranges.

The "body" of the report includes a number of new cross-cutting topics. Some of these topics present both the current state of development in the AFC-CBR as well as the likely direction of future evolution.

The report modules (the majority of the report) is contained in separate files within the AFC-CBR folder and include multiple new reactor types and major revisions of several other modules since the 2009 report.

SUMMARY

The following Table S-1 summarizes the projected FY 2017 constant dollar unit costs (or prices where indicated) for all of the fuel cycle modules. Monetary units were escalated and, unless otherwise noted, rounded to the nearest whole unit. Where possible a range and/or distribution is indicated for each category. The inclusion of more than just a "mode" or "most likely" single-point value allows fuel cycle system modelers and analysts to assess the economic uncertainty associated with complete fuel cycles. This Summary Table is a compilation of the "What-It-Takes" (WIT) tables appearing in subsequent pages of this report. In Note that the following qualitative changes have been made since 2009:

- The addition of five new reactor or transmuter modules ["R" Modules: Pressurized Heavy Water Reactors (R5), Accelerator-Driven Systems (R6), Liquid-fueled Molten-salt Reactors (R7), Solid-fueled Molten-salt Reactors (R8), and Fission/Fusion Hybrids (R9)].
- The inclusion of new data and references for nearly all of the front-end fuel cycle modules (Module Series A, B, C, and D: source materials, conversion, uranium enrichment, and fuel fabrication respectively).
- Updates to the background information on spent fuel storage (Modules E1eliminated and E2 moved to Module I), and the addition of a new module G5 for secondary Greater-than-Class C (GTCC) waste conditioning, storage, and packaging.
- Module L (Geologic Disposal) is now divided into two parts: Module L1 for spent fuel and high level waste (HLW) disposal, and L2 for GTCC disposal.

The following Figure S-1 shows the material flow order of and relationships between the various fuel cycle modules. This order applies to most commonly analyzed fuel cycles.

Figures S-2 and S-3 show pictorial representations of both the triangular and uniform distributions, respectively, suggested for the data in Table S-1. The uniform distribution is defined by two parameters (low and high values) and the triangular by three parameters (low, nominal, and high). The mean or average value is also calculated for each set of WIT values.

New Introductory Material has also been added to the report to cover generic issues such as "cost versus price," historical escalation, the use of discounting, cost analysis for modular reactor systems, and the treatment of uncertainty.

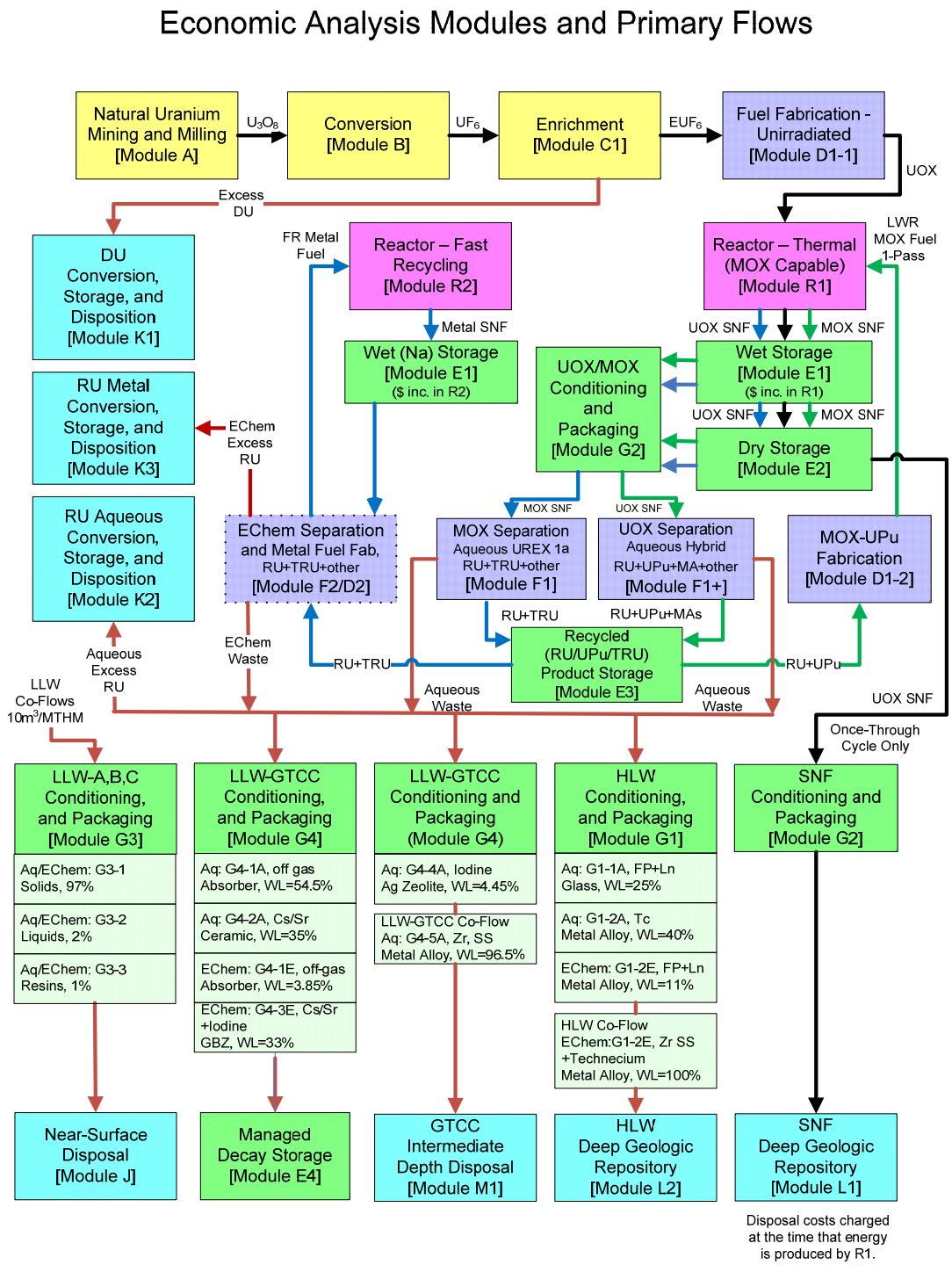

Figure S-1. General Flow of Fuel Cycle Modules.

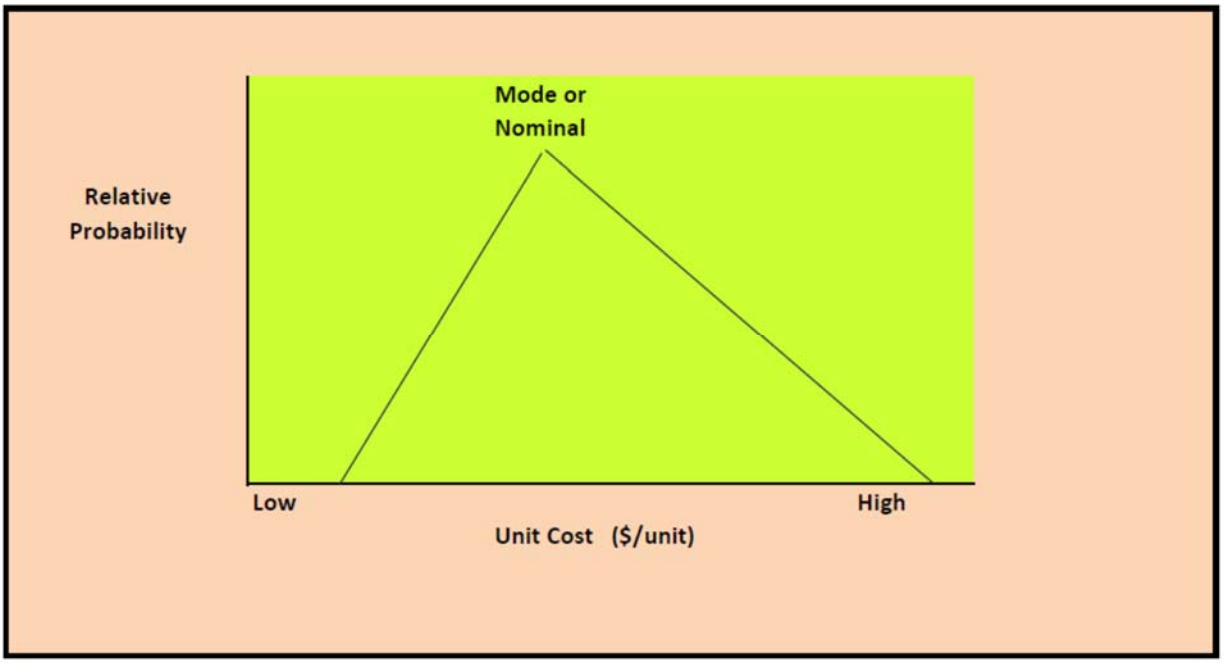

Figure S-2. Triangular Distribution Defined by Three Values.

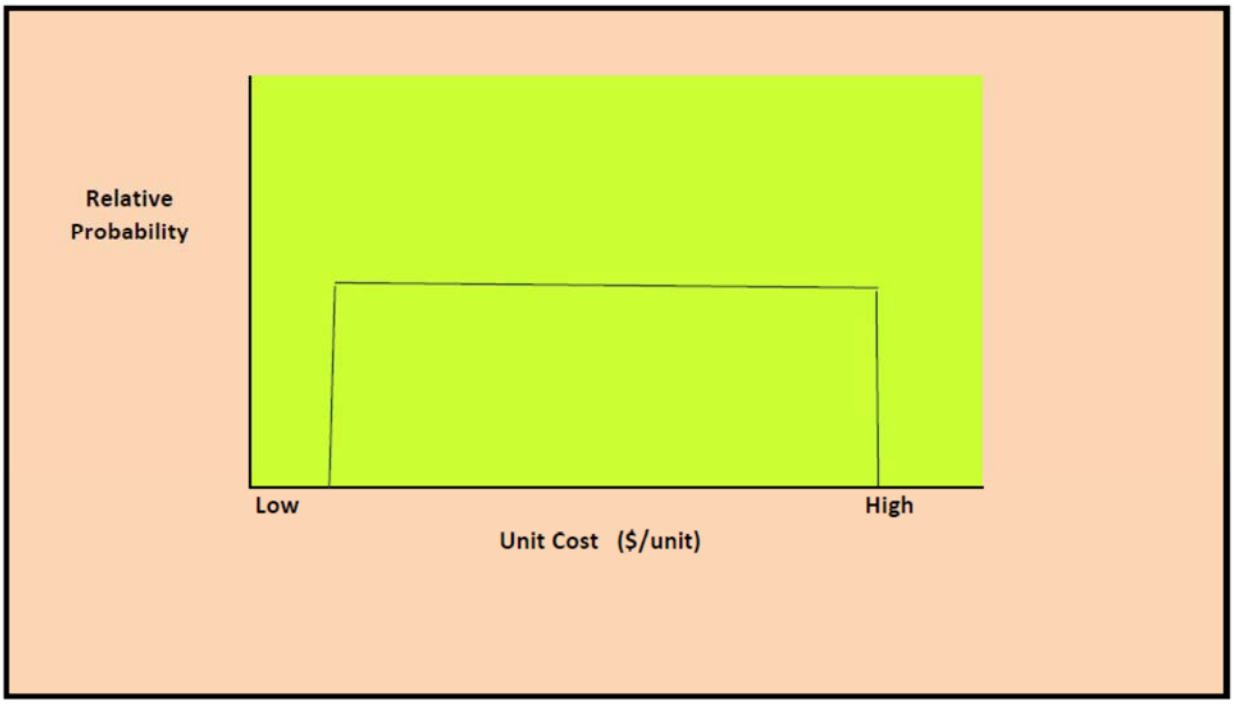

Figure S-3. Uniform Distribution Defined by Two Values.

Table S-1. Projected FY 2017 constant dollar unit costs for all Fuel Cycle Modules.

Cost-related Variables for Modules	Units	2017 AFC-CBR Data				
N/A = Not Available or Not Applicable		Low	Mode	High	Dist Type	Mean
SOURCE MATERIALS						
A1 - Natural Uranium Mining and Milling	$/KgU	34	86	296	TRI	139
	equiv $/lb U3O8	13.1	33.1	114	TRI	53.5
A2- Thorium Mining and Milling	$/kgTh	28	59	200	TRI	93
CONVERSION/ENRICHMENT PROCESSES						
B - Conversion Processes	$/KgU	6.5	13	19	UNI	13
C1-Enrichment	$/SWU	97	125	154	UNI	125
C2- HEU Downblending	$/SWU	N/A	N/A	N/A	—	
FUEL FABRICATION (CONTACT-HANDLED) [CH]						
D1-1 - LWR UO2 Fuel Fab (PWR: Virgin LEU)	$/KgU or $/KgHM	230	400	575	TRI	401
D1-1 - LWR UO2 Fuel Fab (PWR: Reprocessed and re-enriched LEU)	$/KgU or $/KgHM	250	435	635	TRI	435
D1-1 - LWR UO2 Fuel Fab (BWR: Virgin LEU)	$/KgU or $/KgHM	285	400	575	TRI	420
D1-1 - LWR UO2 Fuel Fab (BWR: Reprocessed and re-enriched LEU)	$/KgU or $/KgHM	315	435	635	TRI	440
D1-2 - LWR Pellet MOX Fuel Fab	$/KgHM	800	1,000	1,600	TRI	1,133
D1-3 - Gas-Cooled Reactor Particle Fuel	$/kgU or $/kgHM	3,300	10,900	29,400	TRI	14,500
D1-4 - Ceramic Pelletized FR Driver Fuel such as U/Pu MOX (Contact-handled)	$/kgHM	2,700	4,900	7,600	TRI	5,060
D1-4 - Ceramic Pelletized FR Blanket Fuel: UO2	$/kgU	270	500	690	TRI	487
D1-4 - Ceramic Pelletized FR Enriched Uranium Fuel (MEU)	$/kgU	500	870	1,240	TRI	870
D1-5 - Ceramic Vibrocompacted Fast Reactor Fuel	$/kgHM	720	900	1,440	—	1,020
D1-6 - Metal alloy contact-handled Fast Reactor Fuel	$/kgHM	N/A	N/A	N/A	—	N/A
D1-7 - Ceramic CANDU Reactor fuel (Natural UOX)	$/kgHM	125	218	327	TRI	224
D1-7 - Ceramic CANDU Reactor fuel (Reprocessed or SEU UOX)	$/kgU	164	284	425	TRI	291
D1-8 - Thorium-based contact-handled fuels (U,Th)O2 pelletized	$/kgHM	327	573	818	TRI	573
D1-8 - Thorium-based contact-handled fuels(ThO2 blanket pellets only)	$/kgTh	273	490	687	TRI	483
D1-9 - Inert matrix and other advanced contact-handled (CH) fuels	$/kgHM	N/A	N/A	N/A	—	N/A
FUEL FABRICATION (REMOTE-HANDLED)[RH]						
D2/F2 - Fuel Fabrication of remote handled (RH) Transmutation Fuels (INEL reproc.): Refabrication Portion only	$/KgHM	1,000	1,400	1,800	TRI	1,400
STORAGE OF ACTINIDES, SPENT FUEL, and FISSION PROD						
E3-1a - Recycled Combined Actinide Product Storage (Stand-alone Facility)	$/Kg TRUs	3,762	5,016	6,840	TRI	5,206
E3-1b - Recycled Combined Actinide Product Storage (Co-Located Facility)	$/Kg TRUs	712	950	1,300	TRI	991
E3-2a - Recycled PuO2 Product Storage before MOX fabrication (Stand-alone)	$/kgPu	2,280	2,964	3,762	TRI	3,000
E3-2B - Recycled PuO2 Product Storage before MOX fabrication (Co-Located Facility)	$/kgPu	433	562	712	TRI	570
E4 - Managed Decay Storage of selected separated FPs	$/KgCsSr	11,400	25,650	39,900	TRI	26,500
AQUEOUS REPROCESSING HEAD-END & SEPARATIONS						
F1- UREX+1a Aqueous Separation only for UOX UNF	$/KgHM	1,030	1,277	1,526	TRI	1,277

Cost-related Variables for Modules	Units	2017 AFC-CBR Data				
N/A = Not Available or Not Applicable		**Low**	**Mode**	**High**	**Dist Type**	**Mean**
F1- UREX+3 Aqueous Separation only for UOX UNF	$/KgHM	1,186	1,482	1,776	TRI	1,482
F1- COEX Aqueous Separations only for UOX UNF	$/KgHM	861	1,055	1,250	TRI	1,055
F1- UREX+1a Total Aqueous Reprocessing of UOX UNF	$/KgHM	1,703	2,109	2,523	TRI	2,112
F1- UREX+3 Total Aqueous Reprocessing of UOX UNF	$/KgHM	1,904	2,371	2,836	TRI	2,371
F1- COEX Total Aqueous Reprocessing of UOX UNF	$KgHM	1,263	1,562	1,846	TRI	1,557
F1- COEX for Thorium-bearing fuels (Aqueous separations)	$/KgHM	904	1,161	1,375	TRI	1,147
F1- UREX+1a for Thorium-bearing fuels (Aqueous separations)	$/KgHM	1,080	1,405	1,680	TRI	1,388
F1- UREX+3a for Thorium-bearing fuels (Aqueous separations)	$/KgHM	1,245	1,630	1,954	TRI	1,610
F1- COEX for Thorium-bearing fuels (Total Reprocessing)	$/KgHM	1,326	1,718	2,030	TRI	1,691
F1- UREX+1a for Thorium-bearing fuels (Total Reprocessing)	$/KgHM	1,789	2,320	2,776	TRI	2,295
F1- UREX+3a for Thorium-bearing fuels (Total Reprocessing)	$/KgHM	2,000	2,608	3,142	TRI	2,583
ELECTROCHEMICAL REPROCESSING HEAD-END & SEPS						
F2/D2 - Reprocssing - Electrochemical & RH Fuel Recycle (incl. refabrication)	$/KgHM	2,000	2,600	3,200		2,600
WASTE CONDITIONING, STORAGE, & PACKAGING						
G1-1A - Aqueous-derived HLW Conditioning, Storage, Packaging (FP+Ln) in borosilicate glass	$/Kg FP	2,508	5,700	7,524	TRI	5,244
G1-2A - Aqueous-derived Metal Alloy (Tc)	$/Kg Tc	187,500	228,000	263,900	TRI	225,465
G1-2E - Echem-derived HLW co-flows (hulls, etc, other metal [nobles & Ln])	$/kg FP	13,700	17,214	20,660	TRI	17,190
G2 - Spent UOX Conditioning & Packaging prior to longer-term disposition	$/KgHM	67.5	135	175	TRI	126
G3-1 - LLW Conditioning, Storage, Packaging (solids, debris)	$/m3	1,071	1,612	4,500	TRI	2,390
G3-2 – LLW Cond, Storage, Packaging (liquids)	$/m3	4,455	14,850	29,700	TRI	16,335
G3-3 - LLW Conditioning, Storage, Packaging (resins)	$/m3	109,350	121,500	133,650	TRI	121,500
G4-1A - Aqueous-derived LLW-GTCC Offgas absorber (H3, Kr, Xe, Ru)	$/m3gas	10,800	12,770	17,100	TRI	13,560
G4-1E - Echem-derived LLW-GTCC Offgas absorber (H3, Kr, Xe, Ru)	$/m3gas	10,800	12,770	17,100	TRI	13,560
G5 GTCC Contact Handled-TRU Conditioning, Storage, and Packaging	$/m3	21,660	30,780	42,180	TRI	31,540
E-PLANT or R-PLANT RECOVERED URANIUM STORAGE/DISPOSITION						
E-PLANT TAILS						
K1-1 - Depleted Uranium Disposition (E-Plant Tails Deconversion and Packaging)	$/KgDU	4.4	6.5	8.7	TRI	6.5
K1-2 - Depleted Uranium Disposition (De-converted E-plant Tails Geologic Disposal as Stable Oxide form)	$/kgDU	4.4	14.1	45.8	TRI	21.4
AQUEOUS R-PLANT U-PRODUCT						
K2 - Recovered U Disposition (Conv of "new" UNH to storable U3O8)	$/KgU	4.6	13.7	19.4	TRI	12.6
K2 - Recovered U Disp (Conv of "old" UNH to storable U3O8: incl aq polish)	$/KgU	22.8	45.6	57	TRI	41.8
K2 - Recovered U Disp (Conv of "new" UNH to UF6 for re-enrichment)	$/KgU	6.8	16	22.8	TRI	15.2
K2 - Recovered U Disp (Conv of "old" UNH to UF6 for re-enr.: incl aq polish)	$/KgU	33.7	49	65.4	TRI	49

Cost-related Variables for Modules	Units	2017 AFC-CBR Data				
N/A = Not Available or Not Applicable		Low	Mode	High	Dist Type	Mean
K2 - Recovered U Disp (40-yr storage of U3O8)	$/KgU	8	10.3	34.2	TRI	17.5
K2 - Recovered U Disp (Perm Geologic Disposal of U3O8)	$/KgU	21.8	54.5	81.8	TRI	52.7
K2 - Recovered U Disp (Conv of "new" UNH to MOXable UO2 powder)	$/KgU	N/A	65.4	N/A	—	_
K2 - Recovered U Disp (Conv of "old" UNH to MOXable UO2 powder)	$/KgU	N/A	103.6	N/A	—	_
ELECTROCHEMICAL R-PLANT URANIUM PRODUCT						
K3-Recovered U Disp (Perm Geologic Disposal of metal or oxidized form)	$/KgU	81.8	98.1	164	TRI	114.6
K3- Recovered U-metal ingot 300 yr storage	$/KgU	27.3	32.7	109	TRI	56.3
K3-Recovered U-metal conv to UF6 incl fluoride volatility purification	$/KgU	32.7	43.6	65.4	TRI	47.2
K3 - Recovered U-metal to purified UOX conversion for contact-handled MOX usage	$/KgU	32.7	43.6	65.4	TRI	47.2
GEOLOGIC WASTE DISPOSAL						
I - Monitored Retrievable Storage for LWR SNF	$/KgHM	223	501	644	TRI	456
J - Near Surface Disposal	$/m3 of pkg mat	608	1,688	3,375	TRI	1,890
L1 - Geologic Repository (SNF) [mass pricing]	$/KgHM	289	600	873	TRI	587
L1 – Geologic Repository (HLW)	$/kgFP	1,500	6,000	7,500	TRI	5,000
L2 - Geologic Repository of GTCC Waste in enhanced confinement facilities	$/m3	2,300	3,800	5,320	UNIFORM	3,800
L2 – GTCC in Geologic Repository (co-located with HLW)	$/m3	—	5,180	—	—	
TRANSPORTATION including CONTAINERS (per kg material transported)						
O2 – 55 gallon drum for yellow cake	$/kg	2.1	2.7	3.7	TRI	2.84
O2 – Paducah Tiger overpack for UF6 or DUF6 cylinder	$/kg	1.1	1.3	1.4	TRI	1.28
O2 – UX-30 for EUF6	$/kg	15.3	15.8	16.3	TRI	15.82
O2 – CHT-OP-TU for FUO2, UOX or LLW	$/kg	1.7	2.3	3.3	TRI	2.43
O2 – 9975 for TRU or TRUOX	$/kg	201.7	313.8	479.8	TRI	331.8
O2 – CNS10-160B for FP	$/kg	4.5	6.2	8.5	TRI	6.41
O2 – RH-TRU 72B for TRU or FP	$/kg	7.3	10.2	14.2	TRI	10.57
O2 – MCC-4 for PWR assemblies	$/kg	44.5	46.0	48.0	TRI	46.2
O2 – SP-1,2,3 for BWR assemblies	$/kg	66.4	69.7	74.5	TRI	70.19
O1 – From Reactor to Repository	$/kg	23.9	26.7	29.5	TRI	26.7
O1 – From Reactor to Central Storage Facility to Repository	$/kg	103.5	106.3	109.0	TRI	106.3
NUCLEAR REACTORS and OTHER TRANSMUTERS						
R1 - Thermal LWR Reactor (Overnight Capital)	$/Kw(e)	2,500	4,400	6,300	TRI	4,300
R1 - Thermal LWR Reactor (Fixed component of O&M)	$/Kw(e)-yr	60	73	87	TRI	72
R1 - Thermal LWR Reactor (Variable component of O&M)	mills/kwh	0.8	1.8	2.7	TRI	2.0
R2 - Fast Reactors (Overnight Capital)	$/Kw(e)	2,400	4,100	7,600	TRI	4,700
R2 - Fast Reactors (Fixed component of O&M)	$/Kw(e)-yr	65	76	92	TRI	78
R2 - Fast Reactors (Variable component of O&M)	mills/kwh	1.1	2.2	2.9	TRI	2.1
R3- Gas-Cooled reactors (Overnight cost)	$/Kw(e)	2,500	5,000	8,000	TRI	5170
R3- Gas-Cooled reactors (Fixed component of O&M)	$/Kw(e)-yr	N/A	N/A	N/A	—	_
R3- Gas-Cooled reactors (Variable component of O&M)	mills/kwh	N/A	N/A	N/A	—	_
R4- Small Modular LWR (Module Deleted)	$/Kw(e)	N/A	N/A	N/A	N/A	N/A
R5- PHWR Reactors (overnight cost)	$/Kw(e)	2,400	4,200	6,100	TRI	4,230

Cost-related Variables for Modules	Units	2017 AFC-CBR Data				
N/A = Not Available or Not Applicable		Low	Mode	High	Dist Type	Mean
R5- PHWR Reactors (Fixed component of O&M)	$/Kw(e)-yr	60	72	87	TRI	73
R5- PHWR Reactors (Variable component of O&M)	mills/kwh	0.8	2.0	2.7	TRI	1.8
R6- Accelerator-driven Systems (ADS) (Accelerator Overnight cost)	$/Kw(e)	1,500	8,200	15,400	TRI	8,370
R6- Accelerator-driven Systems (ADS) (Subcritical Reactor Overnight cost)	$/Kw(e)-yr	3,200	5,000	8,400	TRI	5,530
R6- Accelerator-driven Systems (ADS) (Accelerator Fixed component of O&M)	$/Kw(e)-yr	54	166	278	TRI	166
R6- Accelerator-driven Systems (ADS) (Subcritical Reactor Fixed component of O&M)	$/Kw(e)-yr	65	143	250	TRI	153
R6- Accelerator-driven Systems (ADS) (Variable component of O&M)	Mills/kwh	N/A	N/A	N/A	—	_
R7- Liquid-fueled Salt-Cooled Reactors (Overnight cost)	$/Kw(e)	2,400	6,000	9,800	TRI	6,100
R7- Liquid-fueled Salt-Cooled Reactors (Fixed component of O&M)	$/Kw(e)-yr	N/A	NA	N/A	—	_
R7-Liquid-fueled Salt-Cooled Reactors (variable component of O&M)	mills/kwh	N/A	NA	N/A	—	_
R8-Solid-fueled Salt-cooled Reactors (Overnight cost)	$/Kw(e)	2,200	6,000	8,700	TRI	5,600
R8-Solid-fueled Salt-cooled Reactors (Fixed component of O&M)	$/Kw(e)-yr	N/A	N/A	N/A	—	_
R8- Solid-fueled Salt-Cooled Reactors (Variable component of O&M)	mills/kwh	N/A	N/A	N/A	—	_
R9-1 – Magnetic Confinement Fission/Fusion Hybrid (Fusion Reactor Component Capital Cost)	$/Kw(e)	6,100	12,000	17,400	TRI	11,800
R9-1 – Magnetic Confinement F/F Hybrid (Fusion Reactor Component:Fixed Conponent O&M)	$Kw(e)-yr	87	131	174	TRI	131
R9-1 – Magnetic confinement F/F Hybrid (Subcritical Fission Reactoar Component:Capital Cost)	$/Kw(e)	2,300	4,800	7,200	TRI	4,800
R9-1 – Magnetic Confinement F/F Hybrid (Subcritical Fission Reactor Component:Fixed Component of O&M Cost)	$/Kw(e)-yr	65	109	250	TRI	141
R9-2 – Inertial Confinement F/F Hybrid (Fusion Reactor Component:Capital Cost)	$/Kw(e)	5,400	8,700	10,900	TRI	8.300
R9-2 – Inertial Confinement F/F Hybrid (Fusion Reactor Component:Fixed O&M Cost)	$/Kw(e)-yr	54	87	109	TRI	83
R9-2 – Inertial Confinement F/F Hybrid (Subcritical Fission Reactor Component:Capital Cost)	$/Kw(3)	2,300	4,800	7,200	TRI	4,800
R9-2 – Inertial Confinement F/F Hybrid (Subcritical Fission Reactor Component:Fixed O&M Cost)	$Kw(e)-yr	65	109	250	TRI	141

ACKNOWLEDGMENTS

The Advanced Fuel Cycle Cost Basis is a living document that has been in existence for 14 years and updated several times. During that time span, the primary authors and contributors have evolved to the point that a full author's list would be too long to include in a reference. Beginning with the 2015 edition, instead of listing authors on the cover of the report, the authors are listed here. We apologize if any authors of earlier editions were inadvertently omitted. Author affiliations are as of the time of contribution.

