

**YUKON
ENERGY**



YUKON ENERGY CORPORATION

20-YEAR RESOURCE PLAN: 2006-2025

January, 2006

and

SUPPLEMENTAL MATERIALS

May, 2006

TABLE OF CONTENTS

CHAPTER 1 - INTRODUCTION

1.0	INTRODUCTION.....	1-1
1.1	PURPOSE OF THE SUBMISSION.....	1-1
1.2	SCOPE OF SUBMISSION.....	1-2
1.3	RESOURCE PLANNING FRAMEWORK.....	1-3
1.3.1	Power Capacity and Energy in Yukon.....	1-4
1.3.2	Basic Planning Process.....	1-6
1.3.3	Resource Plan and Specific Capital Project Decisions.....	1-8
1.4	CURRENT YUKON SITUATION COMPARED WITH 1992.....	1-9
1.5	SUBMISSION OVERVIEW.....	1-13

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

2.0	BACKGROUND ON YUKON POWER SYSTEMS.....	2-1
2.1	OVERVIEW OF GENERATION FACILITIES AND TRANSMISSION IN YUKON.....	2-1
2.1.1	Generation in Yukon.....	2-3
2.1.2	Transmission in Yukon.....	2-7
2.2	OUTCOMES FROM THE 1992 REVIEW.....	2-8
2.3	MAJOR EVENTS AFFECTING POWER SYSTEMS SINCE 1992.....	2-13
2.3.1	Closure of the Faro Mine.....	2-13
2.3.2	The Growth of Secondary Sales.....	2-14
2.3.3	Shift to Direct Management.....	2-14
2.3.4	Whitehorse Rapids Generating Station Fire Rebuilding Project.....	2-15
2.3.5	Renewal of Water Licences at Whitehorse, Mayo and Aishihik.....	2-15
2.3.6	Mayo-Dawson Transmission Line.....	2-16
2.3.7	System Upgrades and Changes.....	2-17
2.4	BULK ELECTRICAL SUPPLY PLANNING SINCE 1992.....	2-17
2.4.1	Ongoing Yukon Energy Infrastructure Planning Process.....	2-18
2.4.2	BC Hydro Inventory of Potential Future Hydro Supply Options.....	2-18
2.4.3	Bulk Electrical Supply Infrastructure Condition Assessment Work.....	2-18
2.4.4	Generation Capacity Planning Criteria Review.....	2-18
2.4.5	Demand Side Management and the Energy Solutions Centre.....	2-19

CHAPTER 3 – SYSTEM CAPABILITY

3.0	SYSTEM CAPABILITY.....	3-1
3.1	CURRENT FACILITIES CONDITION ASSESSMENT.....	3-1
3.1.1	Yukon Energy's Response to Condition Assessments.....	3-2
3.1.2	Condition Assessment Findings Relevant to Resource Planning.....	3-5

3.2	CAPACITY AND ENERGY OUTPUT OF EXISTING FACILITIES	3-6
3.2.1	Whitehorse Rapids Hydro Firm Capacity.....	3-7
3.2.2	Aishihik Hydro Capacity and Energy.....	3-9
3.2.3	Mayo Hydro Capacity	3-10
3.2.4	Whitehorse Diesel Capacity.....	3-10
3.2.5	Fish Lake Hydro (YECL) Capacity.....	3-11
3.3	CAPACITY PLANNING CRITERIA REVIEW	3-11
3.3.1	Background and Overview on the Evolution of Capacity Planning	3-12
3.3.2	Yukon Energy's Previous Capacity Planning Criteria (prior to late 2005)	3-14
3.3.3	Previous Yukon Criteria Compared with Criteria for Other Jurisdictions	3-17
3.3.4	New Criteria Adopted by Yukon Energy.....	3-20
3.3.5	Rationale for Adopting a Two-Part Criteria on WAF and MD.....	3-21
3.3.6	Implications of the Adopted Criteria	3-23
3.4	SUMMARY: REVISED CAPACITY PLANNING CRITERIA	3-25

CHAPTER 4 – NEAR TERM REQUIREMENTS

4.0	NEAR TERM REQUIREMENTS	4-1
4.1	PLANNING APPROACH AND TIMELINE	4-1
4.2	REQUIREMENTS.....	4-3
4.2.1	Basis for Non-Industrial Load Forecasts	4-4
4.2.2	Basis for Near Term Industrial Load Forecasts.....	4-7
4.2.3	Near Term WAF Load – Cases Analyzed Based on Non-Industrial and Industrial Requirements.....	4-7
4.2.4	Base Case Requirements	4-8
4.2.5	Low Sensitivity Case	4-10
4.2.6	Base Case with Mine Loads.....	4-12
4.2.7	High Sensitivity Case Including Mines	4-14
4.3	OPTIONS.....	4-16
4.3.1	Overview of “Opportunity” Project Options.....	4-17
4.3.2	Aishihik 3rd Turbine.....	4-19
4.3.3	Marsh Lake Fall/Winter Storage	4-20
4.3.4	Carmacks to Stewart Transmission Line Project.....	4-22
4.3.5	Overview of Major Capacity-Related Project Options	4-26
4.3.6	Mirrlees Life Extension Project	4-28
4.3.7	Whitehorse Diesel Replacement/Expansion Project	4-32
4.3.8	Aishihik 2nd Transmission Line Project	4-34
4.3.9	Supplemental Project Options	4-38
4.4	ASSESSMENT	4-39
4.4.1	Assessment of Opportunity Projects	4-40
4.4.2	Assessment of Capacity-Related Projects	4-46

4.4.3	Schedule and Sequencing of Alternatives	4-53
4.4.4	Rate related Impacts of Near Term Options	4-53
4.5	PROPOSED ACTIONS	4-57

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

5.0	INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES	5-1
5.1	PLANNING APPROACH AND TIMELINE	5-1
5.1.1	Need to Consider and Balance Several Key Factors	5-3
5.1.2	Regulatory and Policy Framework	5-7
5.1.3	Planning Framework	5-9
5.2	REQUIREMENTS	5-12
5.2.1	Scenario 1: A 10 MW WAF Industrial Scenario	5-18
5.2.2	Scenario 2: A 25 MW WAF Industrial Scenario	5-22
5.2.3	Scenario 3: A 40 MW WAF Industrial Scenario	5-24
5.2.4	Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline	5-26
5.3	OPTIONS	5-27
5.3.1	Overview of Resource Supply Options	5-28
5.3.2	Options for Scenario 1: A 10 MW WAF Industrial Scenario	5-38
5.3.3	Options for Scenario 2: A 25 MW WAF Industrial Scenario	5-38
5.3.4	Options for Scenario 3: A 40 MW WAF Industrial Scenario	5-40
5.3.5	Options for Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline Scenario	5-42
5.4	PRE-ASSESSMENT AND SCREENING	5-43
5.4.1	Technical Pre-Assessment and Load Fit	5-45
5.4.2	Economic Pre-Assessment	5-49
5.5	PROPOSED ACTIONS	5-51
5.5.1	Proposed Activities Regarding Scenario 1: A 10 MW WAF Industrial Scenario ...	5-52
5.5.2	Proposed Activities Regarding Scenario 2: A 25 MW WAF Industrial Scenario ...	5-53
5.5.3	Proposed Activities Regarding Scenario 3: A 40 MW WAF Industrial Scenario ...	5-54
5.5.4	Proposed Activities Regarding Scenario 4: A 120 to 360 MW WAF Pipeline Scenario	5-55
5.5.5	Proposed “Pre-commitment” activities	5-56

APPENDICES

APPENDIX A: POWER RESOURCE TECHNOLOGY OPTIONS

A.1	POWER RESOURCE TECHNOLOGY OPTIONS	A-1
A.1.1	DIESEL	A-1
A.1.2	HYDRO	A-2
A.1.3	WIND	A-2

A.1.4	BIOMASS	A-4
A.1.5	COAL	A-5
A.1.6	COAL-BED METHANE	A-6
A.1.7	NATURAL GAS	A-6
A.1.8	GEO THERMAL	A-7
A.1.9	HYDROGEN	A-7
A.1.10	SOLAR	A-8
A.1.11	NUCLEAR	A-8
A.1.12	DEMAND SIDE MANAGEMENT	A-9
A.2	LITERATURE REVIEWED	A-10
A.2.1	HYDRO	A-10
A.2.2	WIND	A-10
A.2.3	BIOMASS	A-11
A.2.4	COAL	A-11
A.2.5	LITERATURE REVIEWED ASSESSING MULTIPLE GENERATION TECHNOLOGIES	A-11

APPENDIX B: HYDRO PROJECT OPTIONS

B.1	HYDRO PROJECT OPTIONS	B-1
B.1.1	LEVELIZED COST OF ENERGY (LCOE)	B-4
B.2	EXISTING HYDRO ENHANCEMENTS	B-5
B.2.1	AISHIHIK DIVERSIONS	B-5
B.2.2	ATLIN STORAGE	B-5
B.3	VERY SMALL PROJECTS (1-4 MW)	B-6
B.3.1	DRURY	B-6
B.3.2	SQUANGA	B-6
B.3.3	MORLEY, LAPIE AND ORCHAY	B-7
B.4	SMALL PROJECTS (5-10 MW)	B-7
B.4.1	MOON HYDRO SITE	B-8
B.4.2	SURPRISE LAKE HYDRO SITE	B-9
B.4.3	TUTSHI AND OTHER HYDRO SITES IN THE SOUTHERN LAKES	B-10
B.4.4	MAYO B	B-10
B.4.5	LACK OF OTHER YUKON-BASED HYDRO PROJECTS	B-11
B.5	MEDIUM PROJECTS (10-30 MW)	B-11
B.5.1	PRIMROSE/KUSAWA/TAKHINI HYDRO SITE	B-11
B.5.2	FINLAYSON HYDRO SITE	B-13
B.6	LARGE PROJECTS (30-60 MW)	B-14
B.6.1	HOOLE	B-14
B.6.2	SLATE	B-14
B.6.3	HESS	B-14

B.7	VERY LARGE PROJECTS (60 MW+)	B-14
B.7.1	GRANITE CANYON	B-14
B.7.2	FRASER FALLS	B-15
B.7.3	VARIOUS OTHER LARGE YUKON RIVER SITES	B-15

APPENDIX C: AISHIHIK 3RD TURBINE ASSESSMENT

C.1	AISHIHIK 3RD TURBINE ASSESSMENT	C-1
C.2	AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE LOAD.....	C-4
C.3	AISHIHIK 3RD TURBINE AT 2009 UNDER BASE CASE WITH 10 MW MINE LOADS.....	C-6
C.4	AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS.....	C-8
C.5	AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE WITH 10 MW MINE LOADS.....	C-10
C.6	AISHIHIK 3RD TURBINE AT 2011 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE UNDER BASE CASE LOADS.....	C-12
C.7	SECTION C-7: AISHIHIK 3RD TURBINE AT 2009 ASSUMING EARLIER IN-SERVICE (2007) OF MARSH LAKE FALL/WINTER STORAGE AND (2008) OF CARMACKS-STEWART (CS) UNDER BASE CASE WITH 10 MW MINE LOADS.....	C-14

GLOSSARY OF TERMS

LIST OF TABLES

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

Table 2.1: Generation Capacity in Yukon – YEC and YECL in 2005 2-4

CHAPTER 3 – SYSTEM CAPABILITY

Table 3.1: BC Hydro Generation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 (\$000s) 3-4

Table 3.2: BC Hydro Substation Condition Assessment Recommended spending compared to YEC Budgeted Capital Planning 2004-2009 (\$000s) 3-5

Table 3.3: Yukon Energy Generation Inventory..... 3-7

Table 3.4: Current WAF Generating Complement and Maximum Allowable Peak Load (MAPL) under Previous Planning Criteria 3-17

Table 3.5: WAF Peak and Capacity Surplus (Shortfall) as Whitehorse Diesels are Retired (MW).... 3-24

CHAPTER 4 – NEAR TERM REQUIREMENTS

Table 4.1: Near Term Non-Industrial Load Forecasts..... 4-5

Table 4.2: Summary of Near Term Opportunity Projects to 2012 (2005\$ millions)..... 4-41

Table 4.3: Comparison of Near Term Capacity-focused Options to 2012..... 4-47

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

Table 5.1 Industrial Development Opportunities 5-14

Table 5.2 Potential Hydro Resource Options 5-30

APPENDIX B: HYDRO PROJECT OPTIONS

Table B-1: Potential Hydro Sites B-2

APPENDIX C: AISHIHIK 3RD TURBINE ASSESSMENT

Table C-1: Summary of Aishihik 3rd Turbine Assessment Cases (2005\$, \$000s) C-3

Table C-2A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years)
– IRR based on cash flows C-4

Table C-2B: Aishihik 3rd Turbine Economics (65 years)
– NPV based on annual impacts on ratepayers..... C-5

Table C-3A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years)
– IRR based on cash flows C-6

Table C-3B: Aishihik 3rd Turbine Economics (65 years)
– NPV based on annual impacts on ratepayers..... C-7

Table C-4A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage IRR based on cash flows..... C-8

Table C-4B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers.....	C-9
Table C-5A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage IRR based on cash flows.....	C-10
Table C-5B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers.....	C-11
Table C-6A: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Fall/Winter Storage – IRR based on cash flows	C-12
Table C-6B: Aishihik 3rd Turbine Economics (65 years) with Marsh Lake Storage – NPV based on annual impacts on ratepayers.....	C-13
Table C-7A: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & Carmacks-Stewart (CS) S- IRR based on cash flows	C-14
Table C-7B: Lifetime Economic Analysis of Aishihik 3rd Turbine (65 years) with Marsh Lake Fall/Winter Storage & (CS) S- NPV impacts on ratepayers	C-15

LIST OF FIGURES

CHAPTER 1 – INTRODUCTION

Figure 1.1: 20-Year Resource Plan and Decisions on Specific Projects 1-9
Figure 1.2: Load Situation, Resource Needs and Supply Options 2006-2025..... 1-12
Figure 1.3: Submission Overview 1-13

CHAPTER 2 – BACKGROUND ON YUKON POWER SYSTEMS

Figure 2.1 Map of Yukon Territory Power Infrastructure 2-2
Figure 2.2 Yukon Total Power Generation 1967-1997 2-5
Figure 2.3 YEC WAF Generation 1976-2004..... 2-6
Figure 2.4 Generation on MD 1980–2004 2-7

