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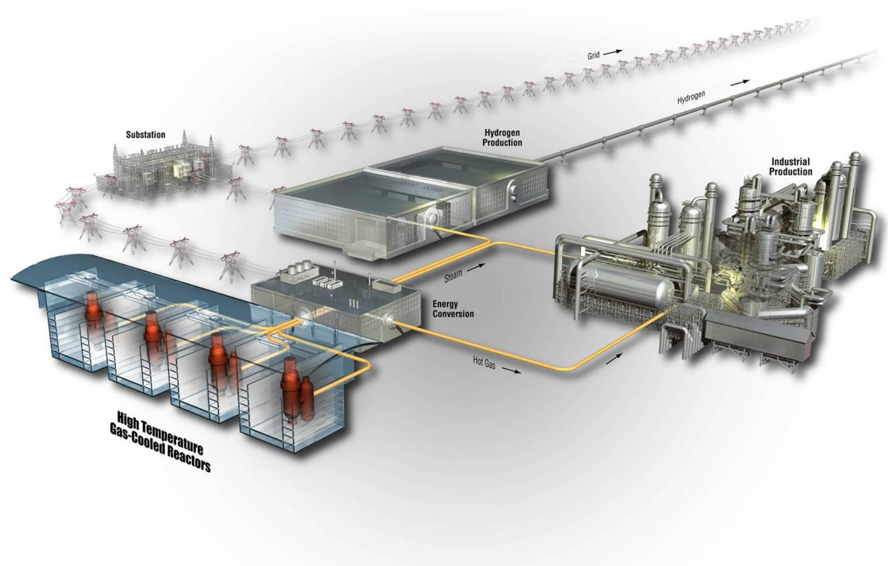
Technical Evaluation Study

Project No. 23843

Assessment of High Temperature Gas-Cooled Reactor (HTGR) Capital and Operating Costs



Idaho National Laboratory

ASSESSMENT OF HIGH TEMPERATURE GAS-COOLED REACTOR (HTGR) CAPITAL AND OPERATING COSTS	Identifier: TEV-1196 Revision: 1 Effective Date: 01/09/2012	Page: 1 of 45

NGNP	Technical Evaluation Study (TEV)		eCR Number: 601042

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REVISION LOG

Rev.	Date	Affected Pages	Revision Description
0	04/29/2011	All	Newly issued document.
1	01/09/2012	4, 38, 39	Fixed a small error in the calculation of NEI costs.

EXECUTIVE SUMMARY

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to address estimating the capital, operating, and decommissioning costs of a high-temperature gas-cooled reactor (HTGR). These results are preliminary and should be refined as the design of the HTGR progresses, if the design of the HTGR is changed significantly, or if additional refinements of the costs become available. The results of this evaluation will be used to update the HTGR capital and operating costs used in previous and future TEVs and economic models developed for the NGNP process heat applications study.

The capital, operating, and decommissioning costs are based on the HTGR design presented in the NGNP Pre-Conceptual Design Report (INL 2007a). Capital costs include the preconstruction costs, direct costs, indirect costs, and project contingency. Operating costs include operating and maintenance (O&M) costs and fuel costs. In addition to estimating the capital, operating, and decommissioning costs for a reactor outlet temperature (ROT) of 950°C, costs for ROTs of 750°C, 800°C, 850°C, and 900°C were also evaluated. HTGR costs were also developed with and without power cycles; the power cycles evaluated included both Brayton and Rankine cycles. Finally, the estimates were generated for single and four-pack reactor configurations for both 350 MWt and 600 MWt power levels, for the NGNP (demonstration), first of a kind, and nth of a kind (NOAK) project phases.

Table ES-1 presents the projected capital, operating, and decommissioning costs of an HTGR with a Rankine cycle for the NGNP and NOAK project phases at a ROT of 850°C. The results include costs for the 350 MWt and 600 MWt power levels for single and four-pack rector configurations (the NGNP phase includes only a single reactor option). The O&M costs presented are based on staffing estimates from the reactor design suppliers; currently there are differences in the projected staffing between designers and the INL estimate, in part because required staffing levels have not yet been established. The capital costs are graphically presented in Figure ES-1 and on a dollar-per-kWt basis in Figure ES-2. The cost model is capable of adjusting capital, operating, and decommissioning costs based on the desired reactor configuration to provide input to multiple process modeling scenarios. The level of project definition for this study was determined to be an AACE International Class 4 estimate, which has a probable error of -30% and +50%.

Table ES-1. Cost Summary for NGNP & NOAK HTGR with a Rankine power cycle, 850°C ROT (2009 basis).

Reactor Phase	NGNP		NOAK			
Reactor Size	600 MWt	350 MWt	600 MWt		350 MWt	
Number of Modules	1	1	1	4	1	4
Capital Costs ($10^6)						
Preconstruction Costs	233.50	233.50	76.50	91.00	76.50	91.00
Direct Costs	1253.70	941.02	764.15	2565.53	543.40	1818.70
Indirect Costs	1734.40	1554.73	459.10	1494.20	332.25	1065.06
Contingency	644.32	545.85	259.95	830.15	190.43	594.95
Overnight Cost ($10^6)	3865.92	3275.11	1559.70	4980.88	1142.57	3569.72
Lower Bound	2706.14	2292.57	1091.79	3486.61	799.80	2498.80
Upper Bound	5798.88	4912.66	2339.55	7471.31	1713.86	5354.57
Overnight Cost ($/kWt)	6443.19	9357.44	2599.50	2075.37	3264.49	2549.80
Lower Bound	4510.24	6550.21	1819.65	1452.76	2285.14	1784.86
Upper Bound	9664.79	14036.17	3899.26	3113.05	4896.73	3824.70
Yearly O&M Costs ($10^6)	37.54	34.39	37.54	99.60	34.39	87.00
Yearly O&M Costs ($/MWt-hr)	7.14	11.22	7.14	4.74	11.22	7.09
Yearly Fuel Costs ($10^6)	57.28	33.41	33.47	133.88	19.52	78.10
Yearly Fuel Costs ($/MWt-hr)	10.90	10.90	6.37	6.37	6.37	6.37
Decommissioning Costs ($10^6)	122.87	71.67	122.87	491.47	71.67	286.69

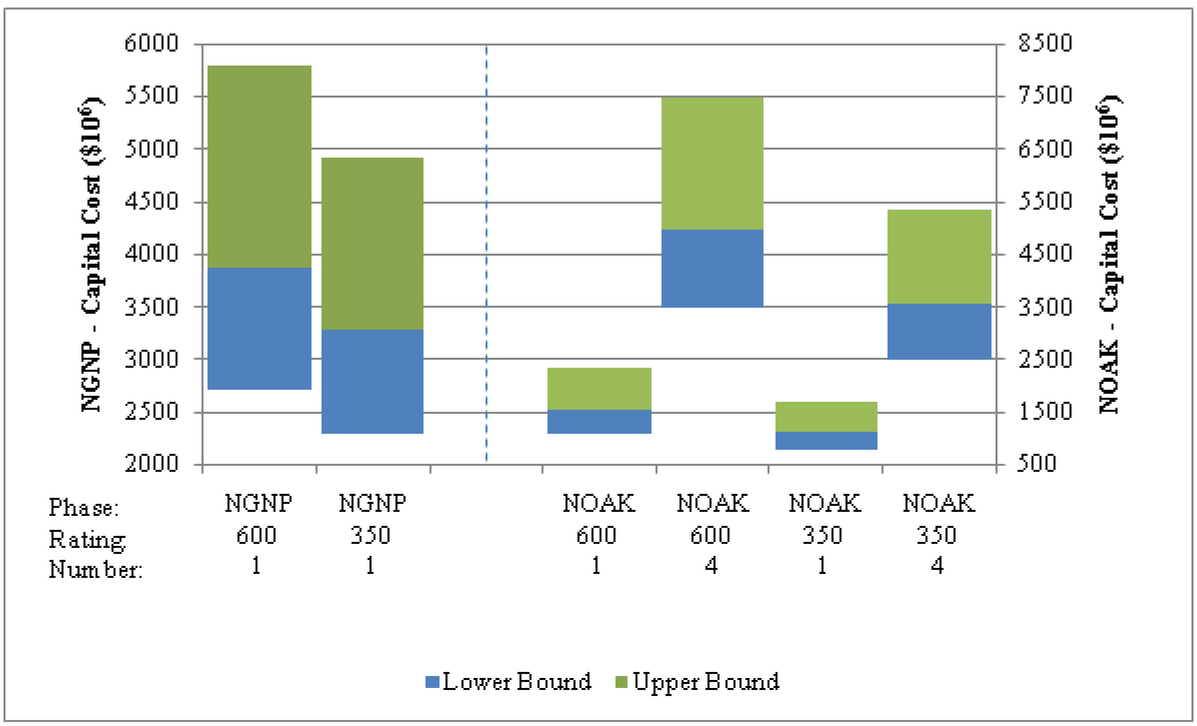

Figure ES-1. Capital Cost Summary for NGNP and NOAK HTGR with a Rankine power cycle, 850°C ROT ($10^6 – 2009 basis).

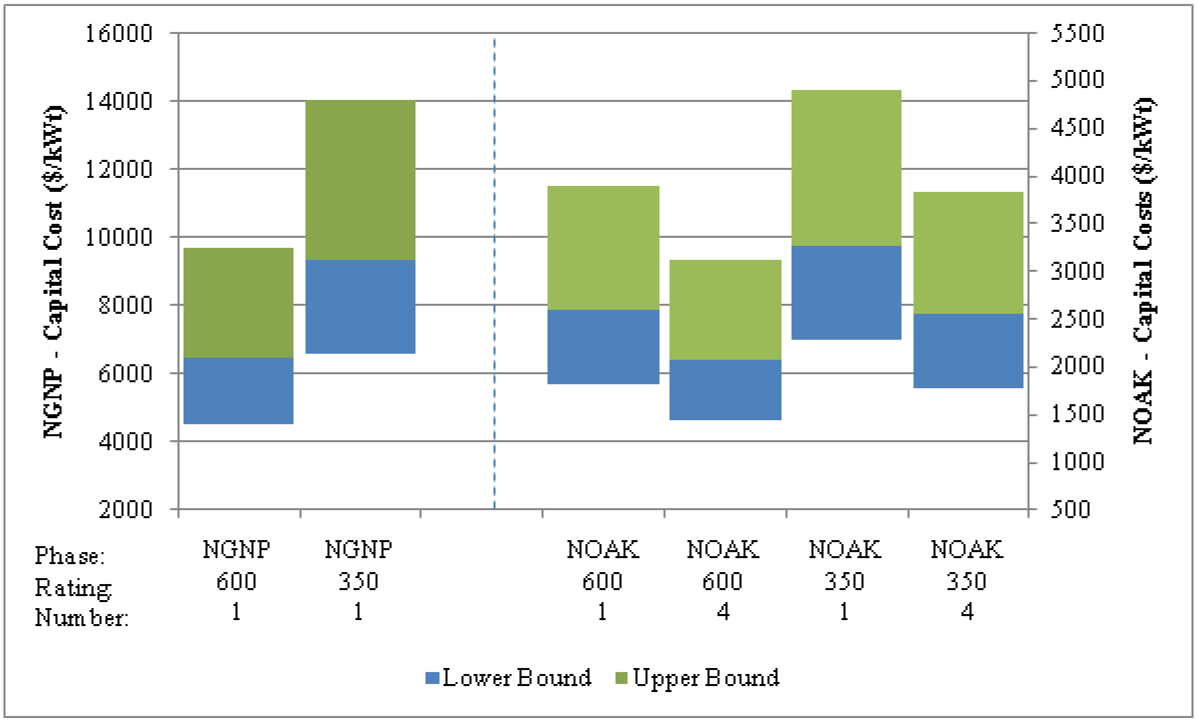

Figure ES-2. Capital Cost Summary for NGNP and NOAK HTGR with a Rankine power cycle, 850°C ROT ($/kWt – 2009 basis).

CONTENTS

ACRONYMS AND NOMENCLATURE

AACE	Association for the Advancement of Cost Engineering
BLS	Bureau of Labor Statistics
BOE	balance of equipment
BWR	boiling water reactor
CEPCI	chemical engineering plant cost index
COLA	combined operating license application
DOE	Department of Energy
DP	duplicate position
ESP	early site permit
FCL	fuel cycle length
FOAK	first of a kind
GA	General Atomics
GIF	GEN-IV International Forum
HP	health physics
HTGR	high temperature gas-cooled reactor
I&C	instrumentation and control
IHX	intermediate heat exchanger
INL	Idaho National Laboratory
INPO	Institute of Nuclear Power Operations
ISI	in-service inspection
LLW	low level waste
LWR	light water reactor
NDE	non-destructive exams
NEI	Nuclear Energy Institute
NGNP	Next Generation Nuclear Plant
NOAK	nth of a kind
NRC	Nuclear Regulatory Commission
O&M	operations and maintenance
PWR	pressurized water reactor
R&D	research & development

RO	reactor operator
ROT	reactor outlet temperature
SC	subcontract
SCM	supply chain management
STA	shift technical advisors
SWU	separative work unit
TCI	total capital investment
TEV	technical evaluation

1. INTRODUCTION

This technical evaluation (TEV) has been prepared as part of a study for the Next Generation Nuclear Plant (NGNP) Project to address estimating the capital, operating, and decommissioning costs of a high-temperature gas-cooled reactor (HTGR). The NGNP Project is being conducted under U.S. Department of Energy (DOE) direction to meet a national strategic need identified in the 2005 *Energy Policy Act* to promote reliance on safe, clean, economic nuclear energy and to establish a greenhouse-gas-free technology for the production of hydrogen. The NGNP represents an integration of high-temperature reactor technology with advanced hydrogen, electricity, and process heat production capabilities, thereby meeting the mission need identified by DOE. The strategic goal of the NGNP Project is to broaden the environmental and economic benefits of nuclear energy in the U.S. economy by demonstrating its applicability to market sectors not being served by light water reactors.