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CONTENTS

ACRONYMS

ADS	Accelerator-Driven System
AFC	Advanced Fuel Cycle
AFC-CBR	Advanced Fuel Cycle Cost Basis Report (any edition)
AFCI	Advanced Fuel Cycle Initiative
AFS	Assured Fuel Supply
ANL	Argonne National Laboratory
AP	Aqueous Polishing
ATW	Accelerator Transmutation of Waste
AVLIS	Atomic Vapor Laser Isotope Separation
BU	Burned Uranium
BWR	Boiling Water Reactor
CANDU	Canada Deuterium/Uranium Reactor
CBR	Cost Basis Report
CH	Contact-Handled
COA	Code of Accounts
CRBR	Clinch River Breeder Reactor
CY	Calendar Year
D&D	Decontamination and Decommissioning
DDR	Declining Discount Rate
DOE-NE	U.S. Department of Energy-Nuclear Energy
DU	Depleted Uranium
DUF_6	Depleted Uranium Hexafluoride
DUO2	Depleted Uranium Dioxide
EBR-II	Experimental Breeder Reactor II (Idaho)
EIS	Environmental Impact Statement
EMWG	Generation IV Reactors Economic Modeling Working Group
EPA	Environmental Protection Agency
EU	Enriched Uranium
EUF_6	Enriched Uranium Hexafluoride
EUO_2	Enriched Uranium Oxide
FC	Fuel Cycle
FCO	Fuel Cycle Options Campaign (of the NTRD Program)
FCRD	Fuel Cycle Research and Development (Program of DOE-NE)
FEP	Fluorine Extraction Process
FFH	Fission/Fusion Hybrid
FFTF	Fast Flux Test Reactor
FOAK	First-Of-A Kind
FP	Fission Product
FR	Fast Reactor
FV	Future Value
FY	Fiscal Year
G4	Generation IV
GCFR	Gas-cooled Fast Reactor

GDP	Gross Domestic Product
GE	General Electric
GW	Gigawatts = 1000 MW
GNEP	Global Nuclear Energy Partnership
GNP	Gross National Product
GTCC	Greater-than-Class C
HA	Higher Actinides
HEU	Highly-Enriched Uranium (U-235 $\geq$20%)
HLW	High Level Waste
HM	"Heavy metal"—elements with Z$\geq$ 89
HTGR	High-Temperature Gas-Cooled Reactor
HTR	High-Temperature Reactor
HVAC	Heating, Ventilating, and Air Conditioning
IAEA	International Atomic Energy Agency
IC	Inertial Confinement
ICF	Inertial Confinement Fusion
IEER	Institute for Energy and Environmental Research
INL	Idaho National Laboratory
JSFR	Japan Sodium-Cooled Fast Reactor
kW	Kilowatts (usually expressed as kw(e) [electric] or kw(t) [thermal)
kT	Thousands of metric tons (or tonnes)
LANL	Los Alamos National Laboratory
LCAE	Levelized Cost At Equilibrium
LEU	Low Enriched Uranium (typically 1% to 20% U-235)
LLNL	Lawrence Livermore National Laboratory
LLW	Low-Level Waste
LUEC	Levelized Unit of Electricity Cost
LWR	Light Water Reactor
MC	Magnetic confinement
MCFR	Magnetic confinement fusion reactor
MES	Minimum economic scale
MEU	Medium-Enriched Uranium
MFFF	MOX Fuel Fabrication Facility
MIT	Massachusetts Institute of Technolocy
MOX	Mixed Oxide Fuel (usually PuO_2 and UO_2)
MSBR	Molten-Salt Breeder Reactor
MSR	Molten Salt Reactor
MT	Metric Ton or Tonne
MTU	Metric Tons of uranium
MW	Megawatts (1 MW = 1000kW)
MTW	Metropolis Works
N/A	Not Applicable or Not Available
NATU	Natural Uranium
NE	DOE Office of Nuclear Energy
NNSA	National Nuclear Security Administration
NOAK	Nth-Of-A-Kind

NPV	Net Present Value
NRC	Nuclear Regulatory Commission (USA)
NTRD	Nuclear Technology Research and Development (Program of DOE-NE)
NTS	Nevada Test Site (recently renamed Nevada National Security Site
NU	Natural Uranium
NUe	Natural uranium equivalent
O&M	Operations and Maintenance
OECD	Organization for Economic Cooperation and Development
OMB	US Office of Management and Budget
ORNL	Oak Ridge National Laboratory
PHWR	Pressurized Heavy Water Reactor
PNNL	Pacific Northwest National Laboratory
PV	Present Value
R&D	Research and Development
RF	Russian Federation
RH	Remote-Handled
RU	Reprocessed Urainum (also abbreviated REPU)
SEU	Slightly-Enriched Uranium (ca 1% U-235)
SFR	Sodium-Cooled Fast Reactor
SMR	Small Modular Reactor
SNF	Spent Nuclear Fuel (usually denotes UNF that will be disposed)
SRS	Savannah River Site
SWU	Separative Work Units
TRISO	Tristructured Isotopic (form of particle fuel)
TRU	Transuranic (Z>92)
TSLCC	Total System Life-Cycle Costs
UK	United Kingdom
UNF	Used Nuclear Fuel
UNH	Uranyl Nitrate Hexahydrate
UOX	Uranium Oxide (UO_2) fuel
USD	United States Dollars
USEC	United States Enrichment Corporation (now Centrus)
USGS	United States Geological Survey
WACC	Weighted Average Cost of Capital
WBS	Work Breakdown Structure
WIT	What-It-Takes

NOMENCLATURE

The following definitions established the common terminology used to develop fuel cycle cost estimates. These terms were developed by the Generation IV Economic Modeling Working Group (EMWG 2007) and, in some cases, have been modified to describe fuel cycle costs. It is understood that some of these terms will not be used or become applicable until much later in the system development and deployment cycle.

Base cost. The base construction cost is the most likely plant construction cost based on the direct and indirect costs only. This cost is lower than the total capital cost because cost elements such as contingency and interest are not included. The direct costs are those costs directly associated on an item-by-item basis with the equipment and structures that comprise the complete production plant, fuel cycle facility, equipment fabrication factory, or end-use plant. The indirect costs are expenses for services applicable to all portions of the physical plant. These include field indirect costs, design services, engineering services, architectural engineer home office engineering and design services, field office engineering and services, and construction management services. Process equipment manufacturer home office engineering and services are included in separate accounts. Owner's costs, such as commissioning, are added to the base costs prior to the application of the contingency allowance.

Common plant facilities. Common plant facilities are those systems, structures, and components that provide common support to the operation at a new plant site. They include such facilities as administration buildings, general warehouse, water supply, general fire systems, energy distribution, cooling water intakes, cooling towers, and civil and engineering offices. These common plant facilities can be sized to share with other production units added subsequently.

Constant money. Constant money cost is the cost of an item, measured in money that has a general purchasing power as of some reference date, (e.g., January 1, 2001). Because inflation is associated with the erosion of the purchasing power of money, constant money analysis factors out inflation. In the NTRD economic analyses carried out using the present guidelines, only constant money costs will be considered.

Construction module. A construction module is a free standing, transportable preassembly of a major portion of the plant, or a system or sub-system of the unit. A construction module may be a preassembly of a single system or portion thereof, or may contain elements of all the systems that exist in a given location in the plant. A construction module may contain parts of the building structure. A construction module might be assembled in a factory, shipped to the plant site, and installed in the plant (perhaps after minor assembly and/or linking). The direct costs for modules should contain their share of the manufacturing costs, including the fair burden of the cost of operating the factory where they are manufactured. If not, the factory-related costs must be accounted for elsewhere. An example would be groups of gas centrifuges for uranium enrichment shipped as production units from a centrifuge machine manufacturing facility.

Contingency. Contingency is an adder to account for uncertainty in the cost estimate. Contingency includes an Allowance For Indeterminates and should be related to the level of design, degree of technological advance, and the quality/reliability level of given components. Contingency does not include any allowance for potential changes from external factors, such as changing government regulations, major design changes or project scope changes, catastrophic events (*force majeure*), labor strikes, extreme weather conditions, varying site conditions, or project funding (financial) limitations. Contingencies can be also applied to the interest during construction (IDC) and the capacity factor to account for uncertainty in the reactor design/construction schedule and reactor performance, respectively.

Deployment costs. Costs of developing a standard facility design and licensing it. These are considered part of First-of-a-Kind (FOAK) costs and are distinct from research and development costs.

Direct cost. All costs that are traceable to construction of permanent plant, but excluding support services such as field indirect costs, construction supervision, and other indirect costs (see also Base cost).

Discount rate. In the context of the present guidelines, discount rate will be taken as equal to the real cost of money unless specifically identified otherwise. This cost will, in turn, depend on the market risk, deployment risk, financing scheme, and other external factors.

Economic life. The number of years of commercial operation over which capital costs are recovered. This value is needed to calculate a fixed charge rate or capital recovery factor. The economic life is usually fixed at the number of years of commercial operation allowed by the regulator.

Escalation rate. The rate of cost change. This rate can be greater than or less than the general inflation rate, as measured by the Gross Domestic Product Implicit Price Deflator. For Advanced Fuel Cycle Initiative cost estimation, it will be assumed to be zero, unless otherwise justified.

Equipment. Equipment for production facilities includes all manufactured items ordered and delivered to a site, and used in construction. Such items may be procured on a design and build contract from qualified vendors, wherein design responsibility belongs to the seller (vendor) or is maintained by the buyer or purchasing agent on a "build-to-print" basis. To facilitate bottom-down estimating techniques, only major process related equipment costs will be categorized as equipment cost. Nonprocess related equipment such as heating, ventilating, and air conditioning (HVAC), plumbing, lifting or maintenance equipment, or large pipe and valves is to be classified as material costs.

Equipment module. An equipment module is a prepackaged and site delivered (skid-mounted, factory-assembled) package that includes (but is not limited to) equipment, piping, instrumentation, controls, structural components, and electrical items. Module types include Box Modules, Equipment Modules, Structural Modules, Connection Modules, Electrical Modules, Control System Modules, and Dressed Equipment Modules. These Modules are applicable to both the Main Process and Balance of Plant, including support buildings.

Factory (manufacturing facility) first-of-a-kind costs. These First-of-a-Kind (FOAK) costs include the development of manufacturing specifications, factory equipment, facilities, startup, tooling, and setup of factories that are used for manufacturing specific equipment for the fuel cycle system. These costs can be minimized if existing facilities are used for module production. These facilities might not be dedicated to, or even principally used for this application (e.g., a shipyard or any other factory that already builds modules for other industries or units). For a new modular production facility, the new equipment module fabrication factory might be considered a FOAK cost and included in module prices. If these costs are to be spread over a production run (or total Number of Plants), then the cost should be estimated on that basis, and the number of plants or production needed to recover the factory costs defined. The module prices are in the unit/plant costs and, as such, the price should be amortized into the unit product cost over some number of modular facilities produced over its projected lifetime. The capital cost of the modules must amortize the module factory capital costs plus the normal annual production (operating) costs for the factory. For a preexisting factory, it is assumed that the price of the modules includes a fair share of any factory operating and capital recovery costs (overheads).

First commercial plant costs. The first commercial plant is the first standard plant of a particular type that is sold to an entity for the purpose of commercial production of fuel and/or other fuel cycle related products or services. The costs include all engineering, equipment, construction, testing, tooling, and project management costs, as well as any other costs that are repetitive in nature. Any costs unique to the first commercial plant, which will not be incurred for subsequent plants of the identical design, will be identified and broken out separately as FOAK plant costs. The "learning" process for this first plant will reflect its first commercial plant status and not be the average over a larger number of later plants.

First-of-a-kind plant costs. The First-of-a-Kind (FOAK) costs are those necessary to put a first commercial plant in place that will not be incurred for subsequent plants. Design and design certification costs are examples of such costs. Refer to the figure on temporal relationship of research, development, and demonstration (RD&D); deployment; and standard plant costs at the end of nomenclature section.

Force account. Construction Labor Force account involves the direct hiring and supervision of craft labor to perform a construction activity by a prime contractor, as opposed to the prime contractor hiring a subcontractor to perform these functions.

Indirect cost. All costs that are not directly identifiable with a specific permanent plant, such as field indirect, construction supervision, design services, and PM/CM services (see Base cost).

Industrial grade construction. Industrial grade construction means construction practices that conform to generally accepted commercial requirements such as those required for fossil-fired plant or general chemical plant construction. Industrial grade construction could be used for nonnuclear parts of fuel cycle facilities, such as a zirconium tube factory in a light water reactor fuel fabrication facility. A module factory could also use industrial grade construction for the production of some modules. See also definition of nuclear grade construction.

Inflation rate. The rate of change in the general price level as measured by the Gross Domestic Product Implicit Price Deflator. The inflation rate is assumed to be zero in constant money based studies.

Interest during construction. Interest during construction (IDC) is the interest accrued for up-front cost financing (i.e., it is accrued to the end of construction and plant startup). This report assumes that once the plant is in commercial operation, the IDC plus the total overnight costs are "rolled-over" to a long-term loan or financing structure.

Levelized cost of electricity at equilibrium (LCAE). The levelized unit cost of electricity for a system in equilibrium. In application, fuel cycle is assumed to be complete utilizing NOAK facilities and retiring facilities are replaced with like facilities. In an LCAE analysis, discounting is treated in a relative manner and all learning is assumed to have already occurred.

Levelized unit of electricity (LUEC) cost. The levelized cost of electricity generation, expressed in U.S.$/MWh or mills per net kWh. For the standard plant, it includes costs associated with nongeneric licensing, capital investment, operation and maintenance of the energy plant, owner's costs, ongoing refurbishment, fuel, waste disposal, and decommissioning the plant at the end of life, and may include revenue offsets due to by-product production. Typically, the four components of levelized unit of electricity cost (LUEC) reported are: the capital component (recovery of capital cost over economic life), the production or nonfuel operating and maintenance component, the fuel component, and the decontamination and decommissioning component. Normally, this cost does not have research and development or demonstration (prototype) cost embedded in it. If the FOAK plant were a commercial plant, it would have some FOAK costs, such as generic design and design certification, recovered in the LUEC. The remaining recoverable costs would be standard plant costs. When multiple reactors (and types) are evaluated in a fuel cycle scenario, then the composite unit cost is referred to as the total cost of electricity (TCOE).

Materials. Materials include field-purchased (site material) and/or bulk commodity items, such as lumber, concrete, structural steel, and plumbing items. All piping is a materials item, as are all wire, cable, and raceways, including those in building service power systems. Also included is nonprocess related equipment such as HVAC, cranes, hoists, doors, plumbing, sewage treatment, etc. To facilitate bottom-down estimating techniques, only process-related equipment is categorized as equipment cost.

Module. See Construction Module and Equipment Module.

Multi-unit plant. A plant consisting of more than one production unit.

Nominal dollars. Nominal dollar cost is the cost for an item measured in as-spent dollars and includes inflation. Nominal dollars are sometimes referred to as "current" dollars, "year of expenditure" dollars, or "as spent" dollars.

Nominal cost of money. The nominal cost of money is the percentage rate used in calculations involving the time value of money containing an inflation component. It explicitly provides for part of the return on an investment to keep up with inflation.

Nth-of-a-kind plant cost. The nth-of-a-kind (NOAK) plant cost is the cost of the nth-of-a-kind or equilibrium commercial plant of identical design to the FOAK plant. NOAK plant cost includes all engineering, equipment, construction, testing, tooling, and project management, as well as any other costs that are repetitive in nature and would be incurred if an identical plant was built. The NOAK plant cost reflects the beneficial cost experience of prior plants. This currently defines the NOAK plant as the next plant after 8.0 GWe of capacity have been built (Chandler and Shropshire 2005). However, some U.S. nuclear analysts suggest that the NOAK plant may be achieved earlier (e.g., closer to four power plants). Refer to the figure on temporal relationship of RD&D, deployment, and standard plant costs at the end of nomenclature section.

Nuclear-safety grade. Nuclear-safety grade construction means construction practices that satisfy the Quality Assurance and other requirements of national licensing. Both reactor and fuel cycle facilities will require some nuclear-grade construction.

Overnight cost. The (total) overnight cost is the base construction cost plus applicable owner's, contingency, and first core costs. It is referred to as an overnight cost in the sense that time value costs (IDC) are not included (i.e., the cost is as if the plant were constructed "overnight" with no accrual of interest). Total overnight cost is expressed as a constant dollar amount in reference year dollars (overnight cost = total capital investment cost – IDC). Commissioning costs are included in the overnight cost for this study, which is not usually the case for conventional facility estimates. This expanded definition is used to reflect the fact that an owner is likely to need to finance the start-up cost in addition to the design and construction costs. Allowing all "up-front" costs to be combined into one lump sum term prior to calculation of the IDC simplifies the algorithms used to calculate the LUEC.

Prototype-of-a-kind. Costs specific to any prototype plant. These include prototype-specific design, development, licensing, construction, and testing, as well as operation of the prototype to support the demonstration of the system or concept (this prototype may assist, but does not meet or satisfy standard plant design certification). These costs are separate from FOAK and are not amortized within the LUEC.

Research, development, and demonstration costs. Costs associated with material, component, system, process, and possibly even fuel development and testing performed specifically for the particular advanced concept. These costs are often borne by governments or by industry consortia, and may be recovered depending on national norms and practices. In the present guidelines, RD&D costs are not distributed into the LUEC; however, their sum for each system is an important figure of merit for decision makers.

Real cost of money. The real cost of money (r) is the percentage rate used in calculations involving the time value of money when the inflation component has been removed (constant money calculations). Calculations using the real cost of money assume that the money maintains a constant value in terms of purchasing power, and, thus, no return on investment is needed to cover inflation.

Reference plant costs. These costs are the basis for estimating costs in the absence of a fully worked up or proven cost for a commercial unit (i.e., a surrogate basis for estimating total plant cost and cost differences). The reference plant is not part of the overall project, but rather a benchmark from which to begin costing the real planned facilities. Obtaining this information may incur some costs. See Chapter 4 of the Generation IV Cost Estimating Guidelines for information on the process for top-down cost estimation using reference plant costs.

Single-unit plant. A stand-alone commercial production plant consisting of a single unit and all necessary common plant facilities is referred to as a single-unit plant or unit. This is the smallest unit of production capacity normally sold to a customer, such as a uranium enricher or fabricator.

Specific cost. Total cost divided by the net capacity (such as net MTHM or kilowatts electric) of the plant.

Standard plant design costs. Costs associated with the engineering and engineering support functions for the design of the standard plant. These are a FOAK cost for the first commercial standard plant. These do not include the site-specific engineering costs that are associated with all standard plants.

Standard production plant licensing costs. Costs associated with licensing-related activities performed to establish that the design of the standard plant is adequate for obtaining a license. In the United States, it includes the design and analysis of prototype tests necessary for certification, coordination with the Nuclear Regulatory Commission, and preparation of documents required for certification of the standard plant design. These are a FOAK cost for the first commercial standard plant. These do not include the site-specific engineering costs that are associated with all standard plants.

Technology development costs. See research, development, and demonstration costs.

Total Cost of Electricity. The total cost of electricity (TCOE) is represented by the composite costs from an alternative consisting of multiple reactors (and potentially types of reactors), expressed in U.S.$/MWh or mills per net kWh. These costs include the individual reactor LUEC and fuel cycle costs. The TCOE can be decomposed into composite contributions from the reactor (thermal and fast) capital component (recovery of capital cost over economic life), operating and maintenance component, fuel component, and the decontamination and decommissioning component. This cost does not represent life-cycle costs which would also includeMy research and development and demonstration (prototype) costs.

Transition period. The period from the start of the construction of the FOAK to the start of construction of the NOAK plant.

Transition period plant-specific capital costs. The capital costs for the transition plants (such as the second and third of a kind). These costs exclude any FOAK costs and include costs for manufacturing of factory equipment, site construction, site-specific engineering, and home office construction support. The transition in costs from FOAK to NOAK and the beneficial cost effects of serial manufacturing and construction should be documented.

Total Capital Investment Cost. The total capital investment cost is an all-inclusive plant capital cost (or lump-sum up-front cost) developed for the purpose of calculating the plant LUEC ($/production unit), or that of a factory-fabricated module or equipment item (such as $/module). This cost is the base construction cost plus contingency, escalation (zero for these studies, unless justified), IDC, owner's cost (including owner's start-up cost), and commissioning (nonowner startup cost, such as that spent by process equipment manufacturer or architectural engineer). Because constant dollar costing will be used in these studies, escalation and inflation are not included.

Unit. See single-unit plant.

The following figure shows the relationship in time between some of the cost categories defined above as well as which costs are included in the cost of product. It should be noted that the horizontal and vertical scales of the graph are illustrative only and not scaled to real time and expenditures.

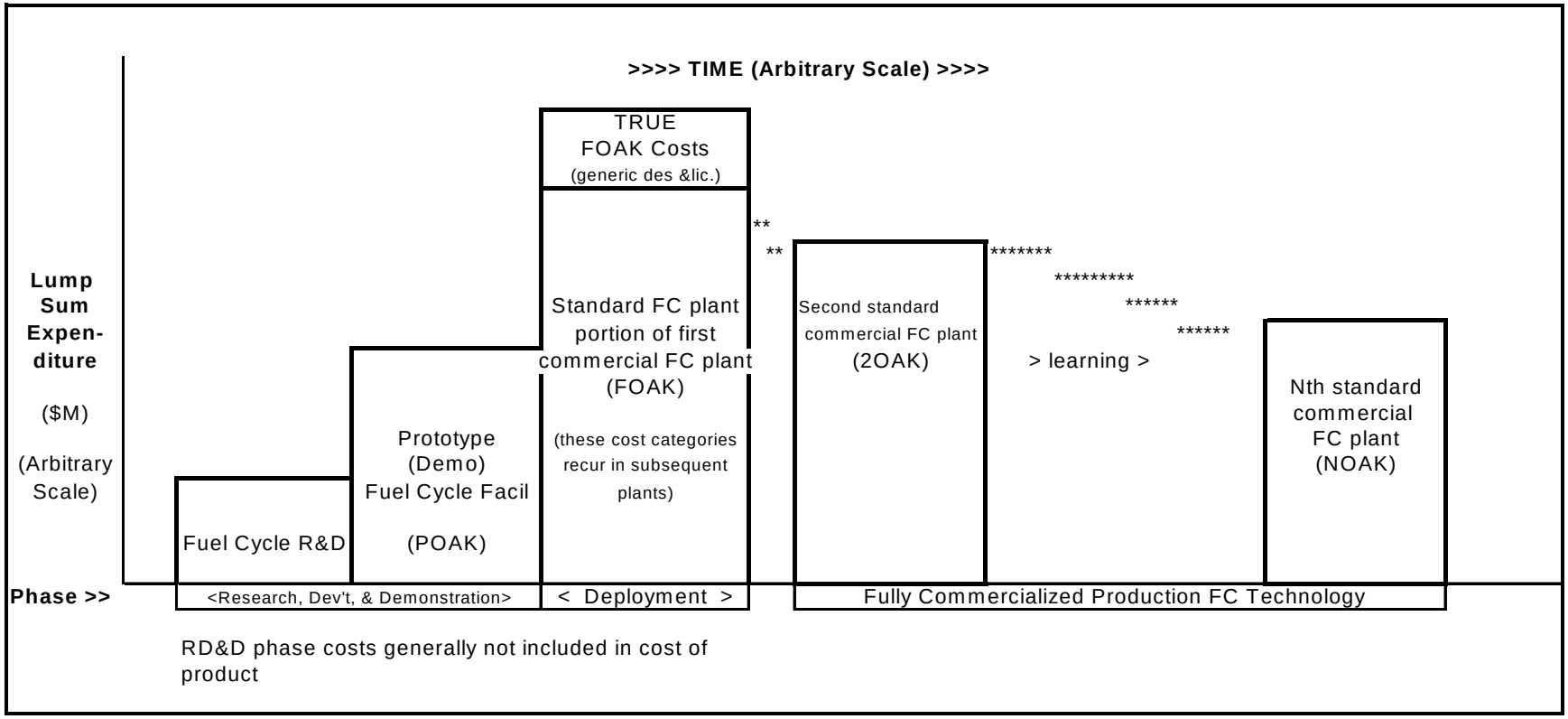

Figure S-4. Temporal relationship of RD&D, deployment, and standard plant costs.

Advanced Fuel Cycle Cost Basis – 2017 Edition

1. INTRODUCTION

This report builds on work performed over the past 14 years by the Fuel Cycle Options (FCO) Campaign of the Nuclear Technology Research and Development (NTRD) Program (formerly the Fuel Cycle Research and Development (FCRD) and Advanced Fuel Cycle Initiative (AFCI) Programs) to develop cost-estimating processes and establish a uniform structure for the collection of fuel cycle cost data. This report describes the advanced fuel cycle (AFC) cost basis development process, and provides reference information for AFC cost modules, a fuel cycle strategy costing procedure, economic evaluation guidelines, discussion of a number of cross-cutting cost analysis topics, and integration of the cost data into economic computer models, and finally conclusions and recommendations. The report does not include an evaluation of the future costs of or technical challenges for other potential future (non-nuclear) electricity generation alternatives. It also does not deal with non-cost (e.g., sustainability, societal, environmental, non-proliferation) issues, nor their cost effects or "externalities". However, these important factors should be considered when evaluating the competitiveness and benefits of nuclear energy.

A significant body of cost data has been collected and organized; however, the report is a continuous "work in progress" where some elements of the overall life-cycle cost for a given fuel cycle step may be incomplete, but new cost data is constantly being added to the database from new sources. Some of the cost and technology information derived from older reference sources are dated, but are included for completeness and will be updated as new data becomes available. This internal release of the AFC Cost Basis (AFC-CBR) report is intended to support ongoing FCO fuel cycle cost evaluations.

There are some general assumptions and caveats of which users of the AFC cost data should be aware. The costs are presented in current-year (2017) dollars, but are assumed to represent longer-term (10–20 year) market conditions, long-term contracts, and mature commercial technologies. The authors recognize that uranium and enrichment spot prices have, in the first 7 years of the 21st century, exceeded the reported range due to the enthusiasm of the nuclear renaissance and then later period of post-Fukushima. These price trends continue to be evaluated and the cost ranges in the report may continue to be revised as appropriate in future updates. The projected costs for recycling facilities and fast reactor projected costs are based on Nth-of-a-kind facilities. Special attention should be directed towards including the costs for recycled product storage, conditioning, and disposition of all waste streams.

The cost data, especially the unit cost data such as the cost per kilogram of heavy metal, may be readily input to cost models to perform engineering cost studies on both open and closed fuel cycles. Users are cautioned that their models may provide different answers and resulting conclusions due to different assumptions on the fuel cycle configuration, mass flows, time delays, cost escalation, technology performance, learning effects, market growth, and other user-defined parameters. Assumptions should be clearly documented and sensitivity analyses performed to evaluate the impacts resulting from the various assumptions.

Any comments are welcomed on the data or text in this study, especially any new data that has not been publicly available or is the result of recent new analyses outside of the Department of Energy. Comments may be provided to Brent Dixon at Brent.Dixon@inl.gov or by calling (208) 526-4928.

1.1 Background

The NTRD's definition of fuel cycle costs is consistent with the Generation IV EMWG's definition of nuclear fuel cycle costs, stated as "the costs of uranium supply, conversion, and enrichment; fuel

fabrication; transport; intermediate storage and final disposal of spent fuel (for the direct disposal option). For the reprocessing option, the costs also include those for spent nuclear fuel (SNF) reprocessing associated with waste management, along with storage and final disposal of high-level radioactive waste, as well as any credits realized through the sale and use of uranium, plutonium, heavy water, or other materials" (EMWG 2007). The NTRD definition also extends into advanced or innovative fuel cycles that may require additional cost elements related to fuel recycling (e.g., recycled product storage, reprocessing variations) and alternative disposal concepts (e.g., deep bore hole).

Current NTRD cost analysis includes an extensive evaluation of the fuel cycle costs and also includes reactor costs to fully understand the interdependency relationships between the fuel cycle and the reactor technology. The EMWG describes the total costs as the levelized unit of electricity cost (LUEC), which is the unit of most interest to utility decision makers. The LUEC "is composed of four main contributors to its total: a capital component (which includes up-front cost of financing and amortization over the economic life); an Operations and Maintenance component; fuel cycle component (fuel reloads); and a decontamination and decommissioning (D&D) component. The component costs and the total are generally expressed in constant money per unit of electricity/energy produced (e.g., $/kWh)" (EMWG 2007).

Several weaknesses of past fuel cycle economic analysis are identified and addressed in this report:

1. A fundamental weakness was the lack of a consistent and comprehensive documented source of fuel cycle cost data. With this report, we have established a documented reference cost basis with a structure and processes for continued improvement of the cost data.
2. Current design bases and requirements for critical NTRD operations (e.g., separations, fuel refabrication, waste forms) are lacking. Improving the design cost basis will shadow the development of fuel cycle technology and facility designs prepared by the NTRD Program. Cost information consistent with the cost structure and processes identified in this report will be obtained through economic integration with the fuels and separation working groups, engineering alternative studies, and through industry engagement.
3. Previous cost studies failed to provide a complete economic accounting of all the fuel cycle costs (e.g., D&D costs, refurbishment, and waste forms were omitted) in the overall life-cycle costs of a facility. Such "partial" studies can result in misleading conclusions. This work will continue to be expanded to encompass all relevant aspects of the nuclear fuel cycle and related cost elements. Internal NTRD review of the module cost data, external reviewers of this report, and input from report users will be used to help identify areas of omission or discontinuity in our estimate basis.

The AFC-CBR series has primarily represented costs to a per-unit cost for the fuel cycle function (e.g. cost of dry storage in $/MT UNF). Looking forward, the FCO Campaign expects to perform more transition analyses, and future editions of the AFC-CBR are expected to include more information on facility costs, including capital and both fixed and variable operating costs to improve modeling of facilities in cases of changing utilization factors due to evolving demand.

1.2 Related Program Interfaces and Related Key Evaluations

The NTRD Economic Analysis activity has developed a close working relationship with the Generation IV EMWG. For this report, we defined a consistent fuel cycle code of accounts (COA) structure, a cost basis development process, and a set of cost estimating terminology. The NTRD Economic Analysis activity has received feedback from the EMWG on key NTRD economic deliverables. Some reactor cost data has been received from the EMWG and from studies sponsored by the International Atomic Energy Agency (IAEA) to support total nuclear system cost calculations.

The FCO Campaign coordinates with the NTRD Advanced Fuels, Material Recovery and Waste Form Development, and Used Fuel Disposition Campaigns. The FCO Campaign supports technical

working group reviews and analysis, and identifies ways to reduce the costs and uncertainty of recycle processes. Through this involvement we gain access the latest design and cost data for input to the cost database and use in NTRD system studies.