CHAPTER 3 – SYSTEM CAPABILITY

Figure 3.1: WAF System – Comparison of Capacity Criteria 3-25

CHAPTER 4 – NEAR TERM REQUIREMENTS

Figure 4.1: WAF Base Case Capacity Requirements 4-9
Figure 4.2: WAF Base Case System Energy Requirements..... 4-10
Figure 4.3: WAF Low Sensitivity Case Capacity Requirements 4-11
Figure 4.4: WAF Low Sensitivity Energy Requirements..... 4-11
Figure 4.5: WAF Base Case with Mine Capacity Requirements 4-12
Figure 4.6: WAF Base Case with Mine Energy Requirements 4-13
Figure 4.7: WAF High Sensitivity Case with Mines Capacity Requirements 4-14
Figure 4.8: WAF High Sensitivity Case with Mines Energy Requirements 4-15
Figure 4.9: Carmacks to Stewart Transmission Line in 2008 4-25
Figure 4.10: Carmacks to Stewart Transmission Line in 2008 4-26
Figure 4.11: Mirrlees Life Extension 4-31
Figure 4.12: Whitehorse Diesel Replacement and Expansion 4-33
Figure 4.13: Aishihik Second Transmission Line 2009 4-36
Figure 4.14: Aishihik Second Transmission Line in 2009 (with Aishihik 3rd Turbine in 2009) 4-37
Figure 4.15: Timing and Sequencing of Opportunity and Capacity-Related Projects..... 4-54

CHAPTER 5 – INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

Figure 5.1: Map of Industrial Development Opportunities and Power Infrastructure 5-13
Figure 5.2: Earliest In-Service Dates and Power Loads for Potential Mine Developments..... 5-16
Figure 5.3: Scenario 1: WAF Capacity Requirements 5-20
Figure 5.4: Scenario 1: WAF Energy Requirements..... 5-21
Figure 5.5: Scenario 2: WAF Capacity Requirements 5-23
Figure 5.6: Scenario 2: WAF Energy Requirements..... 5-24

Figure 5.7: Scenario 3: WAF Capacity Requirements 5-25
Figure 5.8: Scenario 3: WAF Energy Requirements..... 5-26
Figure 5.9: Map of Potential Supply Option Sites 5-29

APPENDIX B: HYDRO PROJECT OPTIONS

Figure B-1: Map of Potential Supply Options B-3
Figure B-2: WAF Energy Requirements under 25 MW Scenario with Moon Lake Hydro..... B-9
Figure B-3: WAF Energy Requirements under 40 MW Scenario with Primrose Hydro..... B-12
Figure B-4: WAF Energy Requirements under 25 MW Scenario with Primrose Hydro..... B-13

1 **1.0 INTRODUCTION**

2 Yukon Energy Corporation's ("YEC" or "Yukon Energy") 20-Year Resource Plan Submission addresses
3 major generation and transmission requirements in Yukon during the period 2006 to 2025. The last
4 Resource Plan, which was submitted for review by the Yukon Utilities Board ("YUB") in 1992, covered
5 1992-2001 and was prepared by YEC and Yukon Electrical Company Limited ("YECL").
6

7 This chapter sets out the purpose, scope, framework, and approach and outline of the 20-Year Resource
8 Plan Submission. The sections for this chapter are as follows:

- 9 • Section 1.1: Purpose of the Submission
- 10 • Section 1.2: Scope of the Submission
- 11 • Section 1.3: Resource Planning Framework
- 12 • Section 1.4: Current Yukon Situation Compared with 1992
- 13 • Section 1.5: Submission Overview

14 **1.1 PURPOSE OF THE SUBMISSION**

15 The Resource Plan Submission provides Yukon Energy's 20-Year Resource Plan with respect to major
16 electrical generation and transmission requirements during the 2006 to 2025 period, with emphasis on:

- 17 a) near term projects that will require YEC commitments before the year 2009 with costs of \$3
18 million or more, and
- 19 b) planning activities that YEC may be required to carry out in order to start construction on
20 other projects before 2016 to meet the needs of potential major industrial customers or other
21 major potential developments in Yukon.
22

23 Yukon Energy is committed to seek YUB review, prior to construction, of any new capital project costing
24 \$3 million or more. Yukon Energy's December 2004 Application to the YUB regarding 2005 Required
25 Revenues and Related Matters also committed Yukon Energy to bring forward to the YUB new or revised
26 capacity planning criteria in advance of capital investment in new generation for capacity reasons.
27 Accordingly, the 20-Year Resource Plan Submission is expected to provide the YUB with the opportunity
28 to review near term generation or transmission projects costing \$3 million or more, including projects
29 that are required based on revised capacity planning criteria now adopted by Yukon Energy.
30

31 The Submission also proposes Yukon Energy planning activities within the next 10 years to protect YEC's
32 ability to start construction on other major generation and transmission projects before 2016 to meet the

1 needs of potential major industrial development opportunities. In some circumstances, to identify and
2 protect power resource options related to industrial development opportunities, some of these planning
3 commitments will need to be made on some form of contingent basis in advance of resolving various
4 major uncertainties.

5 **1.2 SCOPE OF SUBMISSION**

6 The planning and development of new transmission and generation projects requires a forward looking
7 perspective regarding major objectives, options, policies and planning activities. The Resource Plan
8 Submission identifies generation and transmission issues and options facing Yukon Energy in both the
9 near term (i.e., prior to 2009), and within the next 10 to 20 years. The Submission also provides an
10 overview of the development and composition of Yukon's power systems; an update on Yukon Energy's
11 capital planning process since the last Resource Plan submitted in 1992; and the context today for bulk
12 electrical supply ("BES") planning by Yukon Energy.

13

14 With regard to near term generation and transmission projects of \$3 million or more included in the Plan
15 for construction start within the next three years (i.e., by 2009), Yukon Energy has examined:

- 16 • the necessity of the proposed spending commitments, their expected effects on overall utility
17 costs and electricity rates, and (to the extent currently known) their physical and engineering
18 characteristics and their economic consequences;
- 19 • the capability and condition of existing generation and transmission facilities, taking into
20 account appropriate capacity planning criteria;
- 21 • forecast load requirements for electricity and the need for spending commitments to meet
22 these forecast requirements;
- 23 • all reasonable alternative near term options and developed proposals based on reasonable
24 grounds; and
- 25 • the potential risks of each option.

26

27 During the planning process, Yukon Energy reviewed the studies and activities that have taken place
28 before and after 1992. Major initiatives carried out in the past few years include a review the condition
29 of existing assets, and an examination of the adequacy of the current capacity planning criteria.
30 Additional technical project-specific feasibility or planning studies have generally not been carried out
31 since 1992, beyond developments actually undertaken such as the Mayo Dawson Transmission Line
32 Project. Yukon Energy also completed an initial review of a potential Carmacks-Stewart Transmission

1 Line in 2002; a review of a potential Atlin Transmission Line in 2003; and a Small Hydro Assessment in
2 2004.

3
4 Major near term projects addressed in the Submission for construction start prior to 2009 are the result
5 of the adoption in late 2005 of revised capacity planning criteria. Studies are ongoing with regard to
6 leading near term major project options. The Submission proceeds on the basis of current information
7 regarding these near term options, setting out the conditions relevant to proceeding with any specific
8 option. Updates will be provided during the review of the Submission to the extent that relevant new
9 information is forthcoming from ongoing studies on these projects.

10

11 Longer term opportunities addressed in the Submission are contingent on the extent to which new
12 industrial developments do in fact move forward during the next 10 to 20 years. The Submission
13 identifies representative scenarios related to possible future industrial development, and the planning
14 activities appropriate for Yukon Energy to identify and protect relevant generation and transmission
15 options that may need to be developed with respect to these scenarios.

16 **1.3 RESOURCE PLANNING FRAMEWORK**

17 In Yukon, electric power resource planning focuses separately on each electric power system. The
18 Whitehorse-Aishihik-Faro ("WAF") grid, and the Mayo-Dawson ("MD") grid are typically planned as
19 separate systems, as are each of the isolated diesel-served communities.

20

21 The basic electric power resource planning model addresses separately each system's generation
22 **capacity** (MW [megawatts], particularly at the time of system winter peak) and its **energy** generation
23 kW.h or MW.h [kilowatt hours or megawatt hours] over the full year). An overview of power capacity
24 and energy in Yukon is provided below (Section 1.3.1).

25 The basic resource planning process in the Submission is then reviewed (Section 1.3.2), including the
26 following elements (in the following sequence) which the Submission examines separately as required for
27 capacity and energy on both the WAF and MD systems:

- 28 1. **System Capability** – existing system capability over the next 20 years, based on the
29 condition of existing facilities, firm capability of these facilities at the time of winter peak,
30 and capacity planning criteria for each system that define generation capacity (MW)
31 adequacy and load carrying capability;

32

- 1 2. **System Requirements** – capacity and energy requirements forecast over the next 20 years
2 (and beyond) for each system in order to assess the loads that may need to be met under
3 different industrial development scenarios;
4
- 5 3. **New Facility Requirements** – the capability of installed plant on each system over the
6 next 20 years compared to forecast system requirements (to establish forecast requirements
7 for new facilities under each load scenario);
8
- 9 4. **Options** – resource options to meet new facility requirements for each load scenario on each
10 system;
11
- 12 5. **Assessment of Options** – resource options are assessed and/or screened, to the extent
13 feasible today, based on consideration of technical feasibility (including timing), cost
14 efficiency, reliability and risk.

15 **1.3.1 Power Capacity and Energy in Yukon**

16 As the main generator and transmitter of electrical power in the Yukon region, Yukon Energy focuses on
17 serving and planning for the capacity and energy requirements of Yukoners, particularly those supplied
18 on the WAF and MD grids. An overview of power capacity and energy in Yukon is provided below.
19

20 **Capacity:** The capacity requirement on a power system in any year is the highest or peak generation
21 capability (MW) required during the year. This required capability reflects both the operating generation
22 capability needed to serve the peak loads on the system (including provision for system losses over and
23 above customer loads) plus the provision of sufficient generation reserve capability to address unplanned
24 generation outages (based on the system's capacity planning criteria).

25 Capacity requirements on Yukon systems typically drive the need to develop a specific MW amount of
26 new generation facilities within a certain time period. The type of generation selected, however, may
27 depend on forecast energy requirements¹.

¹ Diesel generating units have low capital costs, and very high operating costs; accordingly, diesel units are typically well-suited to meeting capacity needs during system peaks and as reserve capacity, rather than being run to provide sustained energy on a regular basis throughout the year. Conversely, hydro generating plants have relatively high capital costs and very low operating costs; as a result, sustained operation of such facilities over an extended time period in a year can often yield lower unit costs for energy generation than would occur with diesel generation units.

1 In Yukon, the peak power requirement is typically in the winter. For example, during the winter of
2 2004/05, the WAF system peak occurred on Wednesday January 12th, 2005, when the temperature
3 reached -44.5 degrees Celsius. The WAF system integrated hourly peak for generation on that day was
4 56.4 MW.

5
6 The capacity capability of generation facilities can vary depending on the time of year. For example, the
7 winter peak in Yukon occurs on the WAF grid when the capability of the Whitehorse Hydro Plant is
8 reduced due to lower water flows. For a hydro asset, the amount of electricity that the asset can
9 generate is determined in part by the volume of water moving through the plant. The amount of water
10 flowing through the Whitehorse Plant in the winter months under normal or low flow water regimes is
11 typically lower than in the summer months. Accordingly, given that there is very little reservoir storage
12 to retain water for the winter, the Whitehorse Plant firm capacity in the four coldest winter months
13 (about 24 MW) is well below its peak capacity in the summer months (40 MW).

14
15 The capacity planning criteria applied on each Yukon system in the past, as reviewed and recommended
16 by the YUB in 1992, in effect provide a requirement for "reserve generation capacity" equal to the
17 capacity needed to meet forecast winter peak load with the loss of the single largest winter generation
18 unit (on WAF, this is one 15 MW hydro unit at Aishihik) plus the loss of 10% of the installed diesel
19 capacity². In light of changes since 1992, it became timely to review the adequacy of the current
20 capacity planning criteria for the WAF and MD systems.

21
22 **Energy:** The annual energy requirement on a power system is the number of kilowatt hours of electricity
23 that are required to be generated.

24
25 Generation requirements are higher than the sales to customers as a result of system losses between the
26 generation plant and the customers as well as generation station service power requirements. Yukon
27 Energy must generate enough electricity to serve its load, and to account for the associated line and
28 other system losses. Between 2000 and 2004, Yukon Energy's energy losses overall required generation
29 averaging 8% more than YEC's sales to its customers.

30
31 Yukon's existing diesel generation facilities on each system typically are sufficient to provide a reliable
32 supply of firm energy to meet system loads, even under low flow conditions for the hydro generation

² On isolated systems, this is worded so as to require the diesel plant installed, less the largest unit, to be 110% of the forecast peak.

1 facilities. The prime energy-related issue when assessing new facilities in Yukon therefore relates to the
2 opportunity to displace diesel generation with less costly energy supply alternatives.

3
4 Energy requirements in Yukon may establish the economic opportunity for certain types of new
5 generation or even transmission facilities. If sufficient energy is required on a sustained basis, past
6 Yukon experience has shown that opportunities may emerge to develop new hydro or transmission
7 facilities (with access to surplus or cost competitive hydro generation) to displace what would otherwise
8 be served by diesel generation. These opportunities arise because hydro plants have relatively high
9 capital costs and very low operating costs; as a result, sustained operation of such facilities over an
10 extended time period in a year can often yield lower unit costs for energy generation than would occur
11 with diesel generation units³.

12
13 Current surplus hydro generation capability on both the WAF and MD systems limit opportunities today
14 for developing new lower cost generation on these systems. The Resource Plan identifies the future
15 growth conditions required before the current surplus hydro would be fully utilized and new opportunities
16 may emerge to displace diesel generation on these systems.

17 **1.3.2 Basic Planning Process**

18 The basic planning process that Yukon Energy undertook to develop its 20 Year Resource Plan included
19 the following elements:

20 1. **System Capability:** Existing system capability over the next 20 years was assessed, based
21 on the condition of existing facilities, firm capability of these facilities at the time of winter
22 peak, and capacity planning criteria for each system that define generation capacity (MW)
23 adequacy and load carrying capability.

24 a) **Condition assessments of existing facilities:** Yukon Energy commissioned
25 assessments of its existing facilities to determine their condition and their remaining life.
26 The prime focus for the Resource Plan from these assessments is the potential timing for
27 retirement of any generation or transmission facilities during the next 20 years.

³ Conversely, diesel units have low capital costs and very high operating costs; accordingly, diesel units are typically well-suited to meeting capacity needs during relatively brief system peak periods, rather than being run to provide sustained energy on a regular basis throughout the year. Diesel units, however, can be cost effective for sustained operation in many specific situations, e.g., Yukon experience demonstrates instances involving isolation from a grid and/or viable energy options, small scale of requirements, or short term time periods for requirements.