The HTGR produces high-temperature helium that can be used to produce electricity and/or process heat for export in the form of steam or high-temperature helium. This TEV presents the methodology and results of a cost model which was developed to estimate the capital, operating, and decommissioning costs of an HTGR. These costs are based, in general, on the HTGR design presented in the NGNP Pre-Conceptual Design Report (INL 2007a). Although initial HTGR implementations may target a reactor outlet temperature (ROT) of approximately 750°C, temperatures of up to 950°C are anticipated for later designs. Therefore, the cost model was developed to be capable of estimating costs for the ROT range of 750°C to 950°C, in 50°C increments. HTGR costs were also developed with and without power cycles; the power cycles evaluated included both Brayton and Rankine cycles. Correlations are developed for the power cycles, such that combined heat and power facility costs can be evaluated. Finally, the estimates were generated for single and four-pack reactor configurations for both 350 MWt and 600 MWt power levels, for the NGNP, first of a kind (FOAK), and nth of a kind (NOAK) project phases. A four-pack reactor plant includes four reactor vessels with shared control facilities. The NGNP plant is the initial demonstration of the current HTGR design funded through a public-private-partnership cost-share, a FOAK plant is the first privately funded commercial installation of the HTGR technology, while the NOAK plant is a mature privately funded commercial installation of the HTGR technology.

The intended application of the cost model is to develop capital and operating costs for a wide variety of HTGR deployment options, such that the economic impact of HTGR integration into electricity, heat, and/or commercial chemical production can be assessed for business development, project screening, and economic feasibility. As the HTGR is still in the early stages of project development, the cost model has an expected accuracy of -30% to +50%.

This TEV assumes familiarity with the NGNP Pre-Conceptual Design Report; hence, detailed descriptions of the HTGR design are not presented here. The cost model used for this analysis has been developed in Microsoft Excel (Excel 2007). This study makes extensive use of this model; this TEV assumes familiarity with Excel. A detailed explanation of the software capabilities is beyond the scope of this study.

This TEV first presents the approach for generating the HTGR capital costs as a function of the reactor parameters described above. Next the approach for generating the operating costs is presented, followed by the approach for estimating decommissioning costs. Finally, results of the cost models are presented and discussed. These results are preliminary and should be refined as the design of the HTGR progresses, if the design of the HTGR is changed significantly, or if additional refinements of the costs become available. The results of this evaluation will be used to update the HTGR capital and operating costs used in previous and future TEVs and economic models developed for the NGNP process heat applications study.

2. CAPITAL COST MODELING OVERVIEW

The capital costs for the HTGR were assessed using a top-down evaluation; including factored cost estimates for major equipment items and ratio factors based on industry experience and/or program guidance for balance of equipment costs, indirect costs, and project contingency. The costs were evaluated in detail for the following cases[1]:

- Project phases:
  - NGNP
  - FOAK
  - NOAK
- ROTs of 750°C to 950°C, in 50°C increments
- Single and four-pack reactor modules, NGNP phase includes a single reactor only
- Power levels:
  - 350 MWt
  - 600 MWt
- Power cycle configurations:
  - No power cycle, i.e. heat only
  - Brayton cycle
  - Rankine cycle

[1] The detailed cost assessments were used to develop correlations that can be used to estimate the costs for other operating conditions and configurations, e.g., more than four modules in a plant and ROTs other than 750°C to 950°C, in 50°C increments.

The total capital investment (TCI), based on preconstruction, direct, and indirect costs are included in the capital cost estimate for the HTGR.

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. The level of project definition for this study was determined to be an AACE International Class 4 estimate, which has a probable error of -30% and +50%. A Class 4 estimate is associated with a feasibility study or top-down cost estimate and has one to fifteen percent of full project definition (AACE 2005).

2.1 Preconstruction Costs

Preconstruction costs include the followings costs:

- Land and land rights
- Licensing and application

Costs for land and land rights were based on the acreage required for a single reactor or for a four-pack of reactors. It was assumed that a single HTGR requires 50 acres of land, while a four-pack requires 100 acres. This data was approximated based on information provided by General Atomics (GA). A rule of thumb cost of $100,000 per acre was assumed (Wallace 2011).

Licensing and application costs were developed based on input from NGNP regulatory affairs for the various reactor phases; the costs are presented in Table 1. Licensing cost development associated with the single module NGNP HTGR are as described in the NGNP Program Planning Bases for the Schedule and Cost Estimates (INL 2010).

Table 1. Licensing cost summary ($\$10^6$ – 2009 basis).

Reactor Phase	NGNP	FOAK		NOAK	
Task / **Number of Modules**	**1**	**1**	**4**	**1**	**4**
Pre-Application	30	15	15	15	15
ESP[2] and COLA[3] Preparation	69	23	28	23	28
ESP and COLA Review by NRC	108	25	25	12	12
Support of Construction & Initial Operation	18.5	18.5	23	18.5	23
State and Local Permitting	3	3	3	3	3
Total	**228.5**	**84.5**	**94**	**71.5**	**81**

[2] Early site permit (ESP).

[3] Combine operating license application (COLA).

Design certification costs are included in the licensing costs for the NGNP plant. It is assumed that design certification costs would only be incurred for the initial plant and would cover all downstream builds.

Costs for land and land rights and licensing and application are summed to determine the total preconstruction costs, summarized in Table 2.

Table 2. Total preconstruction cost summary ($\$10^6$ – 2009 basis).

Reactor Phase	NGNP	FOAK		NOAK	
Task **Number of Modules**	**1**	**1**	**4**	**1**	**4**
Land and Land Rights	5	5	10	5	10
Licensing and Application Costs	228.5	84.5	94	71.5	81
Total	**233.5**	**89.5**	**104.0**	**76.5**	**91.0**

2.2 Direct Costs

Direct costs for the reactor plant are associated with the cost of materials and installation for the equipment items that make up the reactor plant. Given the nascent stage of the HTGR design, previous reactor cost estimates provided by the reactor design suppliers were assessed to determine the reactor plant equipment items that make up the majority of the direct costs. Based on this analysis, the following equipment items make up approximately 80% of the installed equipment costs:

- Reactor building
- Reactor vessel
- Reactor initial core
- Reactor metallic internals
- Reactor graphite internals
- Reactor cavity cooling system
- Core refueling equipment
- Heat rejection system
- Intermediate heat exchanger (IHX)
- Power generation equipment
  - Rankine cycle
  - Brayton cycle, includes power conversion vessel

The direct costs of the above items were estimated by Dominion for the INL through a separate subcontract. Costs were estimated for the prismatic block reactor, the pebble bed reactor costs will be included in the future revisions of the TEV. Dominion estimated the direct component costs based on information provided in the GA Pre-Conceptual Design Report (GA 2007) and cost data in the public domain for the GA gas turbine-modular helium reactor. For each ROT (750°C to 950°C, in 50°C increments), the most probable material is selected for each component, choosing from SA-508, 2¼Cr-1Mo, and Incoloy 800H, based on the expected component temperature, taking into account allowances for creep-fatigue and corrosion. Certain components, such as the Rankine power cycle, did not include options for material selection as the increase in ROT would have no impact on the material choice. The resulting component costs were adjusted based on the cost ratios for the raw materials as well as a ratio for ease of component fabrication, which is applied to the labor portion of the cost for the component for each material option. The breakdown between material, forming and fabrication, final fabrication, transportation, etc. is based on Dominion's extensive experience with LWR capital costs. Exponential scaling factors, based on LWR and other industrial experience, are used to adjust the capital costs for changes in the component sizes associated with slight capacity adjustments for changes in ROT and the overall thermal and/or power rating. A scaling factor was also used to adjust the costs from single to multiple module units, based on industrial LWR experience. Finally, factors were included to adjust the costs for the NGNP and FOAK project phases, based on data provided by the GEN-IV International Forum (GIF) (2007). Appendix A presents more detailed information on the methodology and approach Dominion used to estimate the direct costs for the specified reactor equipment items.

Cost indices were used to adjust equipment prices provided in the Dominion assessment from 2007 dollars to 2009 dollars using the Chemical Engineering Plant Cost Index (CEPCI) shown in Table 3.

Table 3. CEPCI data.

Year	CEPCI
2003	402.0
2004	444.2
2005	468.2
2006	499.6
2007	525.4
2008	575.4
2009	521.9

To account for the balance of equipment (BOE) costs not included in the Dominion direct cost estimate, the total cost of the items above were multiplied by a factor of 1.25. This factor was based upon the assessment of the previous cost estimates provided by the reactor design suppliers, in which the remaining equipment items contribute 20% of the installed equipment costs, as described previously.

The costs provided by Dominion, the associated balance of equipment costs, and the resulting total direct costs are summarized in Table 4 for the NGNP plant at all ROTs and power levels, Table 5 for a single and four-pack FOAK plant at all ROTs and power levels, and Table 6 for a single and four-pack NOAK plant at all ROTs and power levels.

Table 4. Direct costs NGNP HTGR ($\$10^6$ – 2009 basis).

Power Level	Equipment Item (Modules / ROT)	1: 750	800	850	900	950
600 MWt	Reactor Building	214.30	223.23	232.53	242.22	252.31
	Reactor Vessel	133.65	140.74	148.35	187.17	204.79
	Reactor Initial Core	133.11	133.11	133.11	133.11	133.11
	Reactor Metallic Internals	37.66	42.37	47.63	79.31	95.36
	Reactor Graphite Internals	28.05	29.84	31.75	33.77	33.77
	Reactor Cavity Cooling System	30.75	30.75	30.75	30.75	30.75
	Core Refueling Equipment	98.04	98.04	98.04	98.04	98.04
	Heat Rejection System	44.70	44.70	44.70	44.70	44.70
	IHX	31.09	32.65	34.32	70.56	77.10
	Brayton Power Conversion Vessel	100.18	105.52	111.26	140.53	153.82
	Power Generation –Brayton Cycle	283.94	308.63	335.46	364.63	396.34
	Power Generation – Rankine Cycle	170.79	185.64	201.78	219.33	238.40
	BOE – No Power Cycle	187.84	193.86	200.29	229.91	242.48
	BOE – Brayton Power Cycle	283.87	297.39	311.98	356.20	380.02
	BOE – Rankine Power Cycle	230.54	240.27	250.74	284.74	302.08
	Total – No Power Cycle	**939.19**	**969.28**	**1001.47**	**1149.53**	**1212.42**
	Total – Brayton Power Cycle	**1419.33**	**1486.97**	**1559.88**	**1780.99**	**1900.12**
	Total – Rankine Power Cycle	**1152.68**	**1201.33**	**1253.70**	**1423.69**	**1510.42**
350 MWt	Reactor Building	163.67	170.49	177.60	185.00	192.70
	Reactor Vessel	92.31	97.20	102.45	129.23	141.39
	Reactor Initial Core	86.13	86.13	86.13	86.13	86.13
	Reactor Metallic Internals	35.89	40.36	45.37	75.54	90.83
	Reactor Graphite Internals	28.05	29.84	31.75	33.77	33.77
	Reactor Cavity Cooling System	23.49	23.49	23.49	23.49	23.49
	Core Refueling Equipment	73.53	73.53	73.53	73.53	73.53
	Heat Rejection System	34.14	34.14	34.14	34.14	34.14
	IHX	21.97	23.07	24.25	49.83	54.45
	Brayton Power Conversion Vessel	68.71	72.38	76.31	96.36	105.47
	Power Generation –Brayton Cycle	211.09	229.45	249.40	271.09	294.66
	Power Generation – Rankine Cycle	130.44	141.79	154.11	167.52	182.08
	BOE – No Power Cycle	139.79	144.56	149.68	172.67	182.61
	BOE – Brayton Power Cycle	209.74	220.02	231.10	264.53	282.64
	BOE – Rankine Power Cycle	172.40	180.01	188.20	214.55	228.13
	Total – No Power Cycle	**698.97**	**722.82**	**748.38**	**863.34**	**913.05**
	Total – Brayton Power Cycle	**1048.72**	**1100.10**	**1155.52**	**1322.65**	**1413.21**
	Total – Rankine Power Cycle	**862.02**	**900.05**	**941.02**	**1072.73**	**1140.66**

Table 5. Direct costs FOAK HTGR ($$10^6$ – 2009 basis).