1.3 NTRD Cost Basis

As stated previously, the NTRD Program has established the foundation for cost estimates with a greater level of confidence and completeness, and provided the framework for incremental process improvements. The NTRD Program has been collecting cost references and has expanded the fuel cycle cost data for over 12 years. The intended use of the cost data is relative economic comparison of options rather than for determination of total fuel cycle costs with great accuracy. As technology development progresses and detailed engineering designs are completed, cost estimate accuracy will be further improved. The cost report will be periodically updated to include the latest technology and design information and to support the improvement of processes and tools used to perform fuel cycle cost analysis.

The report is updated with cost data based on U.S. information as well as experience gained in developed and developing nuclear countries. The analysis may be extended to foreign applications as an evolution in the cost development activity.

1.4 Cost Module Description

Each type of fuel cycle facility or activity is referred to as a cost module. A cost module provides a specific fuel cycle function that is separate from but dependent on other fuel cycle activities (e.g., the enrichment module is influenced by the enrichment required by the fuel manufactured in the fuel fabrication module). The cost modules are assembled in various ways to create different fuel cycle scenarios, as illustrated in the NTRD Cost Flow Sheet in Figure 1-1.

The flow sheet includes 24 fuel cycle modules with interface lines that show the flow paths through the fuel cycle from the initial Module A, Mining and Milling, through various open and closed fuel cycle paths that terminate with Modules J, K, and L that provide the function of waste disposition. The interfaces between the functional Modules A through L (associated with facilities) are provided by the transportation process, Module O.

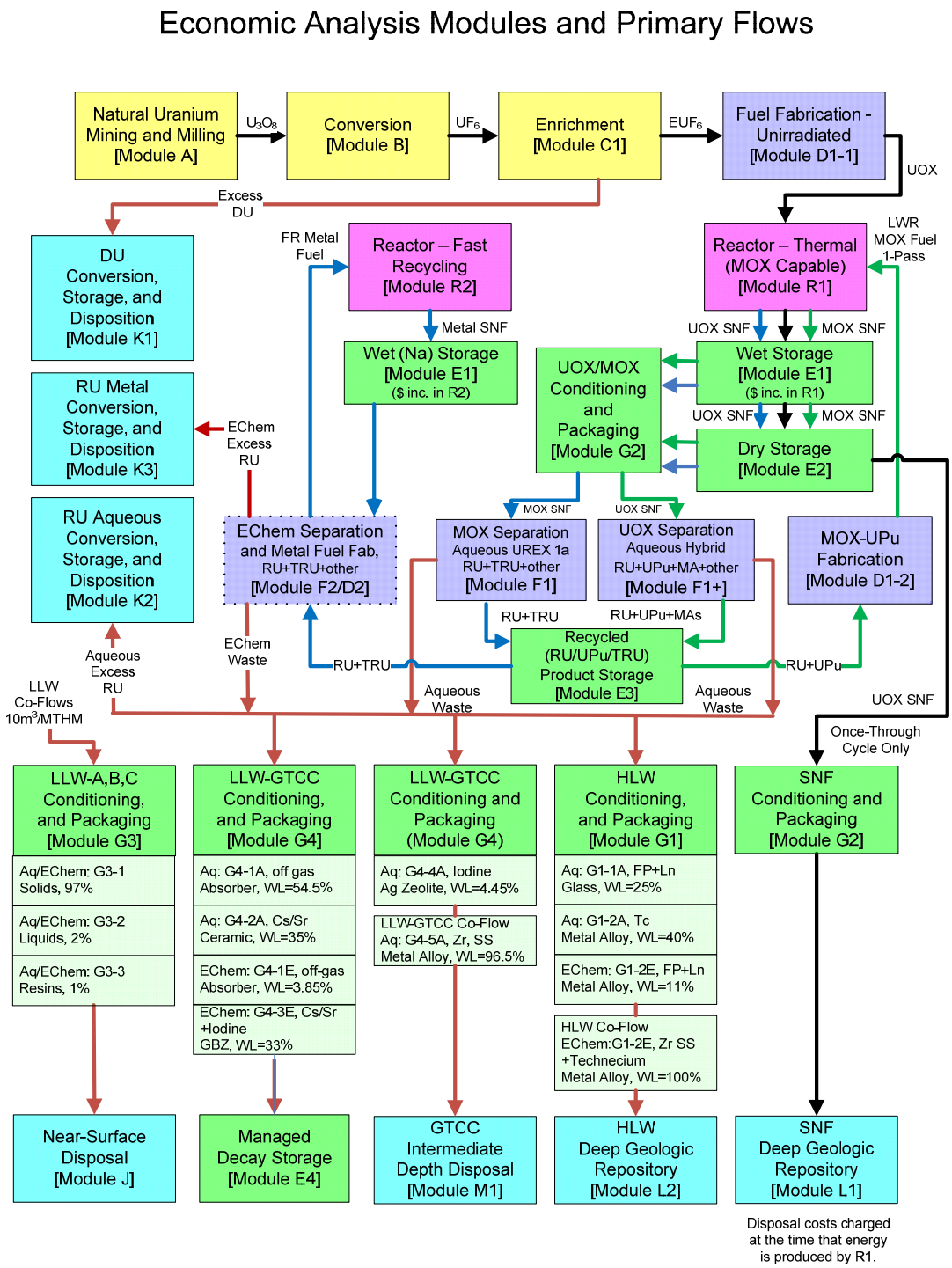

Figure 1-1. NTRD cost flow sheet.

1.5 Structure of the Report

A list of definitions that provide a common set of terminology for describing fuel cycle costing activities is included in the nomenclature section at the beginning of the report.

Section 1 (this section) of this report contains the background, program interfaces, description of the annual report cost activities, description of cost modules and diagram of possible fuel cycle paths.

Section 2 describes the cost development process used to develop the fuel cycle costs. The process includes data collection methodology, cost data normalization (including all code of accounts), verification, data gap analysis, and cost data documentation, and a description of the NTRD cost database. A common cost table that summarizes the module cost data, called the NTRD What-It-Takes (WIT), is described.

Section 3 describes the three basic methods for cost estimating: analogy, parametric, and engineering.

Section 4 describes the organization of the reference cost modules into front-end, back-end, and recycle groups. A general description of the thirty-plus cost modules is provided.

Section 5 provides a procedure for costing fuel cycle options using the unit cost data from the cost modules in this report.

Section 6 includes guidelines for comparing fuel cycle alternatives using qualitative and quantitative techniques.

Section 7 describes the use and integration of the cost data and price data into cost models.

Section 8 provides information on escalation and escalation rates

Section 9 discusses the topic of cost discount rates, including discounting over longer time periods. Recommended discount rates for analyses are included.

Section 10 describes the treatment of uncertainty in the AFC-CBR and discusses current efforts to reduce uncertainty in cost analyses through the development of partial cost correlation co-efficients.

Section 11 provides methodology for evaluation of systems where the use of modular facilities enables phased installation of capacity, including how to treat the phasing of revenue generation and the balance of facility costs.

Section 12 provides a summary of cost analysis tools available to the FCO campaign. These economic models make use of the unit cost data presented in this report.

Section 13 summarizes the conclusions and recommendations resulting from the development of the report.

Section 14 provides general (nonmodule specific) report references, including references for material in the main body of the report.

The 2017AFC-CBR file folder includes multiple separate files for over 2 dozen cost modules. Fuel cycle modules are labelled A through O, as listed in Section 3. Baseline cost information for different types of reactors/transmutation options are included under tab R. Each of the module sections contains cost documentation based on the module outline described in Section 2. The NTRD WIT table is used to summarize the module fuel cycle cost unit data in a consistent manner.

2. NTRD COST BASIS DEVELOPMENT PROCESS

The goal of the NTRD Cost Basis Development Process shown in Figure 2-1 is to establish a credible cost basis and to create a reference source for fuel cycle unit costs. Cost data will be evaluated on discrete fuel cycle activities, called cost modules, which represent the various front-end fuel cycle, back-end fuel cycle, waste disposition, and transportation functions. This task does not include the "bottoms up" development of cost estimates from a design basis. Instead, the cost basis for each module is derived from existing cost reference sources and studies.

2.1 Process Description

The NTRD cost basis development includes cost data collection, cost normalization, data verification, and gap analysis. Data gaps are recommended to DOE as the subjects for future engineering cost studies. For example, specific recommendations were made on additional cost study needs based on the review of the application of the AFC-CBR to the Nuclear Fuel Cycle Evaluation and Screening of FY 2012-2014 (FCRD 2014) and current fuel cycle transition studies.

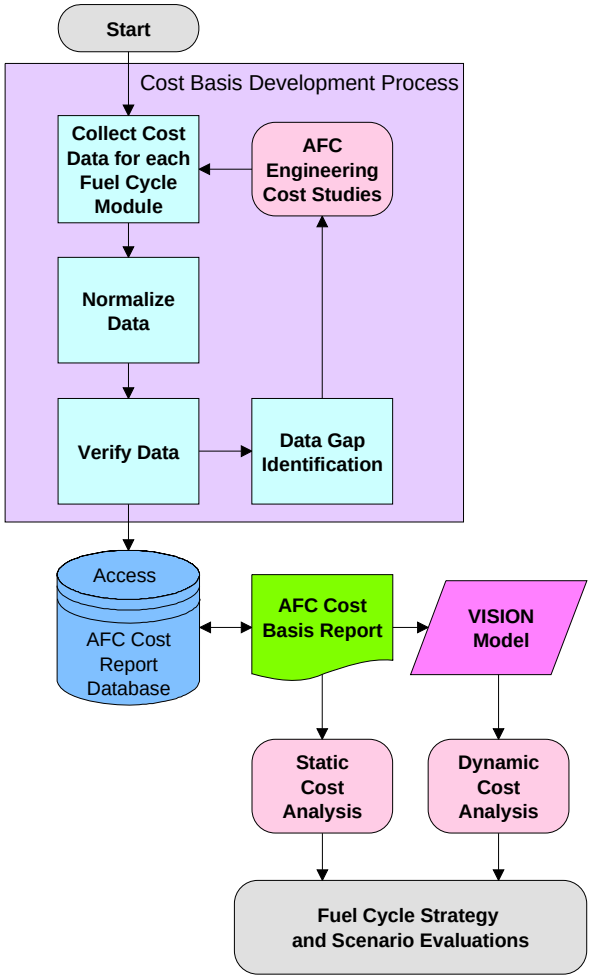

Figure 2-1. NTRD cost basis development process.

2.2 Fuel Cycle Data Collection

Data were collected for a total of 33 fuel cycle modules and submodules and 9 reactor/transmuter modules. The cost data were analyzed and evaluated on a common basis. The complete list of modules is included in Section 4.

The data collection methodology identifies the data sources and selection for use. The source of the cost information is identified, including data generated and maintained/updated by the NTRD program, and those taken from data gathering and modeling efforts of other organizations (e.g., OECD/International Atomic Energy Agency "Red Book" for uranium supply).

2.3 Cost Data Normalization

Fuel cycle cost data were normalized to establish uniform baseline costs and assumptions. The characteristic attributes of the cost data were identified for each module. The following sections describe the unique characteristics that are important to understanding the costs.

2.3.1 Government versus Private Facility Ownership

Ownership affects the methodology by which unit costs are calculated and also affects the categorization of costs. The treatment of risk, especially as it is represented in the assumed discount rate, is also different for government projects as opposed to private commercial projects. Some aspects of the fuel cycle, such as geologic disposal, are typically considered to occur in government facilities while others, such as enrichment, are typically considered to occur in private facilities. To provide both consistency and flexibility, the differences due to ownership are made explicit so that the fuel cycle module (e.g., separations facility) can be estimated for either type of ownership. The reference cost data for each module will identify the ownership basis of the cost estimate. Further discussion on the economics of private sector versus regulated nuclear fuel cycle facilities is included in Chandler and Shropshire's 2006 ICONE conference paper.

2.3.2 Technology Readiness Level (Program/Project R&D Status)

The technology readiness level often affects the detail level of the information needed for cost estimating and also the extent to which contingency must be applied to cover risk in project costs. For this cost basis, the technology readiness is categorized into three classes: Research & Development (R&D) — possible, Pilot — feasible, Commercial — viable. Subsequent to the development of the initial classification, a basis will be developed for relating technology readiness to contingency for purposes of developing cost estimates and associated confidence ranges. The EMWG has evaluated approaches for handling contingency in nuclear energy system cost estimation (EMWG 2007). Guidelines for contingency cost assessments were developed for various stages of a project.

2.3.3 Code of Accounts/Work Breakdown Structure

The COA and associated dictionary provide a means for consistently placing cost information in explicitly defined "bins" or categories that are common to most projects and their life cycles. Having uniformity in the definition of the COA allows useful comparison of process alternatives or competing technologies and provides some insight at the subsystem level. The work breakdown structure (WBS) that eventually evolves from the COA structure can be used for management of the project, such as in subcontracting work packages and tracking costs.

The front-end modules (i.e., natural uranium mining and milling, conversion, enrichment, and fuel fabrication) are typically commercial operations where COA and work breakdown structure cost information is typically not available due to sensitivity over the competitive nature of the information.

The life-cycle costs can basically be divided into costs that are recovered in the price of a product and those which are not. These (nonrecovered) costs may be paid by the government or through public/private

consortia. This would be consistent with what has been done for the Generation IV Reactor Systems program in their draft guidelines. The following level "0" account provides a structure for these costs. The cost categories in bold typeface are the "single digit" COA titles. The "two digit" accounts "roll up" by summing to the "one-digit" value.

0 – Early Life-Cycle Costs Not Normally Recovered in the Price of the Plant Product or Service Sold

0.1 – Planning Costs

0.2 – Research and Development Costs

0.3 – Prototype or Pilot Plant Costs

0.4 – Generic Licensing Costs

The recoverable life-cycle costs can be placed in a more familiar and structured COA typical of nuclear production facilities. The COA structure has been derived by modifying the COA proposed for Generation IV Reactor Systems, and also described in detail in that set of draft guidelines (EMWG 2007). "Capitalized" costs are those "up-front" (time wise) costs that must be financed, and for which costs are recovered in the price charged for facility product over the amortization life of the project. Annualized costs can be represented as the recurring cash sums needed to sustain a constant level of annual production exclusive of the "mortgage." The following summarizes the proposed COA for recoverable fuel cycle facility costs. If all cost data obtained can be placed in such appropriate "bins," useful comparisons of cost data and technological economic potential can be greatly enhanced.

1 – Capitalized Preconstruction Costs

11 – Land and Land Rights
12 – Site Permits
13 – Plant Licensing (including National Environmental Policy Act)
14 – Plant Permits
15 – Plant Studies (e.g., preliminary safety studies and hazards analysis)
16 – Plant Reports (formal documents)
17 – Other Preconstruction Costs
18 – Other Preconstruction Costs
19 – Contingency: Preconstruction Costs

2 – Capitalized Direct Costs

21 – Structures and Improvements
22 – Process Equipment
23 – Equipment
24 – Electrical Equipment
25 – Heat Addition/Rejection System
26 – Miscellaneous Equipment
27 – Special Materials (such as high unit cost nuclear materials)
28 – Simulator
29 – Contingency: Direct Costs

Total Directs = 1 + 2

3 – Capitalized Support Services

31 – Field Indirect Costs
32 – Construction Supervision
33 – Commissioning and Start-up Costs

34 – Demonstration Test Run Field Cost
35 – Design Services Offsite (offsite might be "home-office" of architectural engineer designer)
36 – PM/CM Services Offsite (Project manager/construction manager)
37 – Design Services Onsite
38 – PM/CM Services Onsite
39 – Contingency: Support Services

Base Construction Cost = 1 + 2 + 3

4 – Capitalized Operations (Mostly plant owner costs prior to commercial operation)

41 – Staff Recruitment and Training
42 – Staff Housing
43 – Staff Salary Related Costs
44 – Other Owner Capitalized Costs
49 – Contingency: Operations Costs

5 – Capitalized Supplementary Costs

51 – Shipping and Transportation Costs
52 – Spare Parts
53 – Taxes
54 – Insurance =
58 – Decommissioning Costs (if not covered by escrow fund)
59 – Contingency: Supplementary Costs

Total Overnight Cost (TOC) = 1 + 2 + 3 + 4 + 5

6 – Capitalized Financial Costs

61 – Escalation (not used for constant dollar analysis)
62 – Fees (noninterest fees paid to financial institutions)
63 – Interest during Construction (IDC)
69 – Contingency: Financial Costs

Total Capital Investment Cost (TCIC) = 1 + 2 + 3 + 4 + 5 + 6

7 – Annualized Operations and Maintenance (O&M) Cost

71 – Operations and Maintenance Staff
72 – Management Staff
73 – Salary Related Costs (benefits, Federal Insurance Contribution Act, etc.)
74 – Operations Chemicals (feedstock) and Lubricants.
75 – Spare Parts
76 – Utilities, Supplies, Miscellaneous Consumables
77 – Capital Plant Upgrades (not including financing costs)
78 – Taxes, Insurance, Regulation (Nuclear Regulatory Commission [NRC] inspections)
79 – Contingency: Annualized O&M Costs

9 – Annualized Financial Costs

91 – Escalation (not used for constant dollar analysis)
92 – Fees (noninterest financial costs during operations)
93 – Cost of Money (financing of large replacement capital items or upgrades: interest)
94 – Annual contribution to the D&D Escrow Fund
99 – Contingency: Annualized Financial Costs

Total Project Life-Cycle Cost = Nonrecovered costs (R&D, etc.) + TCIC + Yr of Plant Ops * (7 + 9)

The COA dictionary for estimating costs of fuel cycle facilities (EMWG 2007) provides additional explanations of the content for each of these cost elements. Throughout this cost structure, the government or private enterprise may fund some costs. The ownership definition must be explicitly defined for each module.

2.3.4 Common Currency (U.S.$)

The U.S. dollar is the most common monetary standard for nuclear facility cost estimating and is easily convertible into other currencies. Consideration should be given to the years in which the project costs were incurred (e.g., 1970 versus 2000). The equivalent monetary exchange rates applicable at that point in time may be significantly different than present day exchange rates. In some cases the base currency unit has also changed, for example the French franc is now converted to the European Monetary Union (Euro). Many Web-based calculators are available to perform the conversion calculations.[1]

2.3.5 Common Year (Current Year Basis)

A reference year for constant dollar costing and use of discount/escalation factors was chosen. The NTRD Program has chosen to use 2017 dollars for this latest report. Escalation factors are discussed in Section 8.

2.3.6 Differences in Cost Estimating Methodologies (Top Down vs. Bottom Up)

Both “top-down” and “bottom-up” methodologies can be used for cost estimating. The former is usually used for systems that are not well defined, but for which scaling data from other projects can be used. Bottom-up cost estimating is used for well-defined projects for which material balances, flow sheets, process floor layouts, and detailed drawings are available for “engineering take-off” type cost estimating. Cost estimating groups in Architect Engineer firms usually use the latter technique. There are also differing techniques for calculating cost estimating figures of merit such as unit cost of product and discounted life-cycle cost. The techniques used also depend on the level of cost estimating and project schedule data available. Reference cost information will be evaluated to determine which method was used to develop the costs.

2.4 Cost Data Verification

Cost data verification will consist of performing the following three assessments:

- Definition of data quality based on credibility measures
- Identification of cost estimate limitations and applicability (often technology driven)
- Evaluation of cost data sensitivity, technical cost discriminators (cost drivers), and uncertainty bounds.

The data quality will be defined and categorized based on credibility measures. The measures used to evaluate each data source are based on the degree of detail and rigor of the analysis, use of a consistent basis and approach, and whether data were independently reviewed. Each source will be categorized into one of the following five quality levels.

1. Independently-reviewed detailed assessments using a common basis and consistent approach

1. Web-based currency conversion calculator is available at http://www.x-rates.com/calculator.html; http://www.france-pub.com/currency.html provides a calculator to convert from older French currency bank notes franc(s) to other currency.

2. Detailed assessments using a common basis and consistent approach
3. Scoping assessments using a common basis and consistent approach
4. Engineering judgment of program specialists
5. Potentially biased or conflicting assessments collected from independent sources that do not use a common basis or consistent approach.

Cost estimate limitations and applicability will be determined for each data source/study. The data will be analyzed to determine on what restrictions and assumptions that the estimate was based, omissions from the estimate, unique circumstances, etc. An estimate of the range of applicability of the data will also be developed, indicating bounds in scaling or other parameters beyond which the estimate is not deemed credible.

The cost estimates will be analyzed to understand their sensitivity and uncertainty bounds within the range of applicability. If sufficient cost details are available, then sensitivity modeling may be performed with spreadsheets to determine the sensitivity of the estimates to different estimating assumptions. High sensitivity items that make a sufficient contribution to the overall module cost will be identified and assigned sufficiently wide uncertainty bounds to be a major contributor to the uncertainty of the full module cost estimate.

2.5 Data Gap Analysis

A set of criteria is used to determine when additional engineering cost trade-off studies are needed. The criteria highlight those cost areas with large data gaps, potential for high costs, restrictive assumptions, etc. Pareto analysis is used to identify the largest cost drivers, and to evaluate the limitations of the cost data (technology readiness, data quality). Emphasis is placed on improving the consistency of high sensitivity cost uncertainties within the range of applicability, as well as expanding the range of applicability as needed to fully support NTRD program objectives.

Through the previous analysis, data gaps were identified for aqueous reprocessing, electrochemical reprocessing, hot fuel fabrication, and waste conditioning. In FY 2008, we recognized gaps in understanding the uncertainties associated with fuel separation and waste conditioning processes and fuel cycle market competition. In FY 2009, additional analysis was performed to help fill gaps associated with (1) bottoms-up estimates for aqueous separation and electrochemical separation; and (2) understanding the current status on market competition in the international nuclear industry (NEA 2008). In FY 2012, several gaps were noted in preparation for the Fuel Cycle Evaluation and Screening (FCRD 2014). New sections were added to the main report addressing the use of price data, discounting, and the treatment of uncertainty and a number of additional reactor cost modules were added.

Ongoing cost analyses and methods development continue to identify data gaps that are addressed as they are identified and data is available. Current areas of development include better treatment of uncertainty, drivers for cost overruns in historic data, treatment of discounting over longer timeframes, and treatment of phased capacity additions based on modular facilities.

2.6 Cost Data Documentation

Each cost module is documented with specific information derived from the data collection, normalization, verification, and gap analysis activities. The report structure for this report includes some, or all, of the following data sections, as applicable, for each module.

1. Module (see Section 3 for listing of modules)

   1.1 Basic Information—includes the overall narrative descriptive information (e.g., the facility purpose, design requirements, history).

1.2 Functional & Operational Description—describes the primary functions and flows of the facility as well as provides a functional block diagram that describes the inflows/outflows.

1.3 Pictures and Diagrams—describes layout of the facility, includes pictures, schematics, etc.

1.4 Module Interfaces—describes interdependencies such as with site infrastructure services, dependencies on other modules (e.g., packaging and transportation), secondary waste flows.

1.5 Scaling Considerations—describes special attributes and/or associated scaling factors, including appropriate constraints. This section will also detail the manner in which to apply the associated modifying factors to adjust the cost estimate.

1.6 Cost Bases, Assumptions, and Data Sources—includes the specific bases for design estimates, data sources for key technical reports, and reviews performed by secondary parties.

1.7 Limitations of Cost Data—addresses the credibility and limitations of the cost data. Information may include reported and observed data gaps, estimate details (planning level vs. detailed), safety/environmental/regulatory conditions unique to country of origin, site-specific cost factors due to labor unions, and other limitations.

1.8 Cost Summaries—compiles the cost data that have been placed in the module sections. Data may be presented as graphical cost projections based on parametric scaling analysis of cost vs. capacity or other cost measures. The cost summary information is placed in a WIT table (see example Table 2-1) that shows reference cost bases and the cost analyst's judgment of the potential upsides (low end of cost range) and downsides (high end of the cost range) based on references and qualitative factors, the mean for the selected uncertainty distribution, and a most likely value (mode).

Table 2-1. Example of a WIT table.

What-It-Takes (WIT) Table					
Reference Cost(s) based on reference capacity (normalized costs in CY$ and U.S.$)	Reference cost contingency	Low Cost	High Cost	Mean	Mode
$100/MTHM based on capacity of 2,000 ton/yr	+/- 10%	$90/MTHM	$150/MTHM	$120/MTHM	$120/MTHM
(Further breakdowns and assessments of costs may be provided by code of account element or by listing those items that have the highest costs impacts)	(Based on the stated reference contingency percentage)	Rationale (Explanations such as technology improvements, improved economies of scale, changes in estimating assumptions that are more cost favorable)	Rationale (Explanations such as increased regulatory requirements, worst-case economic conditions, estimate limitations)	(Calculated based on the cost distribution)	Rationale (Cost analyst's overall assessment of the most likely cost based on current conditions)

1.9 Sensitivity and Uncertainty Analysis—describes the analysis performed and explains conclusions. The results of these analyses will be summarized in the cost module documentation, and references to more detailed uncertainty analysis reports will be provided.

1.10 References—lists the most relevant references that form the primary basis for the module costs.

1.11 Bibliography—(optional) Additional (more general) data sources applicable to the module.

3. Cost Estimating Methods

Cost estimating is the method used to populate the organizing structure discussed above. Three primary methods are used to estimate costs: analogy, parametric, and engineering. This section summarizes the salient points of each method. The EMWG's Generation IV cost estimating Gen IV Guidelines Document (EMWG 2007) is an excellent guide to estimating costs in nuclear systems. In it, the authors describe top-down and bottom-up estimating. In the language of this section, analogy and parametric methods are consistent with the guideline discussion of top-down estimating. The engineering method is a form of bottom-up estimating. While this section is not a "how-to" manual on cost estimating, it provides sufficient detail to guide the analyst on what must be considered in choosing an estimation method. The first question the analyst must answer in choosing an estimation method is, "What is the present level of development of the project or system under cost analysis?"

Figure 3-1 is from a text describing cost estimating and analysis in defense acquisition programs (Angelis 2015). As opposed to an "x-y" plot, the figure overlays the estimating methods onto phases of a program life-cycle. What would be an x-axis is phases of program development and a y-axis is not represented. It illustrates that where a program (or project, system, etc.) is in its life-cycle influences the estimating method, which then determines the type of cost estimates that will result. Early phases of development, such as concept definition/refinement and technology demonstration, will yield a gross level of cost estimating (where only high levels of projected cost rollup or aggregation available within the cost estimate) whereas analysis during development or production yields much more detailed estimates (many more detailed individual costs available that can be rolled up to higher level cost figures-of-merit). This variation is a function of data availability. At the planning/conceptual phase little data exists from which a cost analysis can be conducted, but when the system is under construction or operational much more cost data are available for the system.

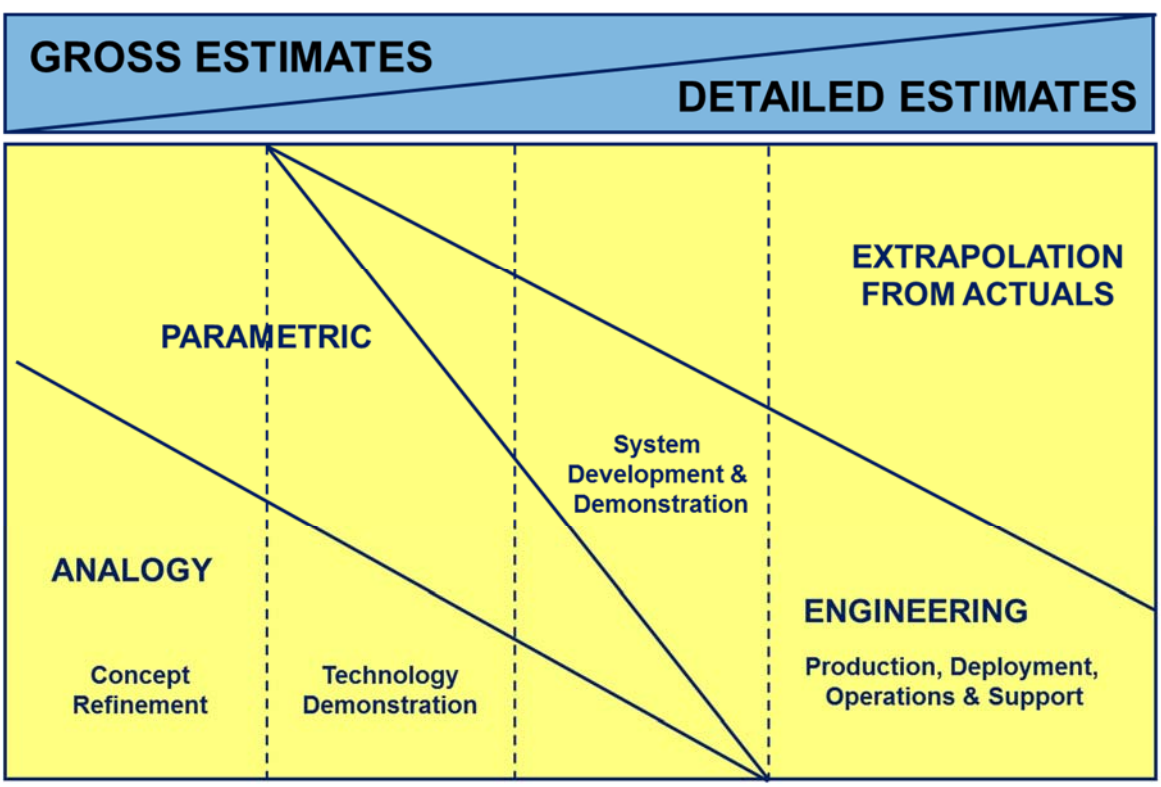

Figure 3-1 Cost Estimating Techniques as a Function of Acquisition Phases (Angelis 2015, p. 118)

Note in the descriptions that follow how projected "should" cost versus actually achieved "did" cost will be reflected. Because analogy and parametric estimating rely on data for similar systems the extrapolated and reference estimates will reflect a "did" cost. Estimates are extrapolated based on these "did" costs for similar systems. On the other hand, the engineering approach – although resource intensive – is a better approximation of "should" costs.