- 1 b) **Firm capability of existing facilities:** The ability of these facilities to provide capacity
2 and energy was reviewed, particularly at system peak periods in winter. This included
3 planned retirements and age-related derates.
- 4 c) **Capacity planning criteria review:** Capacity planning criteria were thoroughly
5 reviewed for each system. These criteria establish the “reserve” capacity (MW) capability
6 that must be planned over and above the capacity needed to supply forecast system
7 winter peak load when each facility is operating at its respective capability (e.g., the
8 reserve needed to cover reasonable contingencies regarding potential generation and
9 transmission or BES unit failures). Yukon Energy has adopted revised capacity planning
10 criteria as a result of this review.
- 11
- 12 2. **System Requirements Forecasts:** Capacity and energy requirements were forecast over
13 the next 20 years (and beyond) for each system in order to assess the loads that may need
14 to be met under different industrial development scenarios. For Yukon, a key historic driver
15 has been opening and closing of major industrial loads (new or existing mines) and planning
16 for each system must therefore address different industrial load scenarios. Generation and
17 transmission are designed, built and operated on each system to provide reliable supply of
18 both capacity and energy to meet forecast non-industrial and industrial requirements:
- 19 a) **Capacity requirement forecasts:** These forecasts address the peak facility power
20 requirements (MW) at the specific time of the system annual peak load in winter,
21 including the provision of sufficient generation reserve capability to meet the capacity
22 planning criteria.
- 23 b) **Energy requirement forecasts:** These forecasts address the energy requirements
24 (kW.h) over the full year; and, where relevant, seasonal energy requirements.
- 25
- 26 3. **Forecast New Facility Requirements:** The capability of installed plant on each system
27 over the next 20 years was compared to forecast system requirements (to establish forecast
28 requirements for new facilities under each load scenario):
- 29 a) **New capacity requirements:** New capacity requirements reflect the extent to which
30 forecast MW requirements at the time of system peak in winter (including provision to
31 meet capacity planning criteria for reserve capability) exceed the forecast system
32 capability of existing plant (i.e., reliable MW of capacity from what is installed today, less
33 those units that are retired over time). Given the short duration of peak capacity needs in
34 any year, capital cost minimization will typically be a key factor in selecting new facility
35 options required solely to meet new capacity needs.

1 b) **New energy opportunities:** To the extent that such requirements affect the choice for
2 new facilities, new energy requirements in Yukon typically reflect cost effective
3 opportunities to displace either existing or new diesel fuel energy generation.
4

5 4. **Resource Options:** Supply side options to meet new capacity and/or energy requirements
6 on each system include: enhancing existing generation facilities; extending the life of existing
7 generation facilities; developing new generation plants (diesel, hydro, coal, wind, biomass,
8 etc); and/or developing new transmission facilities connecting existing and/or new resources
9 to load centres. Demand side options also exist, including conservation, load management,
10 and customer efficiency improvements.
11

12 5. **Assessment of Resource Options:** Available options to meet new capacity and/or energy
13 requirements on each system are assessed and/or screened based on consideration of
14 technical feasibility (including timing), cost efficiency, reliability, and risk.

15 **1.3.3 Resource Plan and Specific Capital Project Decisions**

16 *Figure 1.1: 20-Year Resource Plan and Decisions on Specific Projects* reviews the relationship between
17 the 20-Year Resource Plan process and activities leading to final Yukon Energy construction decisions on
18 specific project opportunities identified by the Resource Plan.
19

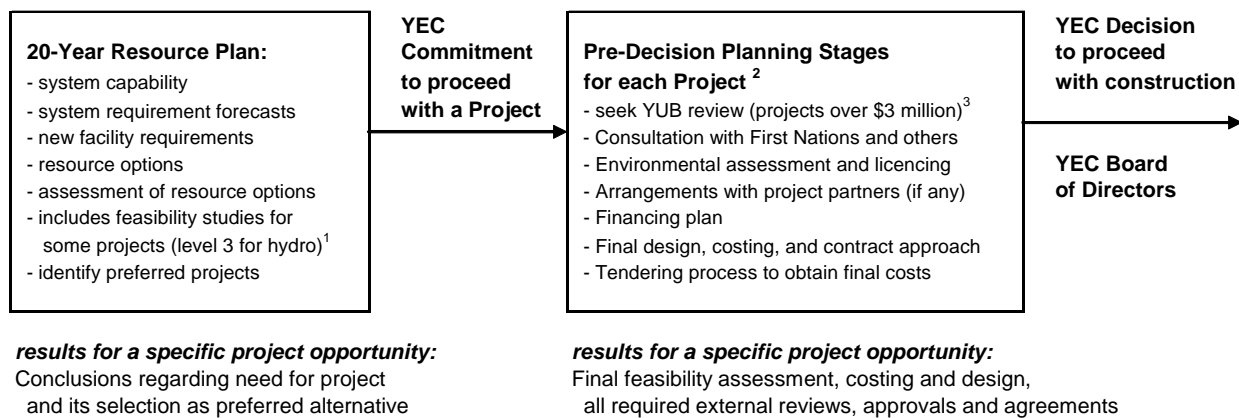
20 The structure and framework of the 20-Year Resource Plan reflect overall broad capabilities and
21 requirements for each system, options to fulfill requirements and/or capture opportunities identified for
22 new facilities, and comparisons/assessments between the options. In assessing specific resource options
23 under the Resource Plan, Yukon Energy carries out varying levels of technical and costing assessments to
24 enable screening of options, including in some instances investigations advanced to the project feasibility
25 stage. The Resource Plan process in this manner identifies preferred projects for which YEC can then
26 commit to proceed with more detailed project-specific pre-decision planning.
27

28 Figure 1.1 identifies pre-decision planning stages that Yukon Energy carries out, as needed, for each
29 preferred project identified by the Resource Plan process prior to any final decision to proceed with
30 construction or implementation. Pre-decision planning for each project reflects specific requirements for
31 that project, including anticipated regulatory review and/or approval needs, consultation requirements,
32 any arrangements needed with other parties, final design and costing needs, and timing needs for
33 bringing the project into service.

1 This Submission includes near term projects at different stages of pre-decision planning. No final decision
 2 has yet been made to implement these projects. In some instances, environmental approvals have
 3 already been secured – in other instances; however, the necessary applications for such approvals have
 4 yet to be made. Final design, costing and tendering tend to be a final stage to be carried out prior to final
 5 Yukon Energy decisions to proceed with construction/implementation.

6
7
8

**Figure 1.1:
20-Year Resource Plan and Decisions on Specific Projects**



1 - In large projects (e.g., over \$30 million), project feasibility stages can exceed \$3 million and YEC would then seek YUB review prior to commitment to these stages.
 2 - For individual projects, these planning stages will proceed in different sequences and with different timing. For projects over \$3 million, Yukon Energy is committed to seek YUB review prior to a decision by the YEC Board to proceed with construction.
 3 - An OIC under the Yukon Utilities Act can direct the YUB to review a YEC submission on need and justification for a project and to report on its findings to the Commissioner in Executive Council. This type of YUB review would be separate and distinct from a normal YUB review of project rate base costs as required for a Yukon Energy revenue requirements and rate application.

9 1.4 CURRENT YUKON SITUATION COMPARED WITH 1992

10 The last Resource Plan that was submitted to the YUB in 1992 was filed jointly by Yukon Energy and
 11 Yukon Electrical Company Limited, and reflected a situation very different from that facing the Yukon
 12 today. At that time, the Faro mine was in operation, the WAF system was consuming significant diesel
 13 fuel throughout each year, and there were substantial uncertainties regarding the life of the Faro mine
 14 load (about 25 MW and up to 180 GWh/yr). The submission also covered the potential opening of new
 15 mines; extensive planning studies previously carried out on Demand Side Management ("DSM"); various
 16 hydro supply development options; and possible transmission developments. There were no projects
 17 being requested in the near term, and the applicability of nearly all projects hinged on which mine load
 18 "scenario" was going to arise, and the risks associated with the load. In the end, due to substantial

1 downside risk related to existing loads, the 1992 Resource Plan did not propose any near or long term
2 projects for development.

3
4 The Yukon economy, and Yukon's electricity loads and systems have changed substantially since the
5 1992 review. Due to the closure of the Faro mine, no reopening of the United Keno Hill Mine ("UKHM"),
6 and no new mines yet having emerged, there is currently a surplus of hydro energy available on the WAF
7 and MD grids. Potential new industrial developments during the next several years may absorb the WAF
8 hydro energy surplus. However, forecast load growth even without new industrial loads, pending
9 retirement of existing diesel generation and the adoption of new capacity planning criteria indicate an
10 immediate need in any event to provide new WAF generation capacity to serve winter peak load
11 requirements even through the WAF hydro energy surplus could remain for most of the current 20 year
12 planning period.

13
14 Beyond near term needs and opportunities, current planning issues must be addressed regarding other
15 potential future major industrial loads and developments during the next 10 to 20 years, including the
16 Alaska Highway Natural Gas Pipeline project. Potential industrial loads need to be considered, and the
17 identification, definition and "protection" of appropriate resource options is required to ensure that Yukon
18 Energy is able to meet new loads when relevant on a timely basis if and when they develop.

19
20 Supply side options potentially relevant for a construction start within the next 10 years vary widely
21 depending on the potential industrial developments considered, and include a range of different hydro
22 possibilities as well as coal-fired generation and potentially natural gas-fired generation.

23
24 Lead times required to plan, approve and develop major new power supply projects, as well as the
25 material planning costs associated with pre-construction activities required to keep these options
26 available on a timely basis, underline the relevance of the current Resource Plan review.

27
28 Yukon Energy has organized generation and transmission project options by different load situations and
29 resource needs. As shown in *Figure 1.2 Load Situation, Resource Needs and Project Options*, the
30 resource needs (capacity or energy) are the primary driver in evaluating the appropriateness of an option
31 for a given scenario. New industrial loads of less than 10 MW typically give rise to capacity-focused
32 options, while new industrial loads above 10 MW may create opportunities for energy-focused options,

1 driven in part by specific opportunities to enhance existing hydro systems and in part by Yukon Energy's
2 revised capacity planning criteria. Changes in Yukon power systems, significant load growth in the
3 Whitehorse area and the potential retirement of three diesel units at Whitehorse prompted a re-
4 examination of these planning criteria. Yukon Energy believes that its revised criteria better reflect the
5 Yukon electrical grids' reliability requirements today.

- 6 • **Potential near term major project options** include opportunities, projects and major
7 capacity shortfall projects as noted in Figure 1.1. These near term project opportunities and
8 options are examined in the context of a range of possible load situations (see Figure 1.2).
- 9 • **Opportunities projects** include enhancements to existing hydro facilities at Whitehorse and
10 Aishihik as well as possible access to government infrastructure funding to develop a
11 Transmission Line from Carmacks to Stewart Crossing connecting the WAF and MD systems.
- 12 • **Major capacity shortfall project options** address major new WAF system capacity needs
13 in the context of current surplus hydro energy on both the WAF and MD systems.

14
15 As outlined in Figure 1.2, planning activities to proceed with other generation or transmission projects
16 beyond 2009 and before 2016 are being driven by the potential needs of a diverse range of possible
17 major industrial customers (such as various possible major new mines) or other major potential industrial
18 developments (i.e., Alaska Highway Pipeline project), and the energy requirements and/or opportunities
19 related to such industrial developments. The Submission examines these opportunities in the context of
20 the different possible load situations outlined in Figure 1.2, the significant uncertainties associated with
21 such load possibilities, and the lead times and other needs associated with Yukon Energy protecting
22 appropriate resource options related to these different loads.