Power Level	Modules / Equipment Item / ROT	1: 750	800	850	900	950	4: 750	800	850	900	950
600 MWt	Reactor Building	185.67	197.52	210.13	223.54	237.81	527.30	560.96	596.77	634.86	675.38
	Reactor Vessel	94.80	99.84	105.26	132.87	145.40	273.13	287.46	302.84	381.24	416.84
	Reactor Initial Core	112.92	112.92	112.92	112.92	112.92	451.69	451.69	451.69	451.69	451.69
	Reactor Metallic Internals	35.78	40.27	45.29	75.51	90.83	104.01	116.76	131.01	216.87	260.38
	Reactor Graphite Internals	26.37	28.05	29.84	31.75	31.75	74.89	79.67	84.75	90.16	90.16
	Reactor Cavity Cooling System	28.91	28.91	28.91	28.91	28.91	115.63	115.63	115.63	115.63	115.63
	Core Refueling Equipment	92.16	92.16	92.16	92.16	92.16	261.73	261.73	261.73	261.73	261.73
	Heat Rejection System	42.02	42.02	42.02	42.02	42.02	168.07	168.07	168.07	168.07	168.07
	IHX	21.98	23.09	24.28	50.08	54.74	64.80	67.95	71.33	144.64	157.87
	Brayton Power Conversion Vessel	71.07	74.87	78.95	99.76	109.21	204.24	215.04	226.63	285.74	312.57
	Power Generation –Brayton Cycle	266.90	290.11	315.34	342.76	372.56	1067.60	1160.44	1261.34	1371.03	1490.25
	Power Generation – Rankine Cycle	160.54	174.50	189.68	206.17	224.10	642.17	698.01	758.70	824.68	896.39
	BOE – No Power Cycle	160.15	166.19	172.70	197.44	209.13	510.31	527.48	545.96	616.23	649.44
	BOE – Brayton Power Cycle	244.64	257.44	271.27	308.07	329.58	828.28	871.35	917.95	1030.42	1100.14
	BOE – Rankine Power Cycle	200.29	209.82	220.12	248.98	265.16	670.86	701.98	735.63	822.39	873.54
	Total – No Power Cycle	**800.75**	**830.97**	**863.50**	**987.20**	**1045.67**	**2551.57**	**2637.40**	**2729.78**	**3081.13**	**3247.20**
	Total – Brayton Power Cycle	**1223.21**	**1287.20**	**1356.36**	**1540.35**	**1647.89**	**4141.38**	**4356.75**	**4589.76**	**5152.08**	**5500.72**
	Total – Rankine Power Cycle	**1001.43**	**1049.10**	**1100.59**	**1244.91**	**1325.80**	**3354.28**	**3509.91**	**3678.16**	**4111.97**	**4367.69**
350 MWt	Reactor Building	141.81	150.86	160.49	170.73	181.63	402.73	428.44	455.79	484.88	515.83
	Reactor Vessel	65.47	68.95	72.69	91.74	100.39	188.72	198.61	209.22	263.32	287.88
	Reactor Initial Core	73.07	73.07	73.07	73.07	73.07	292.27	292.27	292.27	292.27	292.27
	Reactor Metallic Internals	25.27	28.44	31.99	53.33	64.15	73.48	82.48	92.55	153.17	183.89
	Reactor Graphite Internals	21.09	22.44	23.87	25.40	25.40	59.91	63.73	67.80	72.13	72.13
	Reactor Cavity Cooling System	22.08	22.08	22.08	22.08	22.08	88.32	88.32	88.32	88.32	88.32
	Core Refueling Equipment	69.12	69.12	69.12	69.12	69.12	196.30	196.30	196.30	196.30	196.30
	Heat Rejection System	32.09	32.09	32.09	32.09	32.09	128.37	128.37	128.37	128.37	128.37
	IHX	15.53	16.31	17.15	35.37	38.66	45.80	48.02	50.41	102.17	111.51
	Brayton Power Conversion Vessel	48.75	51.35	54.15	68.41	74.88	140.15	147.55	155.50	196.00	214.38
	Power Generation –Brayton Cycle	198.43	215.68	234.44	254.82	276.98	793.71	862.73	937.75	1019.30	1107.93
	Power Generation – Rankine Cycle	122.62	133.28	144.87	157.46	171.16	490.46	533.11	579.47	629.86	684.63
	BOE – No Power Cycle	116.38	120.84	125.64	143.23	151.65	368.97	381.63	395.26	445.23	469.12
	BOE – Brayton Power Cycle	178.18	187.60	197.78	224.04	239.61	602.44	634.21	668.57	749.05	799.70
	BOE – Rankine Power Cycle	147.04	154.16	161.85	182.60	194.43	491.59	514.91	540.12	602.70	640.28
	Total – No Power Cycle	**581.92**	**604.21**	**628.18**	**716.16**	**758.23**	**1844.87**	**1908.17**	**1976.28**	**2226.16**	**2345.62**
	Total – Brayton Power Cycle	**890.89**	**938.00**	**988.92**	**1120.20**	**1198.06**	**3012.21**	**3171.03**	**3342.84**	**3745.27**	**3998.51**
	Total – Rankine Power Cycle	**735.19**	**770.80**	**809.27**	**912.99**	**972.17**	**2457.95**	**2574.56**	**2700.61**	**3013.48**	**3201.41**

Table 6. Direct costs NOAK HTGR ($\$10^6$ – 2009 basis).

Power Level	Modules	1					4				
	Equipment Item ROT	750	800	850	900	950	750	800	850	900	950
600 MWt	Reactor Building	116.46	118.84	121.27	123.74	126.27	330.76	337.51	344.39	351.42	358.60
	Reactor Vessel	80.56	84.82	89.39	112.72	123.32	232.09	244.20	257.19	323.45	353.53
	Reactor Initial Core	72.41	72.41	72.41	72.41	72.41	289.66	289.66	289.66	289.66	289.66
	Reactor Metallic Internals	30.51	34.30	38.54	64.09	77.03	88.69	99.46	111.51	184.05	220.82
	Reactor Graphite Internals	16.27	17.31	18.41	19.59	19.59	46.20	49.15	52.29	55.63	55.63
	Reactor Cavity Cooling System	12.62	12.62	12.62	12.62	12.62	50.46	50.46	50.46	50.46	50.46
	Core Refueling Equipment	56.66	56.66	56.66	56.66	56.66	160.92	160.92	160.92	160.92	160.92
	Heat Rejection System	39.98	39.98	39.98	39.98	39.98	159.93	159.93	159.93	159.93	159.93
	IHX	18.84	19.78	20.79	42.60	46.53	55.56	58.23	61.08	123.02	134.20
	Brayton Power Conversion Vessel	60.33	63.54	66.99	84.58	92.56	173.39	182.51	192.31	242.25	264.92
	Power Generation –Brayton Cycle	103.18	112.16	121.91	132.51	144.03	412.74	448.63	487.64	530.05	576.14
	Power Generation – Rankine Cycle	119.55	129.95	141.25	153.53	166.88	478.21	519.79	564.99	614.12	667.52
	BOE – No Power Cycle	111.08	114.18	117.52	136.10	143.60	353.57	362.38	371.86	424.63	445.93
	BOE – Brayton Power Cycle	151.96	158.11	164.74	190.37	202.75	500.10	520.16	541.84	617.71	656.20
	BOE – Rankine Power Cycle	140.97	146.67	152.83	174.48	185.32	473.12	492.32	513.11	578.17	612.82
	Total – No Power Cycle	**555.39**	**570.90**	**587.59**	**680.51**	**718.01**	**1767.84**	**1811.88**	**1859.29**	**2123.17**	**2229.67**
	Total – Brayton Power Cycle	**759.79**	**790.53**	**823.72**	**951.87**	**1013.76**	**2500.50**	**2600.81**	**2709.22**	**3088.54**	**3281.00**
	Total – Rankine Power Cycle	**704.83**	**733.34**	**764.15**	**872.42**	**926.61**	**2365.60**	**2461.62**	**2565.53**	**2890.83**	**3064.08**
350 MWt	Reactor Building	88.95	90.77	92.62	94.51	96.44	252.62	257.78	263.04	268.40	273.88
	Reactor Vessel	55.65	58.59	61.74	77.84	85.15	160.39	168.74	177.71	223.43	244.18
	Reactor Initial Core	46.86	46.86	46.86	46.86	46.86	187.43	187.43	187.43	187.43	187.43
	Reactor Metallic Internals	21.55	24.23	27.22	45.26	54.40	62.66	70.27	78.77	130.00	155.96
	Reactor Graphite Internals	9.30	9.89	10.52	11.19	11.19	26.40	28.09	29.88	31.79	31.79
	Reactor Cavity Cooling System	9.64	9.64	9.64	9.64	9.64	38.54	38.54	38.54	38.54	38.54
	Core Refueling Equipment	42.50	42.50	42.50	42.50	42.50	120.69	120.69	120.69	120.69	120.69
	Heat Rejection System	21.05	21.05	21.05	21.05	21.05	84.21	84.21	84.21	84.21	84.21
	IHX	13.32	13.98	14.69	30.09	32.87	39.28	41.15	43.17	86.90	94.80
	Brayton Power Conversion Vessel	41.39	43.59	45.95	58.00	63.47	119.00	125.25	131.96	166.19	181.72
	Power Generation –Brayton Cycle	76.71	83.38	90.63	98.52	107.08	306.85	333.54	362.54	394.06	428.33
	Power Generation – Rankine Cycle	88.95	90.77	92.62	94.51	96.44	252.62	257.78	263.04	268.40	273.88
	BOE – No Power Cycle	77.20	79.37	81.71	94.73	100.02	243.06	249.22	255.86	292.85	307.87
	BOE – Brayton Power Cycle	106.73	111.12	115.86	133.86	142.66	349.52	363.92	379.49	432.91	460.38
	BOE – Rankine Power Cycle	100.03	104.19	108.68	124.05	131.89	334.36	348.47	363.74	410.11	435.33
	Total – No Power Cycle	**386.00**	**396.86**	**408.55**	**473.66**	**500.11**	**1215.28**	**1246.12**	**1279.30**	**1464.24**	**1539.35**
	Total – Brayton Power Cycle	**533.63**	**555.58**	**579.28**	**669.31**	**713.31**	**1747.59**	**1819.61**	**1897.43**	**2164.55**	**2301.92**
	Total – Rankine Power Cycle	**500.14**	**520.93**	**543.40**	**620.24**	**659.43**	**1671.82**	**1742.37**	**1818.70**	**2050.54**	**2176.63**

2.3 Indirect Costs

The capital required for construction overhead and other costs not included in the direct costs are included in the indirect costs. Again, given the nascent stage of the HTGR design, it was necessary to estimate the indirect costs as a percentage of the direct costs based on previous reactor design supplier estimates and historical indirect costs for light water reactors (LWRs).

Indirect costs included in the analysis are:

- Construction services – including but not limited to costs for construction management, procurement, scheduling, cost control, site safety, and quality inspections
- Home office and engineering services - including but not limited to costs for estimating, scheduling, project expediting, project general management, design allowance, and project fees
- Field office and engineering services – including but not limited to costs for the field office, field engineering, field drafting, field procurement, and field administrative and general expenses
- Owner's costs – including but not limited to project fees, taxes, and insurance; spare parts and other capital expenses; staff training and startup costs; and administrative and general expenses
- Design costs

Table 7 provides a list of HTGR (based on information provided by the reactor design suppliers) and historical LWR values for indirect costs. These values were averaged to determine the appropriate factors to use in the HTGR capital cost assessment for the indirect costs. These percentages were used for the NGNP plant, FOAK plant, and the NOAK plant.

Table 7. Indirect cost summary (% of total direct cost).

Reference	Const. Services	Home Office & Eng. Services	Field Office & Eng. Services	Owner's Costs	Total
GA 911107 (GA 2007)[4]	20.3%	4.7%	10.4%	8.8%	44.2%
DOE/NE-0009 (DOE 1980)[5]	16%	19%	6%	10%	51%
DOE/NE-0095 (DOE 1988)[6]	24%	25%	13%	16%	77%
Average	**20%**	**16%**	**10%**	**12%**	**57%**

[4] Based on data from cost estimate from GA for the NGNP Pre-Conceptual Design Report

[5] Based on historical LWR costs up to 1980

[6] Based on historical LWR costs including reactors constructed after Three Mile Island

Table 8 provides additional estimates for the total indirect cost as percentage of the direct costs. The values were not used in the average for this estimate as the breakdown for the indirect costs did not match the level of detail desired for this analysis. However, these references provide validation for the calculated average indirect cost.

Table 8. Total indirect cost validation.

	Total %
WSRC-MS-2005-00693 (DOE 2006)	55%
IAEA Bulletin – Vol. 20, No. 1 (IAEA 1978)	52%

The following design costs were also added to the indirect costs outlined above:

Table 9. Design costs ($\$10^6$ – 2009 basis).

Item Phase	**NGNP**	**FOAK & NOAK**
Conceptual Design	84.00	0.00
Preliminary Design	182.00	0.00
Final Design	296.00	20.00
R&D Costs[7]	452.00	0.00
Total	**1,014.00**	**20.00**

The NGNP design costs are referenced from the design costs presented in the NGNP Program Planning Bases for the Schedule and Cost Estimates (INL 2010). Final design costs for the FOAK and NOAK plants are based on information provided by reactor design suppliers and have been adjusted for recent project development and assumed design maturation.

2.4 Project Contingency

A project contingency of 20% was selected for the HTGR capital cost analysis for all project phases (INL 2007a).

2.5 Total Capital Investment

The TCI was calculated by summing the preconstruction costs, direct costs, indirect costs, and project contingency described in the previous sections. These costs are outlined in Table 10 for the NGNP plant at all ROTs and power levels, Table 11 for the FOAK single and four-pack plants at all ROTs and power levels, and Table 12 for the NOAK single and four-pack plants at all ROTs and power levels. In addition to the TCI the costs on a dollar-per-kWt basis are also presented.