3.1.1 Analogy

"It's like one of these." That is the colloquial expression the International Society of Cost Estimating and Analysis (ISCEAA) uses to refer to the analogy method of cost estimating (Angelis 2015). The analogy method is one of comparison. The analyst chooses a project (or system, object, process, etc.) that is very similar to the "subject" project under evaluation. The analyst then selects the reference project to use as the basis for comparison, using it to compare against the new project. Subjectively, the analyst applies comparative techniques to build a cost estimate for the "subject" project. Data used in the comparison stem from cost and technical data on the reference project that the analyst adjusts for application to the "subject" project under evaluation.

Figure 3-1 shows how the analogy method squares with alternative costing methodologies. Analogy is the appropriate choice for estimating when the project is in a conceptual phase, or when technology is at the point of demonstration. This is the best choice when little is known and data is limited.

The analogy method has strengths and weaknesses. Angelis and Nussbaum (Angelis 2015) point out one of each. Cost estimates using this method are based on actual experience, making them strength of analogy estimates. But a weakness is that the analyst must find a very similar project for the reference comparison. The GAO similarly outlines pros and cons of analogy costing (GAO 2009). GAO lists pros of this approach as the ability to produce an estimate from limited data, and as in Angelis and Nussbaum, analogy is based on actual data. Analogy produces quick estimates of conceptual designs and leaves a good audit trail. As for weakness, the GAO identifies analyst bias as a possibility because adjustments from the reference to the actual are subjectively imposed. Regarding estimation accuracy, it all depends on the similarity of the reference project to the actual one being evaluated. Moreover, when using analogy it is difficult to assess the effects of design change; and the estimates are blind to actual cost drivers.

3.1.2 Parametric

"This pattern holds" is the expression the ISCEAA applies to parametric cost estimating (Angelis 2015). Parametric cost analysis uses cost estimating relationships and mathematical algorithm to establish cost estimates (Angelis 2015). Further summarizing from Angelis & Nussbaum, parametric estimating uses statistical analysis to generalize a relationships between system or project characteristics and cost. Typically using Ordinary Least Squares (OLS) regression analysis, the parametric method generates a mathematical equation where system performance or design characteristics become independent variables on the right hand side of an equation and cost is the depended, left hand side variable. It is a technique to explain the correlation between the independent and dependent variables. This method requires a database of elements from similar projects then OLS is applied to estimate coefficients measuring the relationship between the independent and dependent variables. In addition to coefficients, OLS and other statistical techniques, and information about uncertainty based on estimation error can be useful understanding the system under analysis.

Similar to analogy estimating, the parametric method can be applied at early phases of technology development when concepts and technology are under development. Whereas the analogy method uses a *single* system or project as the reference for comparison, the parametric method uses *multiple* similar projects or systems as references for comparison.

In terms of strengths and weaknesses Angelis & Nussbaum and GAO list each. A key advantage of the parametric approach is that once a cost estimating relationship has been established, applying it is

straightforward, easy to use, and useful in early technology development. The approach is objective and reproducible, moving it away from the subjectivity bias which is a weakness in analogy costing. Because the parametric approach can relate several independent variables to cost figure-of-merit, real world effects and cost drivers can be reflected in the cost estimate. As for weakness, model calibration is important because if data used to calibrate the model are widely dissimilar, e.g. the system under analysis is new to the point of not having close approximations, then the cost estimate can be inaccurate.

The following example illustrates an application of parametric estimating. In 2016 the FCO EWG conducted a type of parametric analysis using the COA. Presented with a reactor design outline in (Devanney 2015), the Group's task was to evaluate how this design compared on a cost basis with other reactor designs. Because little data exists on the proposed concept, the Group applied a parametric comparison based on data in (Devanney 2015).

(Ganda 2015a) summarizes previous economic analyses where a form of the COA structure had been applied. From it, descriptive statistics were computed regarding COA categories in each study. Table 3-1 shows the COA categories under "Aggregated Cost Component" then columns list the studies from which the percentages were computed. Separately the group used the COA structure to organize cost data in (Devanney 2015). The Group could then evaluate a new concept (ThorCon molten salt reactor) with historical LWR experience based on cost.

This type of cost estimating was also used by the European Union representative of the Generation IV Economic Modeling Working Group (EMWG) (Roelofs 2011) (Van Heek 2012) to estimate the specific capital costs of non-LWR Gen IV reactor types based on a 2-digit COA breakdown of reference LWR costs. In this case engineering analysis and scaling were used alter each LWR subsystem to one for a different type of reactor (based on physics and engineering constraints under new operating conditions) and then develop cost-size scaling relationships to determine the new COA 2-digit direct cost for each subsystems.

Parametric analysis has also been used to project life cycle costs for non-reactor fuel cycle steps. In 1984 a parametric cost evaluation methodology involving process science/engineering and coupled cost-scaling relationships was developed to assist DOE-NE in the down-selection of advanced uranium enrichment technologies. Detailed documentation of the methodology appears in (Williams 1984) and a shorter journal article describes it in (Williams 1989). It can be applied to any application where a process-economic model is available, and also has a description of how Monte Carlo uncertainty analysis can be used to calculate probabilities of meeting process performance and unit product cost goals.

Table 3-1 Direct Cost Component as a Percent of Total Direct Cost: Comparing studies summarized in Ganda et al. (2015) to ThorCon as described in Devanney et al (2015).

Aggregated Cost Componenet	NEA (1999)	TVA (2004)	EEDB (1987) Median Experience	EEDB (1987) Best Experience	Average	StDev	ThorCon
Structures and Improvements	29%	21%	25%	22%	24%	3%	18%
Reactor/boiler Equipment	36%	38%	32%	34%	35%	2%	26%
Turbine gen. equipment	18%	25%	23%	25%	23%	3%	27%
Electrical	11%	11%	10%	9%	10%	1%	12%
Cooling and miscellaneous	7%	5%	11%	11%	8%	2%	16%
Total Direct Costs as a % of Total Cost	63%	53%	17%	28%	40%	21%	34%

3.1.3 Engineering

The ISCEA expression for engineering based costing is, "It's made up of these" (Angelis 2015). This is also called bottom-up or industrial-level engineering analysis and is the most detailed of the three estimation techniques. Extra detail further means that it is the most expensive methodology to implement

because it requires that each element of the WBS have a detailed cost estimate associated with it, including granular detail on plans (schedule) and designs. Greater time and resources must be allocated for the engineering approach than the other two methods, and the services of professional cost estimators and cost engineers may be required. Further, the analyst must be well-acquainted with the system under analysis and the system itself must be well-defined. Angelis & Nussbaum note that computing systems can be developed where the purpose is to collect detailed information and facilitate the bottom-up approach, but these systems can be very expensive to develop and operate. Computer software such as "Primavera" management systems are often used to integrate cost and schedule for hundreds of individual WBSs. Such systems require trained experts in their use, but are excellent for managing very large construction projects.

As in the other estimating methods, the engineering approach has strengths and weakness that Angelis & Nussbaum and GAO discuss. A key strength is that of the three methods, this produces more accurate estimates because of the level of detail involved. The level of detail involved lends this method to being most sensitive to economic conditions such as labor rates. It is straightforward to audit the assumptions and analysis used. Because of estimation accuracy, this is a time-honored approach. But the great level of estimation accuracy is expensive. Producing such an estimate is time and labor intensive which makes it the most expensive of the three methods. Another weakness is that detailed information about the systems may not be readily available, especially at early stages of development.

3.2 Cost Indices

Data requirements in cost estimating, particularly methods based on comparisons, necessitate some type of data normalization. Data used in cost estimating models are recorded in ways that may not be consistent with the assumptions underlying the cost model. This is particularly true in cost estimating for nuclear systems where available data may come from an array of countries across many years. Predicting future costs with historical data requires data to be relevant and matches the assumption of the cost model (Angelis 2015). As Angelis & Nussbaum write (p. 133), "Data normalization is the process of making data recorded under different circumstances comparable."

Cost indices provide the analyst a means to normalize data. For example if a cost estimating relationship predicts a certain amount of labor for a nuclear system, based on observed costs for a similar system in Korea, then the analyst must normalize data in two dimensions – labor rates and exchange rates.

The EMWG's Gen IV Guidelines Document (EMWG 2007) has (in Appendix G) an extensive list of indices for cost analysis. Although somewhat dated now, (the document was published in 2007), the appendix records exchange rates for countries that may have cost data on nuclear systems. It outlines labor rates for classes of skill that would be used in nuclear projects. A commodities price list documents what prices should be expected for inputs into nuclear projects. Escalation rates are provided based on COA categories, reflecting the fact that escalation does not necessarily occur at the same rate across all sectors of nuclear projects. Then a detailed record of commodities used in existing nuclear systems is provided. The Gen IV Guidelines appendix is a good representation of the types of indices that should be kept current for use in ongoing cost analysis of nuclear projects.

4. FUEL CYCLE REFERENCE COST MODULES

The fuel cycle has been broken down into functional elements called cost modules as described in Section 1.5. This section provides a general description and categorization of these cost modules—details on each of the modules are provided in the tabbed sections in Attachment 1. Table 4-1 summarizes information on the 36[2] fuel cycle cost modules. The following paragraphs describe some discriminating characteristics of these modules that impact the type (and quantity) of cost data available for this report.

1. The front-end fuel cycle modules (A1-2, B, C1, and K1) are generally related to commodity types of services provided by commercial sources. The costs for these types of operations are often market driven and may be obtained from many sources both domestically and internationally. These modules will not be detailed with facility COA breakdown information, but are based on market related unit costs (e.g., U.S.$/kg UF_6). Module C2, which deals with light water reactor (LWR) fuel derived from the blend-down of highly enriched uranium from military sources, was added because such blended material (under arrangements with Russia) was until very recently providing a significant portion of U.S. LWR fuel. UF_6 received from blend-down operations substitutes for fuel cycle operations in Modules A1-2, B, C1, and K1. Module D1, Fuel Fabrication-Unirradiated, is available from a limited number of sources and very little cost data are available at a facility level.
2. Reactor/transmutation baseline cost data are provided in Modules R1 through R9-2 (including numerous types of critical reactors, externally driven systems, and fission-fusion hybrids). The SNF wet and dry storage (Modules E1 and E2) is generally located at reactor sites and have been dropped as separate modules. Wet storage costs (E1) are generally assumed to be a portion of the reactor capital and operations costs and are not typically added on top of reactor costs. The storage costs are based on commercial cost data associated with the reactor construction and operation. Incremental dry storage pads may be added at a reactor site to support extended fuel storage requirements. The reactor operator may have added dry storage pads sometime after reactor construction. Some cost data is available on these storage pads, and may inform the costs of a larger, centralized dry storage facility (Module I).
3. The back-end fuel cycle modules (I and L) are the responsibility of the government as provided by the Nuclear Waste Policy Act. The government funds these functions and the services would be provided by government contractors.[3] Only a limited number of these types of facilities would be built due to their high cost and political sensitivity.
4. The recycle modules (F1, F2/D2, E3, E4, K2, K3, G1-5, J, and M) are associated with fuel reprocessing and may be provided by some combination of government and private sources. Cost data are generally derived from international and domestic sources with various ownership arrangements. Wastes designated for low-level waste (LLW) disposal in Module J may be associated with LLW from reprocessing, or from fuel cycle and reactor facility maintenance and operations. The disposal of U wastes is covered in Modules K1, K2, and K3.
5. The transportation modules (O1 and O2) support the costs for transport of new fuel, recycled fuel, and shipment of SNF, HLW, and LLW. Transportation of raw fuel to the reactor is a commercial cost to the reactor owner/utility. SNF transportation from the reactor to interim storage and the repository is the responsibility of the government. HLW and LLW transportation resulting from recycling could be provided by some combination of government and private sources.

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2. Of the 39 modules, some have been combined or deleted netting 36 currently used modules.

3. Long-term retrievable storage could potentially be funded through a private venture (e.g., Skull Valley, Utah).

Table 4-1. Fuel cycle cost module general descriptions.

Cost Module	Module Name	General Description
A1	Natural Uranium Mining and Milling	Includes the factors involved in extraction of uranium from the earth through production of uranium concentrate in the form of U_3O_8, commonly known as "yellow cake."
A2	Natural Thorium Mining and Milling	Includes the factors involved in extraction of thorium from the earth through production of thorium concentrate in one of three forms in which it is stored: oxide, oxalate, and nitrate.
B	Conversion	Takes the mined U_3O_8 concentrate, further purifies it, and converts it to a UF_6 solid in cylinders for feed to a uranium enrichment plant.
C1	Enrichment (Isotopic Separation)	Uses the UF_6 solid in cylinders to enrich the % of U-235 from 0.711 mass% to the 3–5% typical of the enrichment used for LWR fuel fabrication, or higher for typical VHTR fuels.
C2	Highly Enriched Uranium Blend-Down	U.S. and Russian government-owned highly enriched uranium (blended down as a secondary supply to meet demand for low-enriched uranium.
D1 (D1-1 through D1-9 submodules)	Fabrication of Contact–Handled Fuels	Uses chemical, ceramic/metallurgical, and mechanical steps to take nuclear materials (U, Th & Pu chemical forms) and convert them to finished fuel assemblies.
D2	Fuel Fabrication of Remote-handled (Metal) Fuels and Targets	This module has been combined with Module F2 to create Module F2/D2.
E1 (no longer used)	Wet Storage of SNF	Pool storage (at reactor) of SNF from existing commercial reactor operations. No longer used as costs are included in reactor costs.
E2 (no longer used)	Dry Storage of SNF	Dry storage (at reactor) of SNF coming from reactor wet storage; includes handling costs involved with transfer from wet to dry storage. No longer used as costs are included in reactor costs.
E3	Storage of Combined Recycled Product of Mixed Plutonium, Minor Actinides, and Uranium Product	Storage of the actinide by-products produced from the reprocessing of thermal reactor and fast reactor fuels. Would typically be required to support fissile blending needs.
E4	Managed Decay Storage (of certain fission products)	Storage of immobilized, heat generating, mixed cesium-strontium waste arising from advanced fuel cycles.
F1	SNF Aqueous Reprocessing Facility	Separation of SNF elemental components using aqueous process to support recycling of fissile materials. Includes cost of receipt of SNF through end-product production.
F2	Reprocessing—Electrochemical	This module has been combined with Module D2 to create Module F2/D2.
F2/D2	Electrochemical Reprocessing and Remote Fuel Fabrication	Separation of SNF elemental components using an electrochemical process to support recycling of fissile materials. Includes cost of receipt of SNF through end-product production. Uses chemical, ceramic/metallurgical, and mechanical steps to convert fissile material from the back-end fuel cycle to finished fuel assemblies.

Cost Module	Module Name	General Description
G1	HLW Conditioning, Storage, and Packaging	Stabilizes the waste, provides interim storage of the treated waste, and packages the HLW in preparation for transport to a HLW repository.
G2	SNF Conditioning, Storage, and Packaging	Removes the fuel from wet or dry storage, performs inspection as required, dry, package, seal, leak-check, and prepare the SNF package for shipping to a HLW repository or to an off reactor site storage pool.
G3	LLW Conditioning, Storage, and Packaging	Conditions and packages miscellaneous LLW for disposal in a NRC-licensed near surface landfill.
G4	GTCC Conditioning, Storage, and Packaging	Conditions and packages GTCC LLW for long-term storage for qualification for near surface disposal or direct to GTCC disposal.
G5	TRU Conditioning, Storage, and Packaging	Conditions the waste, certification, interim storage, and packaging of transuranic wastes in preparation for transport to an acceptable TRU disposal facility/repository.
H (no longer used)	SNF Packaging for Transport and Disposal	[Cost data transferred entirely to Module O1]
I	Long-Term Monitored Retrievable Storage	Long-term storage of SNF/HLW until shipped to a geologic repository.
J	Near Surface Disposal	Engineered or trench disposal of LLW, including waste and fill placement and monitoring.
K1	Depleted Uranium Conversion and Disposition	Conversion of DUF_6 and disposal of the resulting stable DU form. In some scenarios, this material is later withdrawn to use in breeder fast reactors.
K2	Reprocessed Uranium Disposition-Aqueous	Conversion, storage, and disposal of burned uranium resulting from aqueous reprocessing such as PUREX or UREX (LWR spent fuels)
K3	Reprocessed Uranium Disposition-Electrochemical	Conversion, storage, and disposal and purification of burned uranium resulting from electrochemical reprocessing of LWR spent fuels. Uranium-metal will contain multiple contaminants, including transuranics and some fission products.
L1	Geologic Disposal of SNF and HLW	Cost from inception through closure for geologic repository operations.
L2	Disposal of GTCC LLW	Includes options for GTCC disposal.
M (no longer used)	Alternative Disposal Concepts	Speculative costs for SNF/HLW disposal alternatives to a deep geologic repository, such as deep bore hole, and others. Deep bore hole costs are now included in L1 while other more speculative options such as deep ocean trench have been dropped.
N (no longer used)	Nuclear Fuel Transportation (Contact and remote handled)	[Cost data transferred to Module O1 and O2]

Cost Module	Module Name	General Description
O1	Transportation of Radioactive Materials	Transportation cost of recycled irradiated fuel and SNF/HLW per relative unit includes handling costs not already included in interim storage costs. Includes cost of required operations to condition and package the SNF for shipment to the repository, interim storage, or to a reprocessing facility.
O2	Transport of Nuclear Fuel and Low-Level Radioactive Materials	Transportation cost for new fuel, unirradiated materials, and LLW per relative unit, includes handling costs not already included in interim storage costs.
R1	Thermal Reactors (LWRs)	Capital, operations and maintenance, and D&D costs for generic thermal reactors in the U.S.
R2	Fast Reactors	Capital, operations and maintenance, and D&D costs for fast reactors in the U.S.
R3	Gas Cooled Reactors	Capital, operations and maintenance, and D&D costs for generic gas-cooled reactors in the U.S.
R4	Small-Medium Reactors	Capital, operations and maintenance, and D&D costs for generic small-medium reactors in the U.S. (Module dropped since SMRs fit other R categories.)
R5	Pressurized Heavy Water Reactors	Capital, operations and maintenance, and D&D costs for generic heavy water reactors in the U.S.
R6	Accelerator-Driven Systems	Capital, operations and maintenance, and D&D costs for generic accelerator-driven subcritical systems in the U.S.
R7	Liquid-Fueled Salt-Cooled Reactors	Capital, operations and maintenance, and D&D costs for generic liquid-fueled salt-cooled reactors in the U.S.
R8	Solid-Fueled Salt-Cooled Reactors	Capital, operations and maintenance, and D&D costs for generic solid-fueled salt-cooled reactors in the U.S.
R9 (R9-1 and R9-2)	Fission/Fusion Hybrid Systems	Capital, operations and maintenance, and D&D costs for generic fission-fusion hybrids in the U.S. Includes both magnetic confinement and initial confinement designs for the fusion reactor.

Additional cost modules have been defined to distinguish cost differences between modules with different technologies, radioactive environments, and regulatory requirements. Over the past three releases of this report, the following modules have been split to accommodate these differences and provide additional cost distinction:

- Module A, Mining and Milling was divided into a sub-module for uranium (Module A1) and a sub-module for thorium (Module A2).
- Module C, Enrichment, was divided into traditional enrichment (Module C1) produced by gaseous diffusion or centrifuge and highly enriched uranium blend down (Module C2).
- Module D1, Fabrication of Contact-Handled Fuel, includes unirradiated fuel. Fabrication of recycled (remote-handled) fuel is discussed in Module F2/D2. There are ten types of fuel that were evaluated for this report. Fuel fabrication submodules were developed to support both different fabrication technologies and fuel applications (i.e., fuels for fast reactors, heavy water reactors, and gas-cooled reactors).
- Module D2, Fuel Fabrication of Remote-handled Fuel/Targets, was combined with Module F2.
- Module E, Interim SNF Storage, was divided into costs for at reactor storage (Module E1 and Module E2), both of which were subsequently dropped as their costs are typically included in reactors costs, a special module (Module E3) for recycled product storage of actinide products produced from the reprocessing of thermal reactor and fast reactor fuels, and E4 was added for managed decay storage.

Cost Module	Module Name	General Description

- Module F, Reprocessing, was divided into modules for aqueous reprocessing (Module F1) and electrochemical reprocessing (Module F2). Module F2 has been combined with Module D2 to create a new Module F2/D2. Modules F2 and D2 were combined into this module because they are considered to be one integrated facility, making it difficult to separate the costs.
- Module G, Waste Conditioning, was divided into modules for HLW conditioning, storage, and packaging; SNF packaging (G2); LLW conditioning (G3); Greater-than-Class-C (GTCC)-LLW conditioning (G4); and transuranic waste conditioning (G5).
- Module K, Uranium Conversion, Storage, and Disposition, was further divided into depleted uranium derived from enrichment (K1) and burned uranium (BU) resulting from reprocessing. The burned uranium was further designed based on the type of reprocessing, where BU from aqueous reprocessing (K2) was evaluated separate from BU from electrochemical processing (K3).
- Module O, Transportation, costs were segregated primarily on the type of transport package. Transportation of low radioactive materials in O1 uses a Type-A package to support unirradiated fuel, LLW, and contact handled transuranic wastes. Transportation in Type-B package materials (O2) supports SNF/HLW and remote-handled transuranic wastes.
- Module R, Reactors, costs were developed for gas-cooled reactors (R3), SMRs (R4), heavy water reactors (R5), Accelerator-driven systems (R6), liquid-fueled and solid-fueled salt-cooled reactors (R7 and R8) and two types of fission/fusion hybrid systems (R9-1 and R9-2).

The cost modules were developed using a consistent structure to provide consistency in data collection, normalization, verification, and documentation. However, the content for each of the modules may vary due to characteristics described above and the availability of the data in the public domain. Attachment 1 contains sections for each of the currently used AFC cost modules listed in Table 4-1.

5. STRATEGY COSTING PROCEDURE

The goal of the NTRD strategy costing procedure, shown in Figure 5-1, is to use the data from the NTRD cost database to support NTRD economic analyses of fuel cycle strategies (Shropshire 2009).

5.1 Process Description

The NTRD strategy costing procedure includes defining the scenario and key parameters, selectively linking and scaling the cost modules, and selecting data from the NTRD Cost Basis to develop complete fuel cycle costs. The fuel cycle costs may be combined with selected reference reactor cost data (Module R or other data sources) to develop total nuclear system costs (or converted into TCOE). The fuel cycle/total nuclear system costs can additionally consider facility ownership options (e.g., regulated, private-sector, government owned, or government/private). The fuel cycle costs and total nuclear system costs can be used to support quantitative cost analysis for fuel cycle and scenario analysis. These processes may be performed manually or through the assistance of a computer model.

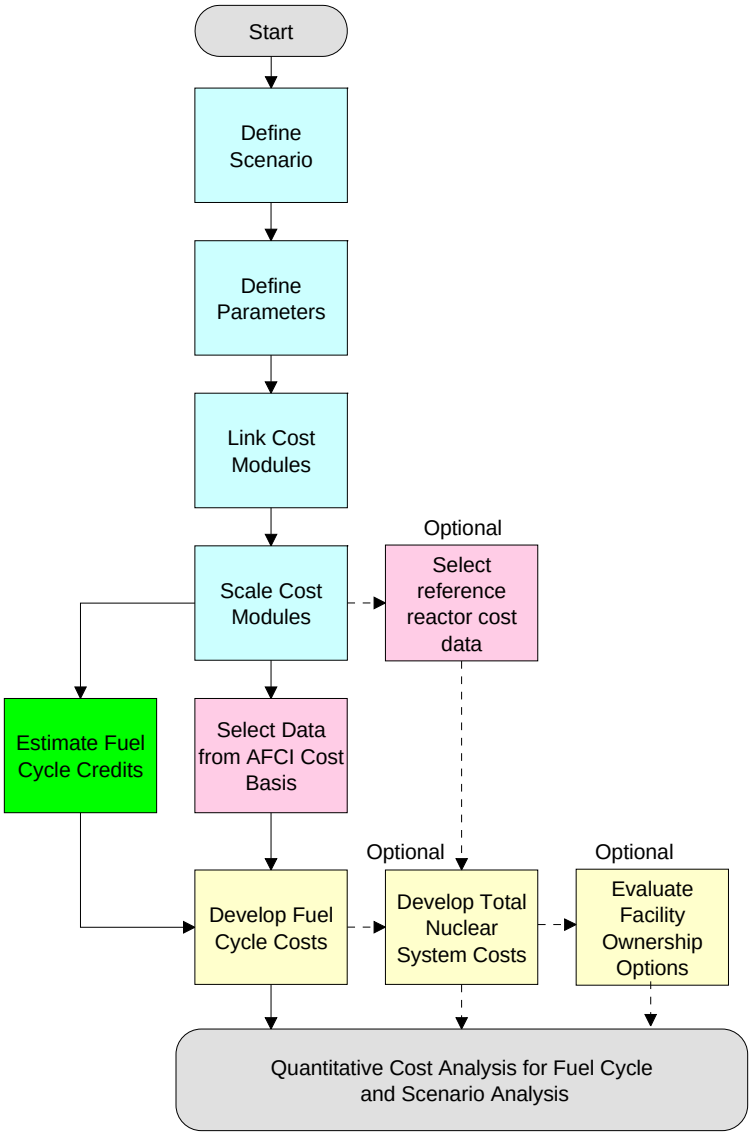

Figure 5-1. NTRD strategy costing procedure.

5.2 Define Scenarios

General strategies (once-through, thermal recycle, thermal/fast recycle, etc.) lead to scenarios that include various options for transmutation, separation, and HLW disposition. An example would be the selection of a once-through fuel cycle with ceramic UO_2 fuel, in an existing light water reactor, with separation of U, Pu/Np/Am/Cm/Sr/Cs, where Tc/I/residuals go to geologic disposal. The selection of a scenario is needed to identify the applicable cost modules. The front-end modules (mining and milling, conversion, enrichment, and fabrication) for most once-through options may be the same. However, the specific parameters may differ depending on the objectives of the scenario (e.g., analysis of high burn-up fuels, percent loading, and enrichment).

Scenarios can focus on a specific part of the fuel cycle, such as used fuel recycling options. Potential scenarios include: fuel cycles to optimize repository space, various reprocessing deployment schedules, selective/total retrieval of fuel for recycle, use of long-term storage, or combinations of these options.

5.3 Define Parameters

After a scenario is developed, additional module parameters are chosen; for example: facility start-up dates, enrichment percent, mass flow rates, storage durations, HLW packaging details, transportation distances, private/government financing arrangements, etc. Integrated functional flow models (mass balance simulations, etc.) may be used to assist in the identification of some parameters and to ensure consistency. The definition of the parameters allows the user to select the most appropriate module data to fit the scenario. The available parameter choices will differ for each module, so the user will need to refer to the specific module section in this report. The nomenclature section at the beginning of this report provides standard definitions for cost estimating terms and parameters that are commonly used in economic analysis.

5.4 Cost Module Coupling

Modules are chosen by linking the front-end modules and the back-end modules to a reactor. Additionally, transportation modules are selected to provide the linkage between the fuel cycle facility modules. There are numerous options for combining the modules to build an integrated fuel cycle system. Figure 5-2 shows a simple example of linked cost modules for a once-through fuel cycle scenario. Further refinement of the module parameters may be necessary based on the specific module interface requirements. The interface requirements are provided for each module in this report. More complex fuel cycle systems may also be developed that include recycle modules. In the case of recycled materials, particular attention must be paid to the recycle material flows to ensure that the facility capacities are sized to adequately support the new and recycled flows. In these cases, a computer model may be required to calculate and evaluate the dynamic flows between the modules (refer to Section 11).

5.5 Cost Module Scaling

Modules may have cost data that can be scaled to a range of capacities. The user may adjust the size/throughput rate of the reference modules, and then determine the associated scaling of costs versus size for their scenario using parametric methods. Data on module scaling are provided (as available) in Section 5 of each of the modules in the cost basis report. The user is advised that scaling is limited to a range of applicability around the reference module capacity; extension of the scaling beyond these bounds may be invalid and is not advised. Because of the large uncertainties involved in scaling costs, this task can become highly detailed and complex.