1
2

**Figure 1.2:
Load Situation, Resource Needs and Supply Options 2006-2025**

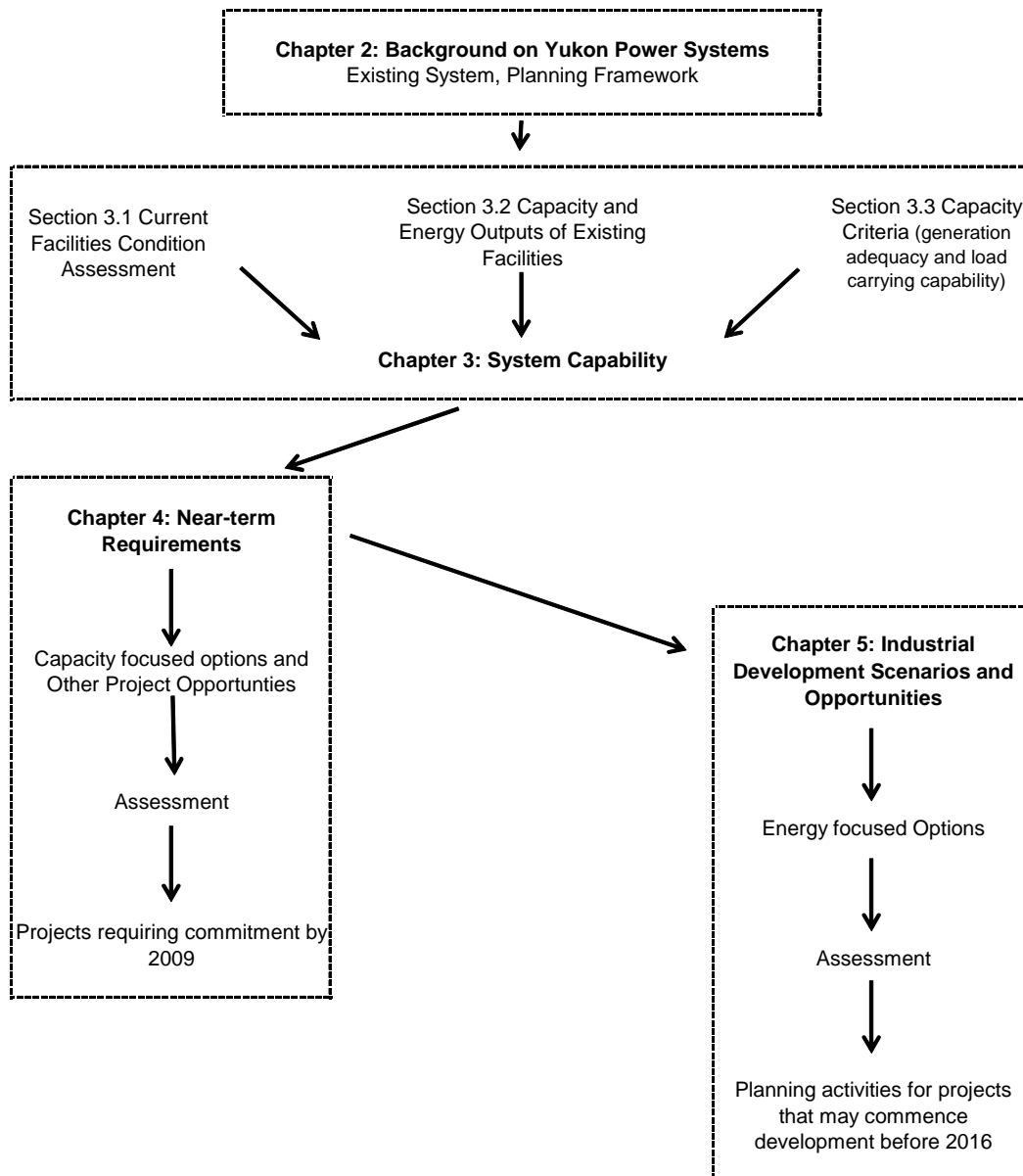
Load Situation (WAF Scenarios)	Resource Needs	Well Defined Project Options	Relatively Undefined Project Options
<p>Scenario 4: A 120 to 360 MW Alaska Highway Natural Gas Pipeline Scenario</p>	<p>Large Energy (223 to 894 GW.h/yr, starting at earliest in 2012-2015 time period)</p>		<ul style="list-style-type: none"> • Granite (80 MW, 660 GW.h/yr up to perhaps 254 MW) • Hoole (40 MW, 275 GW.h/yr) • Fraser Falls (100 MW, 613 GW.h/yr up to perhaps 450 MW) • Yukon River (multiple sites including Rink Rapid, Eagles Nest and Five Fingers, 75-240 MW) • Two Mile Canyon on Hess (53 MW, 280 GW.h/yr), Slate (42 MW, 266 GW.h/yr) • Natural Gas (to be determined)
<p>Scenario 3: A 40 MW WAF Industrial Scenario: Substantial Mining Industry Development in Excess of the Faro Mine</p> <p>(more intense mine development than Scenario 2)</p>	<p>More Energy (max about 250 to 300 GW.h/yr during life of mine projects)</p> <p>Following mine closures, energy requirements at 56 GW.h or less</p>		<ul style="list-style-type: none"> • Primrose (28 MW, 141 GW.h/yr) • Finlayson (17 MW, 129 GW.h/yr) • Coal (previously studied at 20 MW, about 144 GW.h/yr, up to 50 MW or larger, no credible smaller concept developed to date)
<p>Scenario 2: A 25 MW WAF Industrial Scenario: Multiple Major Developments Comparable to Faro Mine</p> <p>(similar to Faro Mine, could comprise multiple mines, such as Minto, Carmacks Copper plus Red Mountain or Division Mountain coal)</p>	<p>Smaller Energy (max about 100 GW.h/yr for life of mine projects)</p> <p>Following mine closures, energy requirements at 35 GW.h or less</p>	<ul style="list-style-type: none"> • Drury (2.6 MW up to perhaps 5.2 MW, 23 GW.h/yr) 	<ul style="list-style-type: none"> • Moon (8.5 MW, 50 GW.h/yr) • Mayo B (10 MW, 48 GW.h/yr) • Aishihik Diversions (maximum 24 GW.h) • Tutshi (7.5 MW, 51 GW.h) • various other hydro (Orchay, Morley, Lapie, Squanqa) • Surprise (8.5 MW, 50 GW.h/yr; removed by other proposals)
<p>Scenario 1: A 10 MW WAF Industrial Scenario: Combined Industrial load up to about 10 MW</p> <p>(focus on Minto and Carmacks Copper mines [9-11 MW, about 60 GW.h/yr], 8-12 years)</p>	<p>Capacity focus - absorb current WAF surplus hydro while both mines operate</p> <p>(21 to 27 MW shortfall by 2012, base case and high load sensitivity)</p>	<p>Minor added capacity over and above base case (diesel or other options noted below)</p>	
<p>Base Case: Existing Non-Industrial Loads</p> <p>(new capacity planning criteria, retirement of 11.4 MW of Whitehorse diesel capability (3 Mirlees units))</p>	<p>Capacity shortfall focus - WAF surplus hydro likely until near end of 20 (Base Case shortfall by 2012 at 19 MW; range 15 to 24 MW)</p>	<p>Major Capacity Shortfall Projects</p> <ul style="list-style-type: none"> • WH Diesel Replacement/Expansion Project (15-24 MW by 2012 without new industrial loads) • Mirlees Life Extension Project (14 MW) • Aishihik 2nd Trans. Line (up to 22 MW, 0 GW.h/yr) <p>Opportunity Projects</p> <ul style="list-style-type: none"> • Aishihik 3rd Turbine (7 MW, 5.4 GW.h/yr) • Marsh Lake Fall/Winter Storage (1.6 MW, 7.7 GW.h/yr) • WAF-MD Interconnect (about 6 MW, 15 GW.h/yr, decreasing as MD load grows) 	<ul style="list-style-type: none"> • Atlin Lake Top Storage (2.0 MW, 9 GW.h/yr) • Aishihik Supply Side Enhancements (about 6 MW potential) • Other Southern Lakes (to be determined)

1 **1.5 SUBMISSION OVERVIEW**

2 *Figure 1.3: Submission Overview* provides an overview of the organization and the interconnections that
3 are present in the document.

4
5

**Figure 1.3:
Submission Overview**



1 The document is composed of five chapters:
2

3 **Chapter One:** Introduction provides the framework for the Submission.
4

5 **Chapter Two:** Background on Yukon Power Systems provides background information. The chapter
6 includes an overview of the Yukon power system; the outcomes from the 1992 review; major events
7 affecting power systems since 1992; and bulk power planning since 1992.
8

9 **Chapter Three:** System Capability provides information on the capability of the Yukon systems to meet
10 the electricity needs of Yukoners, and addresses a review of system capacity planning criteria and the
11 revised criteria that Yukon Energy has adopted.

12 **Figure 1.3:** Depicts the three sections of Chapter Three. These sections are separate, but each
13 contributes in determining the adequacy of the system.

14 **Section 3.1:** Current Facilities Condition Assessment provides information on Yukon Energy's
15 generation, substation and transmission assets. The second section of the chapter,

16 **Section 3.2:** Capacity and Energy Outputs of Existing Facilities focuses on implications of
17 changes to major facility output since 1992, either from age, enhancement, or licencing
18 conditions. The third section of the chapter,

19 **Section 3.3:** Capacity Planning Criteria Review, provides information on Yukon Energy's previous
20 capacity criteria, the Company's 2005 review of its capacity criteria, and its adoption of revised
21 criteria.
22

23 The next two chapters of the Plan reflect differentiation of (a) the near term requirements, and (b) longer
24 term industrial development scenarios and opportunities.
25

26 **Chapter Four:** Near Term Requirements reviews major projects currently in the pre-decision planning
27 stage (Figure 1.1) that Yukon Energy proposes to commit for construction or implementation prior to
28 2009, focusing on near term opportunities with regard to enhancing existing Yukon Energy facilities as
29 well as near term projects which Yukon Energy is required to address under the revised capacity planning
30 criteria. Proposed actions by Yukon Energy are identified regarding major projects that require final
31 commitment decisions prior to 2009.
32

33 **Chapter Five:** Industrial Development Scenarios and Opportunities identifies and assesses on a
34 preliminary basis major energy focused project possibilities during the 20 year planning period beyond
35 2009 and before 2016 in response to different industrial development scenarios. Proposed actions by

- 1 Yukon Energy are identified regarding planning activities that Yukon Energy may be required to carry out
- 2 to start construction on such projects before 2016, including actions to ensure that YEC protects its ability
- 3 to deal with these industrial development loads and opportunities should they arise. No project options
- 4 examined in Chapter 5 are yet at the pre-decision stage of project planning (as reviewed in Figure 1.1).

1 **2.0 BACKGROUND ON YUKON POWER SYSTEMS**

2 The chapter provides background on current Yukon power systems, primarily encompassing the two
3 integrated grids and generation facilities and transmission owned by Yukon Energy.

4
5 The sections for this chapter are as follows:

- 6 • Section 2.1: Overview of Generation Facilities and Transmission
- 7 • Section 2.2: Outcomes from the 1992 Review
- 8 • Section 2.3: Major Events Affecting Power Systems Since 1992
- 9 • Section 2.4: Bulk Electrical Supply Planning Since 1992

10 **2.1 OVERVIEW OF GENERATION FACILITIES AND TRANSMISSION IN YUKON**

11 Yukon Energy is the main BES provider, or main generator and transmitter of electrical energy in Yukon.
12 Yukon Energy currently accounts for 90% of annual Yukon power generation, and operates two
13 independent transmission grids – the WAF and the MD.

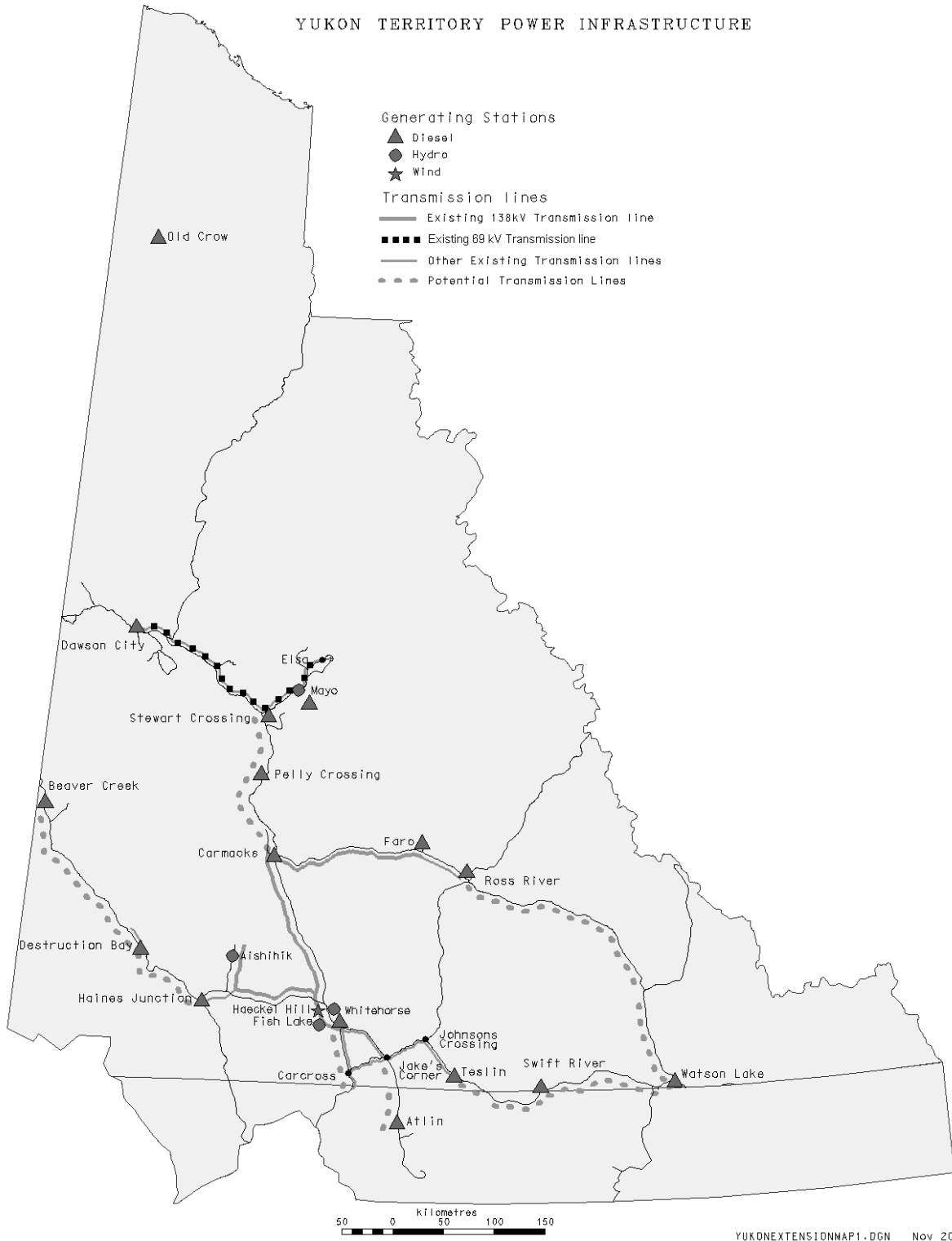
14
15 The power systems identified in this Resource Plan are distinct and independent systems, each being
16 served by its own source(s) of generation. The power systems in the Yukon include: the WAF grid; the
17 MD grid; the diesel community of Watson Lake; and a number of smaller isolated diesel communities
18 (Beaver Creek, Destruction Bay, Pelly Crossing, Swift River and Old Crow). The Yukon power systems are
19 shown in *Figure 2.1: Map of Yukon Territory Power Infrastructure*.

20
21 Yukon Energy currently serves approximately 1700 retail customers, or 11%, of Yukon's customers
22 directly. The retail customers that are served directly include residential and commercial classes. The
23 majority of these customers are located in and around Dawson City, Mayo and Faro.

24
25 Yukon Energy's wholesale customer, YECL, distributes power to the other 89% of Yukon's retail
26 customers. The bulk of Yukon Energy's sales are composed of firm wholesale sales to YECL on the WAF
27 grid. YECL maintains and operates its distribution lines independent of Yukon Energy.

1
 2
 3

Figure 2.1:
Map of Yukon Territory Power Infrastructure



4

1 Hydro generation from the Aishihik and Whitehorse stations supply the WAF communities of: Carmacks,
2 Carcross, Haines Junction, Teslin, Whitehorse, Ross River, Tagish, Deep Creek, Takhini River Sub and
3 Marsh Lake through wholesale sales to YECL. The WAF communities of Champagne, Faro, Johnsons
4 Crossing and Braeburn are served directly by Yukon Energy.

5
6 Hydro generation from the Mayo Generating station is supplied by Yukon Energy to the Town of Mayo,
7 the City of Dawson, as well as to loads along the Mayo-Dawson transmission line route (the North
8 Klondike Highway loads), as well as on a wholesale basis to YECL for service to Stewart Crossing, Elsa,
9 and Keno.

10
11 Hydro generation stations on the Yukon grids are supplemented as necessary by a small amount of diesel
12 for peaking or maintenance purposes, and on the WAF grid, by wind generation. The absence of power
13 grid interconnections with other neighbouring jurisdictions prevents export of surplus generation or
14 import of competitive supplies, and is one of the key factors distinguishing Yukon's situation from that
15 prevailing in most southern jurisdictions in Canada.