[7] Research and development (R&D), includes INL's R&D costs.

Table 10. TCI NGNP HTGR ($\$10^6$ – 2009 basis).

Power Level	Modules / Item / ROT	1				
		750	**800**	**850**	**900**	**950**
600 MWt	Preconstruction Costs	233.50	233.50	233.50	233.50	233.50
	Direct Costs – No Power Cycle	939.19	969.28	1001.47	1149.53	1212.42
	Direct Costs – Brayton Cycle	1419.33	1486.97	1559.88	1780.99	1900.12
	Direct Costs – Rankine Cycle	1152.68	1201.33	1253.70	1423.69	1510.42
	Indirect Costs – No Power Cycle	1553.68	1570.97	1589.46	1674.54	1710.68
	Indirect Costs – Brayton Cycle	1829.58	1868.44	1910.34	2037.39	2105.84
	Indirect Costs – Rankine Cycle	1676.35	1704.31	1734.40	1832.08	1881.92
	Contingency – No Power Cycle	545.27	554.75	564.89	611.51	631.32
	Contingency – Brayton Cycle	696.48	717.78	740.74	810.37	847.89
	Contingency – Rankine Cycle	612.51	627.83	644.32	697.85	725.17
	TCI – No Power Cycle	**3271.65**	**3328.50**	**3389.32**	**3669.09**	**3787.92**
	$/kWt	*5452.74*	*5547.50*	*5648.87*	*6115.15*	*6313.19*
	TCI – Brayton Power Cycle	**4178.89**	**4306.69**	**4444.46**	**4862.25**	**5087.35**
	$/kWt	*6964.82*	*7177.82*	*7407.43*	*8103.75*	*8478.92*
	TCI – Rankine Power Cycle	**3675.04**	**3766.97**	**3865.92**	**4187.13**	**4351.00**
	$/kWt	*6125.06*	*6278.28*	*6443.19*	*6978.55*	*7251.67*
350 MWt	Preconstruction Costs	233.50	233.50	233.50	233.50	233.50
	Direct Costs – No Power Cycle	698.97	722.82	748.38	863.34	913.05
	Direct Costs – Brayton Cycle	1048.72	1100.10	1155.52	1322.65	1413.21
	Direct Costs – Rankine Cycle	862.02	900.05	941.02	1072.73	1140.66
	Indirect Costs – No Power Cycle	1415.64	1429.35	1444.03	1510.09	1538.66
	Indirect Costs – Brayton Cycle	1616.62	1646.14	1677.98	1774.02	1826.06
	Indirect Costs – Rankine Cycle	1509.33	1531.19	1554.73	1630.41	1669.44
	Contingency – No Power Cycle	469.62	477.13	485.18	521.39	537.04
	Contingency – Brayton Cycle	579.77	595.95	613.40	666.03	694.56
	Contingency – Rankine Cycle	520.97	532.95	545.85	587.33	608.72
	TCI – No Power Cycle	**2817.73**	**2862.80**	**2911.10**	**3128.31**	**3222.25**
	$/kWt	*8050.65*	*8179.42*	*8317.43*	*8938.03*	*9206.44*
	TCI – Brayton Power Cycle	**3478.61**	**3575.69**	**3680.41**	**3996.21**	**4167.33**
	$/kWt	*9938.89*	*10216.25*	*10515.45*	*11417.73*	*11906.66*
	TCI – Rankine Power Cycle	**3125.82**	**3197.68**	**3275.11**	**3523.97**	**3652.32**
	$/kWt	*8930.92*	*9136.23*	*9357.44*	*10068.48*	*10435.20*

Table 11. TCI FOAK HTGR ($\$10^6$ – 2009 basis).

Power Level	Item / Modules / ROT	1: 750	1: 800	1: 850	1: 900	1: 950	4: 750	4: 800	4: 850	4: 900	4: 950
600 MWt	Preconstruction Costs	89.50	89.50	89.50	89.50	89.50	104.00	104.00	104.00	104.00	104.00
	Direct Costs – No Power Cycle	800.75	830.97	863.50	987.20	1045.67	2551.57	2637.40	2729.78	3081.13	3247.20
	Direct Costs – Brayton Cycle	1223.21	1287.20	1356.36	1540.35	1647.89	4141.38	4356.75	4589.76	5152.08	5500.72
	Direct Costs – Rankine Cycle	1001.43	1049.10	1100.59	1244.91	1325.80	3354.28	3509.91	3678.16	4111.97	4367.69
	Indirect Costs – No Power Cycle	480.13	497.49	516.18	587.26	620.86	1486.18	1535.50	1588.59	1790.47	1885.90
	Indirect Costs – Brayton Cycle	722.88	759.65	799.39	905.11	966.91	2399.72	2523.47	2657.36	2980.48	3180.82
	Indirect Costs – Rankine Cycle	595.44	622.83	652.42	735.35	781.83	1947.43	2036.86	2133.54	2382.82	2529.76
	Contingency – No Power Cycle	274.08	283.59	293.84	332.79	351.21	828.35	855.38	884.47	995.12	1047.42
	Contingency – Brayton Cycle	407.12	427.27	449.05	506.99	540.86	1329.02	1396.84	1470.22	1647.31	1757.11
	Contingency – Rankine Cycle	337.27	352.29	368.50	413.95	439.42	1081.14	1130.15	1183.14	1319.76	1400.29
	TCI – No Power Cycle	**1644.46**	**1701.56**	**1763.02**	**1996.76**	**2107.25**	**4970.10**	**5132.28**	**5306.85**	**5970.72**	**6284.52**
	$/kWt	*2740.76*	*2835.93*	*2938.37*	*3327.93*	*3512.08*	*2070.88*	*2138.45*	*2211.19*	*2487.80*	*2618.55*
	TCI – Brayton Power Cycle	**2442.72**	**2563.61**	**2694.30**	**3041.95**	**3245.15**	**7974.11**	**8381.06**	**8821.34**	**9883.87**	**10542.64**
	$/kWt	*4071.19*	*4272.69*	*4490.50*	*5069.92*	*5408.59*	*3322.55*	*3492.11*	*3675.56*	*4118.28*	*4392.77*
	TCI – Rankine Power Cycle	**2023.64**	**2113.72**	**2211.02**	**2483.71**	**2636.55**	**6486.85**	**6780.92**	**7098.85**	**7918.55**	**8401.73**
	$/kWt	*3372.74*	*3522.86*	*3685.03*	*4139.52*	*4394.25*	*2702.86*	*2825.38*	*2957.85*	*3299.40*	*3500.72*
350 MWt	Preconstruction Costs	89.50	89.50	89.50	89.50	89.50	104.00	104.00	104.00	104.00	104.00
	Direct Costs – No Power Cycle	581.92	604.21	628.18	716.16	758.23	1844.87	1908.17	1976.28	2226.16	2345.62
	Direct Costs – Brayton Cycle	890.89	938.00	988.92	1120.20	1198.06	3012.21	3171.03	3342.84	3745.27	3998.51
	Direct Costs – Rankine Cycle	735.19	770.80	809.27	912.99	972.17	2457.95	2574.56	2700.61	3013.48	3201.41
	Indirect Costs – No Power Cycle	354.38	367.19	380.97	431.52	455.69	1080.10	1116.47	1155.61	1299.19	1367.84
	Indirect Costs – Brayton Cycle	531.92	558.99	588.25	663.69	708.43	1750.87	1842.14	1940.86	2172.10	2317.62
	Indirect Costs – Rankine Cycle	442.45	462.92	485.02	544.62	578.63	1432.39	1499.39	1571.82	1751.60	1859.59
	Contingency – No Power Cycle	205.16	212.18	219.73	247.44	260.68	605.79	625.73	647.18	725.87	763.49
	Contingency – Brayton Cycle	302.46	317.30	333.33	374.68	399.20	973.42	1023.43	1077.54	1204.27	1284.03
	Contingency – Rankine Cycle	253.43	264.64	276.76	309.42	328.06	798.87	835.59	875.29	973.82	1033.00
	TCI – No Power Cycle	**1230.96**	**1273.08**	**1318.38**	**1484.62**	**1564.10**	**3634.77**	**3754.38**	**3883.06**	**4355.22**	**4580.96**
	$/kWt	*3517.03*	*3637.36*	*3766.81*	*4241.77*	*4468.86*	*2596.26*	*2681.70*	*2773.61*	*3110.87*	*3272.11*
	TCI – Brayton Power Cycle	**1814.77**	**1903.79**	**2000.00**	**2248.07**	**2395.18**	**5840.50**	**6140.60**	**6465.23**	**7225.65**	**7704.16**
	$/kWt	*5185.06*	*5439.40*	*5714.29*	*6423.05*	*6843.37*	*4171.78*	*4386.14*	*4618.02*	*5161.18*	*5502.97*
	TCI – Rankine Power Cycle	**1520.57**	**1587.87**	**1660.55**	**1856.54**	**1968.36**	**4793.21**	**5013.55**	**5251.73**	**5842.90**	**6198.00**
	$/kWt	*4344.49*	*4536.77*	*4744.43*	*5304.40*	*5623.89*	*3423.72*	*3581.11*	*3751.23*	*4173.50*	*4427.14*

Table 12. TCI NOAK HTGR ($\$10^6$ – 2009 basis).

Power Level	Item / Modules / ROT	1					4				
		750	**800**	**850**	**900**	**950**	**750**	**800**	**850**	**900**	**950**
600 MWt	Preconstruction Costs	76.50	76.50	76.50	76.50	76.50	91.00	91.00	91.00	91.00	91.00
	Direct Costs – No Power Cycle	555.39	570.90	587.59	680.51	718.01	1767.84	1811.88	1859.29	2123.17	2229.67
	Direct Costs – Brayton Cycle	759.79	790.53	823.72	951.87	1013.76	2500.50	2600.81	2709.22	3088.54	3281.00
	Direct Costs – Rankine Cycle	704.83	733.34	764.15	872.42	926.61	2365.60	2461.62	2565.53	2890.83	3064.08
	Indirect Costs – No Power Cycle	339.14	348.05	357.64	411.03	432.58	1035.83	1061.14	1088.38	1240.02	1301.21
	Indirect Costs – Brayton Cycle	456.59	474.25	493.33	566.97	602.52	1456.83	1514.48	1576.77	1794.74	1905.32
	Indirect Costs – Rankine Cycle	425.01	441.39	459.10	521.31	552.45	1379.32	1434.50	1494.20	1681.12	1780.68
	Contingency – No Power Cycle	194.21	199.09	204.35	233.61	245.42	578.93	592.81	607.73	690.84	724.38
	Contingency – Brayton Cycle	258.58	268.26	278.71	319.07	338.56	809.67	841.26	875.40	994.86	1055.46
	Contingency – Rankine Cycle	241.27	250.25	259.95	294.05	311.11	767.18	797.42	830.15	932.59	987.15
	TCI – No Power Cycle	**1165.24**	**1194.54**	**1226.08**	**1401.66**	**1472.51**	**3473.61**	**3556.83**	**3646.41**	**4145.03**	**4346.26**
	$/kWt	*1942.07*	*1990.91*	*2043.47*	*2336.09*	*2454.19*	*1447.34*	*1482.01*	*1519.34*	*1727.09*	*1810.94*
	TCI – Brayton Power Cycle	**1551.45**	**1609.54**	**1672.26**	**1914.41**	**2031.34**	**4857.99**	**5047.54**	**5252.39**	**5969.13**	**6332.78**
	$/kWt	*2585.76*	*2682.57*	*2787.10*	*3190.68*	*3385.56*	*2024.16*	*2103.14*	*2188.50*	*2487.14*	*2638.66*
	TCI – Rankine Power Cycle	**1447.61**	**1501.47**	**1559.70**	**1764.28**	**1866.67**	**4603.10**	**4784.55**	**4980.88**	**5595.54**	**5922.90**
	$/kWt	*2412.69*	*2502.45*	*2599.50*	*2940.47*	*3111.12*	*1917.96*	*1993.56*	*2075.37*	*2331.47*	*2467.88*
350 MWt	Preconstruction Costs	76.50	76.50	76.50	76.50	76.50	91.00	91.00	91.00	91.00	91.00
	Direct Costs – No Power Cycle	386.00	396.86	408.55	473.66	500.11	1215.28	1246.12	1279.30	1464.24	1539.35
	Direct Costs – Brayton Cycle	533.63	555.58	579.28	669.31	713.31	1747.59	1819.61	1897.43	2164.55	2301.92
	Direct Costs – Rankine Cycle	500.14	520.93	543.40	620.24	659.43	1671.82	1742.37	1818.70	2050.54	2176.63
	Indirect Costs – No Power Cycle	241.80	248.05	254.76	292.18	307.37	718.32	736.05	755.11	861.38	904.54
	Indirect Costs – Brayton Cycle	326.63	339.25	352.87	404.60	429.88	1024.20	1065.58	1110.30	1263.79	1342.73
	Indirect Costs – Rankine Cycle	307.39	319.33	332.25	376.40	398.92	980.66	1021.20	1065.06	1198.28	1270.74
	Contingency – No Power Cycle	140.86	144.28	147.96	168.47	176.80	404.92	414.63	425.08	483.32	506.98
	Contingency – Brayton Cycle	187.35	194.27	201.73	230.08	243.94	572.56	595.24	619.75	703.87	747.13
	Contingency – Rankine Cycle	176.81	183.35	190.43	214.63	226.97	548.70	570.91	594.95	667.96	707.67
	TCI – No Power Cycle	**845.17**	**865.69**	**887.77**	**1010.81**	**1060.78**	**2429.52**	**2487.80**	**2550.50**	**2899.94**	**3041.86**
	$/kWt	*2414.77*	*2473.41*	*2536.48*	*2888.03*	*3030.81*	*1735.37*	*1777.00*	*1821.78*	*2071.39*	*2172.76*
	TCI – Brayton Power Cycle	**1124.12**	**1165.60**	**1210.38**	**1380.50**	**1463.63**	**3435.35**	**3571.43**	**3718.48**	**4223.21**	**4482.77**
	$/kWt	*3211.76*	*3330.27*	*3458.22*	*3944.28*	*4181.79*	*2453.82*	*2551.02*	*2656.06*	*3016.58*	*3201.98*
	TCI – Rankine Power Cycle	**1060.84**	**1100.11**	**1142.57**	**1287.77**	**1361.83**	**3292.19**	**3425.49**	**3569.72**	**4007.79**	**4246.04**
	$/kWt	*3030.96*	*3143.18*	*3264.49*	*3679.35*	*3890.94*	*2351.56*	*2446.78*	*2549.80*	*2862.71*	*3032.89*

2.6 Correlation Development for Direct Capital Costs

Correlations were developed for the HTGR and power cycle costs based on the ROT, thermal rating, power cycle rating, number of modules, and project phase. These correlations were developed in order to scale the costs for project variations not included in this study. For example, these correlations would be used to estimate the cost of six HTGR modules at an ROT of 775°C for an NOAK HTGR plant. Separate correlations are developed for the HTGR cost without power cycles (i.e. for heat production only), the Brayton cycle cost, and the Rankine cycle cost. The correlations presented are base direct costs, less the adders, which can be added to the correlations to account for the balance of equipment costs, indirect costs, preconstruction costs, and project contingency.