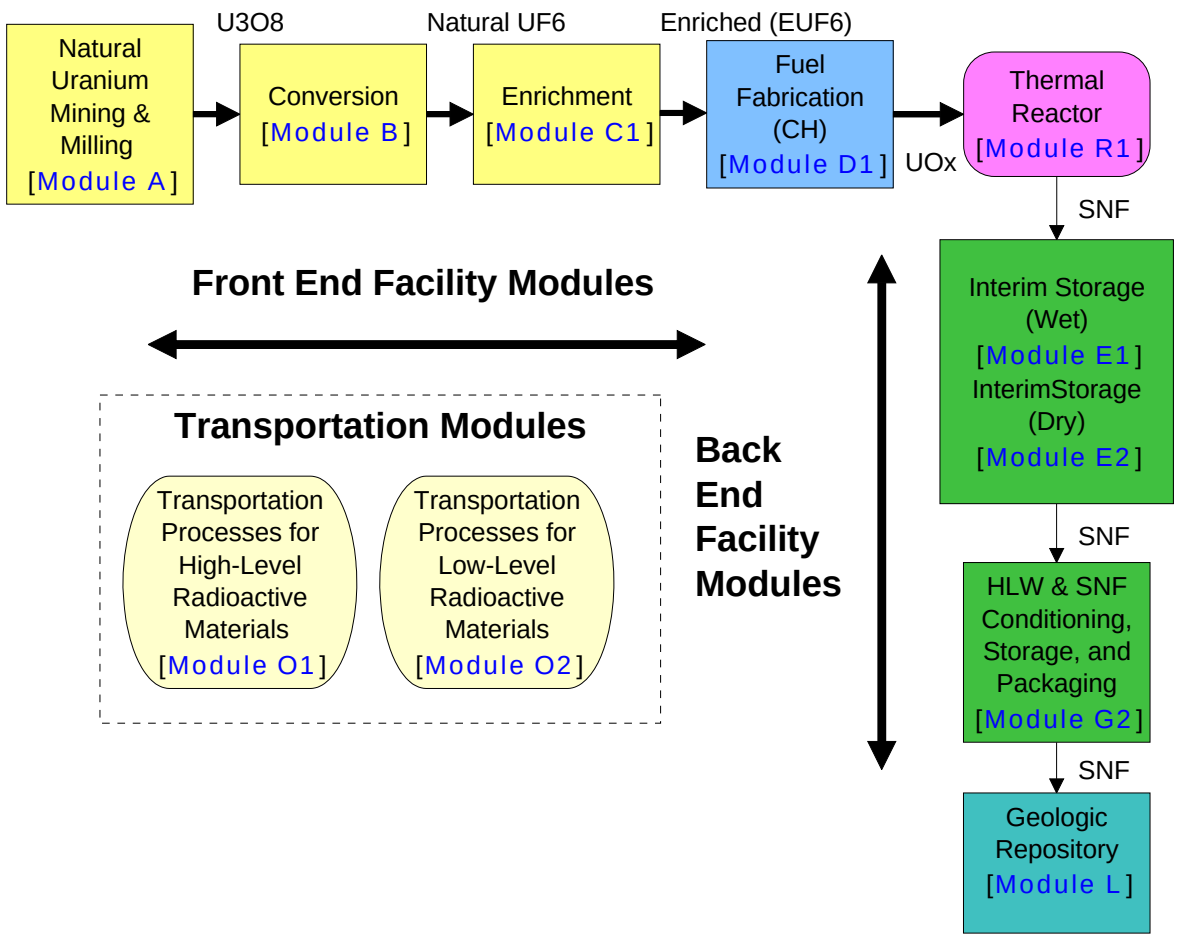

Figure 5-2. Example of linked cost modules.

5.6 Handling of Credits for U, Pu, and Other Materials

In some recycle scenarios, recovered fuel may be sent back to a reactor for reuse. There may be an implied value for this fuel that can be counted as a credit in the fuel cycle cost calculations. This value may be accounted for simply by requiring less new fuel during refueling. In other cases, the materials may take on a commodity value, based on the equivalent cost of the fuels that they are replacing. The user is referred to the applicable front-end cost modules to determine the value of recycled materials.

5.7 Develop Total Fuel Cycle Costs

After the scenario has been defined, applicable modules selected and scaled, and modules linked then a total fuel cycle cost may be derived. The cost estimate is composed of a compilation of cost data that have been normalized, scaled for mass flows, extended based on quantities of production and years of operation.

5.8 Develop Total Cost of Electricity Costs

The total cost of electricity (TCOE) can be developed for a fuel cycle scenario by adding the total fuel cycle contribution or component (in $/MWh) to the other cost components (reactor capital, reactor operating and maintenance, reactor D&D). Baseline cost data for different reactor types is necessary to support development of TCOE. The baseline cost data for current generation light water reactors and fast reactors are provided in Modules R1 and R2. The reader may also seek additional reactor cost data

sources (e.g., EMWG). These data are provided for estimate completeness and to account for the interdependencies between the reactor technology and the fuel cycle. The user is advised to use a range of reactor costs to evaluate the sensitivity of the total TCOE to the reactor/fuel cycle concept.

5.9 Economics of Private Sector vs. Regulated Nuclear Fuel Cycle Facilities

With the expected high costs and significant risks involved in constructing new nuclear facilities, including nuclear reactors and fuel recycle facilities (i.e., reprocessing, refabrication, and HLW form), consideration should be given to the economics of various facility ownership options. These options include government funding, regulated funding, private funding, and combinations of public and private funding options. These different funding approaches may significantly impact the costs of fuel cycle services. As part of the overall quantitative analysis of the fuel cycle, the assessment of the economics based on the ownership of the fuel cycle facilities was conducted. A sensitivity analysis of the fuel cycle facility ownership options was also prepared, evaluating a range of options from fully government owned to fully private owned were evaluated using DPL (Decision Programming Language 6.0), which can systematically optimize outcomes based on user-defined criteria (e.g., lowest life-cycle cost, lowest unit cost). The analysis was presented at ICONE14 in December 2006 in Miami, Florida (Chandler and Shropshire 2005). The topic of risks and associated discount rates for private sector versus government investments is discussed in Section 9. While focused on a different topic, Section 9 provides information that can be used to model differences between vendor costs and utility costs where the utility may be operating in either a regulated or deregulated market.

6. ECONOMIC COMPARSION GUIDELINES

This section provides guidelines for comparing alternatives on a consistent basis. There are two approaches, qualitative analysis and quantitative analysis. Qualitative analysis has been used in analyses such as the DOE AFCI Comparison Report (US DOE 2006). Quantitative analysis will be used in the broad system studies to evaluate system scenarios to identify economic drivers and refine scenario evaluations. Because of the large uncertainties in the designs and costs for many of the fuel cycle cost elements, the qualitative method is being used to provide economic analysis data external to the DOE. Quantitative analysis is the primary application internal to the NTRD Program for system assessment.

Qualitative analysis is used when system cost information is unavailable (no current or relevant cost basis, or uncertainties so large that differences derived from system comparisons are unsupportable). The evaluations use factual system data with economic consequences. The cost comparisons consider sources of additional costs and potential areas for cost savings as compared to the current demonstrated technology (e.g., reduced uranium consumption, fewer waste packages required, reduced transportation, increased amount of waste to be dispositioned).

For example, the economics of separation has implications in many areas across the fuel cycle; however, we can expect that separation costs will be driven by the type of spent fuel, number of recycles, type of operation, separation process and facility requirements, recycled elements, and in-process waste storage. Each of these qualitative parameters is evaluated in order to derive a relative comparison for the separation economics across the various systems. As design information becomes available, the qualitative comparisons will be replaced with actual cost estimates and their associated assumptions.

Quantitative analysis numerically evaluates and compares various fuel cycle systems. The fuel cycle cost data contain a high degree of uncertainty. Understanding the range of cost uncertainty associated with each of the concepts is important for determining if a significant cost difference exists between systems. When the process described in this report is used, the data can be used to understand the relative cost differences between systems. There are two types of quantitative analysis that can be performed, which are described as follows:

- Scenario optimization—hold most factors (modules) constant while varying the parameters of a limited number of interrelated modules to determine the most cost-effective technology combination for a particular fuel cycle strategy.
- Strategy/scenario comparison—compare two different integrated concepts for purposes of determining an economic “score” as part of metric application for program down-selects.

7. USE OF PRICE DATA IN NTRD COST-BASIS ESTIMATES

7.1 Introduction and Scope

The AFC-CBR series seeks to provide a comprehensive, consistent, and well-documented set of cost estimates and supporting data to facilitate comparison of economic performance for future nuclear fuel cycles. The estimates for fuel cycle modules are based largely on the technical features of the modules and the interface requirements between them. These estimates result in cost curves that characterize the costs of each technology at the scales at which it would typically be implemented. In general, the effects of the *market setting* in which technologies would be introduced are not explicitly accounted for. This section begins to address one important element of that market setting – the use of price data as an input to or in lieu of engineering cost estimates. Future versions of or addenda to the AFC-CBR will further explore the implications of market setting considerations for specific modules.

7.2 Costs and Prices Defined

Cost and price are two distinct concepts, both central to economic theory and applied economics. A *cost* is a measure of valuation for a good or service, based on the set of resources used (denied to other uses) in the *production* of that good or service. A *price* is a measure of valuation based solely on the property that a transaction or set of transactions was conducted at that price between a willing buyer(s) and seller(s).[4] In general, *producers* incur costs, *buyers* pay prices.

Thus costs are functions of technology (production functions) and input prices, and are reflected in unit cost and supply curves. Prices are function of (individual or average) *supply and demand* and their (often complex) interactions in markets. They tend to be more volatile than costs of production, which display a degree of inertia related to investment in production technology.

A supply curve illustrates one of the important relationships between production costs and market prices. Figure 7-1 (reproduced with permission from (Rothwell 2009) shows a global market supply curve for Separative Work Units (SWU) the production unit for uranium enrichment plants. Each of the horizontal segments of this curve is derived from a cost estimate for a specific productive element (plant or plants) for a specific producer, and represents the long-run marginal cost of production over that quantity interval. The market price resulting from this supply curve will be the production cost for the "marginal supplier" – that supplier required to produce the last unit of production. The resulting market price (of about $160/Kg-SWU) is above most of the producers' average costs, and far above the prospective long-run marginal cost of a new centrifuge plant.

While conceptually distinct, cost and price can be numerically equal under certain conditions[5]. In the long run (and under certain other conditions) prices can exceed costs. Cost of production to a firm cannot indefinitely exceed product price in a free-enterprise context, but certainly can in a mixed government/private context such as nuclear technology development and deployment. From the perspective of nuclear power in a market setting, prospective prices for nuclear electricity generation must exceed costs of generation by a reasonable margin (profit) to attract investment in new plants.[6]

4. Further a market price is one that at which there is some degree of equilibrium in current demand and supply over many buyers and sellers.

5. Among these are market setting of perfect completion and freedom of entry and exit for producers.

6. Put another way, price must be at least as great as a life-cycle cost which includes a reasonable (given risk) return on investment.

In general, the relationship between costs of production and market prices is a complex subject that has occupied a substantial fraction of microeconomic theory for much of its development. Figure 7-2 below provides a simple conceptual schematic for the important domains and relationships.

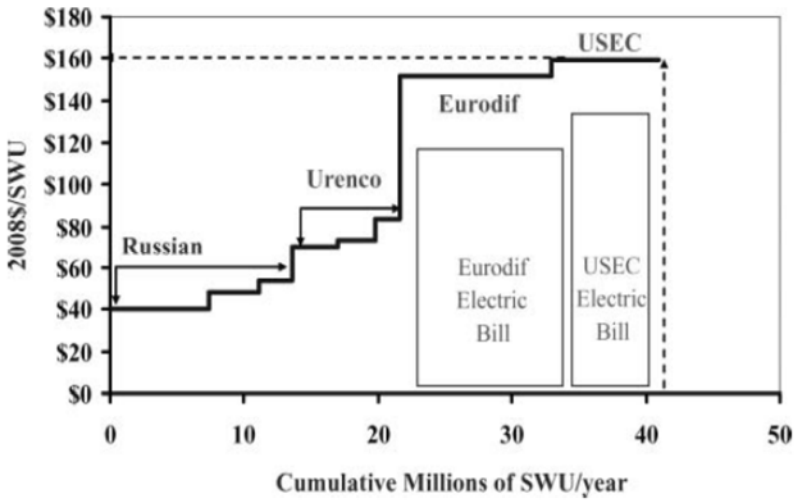

Figure 7-1. SWU market supply curve (Rothwell 2009).

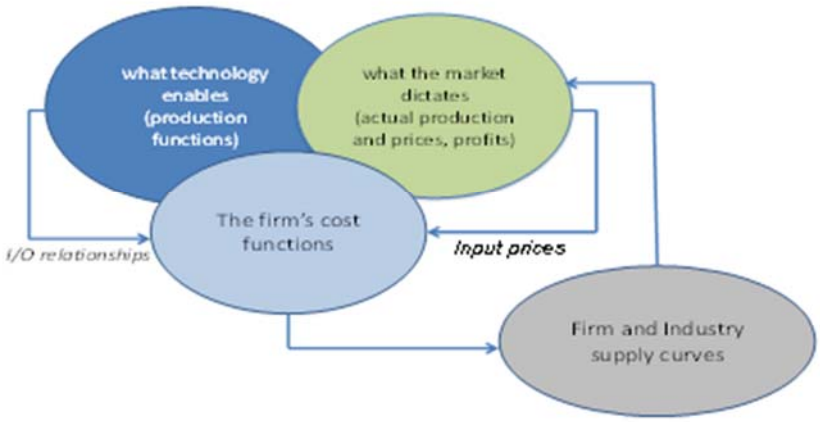

Figure 7-2. Cost and price domains and relations.

7.3 Cost and Prices in the Context of the Cost Basis Report

7.3.1 Objectives for Cost Basis Reports

"The (NTRD's) fundamental objective is to provide technology options that would enable long-term growth of nuclear power while improving sustainability and energy security"[7]

The NTRD Cost-basis series of reports supports this objective by defining a comprehensive and consistent set of cost data for analysis of nuclear technology options, and thus to both identify economic and performance targets for advanced nuclear technology, and identify economically important R&D domains. The focus on identification and evaluation of promising R&D has reinforced a tradition of cost estimates based largely on engineering models.

Within this broad purpose of the cost basis report series, the primary objective for the estimates is;

"…use of the cost data is for the relative economic comparison of [fuel cycle] options rather than for determination of total fuel cycle costs with great accuracy (Summary, 2007 report)."

The fact that the options of greatest interest are emerging or possible future (i.e., advanced) nuclear technologies implies that historical market prices are typically not available as measures of value, and comparison among these options demands estimates of costs "from the bottom up."

Much of the logical content of the estimates derives from *engineering models* of the unit process which can be combined to make complete fuel cycles – that is to say, models that capture the essential features of the physical production functions to which these unit processes contribute, and thus of the cost functions which are their duals.

Prices enter the cost estimation and comparison process in two ways: (1) to calculate probable costs for processes using inputs (materials and services) that are traded, and (2) to acknowledge the broad effects of market setting in implementing the fuel cycle.

The first sense in which prices are relevant is unavoidable. Any cost estimate for a broadly defined nuclear technology domain must, at some level of detail, use price data rather than cost estimates to value inputs to production.[8] In estimating costs for nuclear fuel, we would not typically detail the production technology of fluorspar, used in the production of HF, which is the reducing agent for UF_6 conversion. Instead, an appropriate market price for HF, with appropriate escalation, could be used directly in a fuel cost estimate. All historical data on commodity input costs reflect to some degree market equilibria or transactions (e.g., *prices)*. Seen in this light, it is clear that the real choice is simply the level of input granularity at which price data is introduced into cost-basis calculations.

This section documents current working group practice in using price data, and briefly describes general principles adopted by the working group to insure consistent practice in the future. Such consistency in the use of prices should insure that the comparisons among fuel cycles retain their integrity.

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7. Piet, Steven et all 2005, Objectives, Strategies, and Challenges for the Advanced Fuel Cycle Initiative

8. The alternative involves an infinite regress into 2nd, 3rd, and nth order inputs (inputs to inputs to inputs) of production, which in the limit requires specifying the production function for the global economy, and denominating cost in terms of quantities of a "numeraire good."

7.3.2 Short Run, Long Run, and Very Long Run

Cost functions and curves are typically categorized as short, long, or very long run. *Short run* curves assumes that capital (both type and amount) is fixed and that production is varied by changing the quantity and perhaps the character of other inputs. For example, we might estimate the costs of adding fuel production at a fixed set of plants with additional labor, LEU, and hardware inputs. *Long run* curves assume the scale of capital investment can be altered to its optimal level for a given process, thus assuring production at minimum long-run cost. *Very Long Run* cost estimates or curves assume that the *scale and nature* of technology are variable, allowing optimization of the production processes utilized.

When comparing costs of future nuclear technologies, either in the context of system cost minimization, or in understanding which technologies require support with R&D investment, it is the *long run* and *very long run* estimates that seem most relevant[9]. To the extent that innovative or advanced nuclear technologies are of interest, these estimates are the most difficult, since most of the phenomenological content (neutronics, separations chemistry, etc.) must be explicitly modeled or assumed for each module, rather than based on actual experience.

While it is long-run and very-long run *costs* that seem most relevant to these NE missions, the fact is that prices exist in the reality of the short-run, and in the case of options, the long-run contexts. Understanding very-long-run prices requires a general equilibrium model of the economy that spans the technological options, a computational framework which accounts for multiple, correlated sources of uncertainty, and explicit accounting for possible and evolving market settings.

7.3.3 Observed and Predicted Prices

Part of the advantage of using data on market prices is that they are typically published for broadly traded commodities at regular intervals and under a transparent set of accounting rules. Indices for Uranium prices are a good example. Prices of other inputs to production (specialized construction labor, chemicals, steel, etc.) are also typically well documented. The cost basis working group is working to standardize a set of routine sources for the relevant set of inputs and insure that all modules use these standard sources.

Predicting price movements is difficult. In the specific case of nuclear fuel cycle prices, market structure is important and the "imperfections" in market structure are many.[10]

7.3.4 Comparison of Costs with Prices – The Problem of Market Penetration

While costs and prices are conceptually distinct, they are both monetary valuation measures, and thus explicitly comparable. There are many cases where we compare a prospective technology with an existing one which involves this type of comparison. The general context is that of forecasting market penetration for emerging technologies. The best current example may be understanding the market niche for Small and Modular Reactors (SMRs) vis' a vis' more conventionally sized and constructed nuclear plants.

A similar example is estimating the viability of unconventional Uranium extraction methods. Linder and Schneider (2015) has developed cost estimates for U extracted from seawater based on bench scale

9. In a sense, the cost basis report seeks to understand the general shape of the very long-run cost curve for nuclear power – but it approaches this goal using comparative static analysis of long-run cost functions for specified technologies.

10. Among these are barriers to entry for enrichment technology, departures from economic scale for reasons of national control, decreased marginal cost of production associated with defense fuel cycles, and environmental and proliferation externalities.

experimental data for activated polymers. This set of estimates is then compared against observed and extrapolated "market clearing prices" for Uranium from conventional sources such as commodity brokers.

Another case is that of forecasting MOX fuel penetration in a market dominated by UOX fuel (Rothwell and Wood 2011).[11] This requires comparison of a MOX fuel cost estimated from its unit process components with simulated market prices for UO_2 fuel from a stochastic model. In this case, it was useful to characterize the full extent of uranium price volatility as part of the problem, thus establishing a "real options" framework in which to value the future technology.

All of these uses of cost-basis estimates involve comparison of prospective costs with current or forecast prices, and thus require at least implicit assumptions about market settings.

7.4 Price Data Irrelevance

The forgoing cases cited from various cost-basis sections illustrate cases in which use of price data (i.e., assumptions about market settings) have been used in the development of cost estimates. This section presents a few additional examples in which price data have been judged *as inappropriate* for use in cost basis estimation.

7.4.1 Constrained Markets and Price Volatility

Since the front-end of fuel cycle is historically the most fully commercialized, it is rich with cases in which prices from real markets are used at the process level. In some cases, however, the nature of current market influences is explicitly *not* accounted for in setting reference costs. This was the case for both U and SWU prices in 2007:

> *"The authors recognize that uranium and enrichment spot prices have recently exceeded the high-cost range provided in this cost basis. These price trends are being evaluated and the cost ranges in the report will be revised as appropriate in future updates."*

Thus transient price fluctuations (volatility) are ignored in practice in setting reference module costs, and that only those price trends (or more broadly those market influences) felt to be reasonably persistent are incorporated in the cost basis estimates. A related example in this vein concerns the appropriate interpretation of current market prices for SWU. Both market data (http://www.uxc.com/review/uxc_PriceChart.aspx?) and analyses of technology-based cost functions (Rothwell, 2009) give high prices for SWU ($140 - $160/kG-SWU). In terms of economic application of available technology, these prices are far above the demonstrated long-run marginal cost of available centrifuge technology, and may be explained (Rothwell 2009) as an artifact of the facts that (1) the marginal supplier now uses a much less efficient technology, (2) there are some restrictions on the entry of new firms in this market. The question posed here is "to what extent should reference fuel cycle costs reflect existing market prices, versus an assumption that efficient technologies will enter the market and set prices?" This question requires making some assumptions on the future market setting for enrichment, and thus the roles of governments and multilateral bodies in setting conditions for its use. The working group continues its consideration of this issue. The situation in 2017 is the opposite of that in 2007. Natural gas and the Fukashima accident put an end to the "Nuclear Renaissance" and the high prices anticipated by it. The market for front end services is now severely depressed.

7.4.2 "Implicit Competition"

Estimating costs for competing reactor concepts assumes that each concept will be developed to and "nth of a kind" level of technological maturity (and corresponding low costs of production). Yet this

11. For example, large-scale MOX fuel for LWRs with UO2 fuel. See Rothwell and Wood 2011.

assumption assumes that a concept survives the development process to achieve this level of development – a process that involves competition for limited R&D and investment resources. In such cases, it is tempting to reason that competitive forces will insure convergence of costs for reactor concepts competing in the same era and markets. Yet the history of the nuclear industry suggests this is an unwarranted assumption, and NTRD estimates do not rely on this type of logic.

7.4.3 Reference Quantities

An issue related to the use of price data concerns another aspect of market outcomes – reference quantities. This question comes in two related forms – (1) with respect to scale of capital plant assumed for estimates and (2) reference capacity utilization within a process or sector of the fuel cycle. The effect of scale in unit costs is very significant in any capital-intensive processes. Enrichment plants are a good example. Figure 7-3 below (reprinted with permission from (Rothwell 2011) shows two unit (average cost curves derived under two different capital; cost assumptions), and the resulting derivation of "minimum economic scale"[12] In typical LWR fuel cycles, enrichment, reactors, and reprocessing, and waste disposal all exhibit large economies of scale. (Forsberg, 2005)

Figure 7-3 makes it clear that defining a reference average production cost for given technology is logically coupled to an assumption about the scale of plants that will be built. This is typically explicit for specific proposed commercial reactor designs, but may not be for advanced reactor concepts or other elements of the fuel cycle.

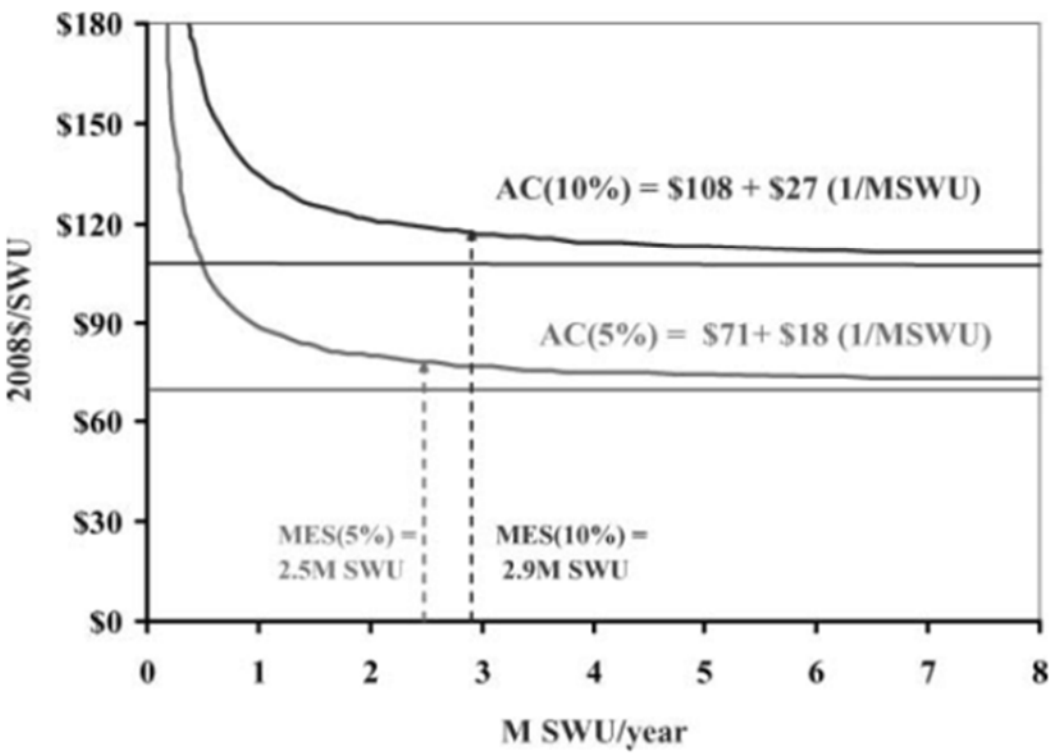


Figure 7-3. Economics of scale in centrifuge enrichment.

12. MES or Minimum economic scale is defined here as the smallest scale of plant (production capacity per year) that achieves a unit cost 10% above the asymptotic limit for a given unit cost curve.

In practice, cost basis results are typically utilized to compare costs of alternative fuel cycles deployed at large scale and often in equilibrium conditions. This context argues that unit costs typical of minimum economic scale for each technology should be used. Unit costs are also sensitive to the capacity factor at which plants are operated, which is to some extent dictated by market setting. Typically, applications of cost basis results include a "mature technology" assumption – a context in which it is reasonable to assume uniformly high capacity factors across plants employing technology from diverse modules.

7.5 Summary of Principles

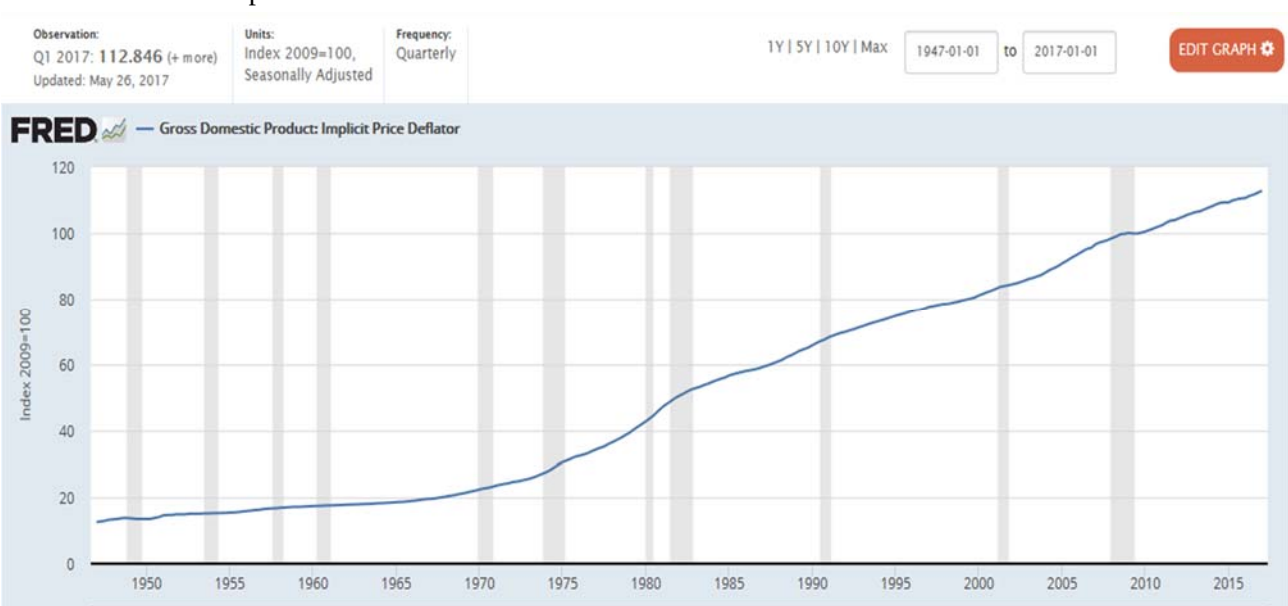
This section summarizes a few principles which we might consider as guidance for use of price data in the cost basis report.

1. Since the objective of the cost basis report and its associated databases is to facilitate comparison among advanced nuclear fuel cycles and their elements, the general model for estimating costs is to rely on a bottoms-up approach in which the production functions characteristic of new or emerging nuclear technologies are modeled as part of the cost estimating process.
2. To the extent that any production function approach specifies inputs to production (which must be valued to estimate costs for the product), some market based (price) data will always be an input to the cost estimation process. Such data should be selected and used in consistent manner from module to module, and should;
   - use broad market averages and indices to the extent possible, and avoid reliance on data from specific transactions or narrow market contexts,
   - reflect long term trends and exclude the transient effects of price volatility in making long term prices assumptions, or
   - be formulated in a stochastic fashion that reflects our degree of uncertainty about future prices.
3. For fuel cycle elements which are already fully commercialized, it may be more efficient to base cost estimates on market data for intermediate products. In cases where this is possible, care should be taken to make explicit the assumptions about continuation or evolution of market structure and efficiency.

8. ESCALATION CONSIDERATIONS

This 2017 AFC-CBD Stand-alone Report has attempted to express as much of the cost data as possible in constant fiscal year (FY) 2017 dollars. Since much of the reference data, and even the 2009 , 2012, 2015, and 2016 AFC-CBD data, are expressed in some other year's constant dollars (even as far back as the 1960's), some manner of escalation must be applied the these values to bring them to 2017$. It should be noted that the term "escalation" is used rather than "inflation". The latter is a term generally applied to a national economy as a whole. In the US general inflation is usually measured by the Implicit Price Deflator calculated by the Bureau of Economic Analysis in the U.S. Department of Commerce. Table 8-1 below shows the Implicit Price Deflator from 1st quarter CY 1947 through 1st quarter 2017 as plotted by the economic research branch of the Federal Reserve Bank of St Louis. The inflation index from a reference year to 2017 is calculated by the ratio of 112.8 (2017 Q1) to the reference years index; which for example year 1965Q1would be 18.6. The ratio is 6.06, which says that in general "things" (the total "market basket" or value of the US Gross Domestic Product [GDP] today is over six times what it was in 1965.) When one starts looking at particular parts of the economy, however, such as nuclear construction, the actual cost ratio actually measured may differ considerable from general inflation. This is due to the fact that the "market basket" for indexing nuclear construction and operations contains items whose prices increased at a rate greater (or in some years less) than inflation. This incremental rate above or below general inflation is called "incremental escalation" and may be positive or negative. Unfortunately for nuclear construction it has been mostly positive and has been affected by commodity price escalation and the labor cost effect of stringent regulation. The net escalation factor in a given year for a given item or industry such as nuclear construction includes both "general inflation" and the "incremental escalation" specific to its "market basket".