16 **2.1.1 Generation in Yukon**

17 Yukon Energy's systems account for 112.4 MW of the 127.4 MW of installed capacity in Yukon. The YECL
18 systems account for the balance, or for 15.0 MW of installed capacity.

19
20 The generation assets currently owned by both Yukon Energy and YECL are shown in *Table 2.1:*
21 *Generation Capacity in Yukon – YEC and YECL in 2005.*

1
2
3

**Table 2.1:
Generation Capacity in Yukon – YEC and YECL in 2005**

Yukon Energy Generation Assets (in MW installed & currently rating)			YECL Generation Assets (in MW installed)		
Hydro Facilities			Hydro Facilities		
Whitehorse	WAF	40.0	Fish Lake	WAF	1.3
Aishihik	WAF	30.0	Base Load Diesel Facilities		
Mayo	MD	5.4	Old Crow	Isolated	0.7
Total Hydro		75.4	Pelly Crossing	Isolated	0.7
Wind Facilities			Beaver Creek	Isolated	0.9
Haeckel Hill	WAF	0.8	Destruction Bay	Isolated	0.9
Diesel Facilities			Swift River	Isolated	0.3
Whitehorse	WAF	22.4	Watson Lake	Watson Lake	5.0
Faro	WAF	5.3	Back-up Diesel Facilities		
Dawson	MD	5.0	Carmacks	WAF	1.3
Mayo	MD	2.0	Teslin	WAF	1.3
Mobile Diesel		1.5	Haines Junction	WAF	1.3
Total Diesel		36.2	Stewart Crossing	MD	0.3
TOTAL YUKON ENERGY			Ross River	WAF	1.0
		112.4	Total Diesel		13.7
TOTAL YUKON GENERATION			TOTAL YECL		
		127.4 (YEC + YECL)			15.0

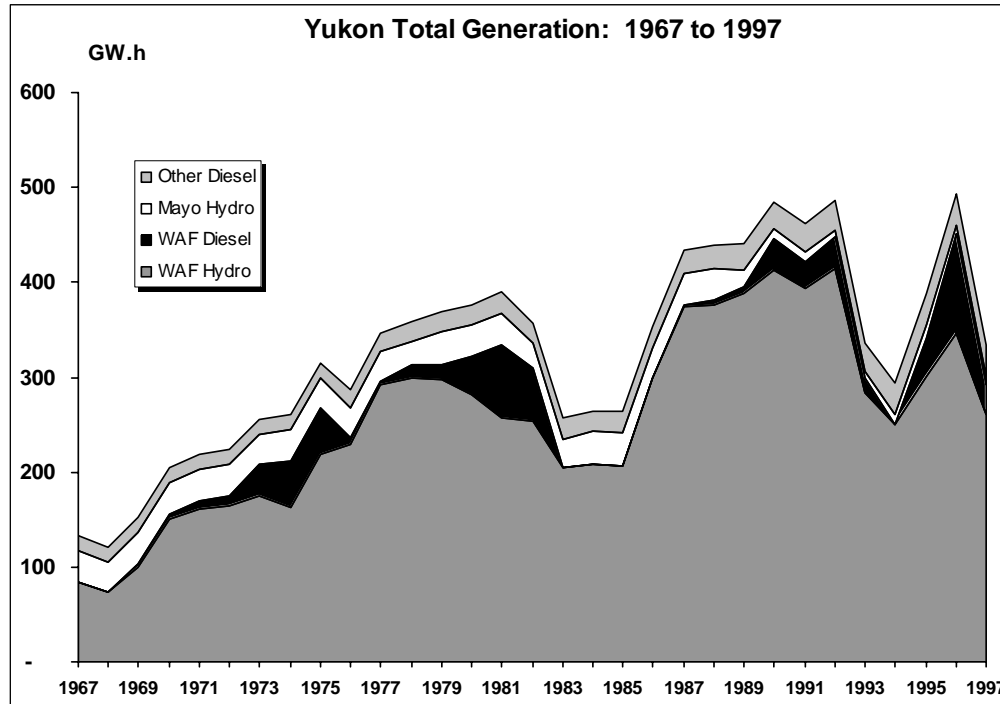
4
5
6
7
8
9
10

Yukon Energy's extensive hydro generation and transmission facilities and the resulting significant reduction in overall reliance on diesel generation are the key factor causing Yukon power costs to typically be lower than those found in Alaska or the Northwest Territories ("NWT"). Without such hydro facilities, Yukon utilities probably would have relied almost entirely on diesel generation with its associated higher costs¹.

¹ See Cabinet Commission on Energy, Technical Background Paper on Electrical Rates and Relief, 1997. Chart 1 in this paper reviewed Residential power bills in North America in 1996. The paper (pages 6-7) reviewed factors affecting northern power costs (e.g., lower population and customer densities, reliance on diesel generation, and the absence of power grid connections with other jurisdictions), and concluded that the lower power costs in Yukon reflect YEC's extensive hydro generating facilities (e.g., YEC hydro generation provided from 70 to 90% of all Yukon power generation each year from 1987 through to 1997). The paper noted that production or generation costs represented almost 70% of all Yukon power costs forecast for 1997 in the 1996/97 GRA.

1
2
3

Figure 2.2:
Yukon Total Power Generation 1967 – 1997



4
5

Figure 2.2: Yukon Total Power Generation: 1967-1997 highlights the overall importance of Northern Canada Power Commission ("NCPC")/YEC hydro generation in Yukon and the evolution of this capability from the late 1960's (after the first two hydro units were installed at Whitehorse Rapids) until the mid 1980s. This figure also demonstrates the relatively minor effect overall for Yukon related to diesel generation required outside the WAF and Mayo areas².

11

Hydro generation in Yukon was developed in the past by the NCPC in response to load developments in the Yukon, particularly mine-related loads at Faro, Keno, and Whitehorse. Yukon Energy acquired these hydro assets in 1987 as a result of the NCPC transfer.

15
16

- In 1952, NCPC built the Mayo Hydro facility to supply power to Mayo and UKHM in Elsa and Keno.

² Completion of the MD transmission line in 2002 materially further reduced diesel generation requirements in Yukon (by displacing diesel generation at Dawson). Figure 2.2 requires access to YECL generation data, which is not available after the years noted in the figure.

- In 1958, NCPC built the first two turbines at Whitehorse Rapids to supply the rapidly growing demand for power in Whitehorse.
- A third turbine was added to the Whitehorse Rapids plant by NCPC in 1969, along with the 138 kV transmission line from Whitehorse to Faro, as a consequence of an agreement between Cyprus Anvil Mining Corporation and Government of Canada to build a mining facility at Faro.
- In response to the Faro mine's power requirements and the opportunity to cost effectively displace diesel generation, the Aishihik hydro plant was developed by NCPC between 1973 and 1975, and the Whitehorse fourth hydro turbine generator was developed between 1982 and 1984.

Figure 2.3: YEC WAF Generation 1967 – 2004 details historic generation on the WAF grid. The majority of WAF generation has been hydro generation. During periods when the Faro mine was in operation there was also ongoing material diesel generation.

**Figure 2.3:
YEC WAF Generation 1967 – 2004**

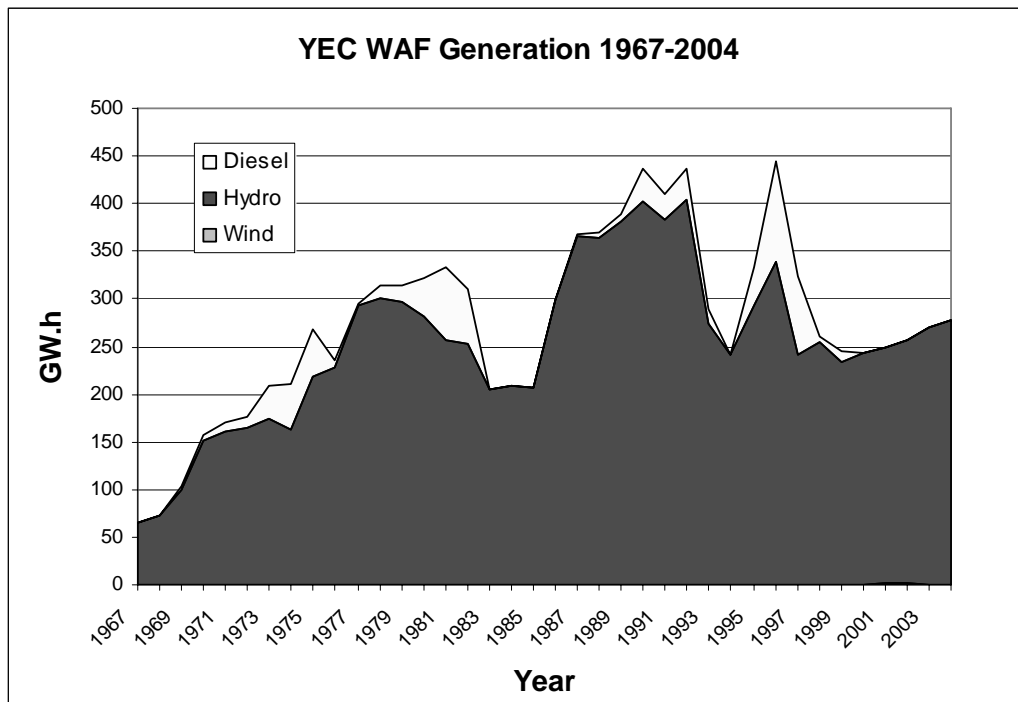
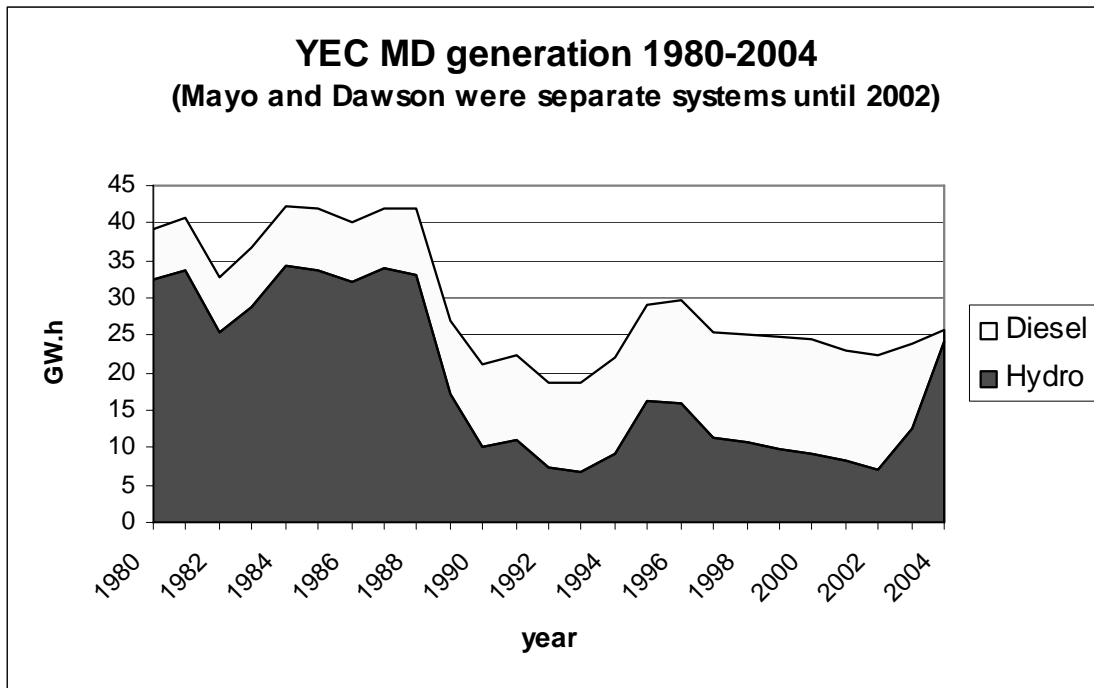


Figure 2.4: YEC Generation on MD 1980 to 2004 details historic generation in the communities that now form the MD grid. Until the UKHM closure in 1989, there was substantial hydro generation being used

1 (primarily at UKHM). Prior to completion of the Mayo-Dawson Transmission Line project in 2002, Dawson
 2 was a diesel served community; with completion of the MD grid, hydro generation has become the main
 3 source of generation for all MD grid communities. By 2004, only 6% of MD generation was by diesel.

4
 5
 6
 7

Figure 2.4:
Generation on MD, 1980 – 2004



8

9 **2.1.2 Transmission in Yukon**

10 Yukon Energy owns and operates the WAF and MD transmission systems in Yukon of 69 kV or higher, as
 11 well as certain lower voltage lines; certain lower voltage lines (25 to 34.5 kV) are also owned and
 12 operated by YECL. The WAF and MD grids, and the other lines in Yukon are identified in *Figure 2.1: Map*
 13 *of Yukon Territory Power Infrastructure*.

14

15 The WAF and MD transmission lines are characterized as transmission lines because the lines transmit
 16 power from one community to another. However, due to the lower voltage, some of these transmission
 17 lines would be considered to be sub-transmission or distribution lines on a larger system.

1 WAF transmission is primarily a 510 kilometre 138 kV line that extends from Aishihik east to Whitehorse,
2 north to Carmacks, and then east to Faro. Separate lower voltage lines connect other communities,
3 comprising a 25 kV line (YEC) to Haines Junction, a 25 kV line (YEC) from Faro to Ross River, and a 34.5
4 kV system (YECL) southeast from Whitehorse to Teslin, Carcross, Tagish, Marsh Lake, Jakes Corner and
5 Johnsons Crossing.

6
7 The MD grid is composed of a 223 kilometer 69 kV transmission line extending from the Town of Mayo to
8 the City of Dawson, and connecting Stewart Crossing. A separate 69 kV transmission line connects to
9 Keno and Elsa, northeast of Mayo.

10 **2.2 OUTCOMES FROM THE 1992 REVIEW**

11 Order-in-Council 1992/092 directed the YUB to review Yukon Energy and YECL (the "Companies") major
12 capital projects and contract commitment proposals required for non-diesel fuel generation, transmission
13 and DSM to 1997. The 1992 Resource Plan submission prepared by the Companies was jointly submitted
14 to the YUB, and provided the first opportunity since the NCPC transfer in 1987 to review long-range
15 major capital planning options for Yukon power systems.

16
17 The 1992 Submission Overview provided a snapshot of an ongoing dynamic resource planning process,
18 and proposed a set of ongoing demand and supply work plan elements for the 1992 to 2001 period
19 rather than the development of a single resource option.