2.6.1 Correlations for the HTGR Cost, Less Power Cycle

The correlation for the HTGR cost as a function of ROT is best fit using a linear step function. The following equation set is used:

$$\begin{aligned} Cost(ROT) &= 0.258 \times ROT + 250.952 & ROT \leq 850 \\ &= 1.487 \times ROT - 793.598 & 850 < ROT \leq 900 \\ &= 0.600 \times ROT + 4.415 & ROT > 900 \end{aligned}$$

The above correlation provides the base cost for an NOAK single 600 MWt HTGR as a function of the ROT. This base cost is then adjusted to account for the number of reactors using an exponential correlation:

$$AdjustedCost = Cost(ROT) \times (Number)^{0.827}$$

A similar adjustment can be made for the reactor thermal rating:

$$AdjustedCost = Cost(ROT) \times \left(\frac{Themal\ Rating}{600\ MWt}\right)^{0.673}$$

Thus, the overall correlation for the NOAK HTGR cost is as follows:

$$HTGRCost = Cost(ROT) \times (Number)^{0.827} \times \left(\frac{Thermal\ Rating}{600\ MWt}\right)^{0.673}$$

Finally, multipliers for the project phases were determined to adjust the cost for FOAK and NGNP project phases:

$$FOAK = 1.486$$
$$NGNP = 1.758$$

Table 13 presents a comparison of the correlation results and the data for the HTGR costs less the power cycles. The costs predicted by the correlations have a percent error of 0% to 4.13%, when compared to the actual cost data.

Table 13. Correlation results and comparison for HTGR costs, less power cycles ($\$10^6$ – 2009 basis).

Power Level	Project Phase	Item / Modules / ROT	1: 750	1: 800	1: 850	1: 900	1: 950	4: 750	4: 800	4: 850	4: 900	4: 950
600 MWt	NOAK	Value	444.31	456.72	470.08	544.41	574.41	1414.27	1449.51	1487.43	1698.54	1783.74
		Model Prediction	444.16	457.04	469.92	544.41	574.41	1398.70	1439.26	1479.82	1714.40	1808.88
		% Error	0.04	0.07	0.03	0.00	0.00	1.10	0.71	0.51	0.93	1.41
	FOAK	Value	640.60	664.78	690.80	789.76	836.54	2041.26	2109.92	2183.83	2464.90	2597.76
		Model Prediction	660.44	679.60	698.75	809.51	854.12	2079.81	2140.12	2200.43	2549.25	2689.72
		% Error	3.10	2.23	1.15	2.50	2.10	1.89	1.43	0.76	3.42	3.54
	NGNP	Value	751.35	775.43	801.18	919.62	969.93					
		Model Prediction	780.97	803.62	826.27	957.25	1010.00					
		% Error	3.94	3.64	3.13	4.09	4.13					
350 MWt	NOAK	Value	308.80	317.49	326.84	378.93	400.09	972.22	996.90	1023.44	1171.39	1231.48
		Model Prediction	308.96	317.92	326.88	378.69	399.56	972.94	1001.15	1029.37	1192.54	1258.26
		% Error	0.05	0.13	0.01	0.06	0.13	0.07	0.43	0.58	1.81	2.17
	FOAK	Value	465.54	483.37	502.55	572.93	606.58	1475.90	1526.54	1581.02	1780.93	1876.50
		Model Prediction	459.41	472.73	486.05	563.10	594.13	1446.72	1488.67	1530.63	1773.26	1870.98
		% Error	1.32	2.20	3.28	1.72	2.05	1.98	2.48	3.19	0.43	0.29
	NGNP	Value	559.17	578.25	598.71	690.67	730.44					
		Model Prediction	543.25	559.00	574.76	665.87	702.56					
		% Error	2.85	3.33	4.00	3.59	3.82					

Figure 1 presents the HTGR cost correlations for the NOAK project phase.

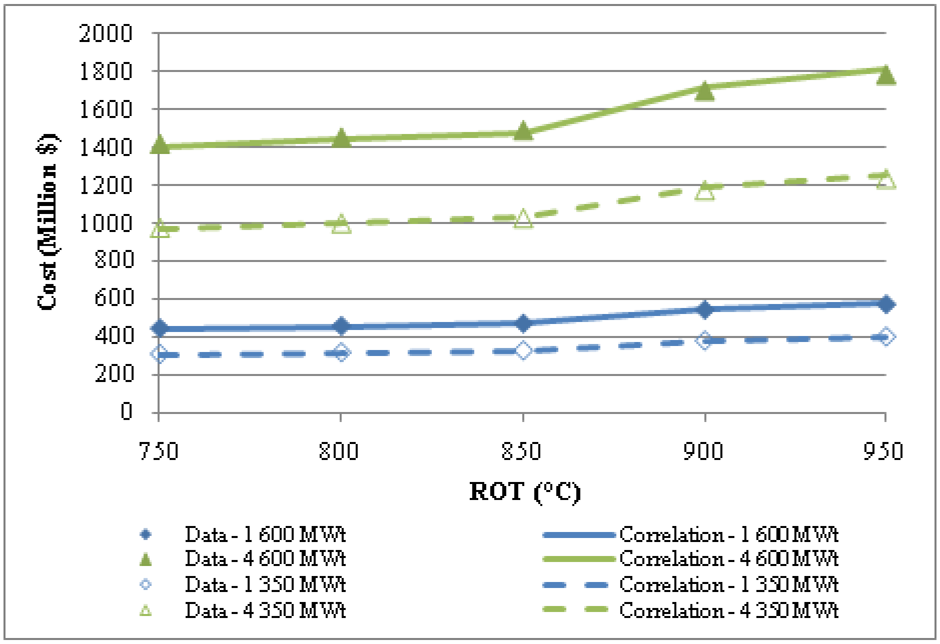

Figure 1. NOAK HTGR cost correlations, less power cycles.

2.6.2 Correlations for the Brayton Cycle Cost

The correlation for the Brayton cycle cost as a function of ROT is best fit using a linear step function. The following equation set is used:

$$\begin{aligned} Cost(ROT) &= 0.254 \times ROT - 27.058 && ROT \leq 850 \\ &= 0.564 \times ROT - 290.269 && 850 < ROT \leq 900 \\ &= 0.390 \times ROT - 134.030 && ROT > 900 \end{aligned}$$

The above correlation provides the base cost for an NOAK single 281 MWe Brayton cycle, which includes both the power conversion vessel and the turbo-machinery. This base cost is then adjusted to account for the number of cycles using an exponential correlation:

$$AdjustedCost = Cost(ROT) \times (Number)^{0.920}$$

A similar adjustment can be made for the power cycle size. Note that the base power cycle size at 750°C for a 600 MWt HTGR is used for this correlation:

$$AdjustedCost = Cost(ROT) \times \left(\frac{PowerRating}{281\ MWe}\right)^{0.604}$$

Thus, the overall correlation for the NOAK Brayton cycle cost is as follows:

$$BraytonCost = Cost(ROT) \times (Number)^{0.920} \times \left(\frac{PowerRating}{281\ MWe}\right)^{0.604}$$

Finally, multipliers for the project phases were determined to adjust the cost for FOAK and NGNP project phases:

$FOAK = 2.074$
$NGNP = 2.354$

Table 14 presents a comparison of the correlation results and the data for the Brayton cycle costs. The costs predicted by the correlations have a percent error of 0% to 7.51%, when compared to the actual cost data.

Figure 2 presents the Brayton cycle cost correlation for the NOAK project phase.

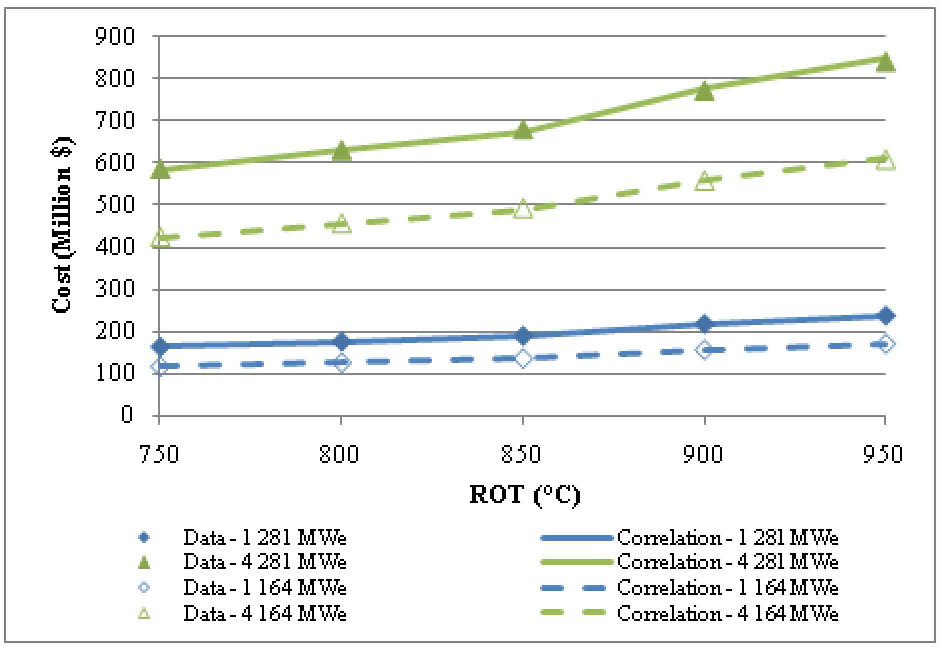

Figure 2. NOAK Brayton cycle cost correlations.

Table 14. Correlation results and comparison for Brayton cycle costs ($\$10^6$ – 2009 basis).

Power Level	Project Phase	Item \ Modules / ROT	1: 750	1: 800	1: 850	1: 900	1: 950	4: 750	4: 800	4: 850	4: 900	4: 950
600 MWt (281 MWe at 750°C)	NOAK	Value	163.52	175.70	188.90	217.09	236.60	586.13	631.14	679.95	772.29	841.06
		Model Prediction	163.35	176.04	188.73	217.09	236.60	584.39	629.81	675.22	776.67	846.46
		% Error	0.10	0.19	0.09	0.00	0.00	0.30	0.21	0.70	0.57	0.64
	FOAK	Value	337.97	364.98	394.29	442.52	481.77	1271.85	1375.48	1487.98	1656.76	1802.81
		Model Prediction	338.83	365.16	391.49	450.31	490.77	1212.21	1306.41	1400.61	1611.04	1755.80
		% Error	0.25	0.05	0.71	1.76	1.87	4.69	5.02	5.87	2.76	2.61
	NGNP	Value	384.11	414.15	446.73	505.16	550.16					
		Model Prediction	384.65	414.54	444.43	511.20	557.13					
		% Error	0.14	0.09	0.51	1.20	1.27					
350 MWt (164 MWe at 750°C)	NOAK	Value	118.10	126.97	136.59	156.52	170.56	425.85	458.79	494.50	560.25	610.06
		Model Prediction	117.93	127.10	136.26	156.73	170.82	421.92	454.70	487.49	560.73	611.12
		% Error	0.14	0.10	0.24	0.14	0.15	0.92	0.89	1.42	0.09	0.17
	FOAK	Value	247.17	267.03	288.59	323.23	351.86	933.87	1010.29	1093.25	1215.29	1322.31
		Model Prediction	244.63	263.64	282.64	325.11	354.32	875.18	943.19	1011.20	1163.12	1267.64
		% Error	1.03	1.27	2.06	0.58	0.70	6.28	6.64	7.51	4.29	4.13
	NGNP	Value	279.81	301.83	325.71	367.45	400.13					
		Model Prediction	277.70	299.28	320.86	369.07	402.24					
		% Error	0.75	0.84	1.49	0.44	0.53					

2.6.3 Correlations for the Rankine Cycle Cost

The correlation for the Rankine cycle cost as a function of ROT is best fit using a linear function; however, a step function is not required for the Rankine cycle cost as the fabrication materials are consistent for all ROTs. The following equation is used:

$$Cost(ROT) = 0.236 \times ROT - 58.775$$

The correlation for the ROT provides the base cost for an NOAK single 267 MWe Rankine cycle. This base cost is then adjusted to account for the number of cycles using an exponential correlation:

$$AdjustedCost = Cost(ROT) \times (Number)^1 = Cost(ROT) \times Number$$

A similar adjustment can be made for the power cycle size. Note that the base power cycle size at 750°C for a 600 MWt HTGR is used for this correlation:

$$AdjustedCost = Cost(ROT) \times \left(\frac{PowerRating}{267\ MWe}\right)^{0.5}$$

Thus, the overall correlation for the NOAK Rankine cycle cost is as follows:

$$RankineCost = Cost(ROT) \times\ Number \times \left(\frac{PowerRating}{267\ MWe}\right)^{0.5}$$

Finally, multipliers for the project phases were determined to adjust the cost for FOAK and NGNP project phases:

$$FOAK = 1.343$$
$$NGNP = 1.429$$

Table 15 presents a comparison of the correlation results and the data for the Rankine cycle costs. The costs predicted by the correlations have a percent error of 0% to 0.81%, when compared to the actual cost data.