Table 8-1. Plot of Implicit Price Deflator from 1947 to 2017

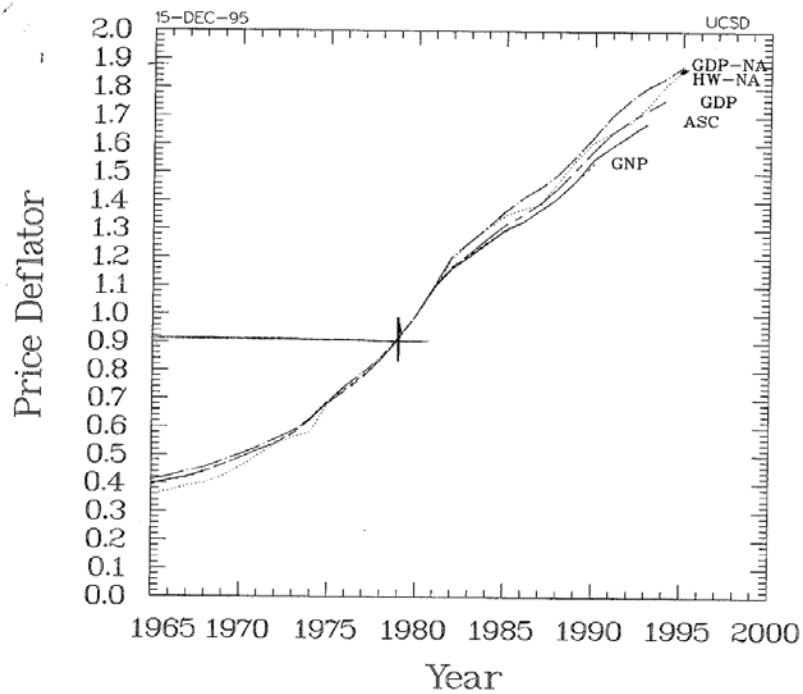


For these AFC-CBR studies the authors attempted to find historical escalation indices which are more specific to the nuclear industry than to the economy as a whole.

Historical escalation indices are published, but generally for very aggregated priced items, such as power plant construction (Handy-Whitman Index), particular labor rates (Department of Labor 2009), or general construction (ENR 2009). It has been difficult to find a publicly available and inexpensive to

purchase (or free) set of escalation indices to use for this purpose. Others have faced the same problem including a University of San Diego author of a nuclear fusion assessment report 1 (Miller 1995). That author, Ronald Miller, compared various indices and found that from the 1960's through 1980 they tracked each other well. (See Figure 8-1 below). From 1980 onward the rate of escalation for construction was higher than for the GNP (Gross National Product) or GDP (Gross Domestic Product as measured by what is now called the Implicit Price Deflator).

For the analyses in this report the Handy Whitman-North America (HW-NA) nuclear power plant construction index (faint dotted line on graph) was used for escalation from years 1965 to 1995.



ASC: Associated Schools of Construction
GDP: Gross US Domestic Product
GNP: Gross US National Product
GDP-NA Gross Domestic Product-North America
HW-NA Handy-Whitman-North America

Figure 8-1. Comparison of various escalation indices (1965-1995).

The Department of Energy occasionally publishes indices for use in budgeting for large construction projects. A November 2009 reference (USDOE 2009) was found with a table that included columns especially for "nuclear" projects. This data is reproduced here:

Table 8-2. DOE Construction Index for Nuclear Projects

Fiscal Year (FY)	Rate (%)	Index 2011 (Base year=1.0)
1990	1.2	0.635
1991	0.9	0.640
1992	0.0	0.640
1993	2.0	0.653
1994	3.0	0.672
1995	2.7	0.691
1996	1.0	0.697
1997	1.9	0.711
1998	0.5	0.714
1999	1.2	0.723
2000	1.0	0.730
2001	0.1	0.731
2002	1.8	0.745
2003	1.0	0.752
2004	12.7	0.848
2005	2.1	0.866
2006	8.1	0.936
2007	3.1	0.965
2008	7.0	1.033
2009	-3.2	1.000
2010	-1.9	0.981
2011	2.0	1.000
2012	1.9	1.019

This DOE Table is used for escalation from 1995 to 2000 since no Handy-Whitman data was available to this project. From 2000 to 2015 the **The IHS North American Power Capital Costs Index (PCCI) was used, since it derived from a larger pool of actual tracked nuclear projects.** The PCCI tracks and forecasts the costs associated with the construction of a portfolio of 30 different power generation plants in North America and tracks the costs of building coal, gas, wind and nuclear power plants, indexed to year 2000. The PCCI is a work product of the IHS North American Power Capital Costs Service, an annual subscription service managed by IHS. Figure 8-2 below shows a plot of the PCCI both with and without nuclear projects included.

Much of the escalation from 2003 to 2008 was due to price increases for steel and concrete, driven heavily by demand in Asia. In 2009 and 2010 there was negative escalation due to the worldwide recession. Only in 2011 did positive escalation resume.

PCCI data for 2015 to 2017 which differentiates nuclear power has not been found, and if they have it this project would have to pay for it. For this reason the GDP Implicit Price Deflator indices were used to derive ratios for 2016 and 2017 escalation.

It can be seen that four methods of escalation indexing have been used in these studies, with each method used for differing times spans:

- Handy Whitman (1965-1995)
- DOE (1995-2000)
- PCCI with nuclear (2000-2015)
- Implicit price Deflator (2015-2017)

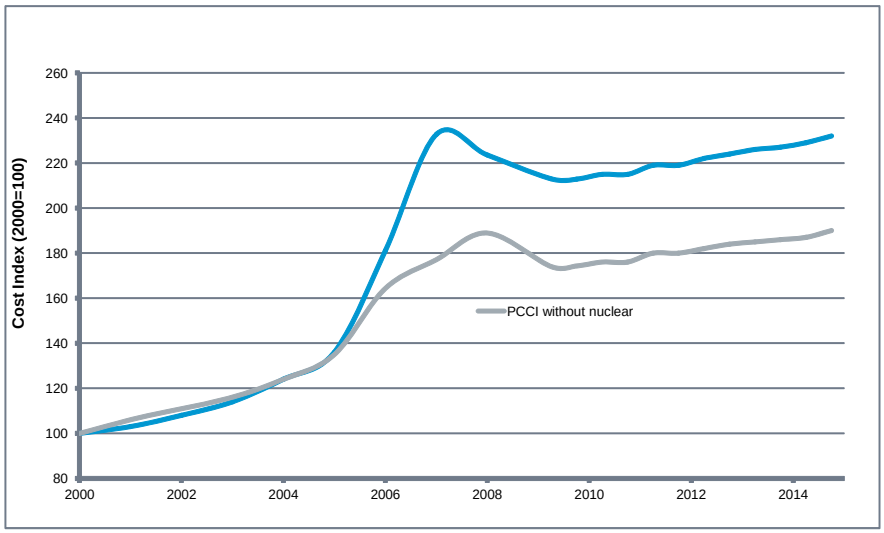


Figure 8-2. Plot of the PCCI Indices (upper curve includes nuclear).

Table 8-3 below shows a composite index derived from all four sources mentioned above which can be used to bring "then year dollars" from any year 1965-2014 to 2017 dollars. This table was prepared by a ratioing method which normalized the three differing indices. The Table 8-3 values will be used to escalate any "then year $" values throughout the cost modules. (For example, if a 1975 cost of $100M was quoted for a fuel fabrication facility, the equivalent today [2017] would be 7.22 from the table below times $100M to obtain $722M). It should be noted that these escalation factors are for the same facility design, and do not include the cost effects of major project scope changes) It should be noted that since 1965 nuclear projects have escalated at a rate about twice that of general inflation as measured by the Gross Price Deflator. General escalation from 1965 to 2017 is over a factor of 6 as opposed to around 13 for nuclear projects.

Table 8-3. Factors for Escalation of "Then Year" Costs to Year 2017 Dollars.

Table 7.3 Composite Historical Cost Index Created from 4 other sets of Indices for which data was available					
1965	13.44	**1982**	4.41	**1999**	2.46
1966	12.74	**1983**	4.06	**2000**	2.44
1967	12.10	**1984**	3.76	**2001**	2.37
1968	11.52	**1985**	3.51	**2002**	2.26
1969	11.00	**1086**	3.40	**2003**	2.14
1970	10.52	**1987**	3.30	**2004**	1.97
1971	9.64	**1988**	3.20	**2005**	1.79
1972	8.90	**1989**	3.11	**2006**	1.35
1973	8.26	**1990**	3.02	**2007**	1.05
1974	7.71	**1991**	2.92	**2008**	1.09
1975	7.22	**1992**	2.83	**2009**	1.14
1976	6.74	**1993**	2.74	**2010**	1.13
1977	6.32	**1994**	2.65	**2011**	1.11
1978	5.95	**1995**	2.57	**2012**	1.06
1979	5.61	**1996**	2.55	**2013**	1.07
1980	5.32	**1997**	2.50	**2014**	1.05
1981	4.82	**1998**	2.49	**2015**	1.03
				2016	1.02
				2017	1.00

Use of this Table: Selection of the "historical" year is important for correct application of escalation to 2017. Within a particular fuel cycle module the "historical" year should be that in which the last "technical" cost basis was changed. For example if a specific ($/kwe) cost in a 2009 AFC-CBD reactor "R" module was based on and escalated from a 1975 detailed cost estimate (latest and best available), the 2017 AFC-CBD should use the above Table 8-3 with the index from 1975 to 2017, i.e. a factor of 7.22.

The following graph shows the differences in escalation indices based on the standard IPD-based "market basket" and the "nuclear market basket" created for use in this report:

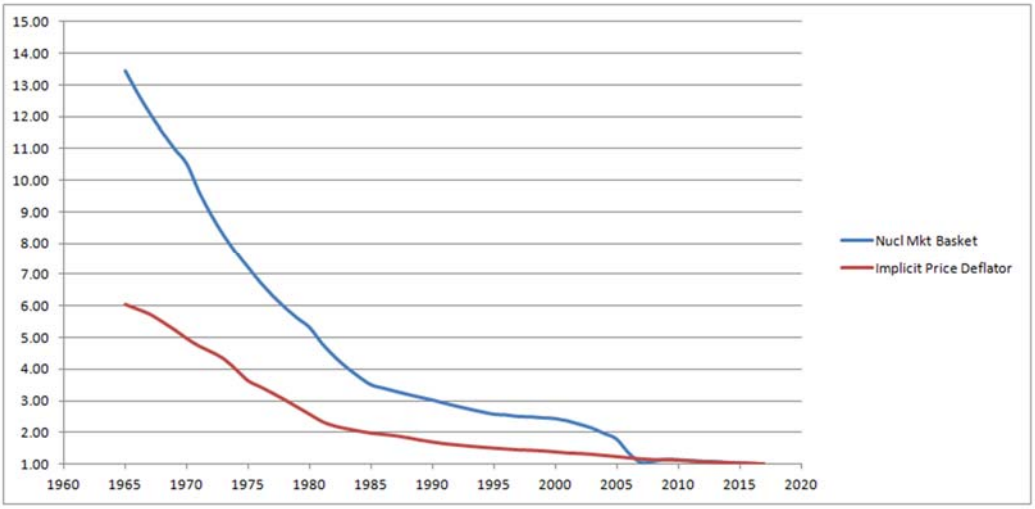


Figure 8-3. Comparison of escalation factors based on IPD and Nuclear "Market Baskets".

9. DISCOUNT RATE FOR NUCLEAR ECONOMIC ANALYSIS

This section presents a topic that was not included in previous AFC-CBR updates, but that is of importance in the economic analysis of nuclear fuel cycles. The conclusions and the suggested values for the practical use of discount rates in the economic analysis of nuclear fuel cycles are based on previous studies on the topic including Chicago (2004), MIT (2003, 2009, 2011), and Arrow (2012), and on the AFC-CBR team's considerations on this topic. It is expected that information on this topic will continue to evolve as new discussions and contributions emerge in the financial and nuclear communities.

9.1 Background Information

The old adage "a bird in the hand is worth two in the bush"[13] illustrates people's preference for the certain over the uncertain because the in-hand, certain bird is twice the value of the uncertain birds in the bush. The past and present are by definition certain so uncertainty is really a characteristic of the future. It follows, then, that since people value certainty over uncertainty, they also value the present over the future (Hansen, 2015). Discounting is the analytical tool whereby the analyst can weight uncertain future cash flows in terms of preferences for the present.

Suppose you have $100 in cash that you can either spend today or deposit in the local bank for 10% annual interest. In making your choice you evaluate what you could do with the $100 now or during the next year versus having $110 at the end of one year. If you left the money in the bank for another year the sum grows to $121 and again you compare the sum to what you could have done with $110 in the intervening year. People who save money recognize this as simply the time value of money where the future value *FV* of the present value sum *PV* grows at a defined rate of interest *r* over the period *t* as in:

$$FV = PV\left(1+r\right)^{t}. \tag{1}$$

The same logic can be used to determine the *PV* of a future sum by simply rearranging the equation as in:

$$PV = FV\left(1+r\right)^{-t}. \tag{2}$$

In discrete terms equation (2) is the mechanism to translate a sum in the future to a value that is meaningful in terms of the present.[14]

Discounting is relatively straightforward; whereas equation (1) identifies the value of money in the future equation (2) reverses the calculation to identify the value of future money today. In the previous example *r* was an interest rate that fit into equation (1) to determine how the $100 deposit grows over time. But in equation (2), as a discount rate, *r* is the rate at which future value is translated into present value. To determine *r* for equation (1) simply call the local bank to find out the rate of interest paid on deposits at that institution. Determining what *r* should be in equation (2) is not such a simple task because it is accounting for opportunity cost and risk. That is the value of the foregone benefits that could have been realized had the sum not been deposited in the bank are what economists call *opportunity cost.* By depositing your $100 in the local bank you risk the chance that you may have been better off using the money in alternative rather than depositing it in the local bank. The trick with discounting is in choosing the rate that best reflects the project's (or investment's) level of "riskiness."

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13. Found in John Ray's 1670 Handbook of Proverbs.
14. If the analysis treats time as a continuous variable (as opposed to discrete) then the discounting equation becomes: $PV = FVe^{-rt}$.

A survey of over 2,000 economists verified that wide disagreement exists over what should be the appropriate discount rate (Weitzman, 2001). Although the economists surveyed disagreed about what *r* should be they agreed on what *r* should reflect. Their consensus is founded in the seminal work on the theory of optimal savings (Ramsey, 1928). More recently the U.S. Environmental Protection Agency (EPA) convened a meeting of 12 eminent economists to inform on the state of the art in discounting. The meeting is summarized in Arrow (2012). Similar to the survey of economists, the leading scholars on discounting did not agree on what should be the value of *r*. But like the survey they agreed that *r* should be based on the Ramsey theory of savings.

Ramsey (1928) identified the optimal savings rate so that savings and consumption maximize well-being of all present and future citizens. Based on the theory *r* should reflect two things that economists call the rate of time preference and the weighted marginal utility of future consumption. Time preference can be interpreted two ways (Hansen, 2013). People are generally impatient and prefer not to wait for things, and they are generally averse to deleterious events like death, war, disease or other unwanted events. The component of *r* that belongs to time preference discounts future well-being (Heal, 2007). Marginal utility captures the degree than future generations will be better off than present generations and the weighting on it captures society's risk aversion with respect to consumption (Hansen, 2013). Here risk aversion in consumption means that the utility of money in the hands of a low income person may not be the same as the utility in the hands of a wealthy person. Therefore the second component of *r* discounts future consumption, weighted by how people value consumption (Heal, 2007).

The two components of the discount rate point to perceptions of risk. Ramsey's model is based on conditions of certainty – and even under that assumption risk emerges as a contributing factor to the discount rate. Relax this assumption to conditions of uncertainty to see that discounting is a mechanism to account for risk in uncertain futures. For any investment the risk is that an alternative may have turned out better – that is for any investment there is an opportunity cost. Discounting accounts for the risk that the alternative investment would have performed better. The disparity of viewpoints on the part of the economists in the survey and in the EPA meeting noted earlier stems from how best to account for risk. Unlike an interest rate that is established in highly functioning capital markets, the discount rate is based on project riskiness. Determining a project's level of risk, and the discount rate to match it, is where the straightforward procedure of equation (2) becomes complex. Which rate to choose?

Figure 9-1 shows the implications of various discount rates. For simplicity suppose the cash flow under evaluation is an annual payment of $100 for the next 100 years. The solid blue line at the top of the figure shows the *PV* of the annual payment where the discount rate is 0%, which is to say no discounting is applied. The annual payment of $100 is worth the same in each year as it is in the initial year. By comparison, the dashed purple line shows how the *PV* changes with a discount rate of 10%. In year 10 the *PV* of the sum is essentially half the original value. The line shows that the *PV* of $100 in year 10 is $50. By year 97 the *PV* of the sum is about a penny. The figure illustrates the mechanics of discounting. The higher the discount rate the lower the *PV* of future cash flows.

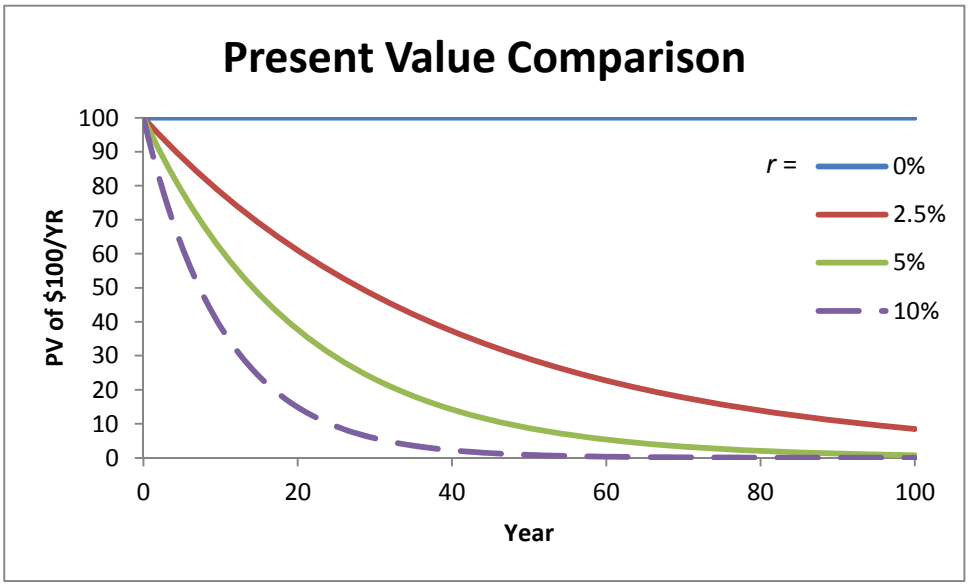
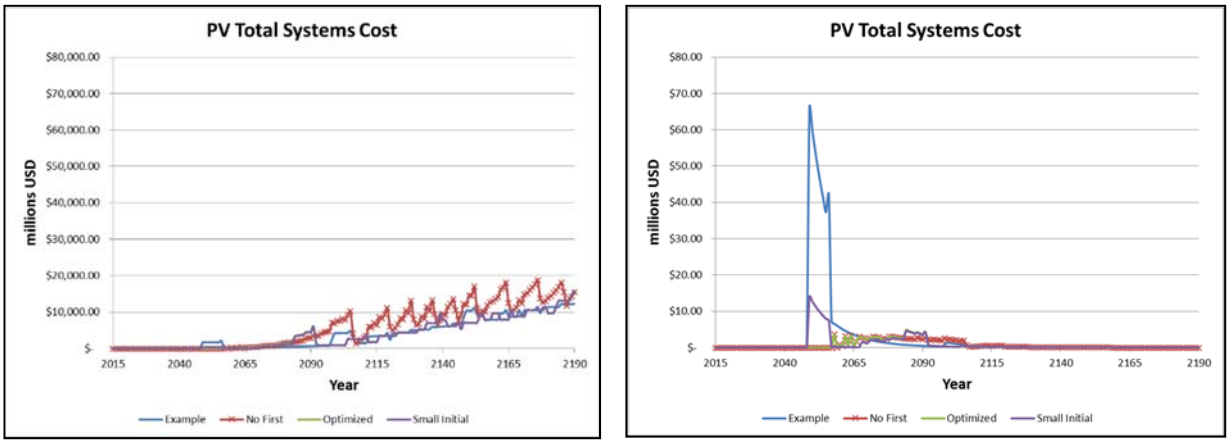


Figure 9-1. PV comparison of an annual payment of $100 over 100 years.

In 2016, EWG researchers conducting analysis on the economics of transition compared four alternative deployment schedules for fuel separations facilities (Dixon 2016). In this analysis the usage cost of LEU fuel (and its accompanying storage) was traded off against the cost of building separations facilities. Because the research question involved cost comparisons over long time horizons (up to 185 years) the analysts applied a 5% discount rate, then conducted sensitivity analysis using a 0% and 10% rate, both consistent with the Cost Basis Update (Dixon 2015). Figure 9-2 is reproduced from that analysis.



(a) r = 0% (b) r = 10%

Figure 9-2 Sensitivity Analysis; testing the sensitivity to the discount rate (Dixon et al., 2016)

The figure illustrates how the discount rate changes the shape of the cost profile over time. In the case of zero discounting, costs escalate with a steady trend, particularly in years beyond 2090 when the number of separations facilities increases with the rate of transition. These are costly facilities and the increasing trend in panel (a) reflects this. (For this discussion on discounting, the specifics on the alternatives are not necessary). Now compare the increasing trend from panel (a) with the decreasing trend from panel (b) where a 10% discount rate is applied. Over the time frame where facility

deployments strongly get underway, the higher discount rate choice essentially "discounts away" the large costs of separations modeled to occur in the next century.

The remainder of this section discusses issues to consider in choosing the discount rate for analysis of investments in nuclear technology made by firms in the private sector and by the government in the public sector. The section addresses issues by sector where investments originate because of how risk is accounted for in each sector.

9.2 Discounting in the Private Sector

In the private sector the expected rate of return on investment *i* (R_i) factors into the choice of discount rate because it represents the firm's opportunity cost from investing in project *i* (Brealey, 2003). Similar to the two components of the discount rate mentioned previously (time preference and utility in consumption), the following equation shows the expected return on investment *i*. It represents how the firm chooses the discount rate.

$$R_i = RF + RP_i \tag{3}$$

In equation (3) RF represents the risk-free component of the discount rate and RP_i represents the risk premium associated with investment *i*. RF can be thought of as reward to investors for postponing consumption and RP_i is the reward for investing in a risky project (Hirschey, 2003). Convention is that RF is typically estimated based on the interest rate paid on short-term US government securities (Hirschey, 2003). Where feasible the Capital Asset Pricing Model (CAPM) is used to estimate RP_i.

The CAPM is used to estimate the expected return on an investment. It is based on the covariance of the investment's risk with market risk. From the CAPM

$$RP_i = \beta_i \left(RM - RF \right), \tag{4}$$

where RM is the market return and β_i is the covariance between investment *i* and the market return. In this model project "betas" are measured econometrically by analyzing the historical relationship between market returns and returns on investments similar to *i*. Projects with $\beta_i < 1$ have less risk than the average risk in the market. Projects with $\beta_i = 1$ have the same risk as average market risk and projects with $\beta_i > 1$ are more risky than market returns.

Applying standard financial theory, based on CAPM, to assess the risk premium for nuclear projects is more challenging than for projects like say a grocery store because of β_i in equation (4). For investments that are widespread in the economy, like grocery stores, ample data exists to econometrically measure the covariance between grocery store success and market success, the β_i. And data is needed to estimate it. Sufficient data is the limiting factor to estimate β_i for a nuclear investment (Chicago, 2004).

Because of the difficulty in measuring project betas for nuclear investments, and therefore the correct risk premium, the weighted average cost of capital (WACC) is a reasonable alternative to choose the discount rate. The WACC can be estimated from data of publicly traded utilities and can therefore proxy for nuclear investments. The standard formula for the WACC is shown in Equation (5),

$$WACC = C_E \frac{E}{E+D} + C_D \frac{D}{E+D} \left(1 - tax_{rate}\right), \tag{5}$$

where C_E and C_D are the costs of equity and debt, E and D are total dollar values of equity and debt of the representative firm, and tax_{rate} is the he tax rate of the representative firms. Equation (5) is based on the fact that, under current U.S. fiscal laws, interest paid on debt is tax-deductible.

The firm's cost of capital, represented in equation (5), is the opportunity cost of capital for the firm's investments. If a firm uses debt financing the expected rate of return on the publicly traded equity is not the same as the return on its assets. The riskiness of the equity is higher because of the financial risk introduced by the use of leverage. In principle, the WACC (including all the existing securities such as common and preferred equity, and debt) should not change if the mix of debt and equity is altered since the riskiness of the underlying assets has not changed (Modigliani 1958). The riskiness of the traded securities may change but the risk in the underlying project has not.

The following sections address considerations and conclusions on the topic of discount rates for nuclear energy projects reported from studies that have presented the topic (Chicago, 2004; MIT 2003, 2009, 2011).

9.2.1 The Chicago Study

A key observation in the Chicago study (Chicago, 2004) is that there is lack of quantitative relationships in the financial literature between risk and risk premiums, as applicable to nuclear projects. This is because a large component of financial risks for nuclear projects is non-systematic rather than systematic. It means that risk in nuclear projects has more to do with project risk than with market risk. This renders the primary tool of modern financial theory of risk, based on correlation of individual securities with market risks (the betas), inapplicable to quantifying financial risks for nuclear projects.

Another important consideration regards the asymmetry of risks for nuclear projects (Chicago 2004). Construction delays and regulatory hurdles, for example, lead to dispersion in possible returns (Chicago, 2004). The effect of different outcomes can be estimated by a weighted average of the returns of each outcome and discounted at the market risk such that a decision tree of possible outcomes results. For projects that entail a non-negligible downside risk (e.g., a nuclear project prevented from operating, and thus prevented from recovering the invested capital, after being constructed), the equivalent discount rate, calculated from such a weighted average, will be higher than the market risk used to discount each branch in the tree.

In this case, it is possible to estimate the higher opportunity cost of capital, r_{Risky}, as shown in Equation (6).

$$r_{Risky} = (1+r) / \left[p_s + (1-p_s)\, f_L \right] \tag{6}$$

Here p_s is the probability of the investment being successful (e.g., a nuclear project finished on time, and starting operations as expected without unexpected cost increases or project delays) and f_L is the fraction of the total investment recovered if the project is not successful (this can also be negative, e.g., if decommissioning costs are incurred if an operational license is not issued).

With regard to the appropriate cost of capital for nuclear projects the following characteristics are listed as advantages and disadvantages based on an investor perspective in Chicago study.

Advantages that reduce investment risk:

- Low and predictable fuel and operation and maintenance (O&M) costs;
- High capacity factor (the current fleet of LWR in the U.S. has been operating at capacity factors above 90% for several years);
- Long Operating Lifetime (currently up to 60 years).

Disadvantages that increase investment risk:

- Large plant sizes (1000-1350 MW_e) and correspondingly large capital outlay (large specific and total unit costs);
- Long construction time (at least twice as long as for combined cycle gas-fired plants). Construction projects for new reactors are assumed in Chicago (2004) at 7 years, in an attempt to cover the entire time range over which construction-related expenditures occur, including the construction start-up phase, the construction and procurement phase and the plant start-up and testing. Expenditures are assumed to occur equally over the construction time.
- Higher specific capital at risk and interest during construction: recent consolidation in nuclear plant ownership should alleviate some of the investment-financing hurdles (based on 2004 data, 13 utilities accounted for 75 of the 103 U.S. reactors), since a larger net worth should make it easier to finance large capital investments.

9.2.2 WACC Numerical Values

The recommended cost of debt and equity from the Chicago study is based on 2004 data from the publicly traded utilities in the US. Financial terms for foreign projects are not necessarily a good guide for the terms that would be appropriate to domestic nuclear projects since at least the following differences exist (Chicago, 2004):

- Differences in business practices and climate;
- Varying degrees of government involvement in nuclear projects and different regulatory regimes.

The costs of debt and equity for US utilities as reported by Bloomberg in 2004 and adjusted from the reported after-tax to the pre-tax rate, is 5.34% for debt and 8.63% for equity. In equation (5) the tax rate is subtracted so the rates in Bloomberg need to be adjusted for the tax effect. However, it is noted that the Bloomberg data are calculated from the spreads over treasury bonds with 10 years maturity, so there is a need to convert those data to a longer maturity to reflect the longer duration of nuclear projects. For this reason, the Chicago (2004) study recommended to add a 0.5% to 1% extra cost of capital to these values of WACC. Additionally, according to Chicago (2004), another 0.5% should be added to the reported rates to account for the abnormally low rates present in 2004, yielding a nominal cost of debt of 6.35 and 6.84% and a nominal cost of equity of between 9.64 to 10.13%. In the Chicago (2004) economic study and calculations, these values have been rounded to 7% and 10%. It is noted that these are nominal rates, (i.e., including the inflation rate). It is also noted that, while these values are justified in the text (see Section 5.4.2.2 in (Chicago 2004)), they appear inconsistent with values given in other parts of the report, such as for example in Table 5-1 in Chicago (2004), and in Section 5.4.3, where values of 15% for equity and 10% for debt are reported.

9.2.3 Debt to Equity Ratios

While there is copious financial literature on the topic of debt/equity ratios, according to the Chicago study proof of a clear target by companies has not been found and/or established. The ratio (in (Chicago 2004)), has been therefore taken to be the average of the utility sector as of 2004, or 50%-50%. Changing the assumption about the ratio will have an impact on the WACC. Here the 50-50 ratio is recognized as a general indication, and is affected by many factors, including the taxation environment of a particular period.

The ratio will vary with the type of financing packages put in place. For example, most nuclear power plants in operation today were built in regulated utility markets where the existing customer base was known providing the utility with an accurate representation of and guaranteed future revenue stream

(IAEA, 2008). This stability reduces the risk premium necessary to attract financing from equity and debt. In today's environment where power plants may be located in de-regulated electricity markets equity investors will likely demand larger risk premiums than was the case for reactors in operation today. Increased risk premiums demanded by equity investors will therefore make debt a more attractive option for capital finance. Greater use of debt over equity will reduce the WACC.