20
21 The YUB conducted a public hearing in October, 1992 to review the 1992 Resource Plan, and submitted a
22 report (the "Capital Hearing Report") with recommendations to the Commissioner in Executive Council on
23 December 7, 1992 (Review of the Capital Resource Plans of YEC and YECL. Yukon Energy and YECL
24 subsequently provided comments on the YUB's forty-eight recommendations in Section 5.3 of the
25 1993/94 General Rate Application ("GRA") Submission. Some of the notable recommendations are
26 detailed below, along with responses by the Companies (as filed in the 1993/94 GRA), and updates on
27 each recommendation:

28
29 **A Framework for Capital Programs to be Pursued:** The YUB's Recommendations 1 and 2 stated
30 that the Capital Hearing Report provided a framework for future capital projects, and that the capital
31 resource plan should be reviewed as part of general rate applications, or as directed by the Board. The
32 Companies agreed.

1 Yukon Energy and YECL provided updates to the YUB on capital planning activities as part of the jointly
2 filed 1993/94 and 1996/97 general rate applications. Yukon Energy provided updated information on
3 capital projects in *Section 5 of the 2005 Required Revenues and Related Matters Application*. The current
4 Resource Plan Submission provides a further and more detailed update for the YUB.

5
6 **Market Risks:** The Companies agreed with Recommendations 3 and 4 that stated the significant market
7 risk associated with the closure of the Faro Mine should be considered in assessing the Companies'
8 Resource Plan and in determining the need for new facilities.

9
10 After the closure of the Faro Mine in 1998, there has been a significant WAF hydro surplus. As a result,
11 there has not been a need for new facilities to address mining loads in Yukon. However, there are now
12 new mining opportunities on the horizon for Yukon.

13
14 Potential mining loads are discussed in *Chapter Five: Industrial Development Scenarios and*
15 *Opportunities*. Yukon Energy's assessment of new facilities in the context of mining loads takes into
16 account the related risks.

17
18 **Load Forecasts and Demand Side Management:** The Board recommended that the low and base
19 case scenarios should be considered in assessing the need for DSM (Recommendation 5).

20
21 The Companies agreed that DSM initiatives should not be based on the high case scenarios. Since the
22 closure of the Faro Mine, there has been a hydro surplus, and the "high" case that the Board considered
23 in 1992 does not exist at the present time (i.e., there is no industrial customer in Yukon today).

24
25 The Board also supported aggressive DSM activities to the extent that it can be demonstrated that the
26 activities result in lower costs to consumers than alternate supply options (Recommendation 22). The
27 Companies agreed that DSM activities should only be pursued where they are more economic than
28 supply-side investments.

29
30 There is currently a hydro energy surplus in Yukon. The incremental cost to produce hydro generated
31 electricity is virtually zero, and therefore there has not been a need on the WAF and MD systems to
32 reduce energy use. As a result, both supply-side and demand-side conservation initiatives have not
33 been a key focus for Yukon Energy since 1997.

1 In terms of managing the demand (customer consumption) on the system, the focus for Yukon Energy
2 since the Faro Mine closure in 1998 has been primarily on developing interruptible energy sales
3 opportunities on the WAF and MD systems (see *Section 2.3.2: The Growth of Secondary Sales*).

4
5 Recent DSM activities have been undertaken by the Energy Solutions Centre ("ESC")³. DSM options that
6 reduce the load on the WAF system at the very immediate peak times (i.e., reduce the capacity
7 requirement of the Yukon system) have the potential to provide value to Yukoners today. Programs that
8 have been developed and tested by Yukon Energy and ESC since 1992 are explored in greater detail in
9 *Section 2.4: Bulk Power Planning Since 1992*.

10
11 **Load Factoring:** The Board's Recommendation 11 recommended that the Companies perform studies
12 and tests to determine the potential to use load factoring to increase the capacity relied on at the
13 Whitehorse Rapids Hydro Plant.

14
15 The Companies continued to experiment with load factoring between 1992 and the 1993/94 GRA. The
16 Companies maintained in the 1993/94 GRA that enhanced load factoring would not result in a firm
17 capacity rating above 24 MW for Whitehorse during non-drought years. This item is further discussed in
18 *Chapter 3*.

19
20 **Load Forecasts and Use Per Customer:** The YUB recommended a more rigorous approach to
21 estimating residential and general service use per customer (Recommendations 7 and 8).

22
23 Yukon Energy and YECL did review the historical use per customer during the 1993/94 GRA. The
24 average use per customer was expected to stay relatively constant. Consequently the driver in the load
25 growth forecasts was the number of customers.

26
27 In the 1993/94 General Rate Application the Companies agreed to explore opportunities to carry out
28 research pertaining to use per customer with the Yukon Government and others, and to document
29 current electric heating use characteristics on the WAF system.

³ The Energy Solutions Centre was under the management of the Yukon Development Corporation. On February 5th, 2005, the Yukon Territorial Government ("YTG") announced its plan to transfer management from YDC to YTG. Release #05-23, "New Model for Energy Solutions Centre to Improve Accountability", Online: <http://www.gov.uk.ca/news/2005/05-23.html>.

1 Yukon Energy and YECL also examined use per residential customer in the 1996/97 GRA. The Companies
2 identified a trend of declining use per customer, and reflected this trend in the sales forecast. The
3 decline in use per customer was attributed to a reduction in electric heat. The Companies suggested that
4 higher electricity rates in the mid-1990s had encouraged conversions from electric heating.

5
6 Yukon Energy has factored a use per customer variable into its current load forecasting methodology for
7 its retail customers. Yukon Energy's current load forecasts have two components: a measure of the
8 increase in the number of customers; and a measure to reflect changes in the average use per customer.
9 Yukon Energy's load forecast methodology is explained in greater detail in *Section 4.2.1: Non-Industrial*
10 *Load Forecasts*. Due to its limited retail customer load, Yukon Energy does not have the data or analysis
11 to weather normalize its past sales or forecasts for its own retail customers. Yukon Energy is not able to
12 carry out analysis on customer numbers or use per customer on YECL's current retail customers.

13
14 **Aishihik 3rd Turbine:** The Board recommended in Recommendation 37 that the Companies pursue
15 approval for the construction of the third turbine at Aishihik, given that it is economically, technically and
16 environmentally feasible. The Board asked the Companies to "report back to the Board before
17 commencing construction" and indicated that "the Companies should pursue installation of the maximum
18 capacity that is economically, technically and environmentally feasible".

19
20 As of the 1993/94 GRA, the Companies were delaying activity on the third Turbine due to the closure of
21 the Faro Mine at that time; similarly, active consideration of developing this project was once again
22 delayed after the Faro Mine closures in 1997 and 1998. The third Turbine, however, remained a
23 component of the Yukon Energy application for Aishihik relicencing throughout the period.

24
25 Yukon Energy received its renewed water licence at Aishihik in 2002 (which extends to December 31,
26 2019), including the environmental approval to install a third Turbine of up to 7 MW. Based on the
27 current Resource Plan, Yukon Energy is now proceeding with the next steps in the Aishihik third Turbine
28 project, including updated costing of the 7 MW installation and confirmation of hydrology.

29
30 **Supply Options:** In Recommendation 36 the Board stated that before pursuing construction of "large
31 projects" (defined as projects with a cost of more than \$5 million), preference should be given to DSM,
32 small utility owned projects and Independent Power Producers ("IPP") that are cost effective for
33 consumers.

1 In the 1993/94 GRA the Companies agreed with this option, providing that these options are cost
2 effective for consumers. Yukon Energy's last internal large-scale Resource Planning exercise took place in
3 1996. In September, 1996, Yukon Energy requested Expressions of Interest from qualified parties
4 interested in providing technologies, investments and/or partnerships to establish new generation
5 facilities in Yukon to displace diesel generation. During that planning process, IPP projects were
6 considered.

7
8 **Independent Power Producers:** The Companies agreed with the Board's Recommendation 45 that
9 IPP's should be encouraged in Yukon, provided that there are no negative rate impacts on consumers.
10 The Board recommended (Recommendation 47) that the Minister direct the Board to hold a hearing with
11 respect to IPP policy and to develop a firm IPP policy for Yukon.

12
13 A hearing was not held. However, as noted above, Yukon Energy did solicit IPP proposals for
14 development in 1996.

15
16 **Feasibility Studies:** Recommendation 39 stated that the Companies should not proceed with any
17 feasibility studies for Drury Creek, Morley River, Lapie River and Orchay River, other than developing
18 long-term hydrological data.

19
20 Yukon Energy has collected hydrological data, but has not proceeded with feasibility studies.

21
22 **Coal:** The Companies agreed with the Board's Recommendation 42 that studies of coal-fired generation
23 should be limited to a review of coal technology, particularly with respect with plants under 20 MW.

24
25 Yukon Energy has not proceeded with any detailed study of coal technology. However, when Expressions
26 of Interest were requested in 1996, three respondents focused on coal-based thermal generation for the
27 WAF system. As a result of the closure of the Faro mine in 1997 and again in 1998, no projects were
28 developed as a result of the call for Expressions of Interest.

29
30 **Mayo-Dawson Transmission Line:** The Companies agreed with Recommendation 42 that no further
31 studies should be conducted on this transmission line unless demand changed sufficient to warrant a
32 review of the project.

33
34 Escalating fuel costs and load growth subsequently led Yukon Energy to update its studies and ultimately
35 commit to proceeding with the MD project in 2001 (including receiving the approval of the Minister). The

1 Line commenced operation in September of 2003, and has offset diesel generation and reduced fuel costs
2 for Yukon Energy. For more information of the MD Transmission Line, see *Section 2.3.6: Mayo-Dawson*
3 *Transmission Line*.

4
5 **Wind:** Recommendation 43 stated that research and development work should continue to be pursued
6 with respect to wind generation. The 1993/94 GRA included the purchase and installation of a wind
7 turbine on Haeckel Hill.

8
9 Yukon Energy has installed two research and development wind turbines at Haeckel Hill with a combined
10 generating capacity of 800 kW.

11 **2.3 MAJOR EVENTS AFFECTING POWER SYSTEMS SINCE 1992**

12 There have been a number of significant changes to the Yukon system since 1992. The most notable of
13 these changes include: closure of the Faro Mine; the increase in Secondary Energy sales; Yukon Energy's
14 shift to direct management; the Whitehorse Rapids Generating Station fire rebuilding project; renewal of
15 Yukon Energy's three water licences; and the construction of the MD Transmission Line. These events
16 are outlined below.

17 **2.3.1 Closure of the Faro Mine**

18 After decades of operation on the WAF grid, including a number of closures and re-openings, the Faro
19 Mine closed in 1998. This mine closure followed the 1989 closure of the United Keno Hill Mine ("UKHM"),
20 which had been served by the Mayo hydro plant. As a result of the Faro Mine closure, there are currently
21 no major industrial customers being served in Yukon. Major industrial customers are defined by Order-in-
22 Council 1995/90 as, "a customer engaged in manufacturing, processing, or mining, whose peak demand
23 for electricity exceeds 1 MW, but it does not include an isolated industrial customer⁴."

24
25 Overall generation and diesel usage declined after the Faro Mine's closures in 1983 and 1993, 1997 and
26 again after its final closure in 1998. When the Faro Mine was in operation, all of Yukon's hydro
27 generation was absorbed by the system, and diesel generation was required on an ongoing basis. Since
28 the final closure of the Faro Mine in 1998, there has been a hydro energy surplus on WAF.

⁴ Rate Policy Directive, Order-in-Council 1995/90, May 29, 1995.

1 **2.3.2 The Growth of Secondary Sales**

2 Secondary Energy has been available from time to time to General Service or Industrial customers based
3 on the availability of surplus hydro since before the NCPC transfer. Rate Schedule 32 – Secondary
4 Energy, provides Yukon Energy with an opportunity to sell excess low-cost hydro power when it is
5 available, but can interrupt secondary sales customers when it is likely that the utility will be required to
6 generate electricity with diesel. There are now approximately 25 retail customers who together receive
7 more than 20 GW.h of electricity under Rate Schedule 32. These customers use the electricity to displace
8 fuel oil, and in some cases, propane.

9

10 The current Secondary Energy rate was approved in YUB Board Order 2005-12 at 66.7% of the
11 equivalent energy price of fuel oil. The rate is adjusted quarterly to reflect ongoing market price
12 adjustments for fuel oil.

13

14 Secondary sales have grown from 3,917 MW.h in 2000, to a forecast 20,613 MW.h for 2005. The recent
15 growth in secondary sales can be attributed to the surplus in hydro energy on the WAF grid since the
16 closure of the Faro Mine in 1998. Surplus hydro generation on the MD grid is also stimulating secondary
17 sales on that system.

18

19 At today's rates, Secondary Energy sales are very beneficial, and help to pay for the fixed costs of the
20 system (more than \$1 million in revenues annually). However, although Secondary Energy are available
21 from existing system assets, the generation system is not planned to provide service to secondary
22 customers. For the purposes of planning the system for capacity requirements or energy projects,
23 Secondary service is not included as required load to be served (however, in some cases the ability to
24 enhance sales of secondary power can provided added economic benefits from certain projects).

25 **2.3.3 Shift to Direct Management**

26 On January 1st, 1998, Yukon Energy assumed full management and operation of its generation,
27 transmission and distribution infrastructure and services. This includes direct responsibility for activities
28 related to planning the Yukon integrated generation and transmission systems today.

29

30 Prior to 1998, Yukon Energy's assets had been managed by Canadian Utilities, a subsidiary of ATCO,
31 which is YECL's parent company. Yukon Energy's billing service is the only service that is still provided by
32 an ATCO company.

1 Yukon Energy and YECL are both regulated by the YUB. YECL was an active intervenor in the spring
2 2005 YUB hearing on Yukon Energy's *2005 Required Revenues and Related Matters* application. This was
3 the first comprehensive revenue requirement submission that either had made to the YUB since the shift
4 to direct management.

5 **2.3.4 Whitehorse Rapids Generating Station Fire Rebuilding Project**

6 On October 30, 1997, a fire started in the pump room of the Whitehorse Rapids generating station. The
7 fire destroyed the generating station building, the system control centre, the Yukon Energy Corporate
8 office, the switchgear, and caused superficial damage to hydro generators 1, 2 and 3. Even with the
9 damage sustained by Yukon Energy, electrical service was not interrupted during the fire.