Table 15. Correlation results and comparison for Rankine cycle costs ($\$10^6$ – 2009 basis).

Power Level	Project Phase	Item (Modules / ROT)	1: 750	1: 800	1: 850	1: 900	1: 950	4: 750	4: 800	4: 850	4: 900	4: 950
600 MWt (267 MWe at 750°C)	NOAK	Value	119.55	129.95	141.25	153.53	166.88	478.21	519.79	564.99	614.12	667.52
		Model Prediction	118.58	130.41	142.23	154.06	165.88	474.34	521.63	568.93	616.22	663.52
		% Error	0.81	0.35	0.70	0.34	0.60	0.81	0.35	0.70	0.34	0.60
	FOAK	Value	160.54	174.50	189.68	206.17	224.10	642.17	698.01	758.70	824.68	896.39
		Model Prediction	159.24	175.12	191.00	206.88	222.75	636.97	700.48	763.99	827.50	891.01
		% Error	0.81	0.35	0.70	0.34	0.60	0.81	0.35	0.70	0.34	0.60
	NGNP	Value	170.79	185.64	201.78	219.33	238.40					
		Model Prediction	169.41	186.30	203.19	220.08	236.97					
		% Error	0.81	0.35	0.70	0.34	0.60					
350 MWt (156 MWe at 750°C)	NOAK	Value	91.31	99.25	107.88	117.26	127.46	365.24	397.00	431.52	469.04	509.83
		Model Prediction	90.57	99.60	108.63	117.66	126.69	362.28	398.40	434.53	470.65	506.77
		% Error	0.81	0.35	0.70	0.34	0.60	0.81	0.35	0.70	0.34	0.60
	FOAK	Value	122.62	133.28	144.87	157.46	171.16	490.46	533.11	579.47	629.86	684.63
		Model Prediction	121.62	133.75	145.88	158.00	170.13	486.49	535.00	583.51	632.01	680.52
		% Error	0.81	0.35	0.70	0.34	0.60	0.81	0.35	0.70	0.34	0.60
	NGNP	Value	130.44	141.79	154.11	167.52	182.08					
		Model Prediction	129.39	142.29	155.19	168.09	180.99					
		% Error	0.81	0.35	0.70	0.34	0.60					

Figure 3 presents the Rankine cycle cost correlation for the NOAK project phase.

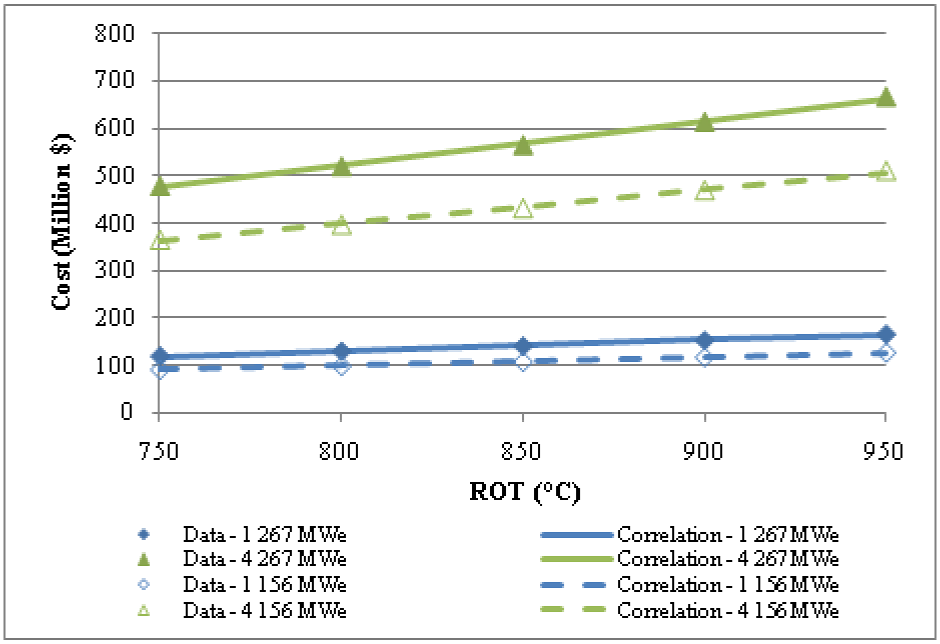

Figure 3. NOAK Rankine cycle cost correlations.

2.7 Capital Cost Results Comparisons

In order to assess the accuracy of the capital cost model, results from the INL cost model were compared to reactor design supplier cost estimates. In order to provide a direct comparison, the cost model design costs (for the NGNP project phase) and project contingencies were adjusted to match the estimates provided by the reactor design suppliers. This allows a more accurate comparison of the project costs, as the design costs and contingencies vary widely between the reactor design suppliers. Furthermore, reactor design supplier costs were adjusted to exclude costs for hydrogen production facilities. The projected model cost is compared to the reactor design supplier average costs, along with the associated cost accuracy range of -30% to +50% for an AACE International class four estimate. The specifics of the design supplier estimates are withheld, as certain aspects of the costs may be considered business sensitive.

Figure 4 and Figure 5 present two separate comparisons for a reactor plant with a thermal rating of approximately 600 MWt and a ROT greater than 850°C from separate reactor design suppliers. Both comparisons include costs for NGNP and NOAK project phases. These comparisons demonstrate that the cost model is within the range of the costs projected by the reactor design suppliers.

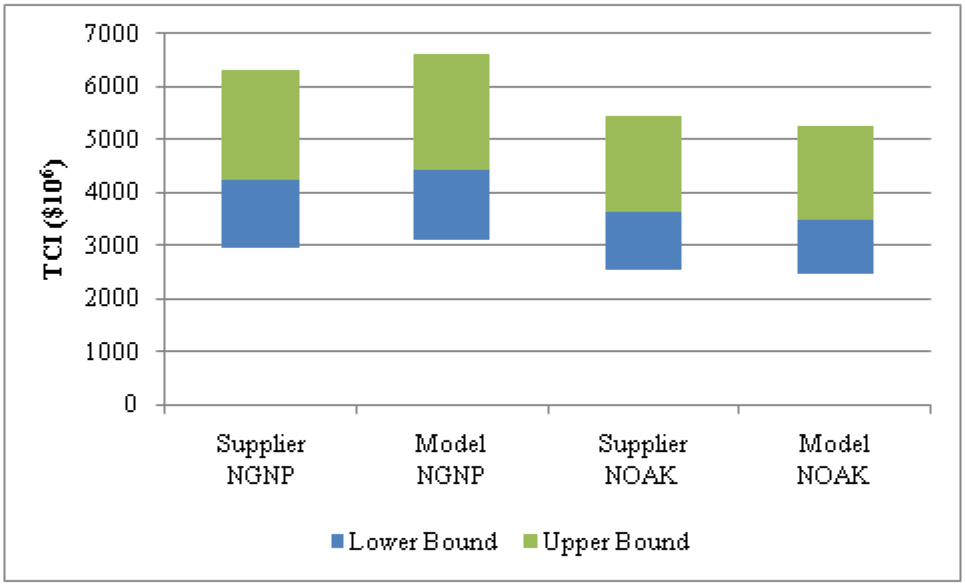

Figure 4. HTGR Model Cost Comparison – Prismatic Block Design 1, ~600 MWt ROT ≥ 850°C.

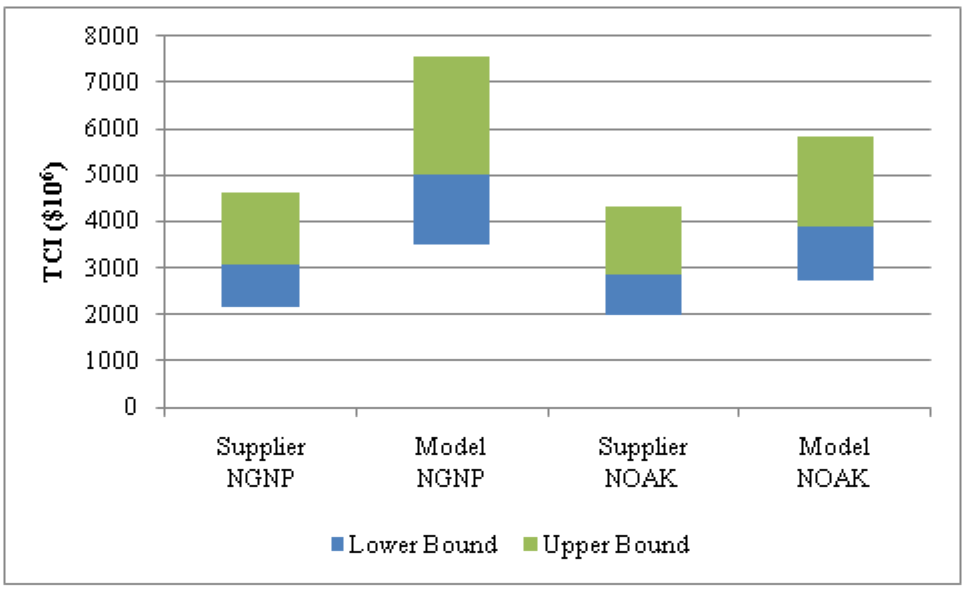

Figure 5. HTGR Model Cost Comparison – Prismatic Block Design 2, ~600 MWt ROT ≥ 850°C.

Figure 6 and Figure 7 present two separate comparisons for a reactor plant with a thermal rating less than 350 MWt and a ROT less than 750°C from separate reactor design suppliers. Only one of the comparisons includes costs for NGNP and NOAK project phases. Again, these comparisons demonstrate that the cost model is within the range of the costs projected by the reactor design suppliers.

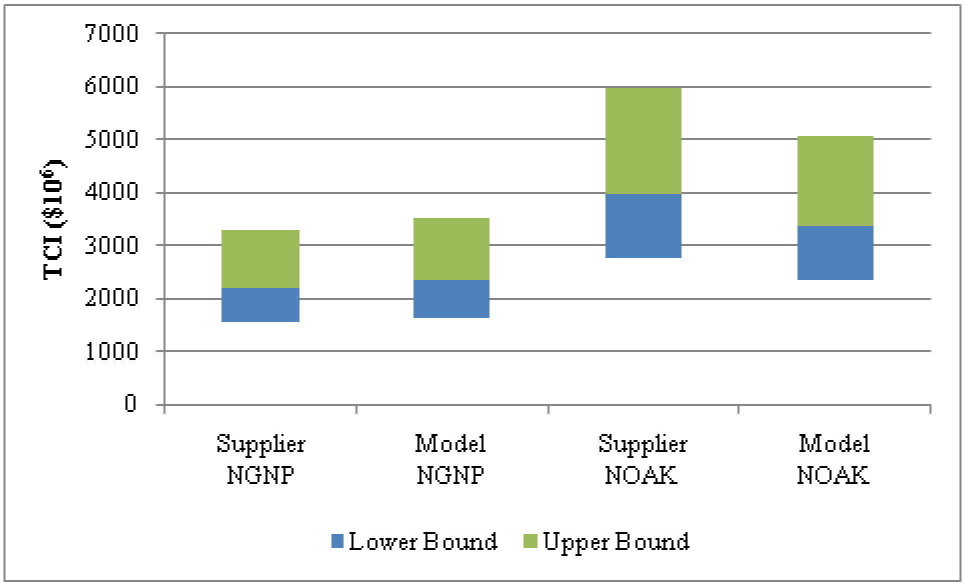

Figure 6. HTGR Model Cost Comparison – Prismatic Block Design 3, ≤350 MWt ROT ≤ 750°C.