9.2.4 Regulation

Regulation of the electricity markets, including both rate of returns and retail prices, has tended to reduce cost of capital for the regulated utilities, by shielding them from market price risks (Hogan, 2002). In regulated markets where the regulator guarantees the utility a constant rate of return the utility faces less risk. This reduces the cost of capital. However, the risk of having some of the costs disallowed from the rate base is still occasionally present in certain projects for regulated utilities. Regulation that prohibits cost being passed onto rate payers may increase project risk and therefore the return demanded by both debt and equity holders.

9.2.5 The MIT Studies of 2009 and of 2011

Important considerations in these studies regarding the appropriate discount rates are the following:

- "…the aggregate social cost of a nuclear fuel cycle must be evaluated using a cost of capital comparable to what would be employed by any commercial entity".
- "The cost of capital is meant to reflect the full set of risks borne by society associated with the activities of the fuel cycle, and so should not be changed to reflect changes in who bears this risk".

The reasons for this, as reported in MIT (2009), are the following:

- State ownership of nuclear assets does not necessarily imply a lower cost of capital. Arguments for that are often based on considerations such as the following (as examples):
- "Governments do not pay taxes, so they need a lower rate of return to recoup their costs"; However, MIT (2009) argues that the fact that taxes are charged or not to state-owned entities "… have nothing to do with the true social cost of the commercial activity making up the nuclear fuel cycle. It is the true social cost that ought to be guiding public policy".
- "Governments can bear a higher risk than private enterprises, so they need a lower risk premium". However, modern developed capital markets allow investors to diversify risk to a degree that renders this argument invalid.
- Based on similar considerations, it is often argued that utilities operating in a regulated environment face less risk than utilities operating in a deregulated environment. However, from MIT (2009) "… similarly, while certain regulatory structures may lower the amount of risk borne by private investors, thereby reducing the rate of return they need to earn to recoup their investment, this is done by shifting that risk onto ratepayers". "The total cost borne by society is not lower due to the regulatory structure, and this total risk is what should matter for a public policy evaluation of alternatives".

The same numerical values for the discount rates used in MIT (2003) are also used in MIT (2009) and MIT (2011): 10% nominal cost of capital and 3% inflation rate. The 10% nominal cost of capital is obtained from a 8% cost of debt and 15% cost of equity, 50% financing of debt and equity and 38% tax

rate, according to equation (5). The 15% cost of equity is justified based on the higher perceived risk of nuclear projects as compared to the standard riskiness of the generating portfolios of traded utilities. This leads to a nominal discount rate of 7.6% (MIT 2009, 2011).

9.2.6 A Note on Alternative Approaches to the Pricing of Risk for Nuclear Projects

The riskiness of nuclear projects decreases once the construction of the infrastructure is completed, the operational license has been granted and normal operation has begun. It is apparent that, upon successful completion of these steps, the riskiness of the cash flow is substantially lower than before construction, when many uncertainties are present, not least the regulatory and technical ones. It may therefore be justified to use different discount rates for different phases of the projects, to reflect the changing degree of riskiness once a different amount of information is obtained. In this case, the cash flow would have to be weighted for the probabilities of different outcomes, such as the probability of not obtaining an operational license. The discounted cash flow at lower discount rate would then have to be further discounted back at the higher discount rate to the time of the decision making, or beginning of construction, and weighted by the probability that the license for the operation of the facility would be granted after construction is completed (Brealey 2003).

9.2.7 Recommended Discount Rate

The previous sections have discussed a number of considerations on the topic of the appropriate discount rate for nuclear projects, as raised in previous studies. The discount rate values suggested in this section are based on the conclusions of the aforementioned studies and on the AFC-CBR team's considerations on this topic. It is expected that information and recommendations on this topic will continue to evolve as new discussions and contributions emerge in the financial and nuclear communities.

Table 9-1 summarizes the numerical values for the cost of capital suggested in the Chicago and MIT studies. The nominal and real costs of capital are highlighted, ignoring the effect of taxes. While it is recognized that taxation can alter the financial framework for nuclear projects as owned and operated by private players, it is also noted that taxes are country specific, and subject to change with the prevailing fiscal regime and taxation laws. It is the purpose of this document to provide the basis for the long term economic evaluation of nuclear fuel cycles: for this reason, it is recommended to avoid the inclusion of the effect of taxes on the cost of capital when performing the types of analyses for which the values proposed here are intended.

Table 9-1. Summary of numerical values for the cost of capital suggested in Chicago (2004) and in MIT (2003, 2009, 2011).

	Chicago Bloomberg[1]	Chicago Base[1]	MIT (2003, 2009, 2011)
Cost of Equity	10%	15%	15%
Cost of Debt	7%	10%	8%
Debt to Assets Ratios	50%	50%	50%
Nominal cost of capital ignoring taxes	**8.5%**	**12.5%**	**11.5%**
Inflation rate	3%[2]	3%[2]	3%
Real cost of capital ignoring taxes[2]	**5.3%**	**9.2%**	**8.2%**
Tax rate	38%	38%	37%

1. Bloomberg values are justified based on 2004 data provided by Bloomberg in (Chicago 2004), Base values are simply provided in Table 5-1 of (Chicago 2004). See discussion in paragraph "*WACC numerical values*".

2. The inflation rate for the Chicago (2004) values is taken as that suggested in the MIT study.

Based on the previous discussions, it is recommended to use the WACC of publicly traded U.S. utilities as the reference discount rate, or *5.3%* in real terms from Table 9-1, rounded to *5%*: it appears the most justifiable, being based as much as possible on observed data. However, it is noted that no utility is currently a "pure nuclear player", and therefore the cost of capital of utilities is just a proxy for the appropriate risk-adjusted cost of capital of nuclear project, which may as well be as high as the higher values in Table 9-2. For this reason the *Chicago Base* value, being the highest at 9.2%, is recommended as the high value, and rounded to 10%.

In light of the high uncertainties surrounding these values, it is recommended to use a set of values for the opportunity cost of capital, as shown in Table 9-2.

Table 9-2. Suggested real discount rates.

	Upside (Low Cost)	Downsides (High Cost)	Selected Values
Real cost of capital ignoring taxes	3% Risk free rate: investors are compensated for delayed consumption but not for risk associated with the nuclear investment	10% Highest value in real terms between the Chicago (2004) and MIT (2003, 2009, 2011) studies from Table 1, rounded up from 9.2%.	5% WACC of publicly traded U.S. utilities in 2004, as provided by Bloomberg and adapted using realistic long-term financial data in Chicago (2004); rounded from 5.3%.

9.3 Discounting in the Public Sector

Transferring risk from utilities to society (e.g. government loan guarantees) requires a treatment of risk from society's perspective. Whereas the previous section addressed risk premiums and discounting from the firm's perspective this section considers risks that discounting should reflect from society's perspective. For example, government responsibilities such as spent nuclear fuel disposal require discounting based on risk accounting from the public's perspective. Additionally, public funding may be required for nuclear investments where the cash flows are distributed over a very long time. Therefore this subsection discusses a starting point for discounting public investments in nuclear energy then presents the current state of the art with respect to discounting over very long time frames.

9.3.1 Discounting US Federal Projects, OMB Circular A-94 and A-4

The US Office of Management and Budget (OMB) published two circulars that outline how the discount rate should be selected for analysis of federal projects. Circular A-94 outlines policies and protocols for conducing benefit cost analysis and cost effectiveness analysis. Discounting is an integral protocol to these methods of analysis (OMB 1992). Circular A-4 describes how to conduct regulatory impact analysis, of which discounting is also a part (OMB 2003). Taken together A-94 and A-4 describe US policy for selecting a discount rate.

Benefit-cost analysis, as described in A-94, identifies net benefits in monetary units accruing to society for investments undertaken by the federal government. The document indicates that benefits and costs, monetized in dollars, should be discounted at a "real" discount rate of 7%. The terminology of "real" or "nominal" distinguishes discount rates where inflation is removed from the discount rate (the real discount rate) versus the case where inflation is reflected in the rate (the nominal discount rate). The document notes that government investment displaces private investment and consumption and that 7% approximates the marginal pretax rate of return on the average investment had resources remained in the

economy. Then A-94 calls for sensitivity analysis where the outcomes of interest are evaluated under a range of discount rates.

Cost-effectiveness analysis is used to evaluate projects where either monetary benefits are constant or where benefits are measured in units of effectiveness. Suppose several alternatives provide an identical stream of monetary benefits but vary in costs. Then A-94 directs the analyst to use cost-effectiveness analysis. Or suppose the alternatives generate non-monetary benefits, such as lives saved. Then costs of each alternative are compared to the units of effectiveness. In the case of cost-effectiveness analysis A-94 directs the analyst to Appendix C[15] where a list of discount rates is provided consistent with maturities of US treasury notes and bonds: 3 years, 5 years, 7 years, 10 years, 20 years, and 30 years. The analyst chooses a discount rate based on the time horizon of analysis and the maturities listed in Appendix C. In real terms the A-94 recommended real rate for projects with maturity close to 30 years is 1.4%.

At first glance of the recommended discount rates from A-94 there could appear to be a contradiction; a wide disparity exists between 7% (the recommended rate for benefit-cost analysis) and 1.4% (the recommendation for cost-effectiveness analysis). The former discounts alternative flows of monetary benefits and costs over time. The latter discounts alternative flows of costs over time. Keeping in mind the notion of opportunity cost relative to the next best alternative, A-94 recommends discounting benefits at a rate commensurate with benefits that may have been realized if resources would have remained in the private sector. The recommended 7% is based on the average pre-tax rate of return. By contrast in cost-effectiveness analysis benefits are not discounted. So discounting costs is based on the rate the government must pay to borrow money.

OMB Circular A-4 (OMB 2003) outlines considerations for the analyst identifying the impact of regulatory actions. Much of the protocol is similar to A-94 because measuring benefits and costs from regulatory action is analogous to measurement of impacts in federal projects. A-4 makes the same recommendation to use a real discount rate of 7% for the base case then recommends sensitivity analysis at 3%.

Circular A-4 brings up an issue not addressed in A-94 that economists call “intergenerational discounting.” A-4 directs the analyst to consider applying the same discount rate to cash flows impacting future generations but cautions against applying a lower discount rate at points in the far distant future because of the distributional and time inconsistency implications. A-4 is not clear on how to address discounting over long time horizons. The maximum time horizon addressed in A-94 is 30 years. But in reality the government makes investments where flows of benefits and costs are realized over time horizons much larger than 30 year. It is not surprising, then, that EPA convened the meeting of leading economists mentioned earlier to discuss intergenerational discounting.

9.3.2 Intergenerational Discounting

A summary of the meeting EPA convened on discounting can be found in Arrow (2012). The purpose of this meeting was to inform EPA on intergenerational discounting based on the expertise of the group of economists. Those called to the meeting were leading economists who have developed theories and models to better understand discounting.

The experts agreed on key, fundamental points regarding discounting. They agreed with the general premise of discounting grounded in the theory of optimal savings developed in Ramsey (1928), that this framework is the approach to maximize social well-being over time. They agreed that considerable uncertainty exists regarding future, social well-being of the society. One part of *r* discounts future consumption, which is based on economic growth and the well-being of future generations. The

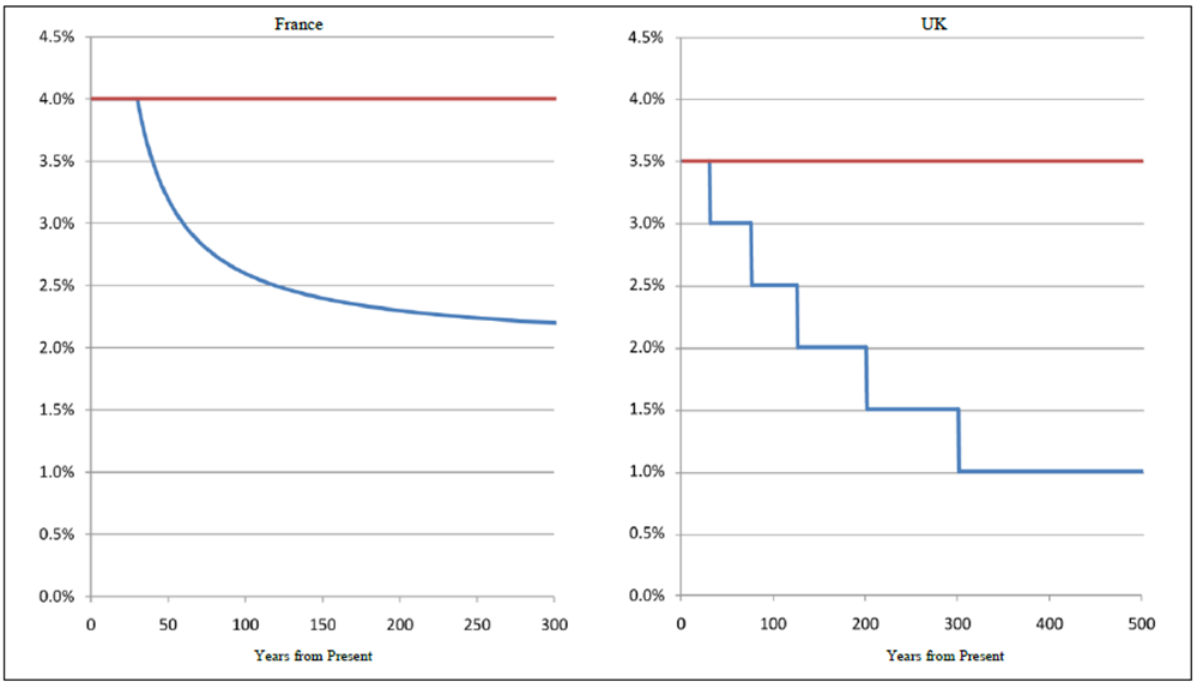
15. Appendix C available at www.whitehouse.gov/omb/circulars_a094/a94_appx-c , last accessed 13 August 2015.

uncertainty revolves around the fact that while societies have been continually better off according to the historic record, continued improvements is not a foregone conclusion. The odds are that future generations will be wealthier and thus better off than the present but the rate at which that growth occurs is uncertain. Uncertainty about that growth induces uncertainty about what is the correct rate to discount benefits and costs that accrue to future generations. Because of this uncertainty the experts agreed that a "precautionary" term should be subtracted from the discount rate. The precautionary term is based on what the economics literature calls "precautionary principle" (Mankiw, 1981). This term accounts for uncertainty, thereby reducing the possibility that the discount rate chosen is too high.

Further, the experts agreed that the precautionary term should not simply be a constant term to subtract from the discount rate. Instead the precautionary term should increase over time so that the discount rate itself declines over time. This leads to what economists refer to as the "declining discount rate" (DDR). So the collective opinion of the experts was that a DDR is appropriate for discounting cash flows in an intergenerational context, but what they did not agree on was how to parameterize the DDR.

The experts noted that two countries have adopted the DDR as the official policy regarding discounting. Figure 9-3, from Arrow (2012) who described it as sourced in Sterner (2012), illustrates the schedule of the DDR in France and the United Kingdom. The French policy regarding the DDR is set forth in Lebegue (2005) and the policy in the United Kingdom is in HM Treasury (2003). At least a couple points stand out as noteworthy. First, the schedules in both countries hold the DDR constant for approximately 50 years. This is consistent with discounting policy in the US (OMB 1992, 2003) discussed previously, and although the DDR begins at a lower rate than the recommended baseline of 7% in A-94 the starting point of the DDR is consistent with the range A-94 directs for sensitivity analysis. A-94 directs that sensitivity analysis be conducted at 3% relative to the baseline 7%. Another noteworthy observation is that the DDR for France and the UK both level off around year 300. In France it levels off slightly higher than in the UK, around 2.25% versus 1%. This is consistent with the interpretation of the summarized response of the survey of economists in Weitzman (2001). Weitzman interpolates from the responses that 300 years is the "distant" future and the discount rate should be 1%. However, in Weitzman (2001) points beyond 300 years are identified as the "far-distant" future and the accompanying discount rate is 0%.

With respect to the DDR, the point where the economists at the EPA meeting disagreed was on how the precautionary term should be parameterized. One group felt that identifying the rate at which the DDR should decrease should follow a prescriptive approach, such that parameterizing *r* should be a matter of policy. Another group felt that parameterizing *r* should follow a descriptive approach and therefore the parameters should be estimated from historical data, including bond rates and market rates of return.



Source: Sterner, Damon, and Mohlin (2012)

Figure 9-3. Declining Discount Rates in France and the United Kingdom (Arrow, 2012).

Arrow (2012) summarizes findings from the literature where the DDR has been estimated for the US. The studies are consistent with the two approaches to parametrizing the DDR, the policy approach and empirical estimation based on data. In review of the studies two insights emerge. Consistent with the policies in France and the UK, in the studies the discount rate is basically constant over the first 50 years of the time horizon. This is consistent with the current US policy on discounting (OMB 1992, 2003). Second, in the studies the DDR levels off around year 300 although this varies a bit based on estimation method. The studies estimate the DDR to begin at 4% certainty-equivalent discount rate[16] then it levels off in a range (0% to 2%) based on policy assumptions and estimation method.

Previously in this chapter the discussion describes the many factors that go into choosing a discount rate, and how the risk perspective influences the choice. The discount rate applied in the discounting formula contributes to a discount factor, which weights future values consistent with the factors that influence discount rate choice (opportunity cost, risk, borrowing cost, etc.). Adjusting the relevant factors of the discount rate leads to, at one end of the spectrum, a 0% discount rate while at the other up to a 10% discount rate. Figure 9-4 shows the effect of the discount rate on the discount factor. The factor illustrates the weight that future values carry in present value terms. Think of the discount factor as the percent of future costs that carry value today.

The figure illustrates how the discount factor, or in other words the weight that future values carry in today's terms, varies with the choice of the discount rate. Looking first at years 0 through 100 shows a fair amount of variation in the discount factor (the lines are spread apart.) This variation is largely what the discount discussion in the economics literature is about; which discount rate choice correctly reflects the underlying assumptions so that the factor accurately reflects the translation of future values to present

16. Certainty-equivalent is a form of adjusting the rate for risk.

terms. But also look at years 100 to 200, where there is scarcely any variation in the discount factors, and the present value collapses to zero. In analysis of nuclear fuel cycle transitions, 100 years-plus is the time frame where much of the cost analysis typically begins! This is the effect the sensitivity analysis shown in Figure **9-2** displays. Any non-zero discount rate weights future cash flows essentially to zero.

One practical impact of discounting in nuclear fuel cycle decisions is that up-front costs of implementing geologic disposal are so much larger than those of dry storage that economic analyses using non-zero discounting will usually favor storage, both for present decisions and future decisions, such as when fuel packaging may begin to degrade and require overpacks.

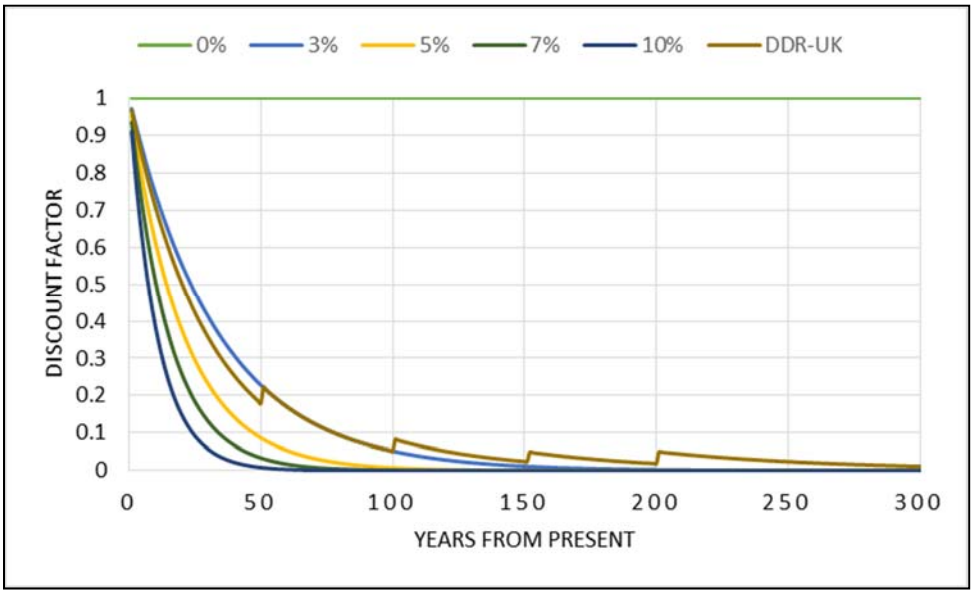


Figure 9-4 Discount Factor by Discount Rate

The Update discussed "Intergenerational Discounting." This is the branch of the literature that seeks to reconcile the need for discounting over time frames into the far distant future. The notion of a declining discount rate (DDR) stems from that literature. Conceptually the DDR decreases the discount rate over time so that the weight of the discount factor does not diminish as quickly with the passage of time. As the Update discusses, national policy in France and the UK prescribe a DDR for analysis of state programs. The discount factor that corresponds to the DDR in the UK is represented in the figure. It tracks similarly to its non-DDR counterparts in the first century of application, and similarly tracks in the second century, approaching zero in the third century.

This example illustrates the importance for the nuclear community to be involved in determining how best to translate cash flows in the far distant future to meaningful present values. Like the arguments regarding climate change mitigation, the benefits of nuclear choices today are long-lived into the future. Without being able to better translate those monetized benefits to meaningful present values, alternative nuclear designs will continue to have difficulty getting past the "kicking the can down the road" type of arguments.

10. TREATMENT OF UNCERTAINTY IN THE COST BASIS REPORT

10.1 Introduction

The objective of the Advanced Fuel Cycle Cost Basis Report is to provide a comprehensive set of cost data supporting an ongoing, credible, technical cost analysis basis for use by the DOE NTRD program. To be credible, this must include acknowledgement and treatment of the significant uncertainties associated with nuclear cost estimates for both existing and advanced systems. These uncertainties arise from multiple sources:

- Large variations in the estimated cost of current nuclear construction projects for similar NRC-certified designs due to differences in financing approaches, regulatory environments (e.g., regulated versus deregulated utilities), differences in grid connection costs, uncertainties of construction schedules, etc.
- Uncertainties for future projects driven by potential changes in designs, interest rates, regulations, construction techniques, fuel costs, competitiveness versus other energy sources, etc., especially when projects may not start construction for decades and the resulting facilities may operate for a half century or more. The future rates of construction and design innovation will also impact learning curves for transition from First-of-a-Kind (FOAK) to Nth-of-a-Kind (NOAK) facilities.
- Significant uncertainties concerning the specific design features and achievable performance of future full-scale facilities using advanced technologies that now have low technical maturities. Most advanced fuel cycles require multiple such technologies.

Due to the above uncertainties, it is unrealistic to expect the AFC-CBR could be used to accurately estimate the cost of an advanced nuclear fuel cycle system. Large uncertainties in the input cost data inevitably lead to large uncertainties in calculated systems costs.

Fortunately, accurate estimates are typically not required to support the NTRD program. Instead, it is usually sufficient to be able to estimate a cost range that includes associated uncertainty and identify the cost drivers. Per Section 1.3, the intended use of the cost data is for the relative economic comparison of options rather than for determination of total fuel cycle costs with great accuracy. Each element of cost has a probabilistic range of accuracy, and when the costs are coupled together into a total fuel cycle system estimate, the uncertainty range is additive.

10.2 Representation of Uncertainty in the AFC-CBR

Each module of the AFC-CBR includes two features that incorporate uncertainty into the recommended unit costs. The first is the “What it Takes” (WIT) table, which summarizes the major drivers for both up-side and down-side costs and provides high and low values along with (usually) a mode and a mean value to use for cost analyses. The intent is for the analyst to use value ranges when assessing system costs, or at least to perform sensitivity studies based on the cost ranges. The WIT is the module author’s opinion or best estimate of the cost range indicated by the cost data collected in developing the module.

The second is a suggested cost probability distribution to use when the analysis tools support uncertainty propagation. Two forms of distribution are used in the current AFC-CBR; a uniform distribution using the high and low values from the WIT table and a triangular distribution where the based on the high, low and mode values (see Figures S-2 and S-3). It is incumbent upon the analyst to use these distributions with care, including testing the sensitivity of key data and even the distribution selection as appropriate for the application.

The cost probability distributions are deliberately simple to reflect the limited cost information typically available for each module. The triangular distribution allows for a modal value near the lower end of the uncertainty range when appropriate based on the available data (e.g., yellowcake prices) or

when there is large up-side technical uncertainty. When there are no such drivers, the mode value is near the middle of the range and provides an approximation of a normal distribution. As in the 2009 AFC-CBR, triangular distributions are used for all modules except modules B and C (Uranium Conversion and Enrichment), where market price data suggested the uniform distribution is more accurate.

The AFC-CBR team has noted that many users of the AFC-CBR have been ignoring the cost ranges and using just the mode values, resulting in "point" cost estimates that imply more accuracy than is credible.

10.3 Treatment of Correlated Uncertainties

The AFC-CBR team has noted that the cost uncertainties in the different modules may not always be independent and additive, as indicated in the summary of the 2009 AFC-CBR, but may instead be due to common causes. For example, changes in construction interest rates or concrete prices would impact the costs in most of the modules in a coupled manner - even though the scale of the impacts would vary, the direction would be the same. The impacts of these correlated cost factors are very difficult to assess without much more detailed cost code of accounts breakdowns than are currently available, but are important in that they are not additive when comparing costs across fuel cycles.

The inability to account for correlated costs is likely producing comparative system cost probability distributions that are wider than the actual uncertainties. This is of particular concern when developing relative comparisons of different systems, because it is hard to define and defend any cost advantages of one system over another when the probability distributions significantly overlap (see Figure 10-1 from Shropshire, et. al. 2009).

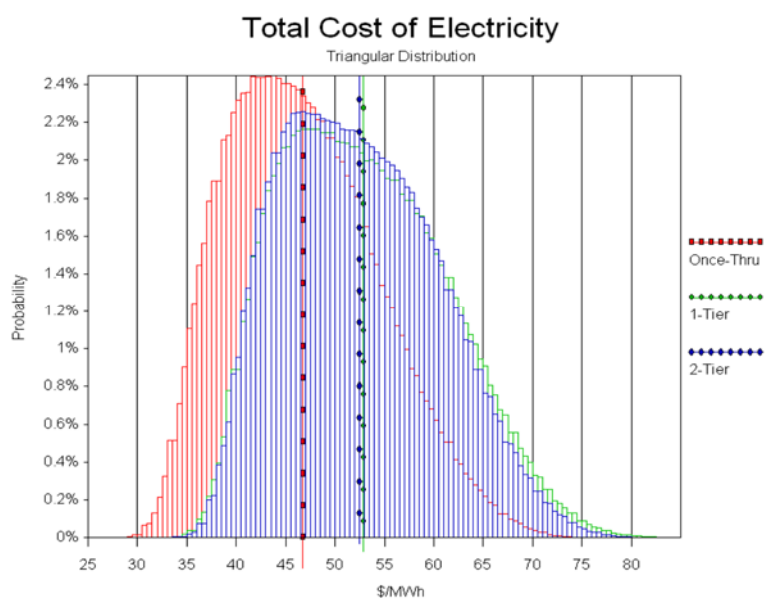


Figure 10-1. Cost comparison of three systems using cost probability distributions[17].

17. From D. E. Shropshire et al., "Advanced Fuel Cycle Economic Analysis of Symbiotic Light-Water Reactor and Fast Burner Reactor Systems", January 2009, INL/EXT-09-15254. www.inl.gov/technicalpublications/Documents/4235622.pdf

Often with comparing nuclear energy systems, some components may be in common. For example, the three cases in Figure 10-1 all use an LWR in their first stage. When performing comparison analyses using the data from the AFC-CBR, the analyst is cautioned in such cases to treat common components as being correlated when appropriate (e.g., built at the same time, etc.). This will properly reduce some of the comparative uncertainty and narrow the comparative probability distributions.

While the correlations between systems using the same reactor types are obvious, other partial correlations also exist. In two of the cases in Figure 10-1, both LWRs and FRs are used. While the reactor core and coolant systems of these two reactor types are very different, the balance of plant (steam turbines, etc.) of all reactor types is very similar. This results in partially correlated costs between reactor systems. The AFC-CBR team is developing and testing partial correlation factors and associated application methods to enable more accurate comparisons of nuclear energy systems. The limiting factor in development, as in many other areas of nuclear cost analysis, is a lack of data on which to base the partial correlation coefficients. The AFC-CBR team is currently pursuing an expert elicitation approach for establishing these coefficients. Initial findings of this effort are in the material of supporting documents – see AFC-CBR section SD3.

11. MODULARITY ANALYSIS

Modular nuclear reactors have garnered considerable attention of late over the traditional single reactors for the production of electricity. Proponents have cited many potential advantages such as design simplification and standardization leading to reduced probability of cost overruns, shorter construction times, off-site-factory fabrication, foreign fabrication, cost-reduction from repeated fabrication and associated learning and process improvements, and lower and periodic capital requirements. A realistic economic analysis could, however, be useful to determine whether these advantages result in a more competitive nuclear reactor system leading to a lower price of electricity to the consumers while ensuring adequate profit to the reactor operator and reactor manufacturer, particularly in an environment where the price of electricity is controlled by deregulated market forces.

A realistic economic analysis could also account for several factors that influence the cost of construction of the reactor infrastructure and the reactor modules, the cost of nuclear fuel, the operation and maintenance cost, and the cost of borrowing. Modular reactors, because they typically have a smaller generation capacity than a single reactor (for example, the 12-module system of 50 MWe capacity each proposed by NuScale, as opposed to a single traditional unit of 600 MWe capacity), may also be configured differently in time. The example NuScale system could be constructed to start electricity generation either as a single-pack system at one site or as a multi-pack system with different modules coming into generation at different points in time at one site. Configuration flexibility, while offering more choices on how modularity is delivered to the utility and power to the customer, also poses important questions such as the economic feasibility of the different configurations and choice of an optimal system. An economic analysis could also verify the cost reductions, as claimed by the proponents, that may be achieved from learning and improvement following the fabrication of each successive module and the possibility that the balance of the site infrastructure (everything except the reactor) could be built initially and separately from the modules and turbines which would then be simply plugged in ("plug and play" concepts).