10

11 Yukon Energy filed insurance claims under its insurance provisions, and received a favourable settlement.
12 The fire destroyed assets with a rate base of \$2,280,000. A total of \$11,604,000 of new assets were
13 placed in service to replace the assets destroyed or damaged during the fire. A total of \$1,799,000 in
14 betterments were also completed. Yukon Development Corporation ("YDC") paid for \$1 million of these
15 costs. The balance of \$799,000 was put into rate base.

16

17 The insurance claim resulted in a net benefit to ratepayers. Aging assets were replaced at essentially no
18 cost to ratepayers. There was also a resulting insurance gain of \$744,000.

19 **2.3.5 Renewal of Water Licences at Whitehorse, Mayo and Aishihik**

20 Yukon Energy is required to have water licences for the hydroelectric facilities that it owns and operates
21 in Whitehorse, Mayo and Aishihik (near Haines Junction, Yukon). Water licences in the Yukon are issued
22 for a period up to, but not exceeding 25 years. All of the water licences for these three facilities expired
23 since the 1992 Resource Plan filing, and renewal of each licence has been obtained.

24

25 **Whitehorse:** The Whitehorse Water Use Licence (HY99-010) expired in 2000, and was renewed for 25
26 years (expires in 2025). It combines two prior licences, Marsh Lake and Whitehorse Rapids. The renewal
27 of the licence was sought on the basis of no relevant changes being made to its terms and conditions,
28 and included only administrative changes. The licence renewal was granted by the Yukon Territorial
29 Water Board ("YTWB") on this basis. Dam safety monitoring requirements were formalized in the new
30 licence. This was consistent with Yukon Energy practices and current Canadian Dam Safety Guidelines.

31

32 **Mayo:** Mayo Water Use Licence (HY99-012) expired in 2000, and was renewed for 25 years (expires in
33 2025). Similar to the Whitehorse facility, the renewal of the licence was sought on the basis of no

1 relevant changes being made to its terms and conditions, and included only administrative changes, and
2 the licence renewal was granted by the YTWB on this basis. Dam safety monitoring requirements were
3 formalized in the new licence, which was consistent with Yukon Energy practices and current Canadian
4 Dam Safety Guidelines.

5
6 **Aishihik:** Relicensing of the Aishihik hydroelectric facility took place over a number of years. It involved
7 four amendments to the 1978 licence. A new licence with a Fisheries Act Authorization was issued in
8 2002 upon expiry of the 1978 licence. Yukon Energy had sought a new licence, and a 17-year licence
9 was granted. Similar to Whitehorse and Mayo, the dam safety requirements in the licence are normal
10 modern utility standards that would need to be completed whether a requirement of the licence or not.
11 The renewal of the licence called for ongoing heritage payments, the construction of a boat launch at the
12 north end of the lake, and an annual fish monitoring program.

13
14 New terms of the 17-year licence provide for a conditional seven-foot operating range subject to the
15 terms of the Department of Fisheries and Oceans (“DFO”) Fish Act Authorization, and allow for the
16 installation of a third turbine not exceeding 7 MW (subject to the requirement for YTWB approval of an
17 operating plan when the third turbine is installed). Additional details on the Aishihik Licence renewal
18 were provided in Interrogatory Response YUB-YEC-1-55 in Yukon Energy’s 2005 Required Revenues and
19 Related Matters Application.

20 **2.3.6 Mayo-Dawson Transmission Line**

21 The MD Transmission Line Project came into service in September of 2003. The MD project was the first
22 large-scale transmission infrastructure development project undertaken by Yukon Energy since the NCPC
23 transfer in 1987. The 223 kilometre 69 kV transmission line links Mayo, a community with surplus hydro,
24 with Dawson, a community that was previously served solely by diesel generation. The transmission line
25 now supplies almost all of Dawson’s energy requirements. The line also provides hydro power to YECL at
26 Stewart Crossing, which was previously served with diesel generation, as well as various locations along
27 the North Klondike Highway that were not previously served by utility power.

28
29 The costs of the MD Transmission line were projected to be \$35.6 million as of the end of 2005. A total
30 of \$5.8 million of this amount was provided by Yukon Development Corporation at no cost to ratepayers.
31 YDC has also provided flexible debt financing to Yukon Energy. This financing ensures that ratepayers

1 will be protected so that they are not paying, in any year, more than they would have paid had Dawson
2 remained on diesel fuel generation⁵.

3 **2.3.7 System Upgrades and Changes**

4 In addition to the completion of the MDTransmission Line project, and relicensing of its three hydro
5 plants, Yukon Energy has undertaken additional system upgrades since the submission of the 1992
6 Resource Plan. Recent Upgrades include:

- 7 • Aishihik Unit #1 Rewind in 2003 (cost \$1.2 million)
- 8 • Mayo Hydro Unit #1 and Unit #2 Capacity Increase in 2002 (cost \$1 million)
- 9 • Addition of Wind Turbine #2 in 2000 (cost \$2 million)

10

11 Yukon Energy has also been able to extend the service life of its three Mirrlees Blackstone base load
12 diesel units located in its Whitehorse diesel plant (diesel units WD1, WD2 and WD3). WD3 is currently
13 scheduled for retirement in 2007; WD2 is currently scheduled for retirement in 2009; and WD1 is
14 currently scheduled for retirement in 2011. The 1992 Resource Plan had scheduled the retirement of
15 WD1, WD2, and WD3 in 1998, 1998, and 2000 respectively. By 1996 the retirement was extended.
16 After the Faro Mine closed, these units provided required reserve capacity for the system.

17

18 Since the Faro Mine closure in 1998, a 5 MW diesel unit was retired at Faro. Two diesel units with a
19 combined capacity of 2 MW were moved to Mayo, and a 1.3 MW unit was removed from Faro to act as a
20 mobile unit. The result is a decrease in the Faro diesel plant size from 13.6 MW to 5.3 MW.; in addition,
21 two diesel units with a combined capacity of 1.3 MW were retired from Mayo.

22 **2.4 BULK ELECTRICAL SUPPLY PLANNING SINCE 1992**

23 Yukon Energy has been engaged in a number of power planning activities since the 1992 Resource Plan
24 submission. In addition to the submission of the current plan, Yukon Energy has provided updates to the
25 YUB in its rate and revenue application submissions. Yukon Energy's planning has included: developing
26 an inventory of future supply options with YDC and BC Hydro; condition assessment work of its key
27 generation and transmission assets; a review of the WAF and MD capacity criteria review; and work with
28 ESC on DSM. Yukon Energy's significant power planning activities since 1992 are outlined in the
29 following sub-sections.

⁵ YUB Board Order 2005-12 approved \$29.046 of the costs of the MD Transmission Line for inclusion into YEC's ratebase, net of the \$5.75 million contribution by YDC (\$0.05 million of the amount provided by YDC was an interest-free advance, not a contribution) and about \$0.8 million being disallowed (amounts YEC cannot charge to ratepayers).

1 **2.4.1 Ongoing Yukon Energy Infrastructure Planning Process**

2 Infrastructure updates were provided as part of Yukon Energy's GRAs to the YUB in 1993/94, 1996/97,
3 and in the *2005 Required Revenues and Related Matters* Application. These updates were in response to
4 the YUB's Recommendation 2 from the 1992 Resource Plan hearing. The YUB recommended that the
5 Companies' capital resource plan should be reviewed on an ongoing basis as part of general rate
6 applications, or as directed by the Board.

7 **2.4.2 BC Hydro Inventory of Potential Future Hydro Supply Options**

8 YDC commissioned BC Hydro to work with YEC to conduct a Small Hydro Resource Study in 2002. The
9 study included a review and assessment on existing information on hydro sites located in Yukon and
10 relevant projects located in northern British Columbia. BC Hydro summarized over 200 sites which has
11 provided Yukon Energy with a consolidated source for information on potential project options. The area
12 studied included the WAF and MD transmission corridors, roughly 50 kilometres from the grids or
13 highways. On WAF the study was extended from the current grid to Watson Lake along the Alaska
14 Highway area.

15 **2.4.3 Bulk Electrical Supply Infrastructure Condition Assessment Work**

16 Yukon Energy commissioned three recent condition assessment studies. Acres International was
17 commissioned to assess Yukon Energy's key transmission assets, while BC Hydro was commissioned to
18 complete two studies: a study of Yukon Energy's key generating assets, and a study of selected
19 substation assets. In May of 2004, BC Hydro completed its *Condition Assessment of Selected Yukon*
20 *Energy Generating Assets*. BC Hydro's second report, *Condition Assessment of Selected Yukon Energy*
21 *Corporation Substation Assets* was completed by BC Hydro in June of 2004. The Acres International
22 report, *Assessment of Transmission Lines for Yukon Energy Corporation* was completed in December of
23 2003. A more thorough review of the findings from the condition assessments can be found in this Plan
24 in *Section 3.1: Current Facilities Condition Assessment*.

25
26 Most of the assets examined by Acres International and BC Hydro were found to be in good to relatively
27 good condition, and were expected to have operating lives of 20 additional years or more. The main
28 exception is the Whitehorse Mirrlees diesel engines, which are further discussed in *Chapters 3 and 4*.

29 **2.4.4 Generation Capacity Planning Criteria Review**

30 There have been changes to the Yukon systems since the last detailed Yukon Utilities Board review of
31 bulk system planning in 1992 as well as in the 1993/94 and 1996/97 GRAs including: closure of the Faro

1 Mine; growth in Whitehorse area loads; the interconnection of Mayo-Dawson; and the need to address
2 the near term retirements of the Whitehorse Mirrlees engines. In combination, the above factors raised
3 concerns regarding the ability of the assets in the Whitehorse area to serve the city in the event that the
4 Aishihik Line was out of service for a substantial period during the winter peak. As a result, Yukon Energy
5 undertook a review of the Capacity Planning Criteria.
6

7 For the Whitehorse area capacity, one specific issue was to determine how to approach the pending
8 retirement of 14 MW of nameplate capacity for three Whitehorse Mirrlees diesel (WD) units (WD1, WD2
9 and WD3). Reviewing the adequacy of capacity planning criteria is a prudent first step prior to making (or
10 rejecting the need to make) any such new capital investments.
11

12 NWT Power Corporation recently undertook a similar review of their Yellowknife grid. NWT Power
13 Corporation commissioned a study of their capacity planning criteria by Dr. Billinton from the University of
14 Saskatchewan. The NWT Power Corporation received approval from its regulator for its revised capacity
15 planning criteria in November of 2004.
16

17 Yukon Energy retained Drs. Billinton and Karki from the University of Saskatchewan to study the key
18 areas and characteristics of the Yukon systems (focused on WAF) relevant for a review of the required
19 firm capacity planning criteria. As part of the capacity criteria review, Yukon Energy worked with Drs.
20 Billinton and Karki to develop recommendations on capacity planning criteria for the Yukon systems. The
21 conclusions from that work are detailed in *Section 3.3: Capacity Planning Criteria Review*.

22 **2.4.5 Demand Side Management and the Energy Solutions Centre**

23 *Section 2.2: Outcomes from the 1992 Review* touched on Yukon Energy's approach to DSM. When the
24 Faro Mine was in operation, hydro generation was fully utilized and Yukon Energy actively pursued DSM
25 opportunities in order to save diesel generation costs. The Faro Mine closures shifted Yukon Energy's
26 focus away from DSM due to surplus diesel generation costs. After the final closure of the Faro Mine in
27 1998, the focus on DSM activities decreased greatly. The key activities from the 1992 to 1998 are
28 outlined below.
29

30 **DSM From 1992 to 1998**

31
32 **Smart Home on Wheels Community Tour:** In 1992 the Companies developed a Smart Home on
33 Wheels Community Tour to educate Yukon residents and retailers outside of Whitehorse of the benefits
34 of Power Smart products. This program was intended to parallel the impact of The Power Smart Idea

1 Shop which was located in Whitehorse. Between October 26 and December 14, 1992, the Tour visited
2 the communities of: Burwash Landing, Beaver Creek, Carmacks, Pelly Crossing, Teslin, Haines Junction,
3 Mayo, Stewart Crossing, Dawson City, Carcross, Tagish, Watson Lake, Ross River and Faro. Fifteen
4 presentations were made to local schools, and over 500 people visited the trailer. A survey was
5 completed by the majority of visitors to the trailer, and 99% of respondents indicated that they learned
6 something new about energy management. A further 85% identified steps that they planned to take to
7 reduce energy consumption.

8
9 **Home Smart:** In March 1993 Phase one of the Home Smart program was completed. The program
10 provided subsidies on six energy-saving and energy efficient products, including: outdoor timers, water
11 saver kits, water tank wraps and pipe insulation, power cord savers, compact fluorescent light bulbs and
12 compact fluorescent hardware fixtures. The program was retail focused, and 59 Yukon retailers
13 participated by carrying Power Smart products, information displays and information.

14
15 **Energy Management Working Group:** On November 1st, 1996, Yukon Energy and YECL submitted a
16 Final Report to the Yukon Utilities Board on the activities of the Energy Management Working Group. The
17 group was formed as per Item 4 of the 1996/97 GRA Settlement, as approved by the Board in Order
18 1996-7. The parties who participated in the process included:

- 19 • Utilities Consumers' Group
- 20 • Yukon Housing Corporation
- 21 • Yukon Energy/YECL
- 22 • Yukon Chamber of Mines
- 23 • Whitehorse Chamber of Commerce
- 24 • City of Whitehorse
- 25 • The Government of Yukon

26
27 The Report identified work in progress that Yukon Energy and YECL set to achieve within the 1996/97
28 GRA period. The activities noted were:

- 29 • Education to the general public via bill stuffers, trade shows, etc.
- 30 • Opportunity assessments completed for customers on request
- 31 • An Opportunity Assessment was completed for Anvil Range Mining Corporation and paid for
32 by Yukon Energy
- 33 • Opportunity Assessments were completed by YECL for the City of Whitehorse and Town of
34 Haines Junction to train their employees

- 1 • YECL committed to investigate and study programmable electric hot water controllers to shift
- 2 the peak load
- 3 • Yukon Energy planning a "Opportunities Assessment" of their plants
- 4 • Studies on capacity enhancements were scheduled for 1997
- 5 • YECL committed to start a more aggressive energy management initiative with its major
- 6 users
- 7 • Rebate programs for residential customers were scheduled for study in 1997

8

9 **Demand Side Management Since 1998**

10

11 Since the closure of the Faro Mine in 1998, there has been a hydro energy surplus. Consequently there
12 has been minimal economic justification to pursue DSM initiatives for most Yukon assets. However, DSM
13 programs have not been terminated.