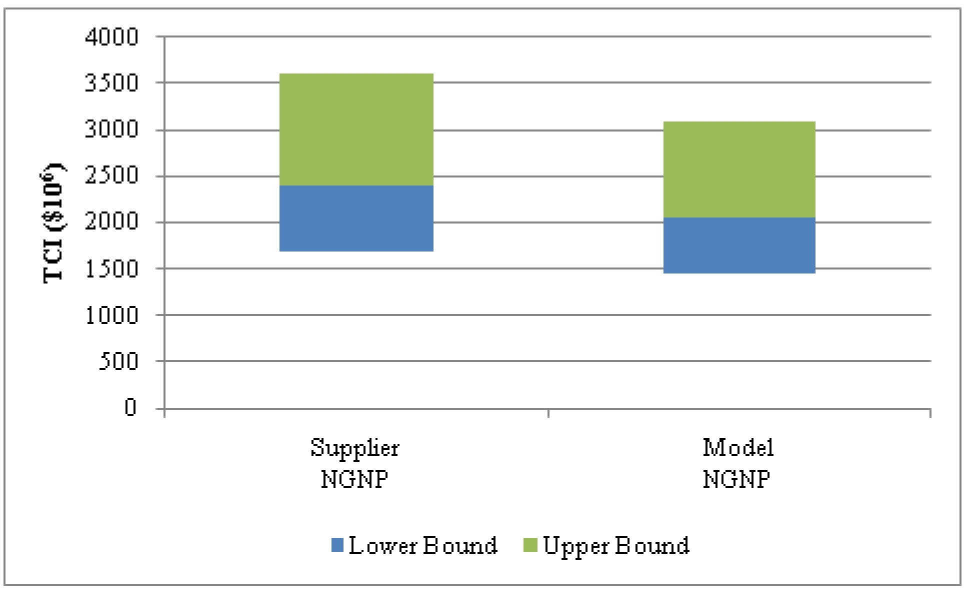

Figure 7. HTGR Model Cost Comparison – Pebble Bed Design, ≤350 MWt ROT ≤ 750°C.

3. ESTIMATION OF OPERATING COSTS

Operating costs were evaluated for the HTGR for the NGNP, FOAK, and NOAK plants, for single and multiple module scenarios. Operating costs are assumed to include operations and maintenance (O&M) costs and refueling costs.

3.1 O&M Costs

O&M costs were estimated based on methodology presented for a study of advanced reactor technologies, specifically the study of O&M staffing and costs conducted by Dominion with advice from Entergy (Dominion 2004). O&M costs are assumed to include the following items:

- Staffing requirements, including expenses for overtime, benefits and retirement, bonuses and incentives, and payroll taxes
- Nuclear Regulatory Commission (NRC) fees
- Institute of Nuclear Power Operations (INPO) fees
- Nuclear Energy Institute (NEI) fees
- Insurance and taxes
- Material supplies, services, and upgrades
- Outage costs
- Administration and general cost overhead

Staffing requirements were estimated based on the staff positions outlined in the Dominion study with input from Entergy. Staffing was estimated for single modules as well as estimates for an additional unit for multiple module scenarios. It was assumed that staffing levels would be the same for both the 600 MWt and 350 MWt power levels. Staffing assumes five shifts, three shifts active per day, one shift inactive, and one shift in training. It is assumed that staffing levels are independent of ROT, heat or power production, power cycle type, as well as the reactor phase, i.e. staffing levels are the same for the NGNP, FOAK, and NOAK project phases. Table 16 presents the staffing levels for the HTGR modules. SC indicates a position that is subcontracted if required, DP indicates a position that is duplicated by another staff member.

The lower levels of staffing assumed for the HTGR when compared to current LWR operations take into account advanced system automation, passive reactor safety systems, and reductions in security due to partially burying the core.

Table 16. Staffing levels by title.

Position	Units	Single Unit	Additional Unit
Management			
Supervisory			
Vice President		1	0
Director O&M		1	0
Director Site Safety		1	0
Non-Supervisory			
Executive Assistant		1	0
Human Resources Generalist		1	0

Table 16. Staffing levels by title.

Position Units	Single Unit	Additional Unit
Financial Support Services	2	0
Total Management	**7**	**0**
Operations		
Manager Operations	1	0
Assistant Manager Operations	0	0
Administrative Assistant	1	0
Shift Operations		
Shift Supervisor	5	0
Assistant Shift Supervisor	5	0
Licensed Reactor Operators (RO)	5	5
Non-Licensed ROs	15	10
Shift Clerks	2	0
Supervisor Shift Operations	0	0
Operations Support		
Supervisor Operations Support	1	0
Refueling Operators/Off-Shift Reactor Operator	0	0
Operations Engineer	1	0
Administrative Support	1	0
Plant Label Coordinator/Special Projects	0	0
Operations Maintenance Advisor	0	0
Off-Shift Senior Reactor Operator - Special Projects	1	0
Total Operations	**38**	**15**
Maintenance		
Manager Maintenance	1	0
Administrative Assistant	1	0
Electrical Maintenance Supervisor	1	0
Electrical Foreman	3	0
Electricians	8	0
Mechanical Maintenance Supervisor	1	0
Mechanical Foreman	3	0
Mechanics	9	6
Welding Foreman	1	0
Welders	2	0
Instrumentation and Controls (I&C) Supervisor	1	0
I&C Foreman	3	0
I&C Technicians	12	6
Control Operations Supervisor	1	0
System Protection Technician	1	0
Maintenance Support Supervisor	1	0
Maintenance Coordinator	1	0
Maintenance Outage Scheduling/Special Projects	2	0
Maintenance Human Performance Coordinator	0	0
Quality Inspectors	3	0
Maintenance/Procurement Interface	1	0
Total Maintenance	**56**	**12**
Engineering		
Engineering Manager	1	0
Administrative Assistant	1	0
Systems Engineering Supervisor	1	0

Table 16. Staffing levels by title.

Position Units	Single Unit	Additional Unit
Systems Engineers	10	0
Reactor Engineers	3	0
In-Service Inspection (ISI)/Non-Destructive Exams (NDE) Supervisor	1	0
NDE Technician	1	0
ISI Engineers	1	0
Component Engineering Supervisor	1	0
Component Engineers	4	2
Reliability Engineers	1	0
Predictive Maintenance Technicians	2	0
Site Civil/Mechanical Design Supervisor	1	0
Mechanical Design Engineer	3	1
Civil Design Engineer	1	0
Site I&C and Electrical Design Supervisor	1	0
Electrical Design Engineers	2	0
I&C Design Engineers	3	0
Engineering Work Management Supervisor	0	0
Design Control Engineer	1	0
Draftsman	2	0
Administrative Assistant	3	3
Schedule/Cost Engineer	1	0
Records Supervisor	1	0
Records Clerks	2	2
Total Engineering	**48**	**8**
Outage and Planning		
Outage and Planning Manager	1	0
Administrative Assistant	1	0
Nuclear Scheduling Supervisor	1	0
Work Week Manager (Non-Supervisor)	3	0
Electrical Scheduler	1	0
Mechanical Scheduler	1	0
I&C Scheduler	1	0
Nuclear Planning Supervisor	1	0
Electrical Planner	3	0
Mechanical Planner	2	0
Planned Maintenance Planner	1	0
I&C Planner	3	0
Unit Outage Coordinator	1	1
Outage Planner	1	1
Supervisor Turbine Maintenance	1	0
Turbine Equipment Specialist	1	0
Turbine Generator Engineer	1	0
Turbine Planner	0	0
Total Outage and Planning	**24**	**2**
Major Modification and Site Support		
Nuclear Support Services Manager	1	0
Administrative Assistant	1	0
Construction Engineering Supervisor	0	0
Quality Inspectors	2	0
Construction Engineers	2	1
Construction Specialists	1	1

Table 16. Staffing levels by title.

Position Units	Single Unit	Additional Unit
Electrical Construction Supervisor	SC	0
Construction Specialists	SC	0
Civil/Mechanical Construction Supervisor	SC	0
Construction Specialists	SC	0
Scaffolding/Insulation Support	2	2
Project Controls Supervisor	1	0
Controls Specialists	1	0
Facilities Support Supervisor	1	0
Vehicle Management	SC	0
Construction Equipment Management	1	0
Labor Supervisor	1	0
Labor Support	5	3
Construction Craft and Supervision	SC	SC
Total Major Modification and Site Support	**19**	**7**
Organizational Effectiveness		
Organizational Effectiveness Manager	1	0
Administrative Assistant	1	0
Licensing Supervisor	1	0
Licensing Engineers	2	1
Human Performance Supervisor	1	0
Human Performance Coordinator	0.5	0
Self-Assessment Coordinator	0.5	0
OE Coordinator	0.5	0
Benchmarking Coordinator	0.5	0
Nuclear Safety Supervisor	1	0
Corrective Action Coordinator	1	0
Shift Technical Advisors (STA) (On-Shift)	5	0
STA Office Staff (Off-Shift)	0	0
Root Cause Coordinator	1	0
Total Organizational Effectiveness	**16**	**1**
Nuclear Oversight		
Nuclear Oversight Manager	1	0
Administrative Assistant	1	0
Nuclear Quality Specialists	2	1
Nuclear Specialists	2	1
Total Oversight	**6**	**2**
Radiation Protection		
Radiation Protection Manager	1	0
Administrative Assistant	1	0
Health Physics Operations Supervisor (On-Shift)	1	0
Health Physics (HP) Coordinator	1	0
ALARA Coordinator	1	0
ALARA Technicians	2	0
HP Shift Supervisor	4	0
Shift HP Technicians	12	0
Decon Supervisor	1	0
Decon Technicians	4	0
HP Technical Support Supervisor	0	0
Health Physicist	1	0
Rad Analysis and Material Control Supervisor	DP	0
Count Room Technician	2	0

Table 16. Staffing levels by title.

Position Units	Single Unit	Additional Unit
Radwaste Technician	2	0
Exposure Control & Instrumentation Supervisor	DP	0
Instrumentation Technician	1	0
HP Specialists	2	0
Chemistry Supervisor	1	0
Asstistant Chemistry Supervisor	DP	0
Chemistry Technicians	8	4
Total Radiation Protection	**45**	**4**
Training		
Nuclear Training Manager	1	0
Administrative Assistant	1	0
Ops Initial Training Supervisor	1	0
Engineering Support Personnel (Engineering) Instructors	1	0
License Class Instructors	2	0
STA Initial Instructors	0	0
Simulator Technician	2	0
Ops Continuing Training Supervisor	1	0
Licensed Operator Re-Qualification Program Instructor	2	0
Shift Supervisor Instructor	0.5	0
STA Continuing Instructor	0.5	0
Non-Licensed Operator Instructor	1	0
Maintenance/Rad Protection Training Supervisor	DP	0
HP Instructor	1	0
Chemistry Instructor	0.5	0
New Employee Training Instructor	0.5	0
Electrical Instructor	1	0
Mechanical Instructor	1	0
I&C Instructor	1	0
Nonaccredited Training Instructor	DP	0
Total Training	**18**	**0**
Security		
Nuclear Protection Services Manager	1	0
Administrative Assistant	1	0
Security Operations Supervisor (On-Shift)	1	0
Security Shift Supervisor	5	0
Security Officers	70	20
Technical Security Coordinator	1	0
Security Training Coordinator	1	0
Security Field Team Leader	5	0
Fitness-For-Duty Coordinator	1	0
Safety and Loss Prevention Supervisor	DP	0
Loss Prevention Technicians	1	0
Environmental	DP	0
Nurse/Medical	1	0
Site Emergency Planning Specialist	1	0
Total Security	**89**	**20**
Supply Chain Management		
Supply Chain Management (SCM) Manager	1	0
Administrative Assistant	1	0

Table 16. Staffing levels by title.

Position Units	Single Unit	Additional Unit
Warehouse Supervisor	0.5	0
Storekeepers	5	0
Receiving/Inspection Supervisor	0.5	0
Storekeepers	DP	0
Material Verification Specialist	1	0
Emergent Sourcing	DP	0
SCM Coordinator	DP	0
Total Supply Chain Management	**9**	**0**
Telecommunications		
IT Business Area Manager	1	0
Business Analyst	1	0
Local Area Network Field Services	3	0
Telecommunications Services - Telephone	1	0
Telecommunications Services - Servers	1	0
Total Telecommunications	**7**	**0**
TOTAL PLANT STAFF	**382**	**71**

The total cost of the site staff salary was estimated by taking the calculated staffing level and multiplying it by the average annual 2009 salary for electric power workers, $63,400 (BLS 2011). The average salary takes into account the average plant breakdown between management, engineering, technicians, etc. Next, yearly overtime, assumed to be 7.5% of the site staff salary; retirement and benefits, assumed to be 38.5% of the site staff salary; bonus and incentives, assumed to be 8% of the site staff salary; and staff payroll taxes, assumed to be 7.7% of the site staff salary, were calculated (Dominion 2004).

NRC fees are based on fees presented in 10 CFR 171.15 (b) (1), INPO fees, NEI fees, outage costs, and the administration and general cost overhead were estimated based on values in the Dominion report (2004). Insurance and taxes were assumed to be three million dollars per year for the single unit and one million dollars per year for each additional unit. Material supplies, services, and upgrades are assumed to be five million dollars per year per reactor for the 600 MWt unit and three million dollars per year per reactor for the 350 MWt unit. Outage costs were estimated based on an assumed cost of 12 million per year for a 1,200 MWe LWR (Dominion 2004). Outage costs are approximately four million per year per reactor for the 600 MWt unit and three million per year per reactor for the 350 MWt unit. Again, these fees are assumed to be independent of ROT and the project phase.