A systematic methodology for conducting an economic feasibility analysis for a modular reactor system is presented in the discussion below. The methodology is quite general and scalable in scope. It has been developed to address both the traditional reactor system and multiple configurations of co-located modular reactor systems; but a multi-site configuration is not addressed in the methodology. A number of endpoints could be used to compare a modular reactor system configuration with a single traditional reactor system or with other configurations of the modular reactor system. The levelized unit of electricity cost (LUEC), expressed as $/MWh, and the net present value (NPV) of the venture from a utility's perspective are the two primary endpoints that are used in the methodology.

The annual contribution to the levelized cost, *AC*, for a power plant can be estimated using the following equation:

$$AC = [CF + FUEL(F, p_F) + O\&M(L, p_L)]/E \qquad (7)$$

where *CF* is the annual cost to the utility from construction of balance of infrastructure and fabrication of reactor modules over the operational life of the reactor system ($); *FUEL* is the annual fuel payment ($) and it is a function of amount of fuel (kgU), *F*, and price of fuel ($/kgU), p_F; *O&M* is the annual operations and maintenance expense ($), which is a function of the amount of labor (person-h), *L*, and the price of labor ($/person-h), p_L; and *E* is the total energy output (MWh). LUEC is estimated as the sum of *AC*'s discounted to the start of commercial electricity generation at the discount rate *r* over the operational lifetime of the plant.

The annual profit of a venture, *P*, is estimated on an annual basis using the following equation:

$$P = E \cdot p_E - LC \cdot E \qquad (8)$$

where p_E is the price of electricity. The NPV of the power-plant venture is estimated as the sum of the P's discounted to the start of commercial electricity generation at the discount rate r over the operational lifetime of the plant.

This formulation for the estimation of LUEC and NPV is currently in use for the traditional single reactor system (e.g., Rothwell and Ganda, 2014) in which CF is parameterized as the annual overnight cost. When extending the formulation to the modular reactor system, additional considerations need to be addressed. These include, as mentioned earlier, the addition of modules at different points of a system's operational life, the presence of a learning curve that allows the future modules to be manufactured at lower cost or in shorter time, and the specific financing arrangement a utility enters into with lenders. Treatment of these considerations within the framework of Equations (7) and (8) is presented below.

The annual cost to the utility from construction and fabrication consists of two distinct components – the modular reactor fabrication component and the balance of site infrastructure component. The cost for the modular reactor fabrication component is influenced by the specific financial agreement that the utility enters into with the manufacturer of the modules; however, it is estimated on the basis of how the utility finances the payments to the manufacturer. For example, the manufacturer could decide to sell each module at a fixed price regardless of when the modules are delivered and installed at the site. This option allows a manufacturer to take a loss with the initial modules, but as his cost goes down with the learning and standardization after each module, he is able to make profits on later modules. He uses this "loss leader pricing" strategy for market entry as he competes with other technologies in the energy sector. Alternatively, the manufacturer may offer to sell each unit at a price that includes his costs plus a fee provided the utility pays for the fabrication cost as it is incurred, thus reducing the manufacturer's burden of financing the entire fabrication cost up front. The latter transaction is adopted here to explain how CF is estimated for a modular reactor system. In both examples, the utility borrows from a lender to pay the manufacturer; again, the methodology presented here is conducted from the economic perspective of the utility.

There are three distinct periods in the lifetime of a module from fabrication to the end of operation. The first period is the pre-fabrication period in which the annual cost to the utility for a module m is zero; i.e.,

$$F_m = 0 \; for \; t < t_{SFm} \tag{9}$$

where F_m is the cost of fabrication during the fabrication period for module m ($); t is the time (y), $t = 0$ at the start of the construction of infrastructure at the utility's site; and t_{SFm} is the time at the start of fabrication (y).

The second period is the fabrication period; the fabrication occurs at the manufacturer's facility. As discussed earlier, the utility agrees to pay the manufacturer the quoted sales price which includes the fabrication cost plus a fixed fee; all costs up to the power production, including delivery, installation, and commissioning of the module are assumed to be included in the fabrication cost. Since the utility has also agreed to make the payments for the module during the fabrication process as the manufacturer incurs the cost, it borrows the entire amount of the sales price and makes interest-only payments to the lender during the fabrication period and makes fixed payments each year over the expected operational period of the module to pay off the loan. The interest-only part of the repayment during fabrication is similar to the credit card interest-only payment that leaves the principal unaffected. The full payment over the operational period of the module is similar to the home-mortgage amortization scheme in which a fixed payment that includes both principal and interest is made every year towards the loan.

The manufacturer's sale price, in turn, is a function of time and reflects the combined effect of cost reductions through repeated fabrication, installation, and commissioning of the module using a standardized design and associated learning after successful delivery of each module. To address the

overall reduction in cost and the sales price over the years, the manufacturer determines his sale price for module *m* according to the following equation:

$$S_m = S_0 e^{-k_L(t_{Pm} - t_{P0})} \tag{10}$$

where S_m is the sale price of the module ($) at time t_P, S_0 is the sale price of the module at time $t = 0$; k_L is a learning rate constant (1/y); and t_{Pm} is the time (y) at which the module *m* is expected to put electricity on the grid; and t_{P0} is the time when the manufacturer‘s first unit generated power at the Utility’s facility (y). Thus, the manufacturer is able to reduce his sale price as a function of time and the value of k_L controls the speed of learning, higher k_L resulting in faster learning and faster reduction in the sale price.

The Utility’s annual cost during the fabrication period for a specific module m is then estimated as

$$F_m = I_F \; for \; t_{SFm} \leq t \leq t_{Pm} \tag{11}$$

where I_F is the total of the monthly interests ($) the utility pays to the lender in a year on the principal S_m during the fabrication period.

The monthly interest rate can be estimated from the discount rate using

$$i = (1 + r)^{\left(\frac{1}{12}\right)} - 1 \tag{12}$$

where *r* is the annual discount rate (%/y) and *i* is the monthly interest rate (%/m).

In the last period, which represents the expected operational period of the module, the utility repays the loan as a fixed annual payment, amortized over the expected operational period of the module so that

$$F_m = FCR \cdot S \; for \; t_{Pm} \leq t \leq T \tag{13}$$

where *FCR* is the fixed charge rate (%/y) and T is the expected operational life of the module. *FCR* is based on the discount rate and is estimated as

$$FCR = \frac{r \cdot (1+r)^T}{(1+r)^T - 1} \tag{14}$$

In a multi-pack modular reactor system, the values of t_{SFm} and t_{Pm} are module-dependent; i.e., they could be different for each module depending on when its fabrication begins and it starts loading power into the grid. The annual cost *F* depends on contributions from all modules, each module’s contribution to the annual cost being evaluated on the basis of the applicable period of the module in the year being evaluated. Thus,

$$F = \sum_{m=1}^{M} F_m \tag{15}$$

where *M* is the total number of modules in the system.

The cost for the balance of infrastructure is also dependent on the specific agreement the utility makes with the lender. Assuming, as before, that the utility makes interest-only payment to the lender until the construction of the infrastructure is complete and pays a fixed annual amount thereafter, the annual balance of infrastructure construction cost can be estimated as

$$C = I_C \; for \; t < t_{P0}, \tag{16}$$

where C is the annual balance of infrastructure construction payment the utility makes to the lender and I_C is the total of the monthly interests ($) the utility pays to the lender in a year on the principal (the total balance of infrastructure cost ($),$C_0$), and the monthly interest rate to estimate I_C is the same as *i*, estimated using Equation (12). The construction loan is then fully paid off during the expected operational period of the facility as a fixed amount *C*, which is estimated as

$$C = C_0 \cdot FCR \; for \; t_{P0} \leq t \leq T. \tag{17}$$

The annual construction cost ($), FC, is then estimated as

$$FC = F + C. \tag{18}$$

Typically, LUEC is estimated in the year the plant starts commercial operation (e.g., Rothwell and Ganda, 2014). For a modular reactor system, it is possible to have different modules starting commercial productions at different points in time. For consistency in assessments and comparisons across different configurations, the LUEC and NPV should be evaluated in the first year that the system starts commercial production.

While Equations (9) through (18) have been developed with specific assumptions regarding financing, they are generalized enough that deviations can be accommodated easily. For example, if the utility does not incur any interest payments prior to the delivery and installation of a module, the annual cost of fabrication for each module will remain zero until the first generation of power from it. As explained earlier, the system of equations is also applicable directly to the case of a traditional single-module reactor; *CF* in Equation (7) can be directly estimated from the overnight cost. For a detailed and comparative analysis of the economic feasibilities of the various modular reactor systems and the traditional reactor system, a sensitivity analysis may be conducted to identify parameters that would most influence the LUEC or NPV. Parameters that may be tested include the learning rate constant, thermal efficiency of the system (which would directly affect the amount of fuel being consumed and, therefore, the fuel cost), time-dependent deployment of the modules (which would reflect differently on the cost profile over the operational period of the system), manufacturer's method of establishing module's sale price (e.g., a fixed sale price to take loss on initial modules and make profit on later ones), discount rate (to accommodate different financing schemes; e.g., different debt to equity ratios), and price of electricity (to account for effects on revenue stream under different configurations of modular system). Alternate estimates of these parameters may be developed to study their impacts on the LUEC and the NPV.

12. ECONOMIC COMPUTER MODELS

12.1 Integration of Cost Modules into Cost Models

The module-by-module unit cost information and general economic parameter cost information included in this report may be used in conjunction with computer models to provide quantitative analysis of fuel cycle options. The costing procedure described in Section 4 is directly relevant to the use of cost data in the cost models. It is strongly recommended that the user become experienced with manually using the cost data in scenario studies before incorporating the data in a cost model. Manual checks on modeling results are recommended for verification.

Cost models can be wonderful time saving analysis tools, but may also provide misleading answers. Wrong conclusions will result from a number of sources:

1. Cost data were not intended for use in the type of scenario.
2. Bounding capacities of the reference facility were exceeded.
3. Module capacities and mass flows were not properly calculated to account for recycling, blending, maximum versus operating capacities, etc. (Incorrect material balance.)
4. Cost module uncertainties bounds were not considered.
5. Misunderstanding of ownership (private versus government) and associated treatment of interest charges for capital, taxes, etc.
6. Inadequate account taken of the technology maturity level and R&D funds needed.
7. Hidden/implicit assumptions
8. Impacts on processing efficiency resulting from future technologies.

12.2 Computer Software and Simulations

Several fuel cycle models have been developed that produce mass flows through the fuel cycle based on various fuel cycle scenarios. Some of the fuel cycle models that could be adapted for use with the NTRD cost data are described in the following sections.

12.2.1 NFCSim

NFCSim Version 3.0 is a JAVA-based model developed by Los Alamos National Laboratory that tracks the flow of nuclear materials at charge level (isotopic level) throughout the nuclear fuel cycle. The object-oriented model reenacts the history (i.e., simulates the operation with the historical variation in burnup and availability) of the U.S. reactor fleet, which includes 104 operating and 14 decommissioned reactors, to obtain an estimate of the associated SNF generated by these reactors. The class structure of the model includes facility classes for the complete fuel cycle, including reactor and accelerator driven systems. The model is coupled to ORIGEN and can produce detailed isotopic flows resulting from irradiation in a reactor or decay while in storage. NFCSim includes a costing model using input unit cost data. The calculation of annual costs is assessed for the year in which the service is rendered. Pre and postoperational costs (e.g., initial core loading) are included in the mortgage and D&D escrow account, respectively. Costs for storage can be assessed on a $/kg/yr or $/kg basis. Costs and revenues with a time component (e.g., O&M and electrical production) are apportioned according to the fraction of a year for which they apply (Bathke et al. 2002).

12.2.2 Dynamic Model of Nuclear Development (DYMOND)

DYMOND Version 1.0 and DANESS (not reviewed) are system dynamics models developed by Argonne National Laboratory to perform 100-year global nuclear energy scenarios. The DYMOND

model was further developed in FY 2005 by modelers at Argonne and the Idaho National Laboratory to perform fuel cycle systems analysis. The Stella/iThink models provide a summary level simulation of SNF for the U.S. reactor fleet. These types of models support continuous, nonlinear feedback systems. The modeling environment is adaptable to various reactor systems but is less sophisticated than object-oriented tools. The model handles radioactive decay at a summary level, parametrically estimating rates for key isotopes. Unit cost data may be incorporated into the model to determine the total costs resulting from mining, conversion, enrichment, storage, fuel fabrication, recycling, disposal, and power production.

12.2.3 Harvard Spreadsheets

The economic models used in the 2003 Harvard economic study, *The Economics of Reprocessing vs. Direct Disposal of Spent Nuclear Fuel* (Bunn 2003), are available as spreadsheets (http://www.puaf.umd.edu/Fettr/programs/COE-LWR.xls). The spreadsheet models are self-documenting. There are two spreadsheets, one for LWR and one for fast reactors. Either can be used to estimate the LUEC (in $/MWh) based on key user-input parameters such as U ore price ($/kg), mixed-oxide (MOX) or fast reactor fuel fabrication cost ($/kg), geological disposal cost ($/kg), separation cost ($/kg).

12.2.4 Generation IV Economic Modeling Working Group Levelized Cost of Electricity Model

The International Generation IV EMWG has an EXCEL-based model called G4 ECONS (EMWG 2007) that considers open fuel cycles and equilibrium closed fuel cycles. The intent of the model is to allow comparison of all six Generation IV concepts and their variants. The financial model is very simple, since the intent is comparison of technologies and not financing or deployment options. The fuel cycle portion of the model inputs unit costs in much the same form that they are given in this report. The fuel cycle component cost for all of the major parts of the fuel cycle is then calculated in mills/kWh ($/MWh), $/kg heavy metal (HM), and $/yr. In order to keep the model—which must also consider capital, O&M, and decommissioning costs—simple, fuel cycle lag and lead times and losses are ignored. So far, the EMWG model has been used for a range of nuclear system analysis, including Japanese Sodium Fast Reactors under study by the Generation IV technology groups.

The first purpose of the highly-transparent and simple G4-ECONS formulation for fuel cycle modeling is to allow comparison of vastly different reactor and fuel cycle technologies being developed by many international partners; secondly, not enough information on the timing of technology deployment and financing is available to allow the use of more sophisticated models. No allowance is made for interest charges due to lag time or lead time in purchase of services, as is done in more sophisticated business models used by utilities.

12.2.5 Total System Model

Bechtel SAIC has developed a model for the Yucca Mountain Project. The objective of the Total System Model is to evaluate alternative approaches for Spent Nuclear Fuel and HLW disposal. The model encompasses the back-end of the fuel cycle and provides discrete event simulation of waste packages from the 104 U.S. reactors to final disposition at the HLW repository. The model was developed in SimCad and is designed to evaluate life-cycle costs, total project cost, and funding requirements. The model was developed based on a once-through fuel cycle and does not currently support recycling alternatives (Shropshire 2003).

12.2.6 VISION.ECON

The existing fuel cycle models, previously discussed in this section, were not developed specifically to support comprehensive dynamic analysis of fuel cycle costs. A cost module called VISION.ECON was added to the Verifiable Fuel Cycle Simulation (VISION) model (AFCI 2005, Jacobsen 2005) for this purpose. This model was used to perform fuel cycle analysis in support of the AFCI Systems Analysis in

2008 (AFCI 2008). This model used the cost data from this report to analyze various fuel cycle alternatives. Results from the dynamic VISON.ECON were compared to the G4 ECONS model for verification purposes and to help in understand the impacts from modeling under dynamic conditions.

VISION.ECON was created as a submodel of VISION to provide economic analysis of nuclear fuel cycle cases. The submodel produced cost distributions for relative economic comparisons rather than absolute value cost estimates. VISION.ECON extended the modeling capability beyond static equilibrium analysis tools by providing insight to dynamic modeling impacts to cost over time. The tool included the functionality to evaluate cost and system uncertainties. Model output showing the total cost uncertainties of a case were generated within VISION.ECON in a post processing mode using a modified Monte Carlo method. Cost and system uncertainties could be used to identify the variables within the model that have the largest impact on the cost for each case. Updates of VISION.ECON were suspended in VISION version 3 and are not included in the current VISION release, but could be reactivated if need arises.

12.2.7 NE-COST

NE-COST was developed in 2012 to support the nuclear fuel cycle evaluation and screening; specifically for the calculation of the Levelized Cost At Equilibrium (LCAE) metric for complex fuel cycles. One design objective for NE-COST was to allow the calculation of the cost of electricity of arbitrarily complex systems by just changing the input, without the need to alter the code. For this purpose, an “island approach” was adopted where each stage of a fuel cycle can be calculated separately and the results combined. Figure 12-1 shows how the AFC-CBR modules in Figure 1-1 are modeled using the island approach for a three stage fuel cycle that includes a fleet of PWRs fueled with UOX feeding a fleet of PWRs fueled with MOX, which in turn feeds a fleet of burner fast reactors (Ganda 2012). To accommodate the island approach, the general structure of the NE-COST MATLAB code has been developed allowing several alternative front-end and back-end paths, which can be selected by the user by using switches in the input (see Figure 12-2).

NE-COST has been developed with the capability to handle uncertainty as a required functionality, through the capability (1) to estimate the magnitude and the functional form of the uncertainty in the calculated LCAE; and (2) to identify the biggest uncertainty drivers and their individual impact. To this end, the NE-COST structure has been developed specifically to handle distribution information. A Monte-Carlo sampler has been developed, as well as a methodology for the correct propagation of uncertainty between islands, to create a system-wide cost of electricity uncertainty distribution. A suite of tools have also been created to handle the stochastic combination of distributions and the plotting of the results.

NE-COST has been benchmarked against the well-established nuclear economic code G4-ECONS, as well as against previous economic analyses performed under the Global Nuclear Energy Partnership (GNEP) program. In both cases, the NE-COST results are in excellent agreement with the previously-obtained results.

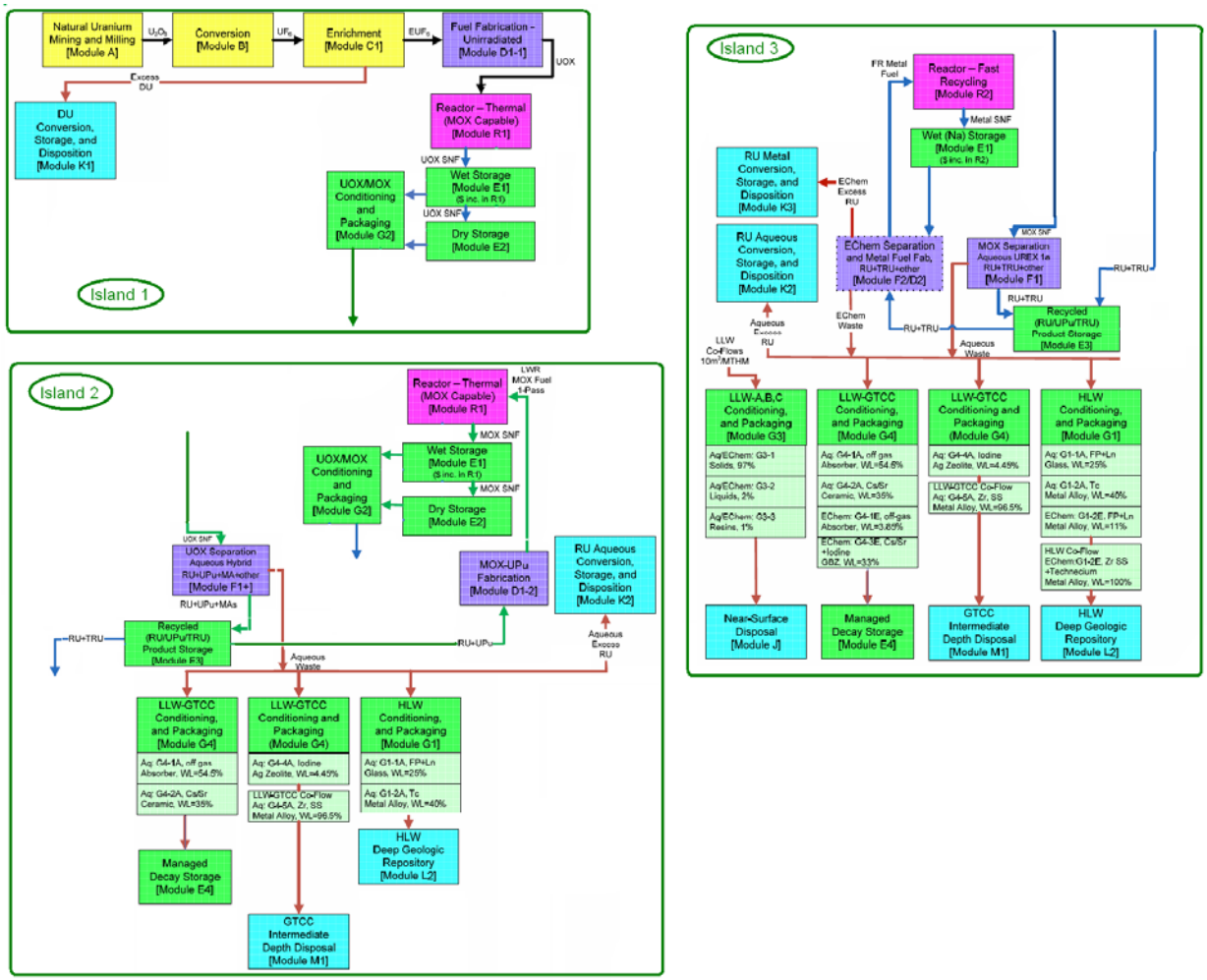


Figure 12-1. Schematic representation of a 3-stage fuel cycle using the island approach.

12.2.8 Additional Tools

Additional cost analysis tools are always under development by NTRD economics personnel to support specific cost evaluations. These typically are simple spreadsheets that are developed, validated, and used for a limited number of analyses. However, some may evolve into more general purpose tools that may be added to this chapter in the future. Several of the tools already in this chapter had similar beginnings.

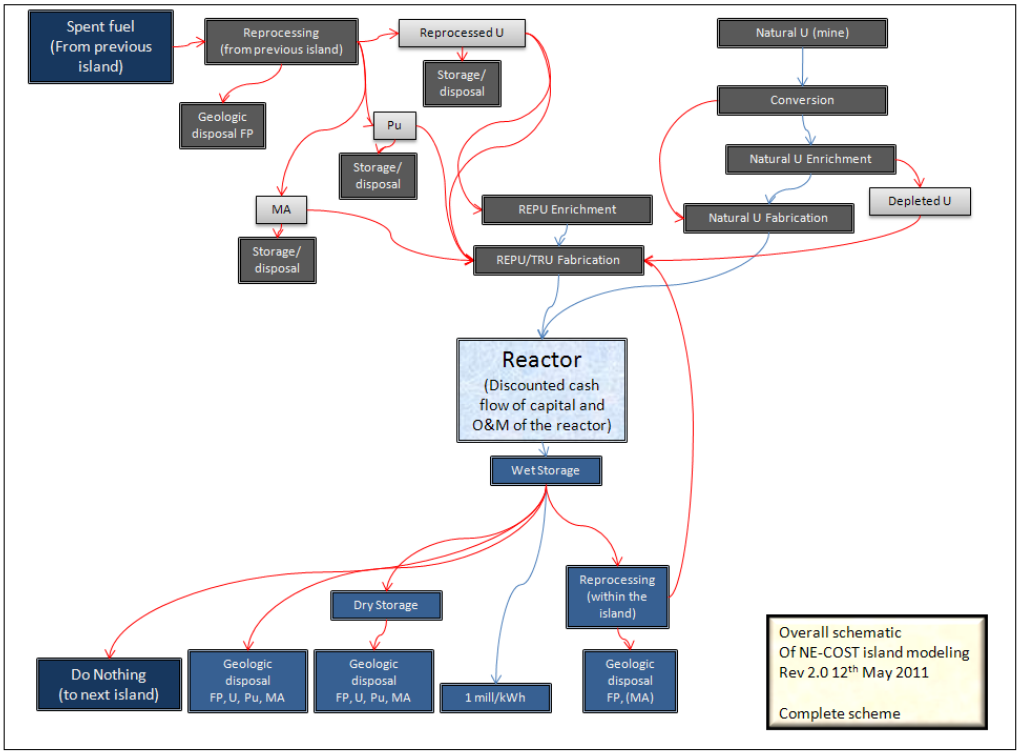


Figure 12-2. Schematic representation of the NE-COST structure.

13. CONCLUSIONS AND RECOMMENDATIONS

The NTRD Economic Analysis team has established the processes and structure to support the collection of fuel cycle cost data. The cost data were drawn from over 200 reference reports, reviewed and summarized, normalized for consistency, verified through cost sensitivity analysis, input to models for evaluation of various fuel cycle scenarios, and applied toward new approaches for communicating fuel cycle economics.

13.1 Creation of a Credible Reference NTRD Cost Basis

The Advanced Fuel Cycle Cost Basis report, commissioned by DOE, provides a comprehensive set of cost data supporting an on-going, credible, technical cost basis for use on the NTRD Program. System analysts have used this report to evaluate the impacts and benefits of a wide range of nuclear fuel cycles and deployment scenarios. The report is meant to aid analysts in (1) understanding the issues and opportunities for keeping nuclear power an economically competitive option, (2) evaluating the elements dominating nuclear fuel cycle costs, and (3) developing the tools to evaluate the economics of creative solutions to make the nuclear fuel cycle even more cost competitive.

The intended use of the cost data is for the relative economic comparison of options rather than for determination of total fuel cycle costs with great accuracy. Each element of cost has a probabilistic range of accuracy and, when the costs are coupled together into a total fuel cycle system estimate, the uncertainty range is additive. The cost data are being used in studies to evaluate costs of fuel cycle options. Fuel cycle costs are an important part of the comprehensive evaluation that also includes measures of sustainability, proliferation resistance, adaptability to different energy futures, and waste management impacts. These evaluations will result in the identification of cost drivers within the fuel cycle where development may be focused to reduce the costs within the system.

This report describes the NTRD cost basis development process, reference information on NTRD cost modules, a procedure for estimating fuel cycle costs, economic evaluation guidelines, and a discussion on the integration of cost data into economic computer models. This report contains reference cost data for 36 cost modules and sub modules—26 fuel cycle cost modules and 10 reactor/transmuter modules. The cost modules were developed in the areas of natural uranium mining and milling, thorium mining and milling, conversion, enrichment, depleted uranium disposition, fuel fabrication, interim spent fuel storage, reprocessing, waste conditioning, SNF packaging, long-term monitored retrievable storage, managed decay storage, recycled product storage, near surface disposal of LLW, geologic repository and other disposal concepts, and transportation processes for nuclear fuel, LLW, SNF, transuranic, and high-level waste. The NTRD cost developers coordinated closely with the Generation IV EMWG during the initial development of the AFC-CBR and adopted many of the EMWG estimating structures, assumptions, and estimating processes. Additional processed have been developed based on needs of the NTRD Program, including methods for assessing fuel cycles at equilibrium, during transition, and using modular implementation.

This report is based on data collected from historical reports and expert knowledge of past and current fuel cycle facilities and processing requirements. The reference data have been placed into a cost collection database, screened, normalized for U.S. facilities, and summarized for this report. The fuel cycle requirements for future generation nuclear reactors are also being assessed and will be included in the cost basis as the technology matures. The cost basis information will be updated periodically with advancements in the knowledge gained in the technology development studies.

This report establishes fuel cycle modules with “What it takes” (WIT) values and a plausible cost distribution for a particular service, operation, or material. In most cases a cost or price is given and does not include any taxes, carrying charges, or other overheads sometimes applied to such items by utility accounting systems. For example, some utilities may add refueling service overheads or significant carrying charges to the front end costs for UO_2 fuel. This may result in open cycle fuel cycle front-end

costs of 10 mills/kWh or higher. The constituent unit costs given are intended to be used in a simple, but highly transparent, "value added" cost analysis models such as the Generation IV G4-ECONS reactor economics code. Due to the uncertainty associated with cost data, the use of codes with uncertainty capabilities, such as the NE-COST code are encouraged.

13.2 Path Forward

This report will continue to be updated in future years based on the input from technical reviews; updated cost information; advances in the knowledge gained in the technology development studies; information collected through integration with NTRD and interaction with other programs and organizations involved with nuclear cost analysis. Additional cost sensitivity and uncertainty analysis will be performed to expand the knowledge base. Additional studies are underway, including:

- Review of historic cost data to separate added costs of FOAK, regulatory, and special items that added to facility costs and construction times beyond the underlying base costs of those facilities.
- Development of methods for discounting that consider the risks inherent in nuclear facility projects while also incorporating the latest recommendations on discounting over very long time frames such as are expected for fuel cycle transition scenarios.
- Development of more specific imformation on facility capital and fixed and variable operating costs to supplement the current unit-based costing for improved analyses of transitional systems where facility capacity factors are subject to evolving demand.
- Gathering of partial correlation information for improved uncertainty modeling in pair-wise comparisons of fuel cycles and scenarios.
- Identification of factors specific to modular facility deployments that may provide opportunities for cost reduction or value improvement.
- Development of methods and tools for improved modeling of transition-related system costs.

All reference fuel cycle cost data and source documentation will continue to be placed in the NTRD Cost Collection database. The fuel cycle requirements for future generation nuclear reactors will also be assessed with the help of the Gen IV EMWG and included in the cost basis as this technology matures. An updating of the Cost Collection database is planned.

NTRD systems cost analysis will continue to be performed using both static and dynamic models as a check on estimating assumptions, modeling algorithms, and data integrity.

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