The annual O&M costs were calculated by summing the above annual costs, and are summarized in the following table.

Table 17. INL Annual O&M costs ($\$10^6$ – 2009 basis).

Item / Power Level / Units	600 MWt Single Unit	600 MWt Additional Unit	350 MWt Single Unit	350 MWt Additional Unit
Payroll				
Site Staff Salary	24.22	4.50	24.22	4.50
Overtime	1.82	0.34	1.82	0.34
Retirement & Benefits	9.32	1.73	9.32	1.73
Bonus &Incentives	1.94	0.36	1.94	0.36
Payroll Tax	1.86	0.35	1.86	0.35
Total Payroll	**39.16**	**7.28**	**39.16**	**7.28**
NRC Fees	4.78	4.78	4.78	4.78
INPO Fees	0.71	0.18	0.71	0.18
NEI Fees	0.06	0.06	0.03	0.03
Insurance and Taxes	3.00	1.00	3.00	1.00
Material Supplies, Services, & Upgrades	5.00	5.00	3.00	3.00
Outage Costs	4.07	4.07	2.95	2.95
Administration & General Cost Overhead	3.00	3.00	3.00	3.00
Total Annual O&M Costs	**59.78**	**25.37**	**56.63**	**22.22**
$/MWt-hr	*11.37*	*4.83*	*18.47*	*7.25*

When compared to the reactor design supplier estimates for staffing, the staffing projected by INL is higher. As a result, the INL will continue to work with the reactor design suppliers to update the O&M costs to reflect the most probable plant staffing requirements. In the interim, the reactor design supplier staffing estimates will be used in the O&M estimate until the differences can be reconciled. The staffing estimates from the reactor design supplier (GA 2007), and the resulting O&M costs are presented in Table 18.

Table 18. Annual O&M costs using design supplier staffing ($\$10^6$ – 2009 basis).

Power Level	600 MWt		350 MWt	
Item **Units**	**Single Unit**	**Additional Unit**	**Single Unit**	**Additional Unit**
Staffing (FTE)	165	25.3	165	25.3
Payroll				
Site Staff Salary	10.46	1.61	10.46	1.61
Overtime	0.78	0.12	0.78	0.12
Retirement & Benefits	4.03	0.62	4.03	0.62
Bonus &Incentives	0.84	0.13	0.84	0.13
Payroll Tax	0.81	0.12	0.81	0.12
Total Payroll	**16.92**	**2.60**	**16.92**	**2.60**
NRC Fees	4.78	4.78	4.78	4.78
INPO Fees	0.71	0.18	0.71	0.18
NEI Fees	0.06	0.06	0.03	0.03
Insurance and Taxes	3.00	1.00	3.00	1.00
Material Supplies, Services, & Upgrades	5.00	5.00	3.00	3.00
Outage Costs	4.07	4.07	2.95	2.95
Administration & General Cost Overhead	3.00	3.00	3.00	3.00
Total Annual O&M Costs	**37.54**	**20.69**	**34.39**	**17.54**
$/MWt-hr	*7.14*	*3.94*	*11.22*	*5.72*

3.2 Fuel Costs

Fuel costs were calculated for the prismatic fuel configuration provided by GA for the NGNP Pre-Conceptual Design (GA 2007). The design parameters for the nuclear fuel for a 600 MWt HTGR and general information for calculating the uranium requirements are presented in Table 19.

Table 19. Fuel design parameters.

Description	**Value**
Number of Fuel Blocks per Reload *(Blocks)*	510
Average Uranium Loading *(Loading)*	4.4 kg/fuel block
Average Fuel Enrichment *(% E)*	15%
Fuel Cycle Length *(FCL)*	18 months
Mass of Heavy Metals per Refueling Segment	2,262 kg
Uranium in Tailings *(% T)*	0.20%
U_{235} in Natural Uranium *(% U_{235})*	0.72%
Uranium in U_3O_8	85%

Based on the information presented above, the enriched uranium mass flow required on average per year for refueling was calculated according to the following equation:

$$Product = Blocks \times Loading \times \frac{12\ months}{FCL}$$

The associated annual mass flows of natural uranium required for refueling and uranium tailings were calculated as follows (Glasstone 1994):

$$Feed = Product \times \frac{\%\,E - \%\,T}{\%\,U_{235} - \%\,T}$$

$$Tailings = Product \times \frac{\%\,E - \%\,U_{235}}{\%\,U_{235} - \%\,T}$$

The U_3O_8 feed required is calculated by dividing the natural uranium requirement by the percentage of uranium in U_3O_8, 85%, the ratio of the molecular weights of uranium and U_3O_8.

Next the amount of separation done by an enrichment process, separative work units (SWU), was calculated as follows (Glasstone 1994):

$$SWU = Product \times V(\%\,E) + Tailings \times V(\%\,T) + Feed \times V(\%\,U_{235})$$

where $V(x)$ is the value function, defined as (Glasstone 1994):

$$V(x) = (1 - 2x) \times ln\left(\frac{1-x}{x}\right)$$

The annual uranium requirements, based on the above calculations, are presented in Table 20 for the 600 MWt HTGR.

Table 20. Annual uranium calculations, 600 MWt HTGR.

Description	Value
Uranium Product	1,496 kg
Uranium Feed	42,909 kg
U_3O_8 Feed	50,601 kg
Tailings	41,413 kg
SWU	49,470

The associated annual costs for the various steps associated with fuel fabrication were calculated for the 600 MWt case for the NGNP and NOAK reactor phases, the fuel costs for the FOAK phase are assumed to be the same as the NGNP fuel costs. It is also assumed that the number of refueling blocks required scales linearly with the reactor power rating, i.e. the 350 MWt reactor would require 255 fuel blocks, and that the fuel costs remain constant for all ROTs. The unit costs are based on those presented in the Advanced Fuel Cycle Cost Basis, which were inflated to 2009 dollars assuming a standard three percent rate of inflation (INL 2007b).

Table 21 presents the annual refueling costs and the refueling cost per core. Refueling costs were independently reviewed and validated by Dominion. In addition, fuel costs were consistent with fuel costs presented by the reactor design suppliers.

Table 21. Annual fuel costs, single 600 MWt HTGR ($\$10^6$ – 2009 basis).

Reactor Phase	Annual	NGNP/FOAK		NOAK	
Description	**Usage**	**Unit Cost**	**Annual Cost**	**Unit Cost**	**Annual Cost**
Uranium Ore (U_3O_8)	50,601 kg	$106/kg	$5,368,240	$106/kg	$5,368,240
Uranium Conversion	42,909 kg	$11/kg	$455,217	$11/kg	$455,217
Uranium Enrichment	42,909	$122/SWU	$6,035,534	$122/SWU	$6,035,534
Tails Disposal	41,413 kg	$11/kg	$439,346	$11/kg	$439,346
Fuel Fabrication	1,496 kg	$26,523/kg	$39,677,660	$10,609/kg	$15,871,064
Spent Fuel Storage	2,262 kg	$233/kg	$335,966	$233/kg	$335,966
Spent Fuel Disposition	2,262 kg	$3,293/kg	$4,965,361	$3,293/kg	$4,965,361
Total – Annual Cost			**$57,277,323**		**$33,470,727**
$/MWt-hr			*10.90*		*6.37*

The refueling cost per core, presented in Table 22 are calculated by taking the annual average cost, dividing by the number of cores, multiplying by the fuel cycle length, and dividing by 12 months:

$$Refueling\ Cost\ Per\ Core = \frac{Average\ Annual\ Cost}{Number\ of\ Cores} \times \frac{FCL}{12\ Months}$$

Table 22. Total refueling costs per core ($\$10^6$ – 2009 basis).

Reactor Phase	NGNP/FOAK		NOAK	
Power Level	**600 MWt**	**350 MWt**	**600 MWt**	**350 MWt**
Refueling Cost Per Core	$85,915,985	$50,117,658	$50,206,091	$29,286,886

4. DECOMMISSIONING COSTS

Decommissioning costs were estimated based on the methodology presented in NUREG-1307, Rev. 14. As this document is for estimation of decommissioning costs for large LWRs, the decommissioning costs were converted to a $/MWt basis in order to estimate the costs for decommissioning the HTGR.

Estimated decommissioning costs are based on the following formula:

$$Estimated\ Cost = C_{1986} \times (0.65 \times L + 0.13 \times E + 0.22 \times B)$$

where C_{1986} is the base decommissioning cost from 1986 (the cost basis specified in NUREG-1307), L is the labor cost adjustment factor, E is the energy cost adjustment factor, and B is the burial/disposition cost adjustment factor, all of which are used to adjust the cost of decommissioning from a 1986 cost basis to 2009 values (NRC 2010).

The labor adjustment factor (L) was averaged for all labor areas, Northeast, South, Midwest, and West, to determine a generalized labor cost adjustment factor. Values for the base decommissioning cost (C_{1986}) and energy cost adjustment factor (E) were presented for pressurized water reactors (PWRs) and boiling water reactors (BWRs). The PWR and BWR values were averaged to determine an overall $/MWt basis for decommissioning. Finally, values for generic low level waste (LLW) disposal were presented for direct disposal and direct disposal with waste vendors, where 85% of the LLW is dispositioned using a waste vendor and the remaining 15% is dispositioned at a full-service disposal facility. These values were also averaged to determine a generic factor for LLW disposal (NRC 2010). All adjustment factors presented in NUREG-1307 are for 2010; because the basis for the HTGR cost estimate is 2009, costs were adjusted to 2009 values using the standard rate of inflation, three percent. The adjustment factors and associated decommissioning costs are presented in Table 23.

Table 23. Decommissioning costs ($ – 2009 basis).

Item	Value
C_{1986} ($$10^6$ – 1986 basis)	120
L	2.23
E	2.10
B	18.54
Estimated Cost ($$10^6$ – 2009 basis)	696.25
MWt	3,400
$/MWt	**204,780**

The $/MWt cost calculated above was compared to a recent decommissioning estimate for advanced LWRs conducted by Dominion (2004). The Dominion estimates were scaled from 2003 to 2009 dollars using the CEPCI. Table 24 presents the decommissioning costs from the Dominion report. The estimates of decommissioning costs from the two sources are within 10%.

Table 24. Dominion decommissioning estimates.

Reactor	$$10^6$ – 2003	$$10^6$ – 2009	MWt	$/MWt (2009)
ABWR	594.99	773.03	3,926	196,900
ACR-700 U1	426.36	553.94	1,982	279,485
ACR-700 U2	444.19	577.10	1,982	291,173
AP1000	416.41	541.01	3,415	158,422
ESBWR	570.43	741.12	4,500	164,693
Average $/MWt				**218,134**

The calculated decommissioning rate from NUREG-1307 is assumed to adequately estimate decommissioning costs for the NGNP, FOAK, and NOAK project phases. Also, it is assumed that the decommissioning costs scale linearly with reactor size and that the ROT does not impact the decommissioning cost. Table 25 presents the decommissioning costs for the single and four-pack HTGRs at 600 MWt and 350 MWt power levels. The results are in millions of 2009 dollars; thus, to determine the cost at the end of the reactor life, the costs must be escalated to account for inflation during reactor operation.

Table 25. Decommissioning costs for 600 and 350 MWt HTGRs ($\$10^6$ – 2009 basis).

Power Level Modules	**1**	**4**
600 MWt HTGR	122.87	491.47
350 MWt HTGR	71.67	286.69

5. FUTURE WORK AND RECOMMENDATIONS

As the design of the HTGR progresses towards finalization, this TEV will be updated if the design of the HTGR is changed significantly or if additional refinements of the capital costs become available from the reactor design suppliers. There are differences in the projected staffing between designers and other knowledgeable parties, in part because required staffing levels have not yet been established. Direct interface between the design suppliers and NGNP staff is recommended to fully understand the differences. The results of this evaluation will be used to update the HTGR capital and operating costs used in previous and future TEVs and economic models developed for the NGNP process heat applications study.

The costs presented are for the prismatic block reactor configuration. Costs for the pebble bed reactor configuration will be included in a future revision of the TEV; however, the capital costs are roughly equivalent and the difference does not affect the overall accuracy of the estimates for both prismatic and pebble bed configurations. In addition, the current TEV assumes that a partially rated IHX is included for all plant configurations. Future revisions of the TEV will allow for both full and partially rated IHXs and a steam generator for more nuanced process heat supply configurations.

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7. APPENDIXES

Appendix A – Independent Evaluations of Costs of Major Capital Items for High Temperature Gas Cooler Reactors

Appendix A

The following appendix includes the data used in the report to derive the capital costs of the equipment items described in Section 2.2. The direct costs were estimated by Dominion for the INL through a separate subcontract. The following memo presents the methodology and approach Dominion used to estimate the direct costs for the specified reactor equipment items. The following changes/assumptions were made to the data provided by Dominion:

- Dominion costs were provided in 2007 dollars and were adjusted to 2009 dollars using the CEPCI.

- Reactor vessel costs for the 7 MPa reactor design pressure were used in the cost model as this reflects the most recent vessel design pressure.

- Dominion provided costs for the single module FOAK plant. Estimates were generated for the four-pack FOAK costs using the ratio of the four-pack and single NOAK plants. This assumption was confirmed by Dominion.

- The reactor initial core costs were assumed to be the same for all ROTs, based on the cost for the initial core at an ROT of 850°C.

- NGNP costs for ROTs other than 950°C were estimated based on the ROT trends for the FOAK and NOAK plants.