14

15 Since 2000, management of DSM programs has been undertaken by the ESC. ESC is a service and
16 program delivery agency for energy efficiency and green power programs for the Federal and Yukon
17 governments. The programs run by ESC include electricity programs, and programs focussed on
18 improving the energy efficiency of other energy sources, such as wood-burning. As reported by ESC, the
19 ESC programs that specifically address electricity conservation include the following:

20

21 **2002-2003 Fridge Exchange: A Pilot Project of Yukon Development Corporation and Natural**
22 **Resources Canada:** The program encouraged Yukoners to exchange fridges that were 10-years old or
23 more, for new, and more energy efficient ENERGY STAR fridges. Yukoners were responsible for
24 purchasing the new appliances, however incentives were given. The program resulted in the following
25 savings:

- 26 • 58 reduced tonnes of CO2 generation
- 27 • 72 megawatt hours of savings
- 28 • \$14,400 in avoided costs

29

30 **Final Report to Climate Change Action Fund Public Education and Outreach, Completed June**
31 **2001:** The program targeted 2,000 house call energy audits. A total of 1,457 homes were visited. The
32 program focussed on low flow showers to reduce water heater use; water heater blankets; and higher
33 efficiency bulbs. The program resulted in:

- 34 • 2,203 reduced tonnes of CO2 generation
- 35 • 2,938 megawatt hours of savings

1 **“Six Pack” Parking Lot Controller Pilot Project:** A 2003 study of Intelligent Parking Lot Controllers
2 in six Whitehorse locations: This pilot project evaluated the use of a block heater conservation device
3 that limited the number of hours that block heaters would be in use during the business day. The test
4 year that was used for the analysis was a warmer than average year which reduced the savings realized
5 during the year. The total savings realized were 6,426 KWh. However, the payback period for the
6 equipment was very difficult to forecast.

7

8 **Penguin Pilot Project: Assessing the acceptability of residential tank timers: Results and**
9 **Evaluation report, December 2003:** The pilot project evaluated timers on residential water heaters.
10 The bulk of the water heaters in the pilot project were 40-gallon capacity, with two 3,000 watt elements.
11 The pilot project included 50 hot water tanks, and had a combined load of 150 KW.

12

13 **The GreenHog Handbook:** The handbook was launched in March 2004 by ESC. The handbook
14 solutions to reduce greenhouse gas emissions in the Yukon. The 50-page handbook includes information
15 on climate change, practical tips and solutions for lowering greenhouse gas emissions, coupons for free
16 and discount items, and a booster card for discounts on locally available products and services. This
17 handbook provides a number of suggestions and detailed information, but it is difficult to calculate the
18 greenhouse gas emissions reduced due to this program.

1 3.0 SYSTEM CAPABILITY

2 In order to begin an effective resource planning exercise, it is necessary to assess the capability of the
3 existing system to supply loads today and into the future under various time horizons and scenarios. This
4 includes assessing the condition of Yukon Energy's assets, their capability to provide capacity and energy
5 to the system, and ensuring that an adequate capacity planning criteria for the system is in place. This
6 chapter provides a review of the condition and output of Yukon Energy's assets, and Yukon Energy's new
7 capacity planning criteria.

8
9 The sections for this chapter are as follows:

- 10 • Section 3.1 Current Facilities Condition Assessment
- 11 • Section 3.2 Capacity and Energy Output of Existing Facilities
- 12 • Section 3.3 Capacity Planning Criteria Review
- 13 • Section 3.4 Summary: Revised Capacity Planning Criteria

14

15 The condition assessment section contains a description of three recent condition assessment reports
16 requisitioned by Yukon Energy, and the findings of the assessments.

17

18 The capacity and energy output of the existing facilities are reviewed in the second section, which
19 focuses on implications of changes to major asset output since 1992, either from age, enhancement, or
20 licencing conditions.

21

22 The capacity planning criteria review section provides an overview of Yukon Energy's past capacity
23 criteria, and the new capacity criteria that was recently adopted. Yukon Energy's past criteria was
24 developed by NCPC, adopted in 1987 when Yukon Energy acquired NCPC's assets, and modified slightly
25 in 1992. Yukon Energy reviewed its capacity criteria in 2004-2005 to determine if the criteria still reflects
26 the needs of the Yukon system, and concluded that changes are required as set out in Section 3.4.

27 3.1 CURRENT FACILITIES CONDITION ASSESSMENT

28 Yukon Energy has recently had independent assessments of its key generation, substation and
29 transmission assets.

- 30 • In May of 2004, BC Hydro completed its *Condition Assessment of Selected Yukon Energy*
31 *Generating Assets*. This assessment was focused on Whitehorse Hydro (Units WH1 through

1 WH4), Whitehorse Diesel (Units WD1 through WD7) and Aishihik Hydro (units AH1 and AH3).
2 The condition assessment did not review the other diesel plants or the Mayo hydro facility.

- 3 • *A Condition Assessment of Selected Yukon Energy Corporation Substation Assets* was
4 completed by BC Hydro in June of 2004. The focus of BC Hydro's assessment was on circuit
5 breakers and transformers located at the substations at Aishihik, Takhini, MacIntyre,
6 Whitehorse (all on WAF) plus Mayo.
- 7 • Acres International was commissioned to assess Yukon Energy's transmission assets. The
8 Acres International report, *Assessment of Transmission Lines for Yukon Energy Corporation*
9 was completed in December of 2003. The condition assessment by Acres International of
10 Yukon Energy's transmission lines was of a significantly different type than the Generation
11 and Substation assessments. In the Acres assessment, the primary item to be addressed was
12 the expected remaining life of the transmission assets, based on a sampling of the WAF
13 transmission lines.

14
15 The three reports were filed in YEC's 2005 Required Revenues and Related Matters Application as
16 Interrogatory Response YUB-YEC-A52. BC Hydro and Acres International found Yukon Energy's assets to
17 be in good to relatively good condition with a few notable exceptions:

- 18 • Whitehorse Diesel Units WD1, WD2 and WD3 were assessed to be at their "end of life" and
19 either need to be retired, or require substantial investment;
- 20 • Mayo Substation transformer T1 needs to be replaced in the next five years; and
- 21 • A number of circuit breakers need to be replaced at various substations.

22
23 Other smaller projects for modernization or life extension were also recommended in the various
24 condition assessments.

25 **3.1.1 Yukon Energy's Response to Condition Assessments**

26 As a result of the condition assessment documents, Yukon Energy developed short to medium term
27 capital investment plans to address the bulk of the items identified by BC Hydro and Acres International.
28 This Yukon Energy plan was provided in the 2005 Required Revenues and Related Matters Application
29 and has been reviewed by the Yukon Utilities Board. To summarize:

- 30 • **BC Hydro Condition Assessment of Selected Yukon Energy Generation Assets:** As
31 shown in the Table 3.1, the BC Hydro report recommended \$2.454 million in work on these
32 units. Yukon Energy's capital plan for these same units over the period 2004-2009 reflects
33 overall approximately the same scope of work (also shown on Table 3.1). Yukon Energy's
34 plan consists of \$3.760 million. The reason for the \$1.306 million variance is primarily

- 1 material costs associated with the WH1 and WH2 trunion bushing capital projects that were
2 not forecast by BC Hydro for \$824,000, plus a 2004 project for major capital work on WD5
3 for \$201,000 that was already in progress when BC Hydro prepared their report (and
4 therefore is not addressed in the BC Hydro recommendations).
- 5 • **BC Hydro Condition Assessment of Selected Yukon Energy Corporation Substation**
6 **Assets:** In this report, BC Hydro reviewed a number of Yukon Energy's substations and
7 recommends \$921,000 in work over the "medium to long-term" at Appendix I of their report
8 (also see Table 3.2). Yukon Energy's capital plan for 2004-2006 includes \$880,000 to
9 complete this work, including further detailed assessment of each of the recommendations.
10 YEC intends to review other options before proceeding with circuit breaker replacements
11 estimated at \$210,000.
 - 12 • **Acres International Assessment of Transmission Lines for Yukon Energy**
13 **Corporation:** Although some token amounts were identified as being recommended as
14 capital to be spent in the next five years (\$43,000 per page 28), the majority of the report
15 was not aimed at determining the appropriate capital investment in transmission line. Yukon
16 Energy has incorporated the amounts identified by Acres International in its five year capital
17 plans for transmission spending.

1
2
3
4

Table 3.1:
BC Hydro Generation Condition Assessment Recommended
spending compared to YEC Budgeted Capital Planning 2004-2009 (\$000s)¹

BC Hydro 5 year Recommendation

	P125	P126	P127	AH0			
Unit Life Extension Mech	\$152	\$438	\$84	\$22			\$696
Unit Life Extension Elect	\$20		\$40	\$130			\$190
Plant Life Extension Mech	\$37	\$245	\$0	\$8			\$290
Plant Life Extension Elect	\$10	\$4	\$43	\$15			\$72
Unit Modernize Mech	\$92		\$55	\$181			\$328
Unit Modernize Elect	\$70		\$120	\$160			\$350
Plant Modernize Mech	\$48		\$40	\$80			\$168
Plant Modernize Elect	\$50		\$10	\$300			\$360
	\$479	\$687	\$392	\$896	\$0	\$0	\$2,454

YEC Budget Planning

	2004	2005	2006	2007	2008	2009	
P126 Diesel Life Ext (Mech)	\$201						
P126 Diesel Life Ext (Elect)	\$19						
Generation Unit Life Mech		\$75	\$75	\$250	\$150		
Generation Unit Life Elect		\$75		\$100			
Plant Life Mech					\$250		
Plant Life Elect			\$50				
Unit Modernize Mech					\$250		
Unit Modernize Elect			\$50		\$250		
Plant Modernize Mech				\$150			
Plant Modernize Elect				\$250	\$100		
P125 Vibration Monitoring	\$120	\$60					
P125 Trunions	\$504	\$400					
P127 Exciter Assessment		\$21					
P127 Unit Mech Overhaul				\$350			
P127 Ventilation		\$10					
	\$844	\$641	\$175	\$1,100	\$1,000	\$0	\$3,760

Notes:

YEC budget does not align with BC Hydro recommendations due to:
YEC not in full agreement all work is appropriate, and costs estimates are
different between BC Hydro and YEC.

5

¹ P125 is Whitehorse Hydro plant containing units WH1, WH2 and WH3; P126 is the Whitehorse diesel plant; P127 is the hydro plant containing WH4; AH0 is Aishihik.

1
2
3
4

Table 3.2:
BC Hydro Substation Condition Assessment Recommended
spending compared to YEC Budgeted Capital Planning 2004-2009 (\$000s)

BC Hydro Medium and Long Term Recommendations							
	S249	S150	S164	S167	S171	General	
Transformer Replace	\$150						
Circuit Breaker Replacements		\$210					
Vertical Break Switches			\$130	\$130			
Disconnect Replacements		\$30					
Station Service Upgrade			\$60		\$60		
Insulation Coordination Study						\$30	
Circuit Breaker Analyzer						\$18	
Infrared Digital Camera						\$3	
Stock Inventory						\$100	
	\$150	\$240	\$190	\$130	\$60	\$151	\$921
YEC Budget Planning							
	2004	2005	2006	2007	2008	2009	
Transformer Replacement			\$200				
Station Service Upgrades				\$150			
Breaker Analyzer		\$40					
Transformer Leveling		\$40					
Substation Follow Up Work		\$150	\$150	\$150			
	\$0	\$230	\$350	\$300	\$0	\$0	\$880

Notes:

Only YEC plans that correlate to the BC Hydro report are shown here. Other work is planned for substations or components that BC Hydro did not assess.

5 **3.1.2 Condition Assessment Findings Relevant to Resource Planning**

6 The Condition Assessment findings indicate Yukon Energy's system is generally well suited to meeting the
7 future WAF and MD system load requirements over the duration of the Resource Plan within the as-built
8 capabilities of each the various units studied. Aside from new requirements related to load growth, the
9 clear exception is the three Whitehorse Mirrlees diesel units, WD1, WD2, and WD3, located at the
10 Whitehorse diesel plant.

1 It has been well known to Yukon Energy that the Mirrlees units were approaching retirement, and in fact
2 earlier Yukon resource planning exercises (both 1992 and 1996) were based on these three units being
3 retired prior to 2006. The units have been retained in-service due to the current system load, which has
4 not required material running time for these three units during the 1993-1995 closure, or since the 1998
5 closure of the Faro mine and into the future until at least the current hydro surplus on the WAF system is
6 consumed by firm load.

7

8 The issues and options relating to the requirement to retire the Mirrlees units are further addressed in
9 *Chapter 4*.

10 **3.2 CAPACITY AND ENERGY OUTPUT OF EXISTING FACILITIES**

11 The generating assets in service are required to meet both capacity (instantaneous peak) and energy
12 (annual and sometimes seasonal requirements) of the individual systems (WAF, MD, isolated). An
13 overview of Yukon Energy's generating assets is set out in Table 3.3. On each of the WAF and MD grids,
14 supply is also available from diesel and, in one case, hydro assets owned by YECL.

15

16 This section reviews the capability of key Yukon generation assets to meet capacity and energy
17 requirements of the various systems.

18

19 The capacity ratings of Yukon Energy's assets reflect design or "nameplate" ratings, as adjusted in certain
20 cases to reflect the real-world conditions with respect to the individual unit, or conditions that exist at the
21 time of year when capacity requirements are highest (e.g., winter). Capacity ratings for resource planning
22 also must reflect what can be relied upon in worst case conditions, in particular drought conditions for
23 hydro units.

24

25 Energy ratings could similarly be developed to reflect reliable output in worst case conditions (such as a
26 drought for hydro units). However, given the current surplus energy conditions on the two main Yukon
27 systems, energy output is only addressed in this section with respect to Aishihik, which has been
28 moderately affected by recent changes to the Water Licence under which it operates.

1
2
3

**Table 3.3:
Yukon Energy Generation Inventory**

<u>Location</u>	<u>Unit No.</u>	<u>Type</u>	<u>Manufacturer</u>	<u>Mover Model</u>	<u>Name Plate Capacity</u>	<u>MCR Rating (kW)</u>	<u>In-Service Date</u>	<u>Planned Retirement Date</u>
Aishihik	AH1	hydro	Dom Eng.	Francis	15,600	15,000	1975	none
	AH2	hydro	Dom Eng.	Francis	15,600	15,000	1975	none
Faro						5,300		
	FD3	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	FD5	diesel	Caterpillar	3516	1,400	1,300	1990	2020
	FD7	diesel	Caterpillar	3612	3,000	3,000	1992	2027
Dawson						5,000		
	DD1	diesel	Caterpillar	3512	800	800	1988	2018
	DD2	diesel	Caterpillar	3516	1,000	1,000	1987	2017
	DD3	diesel	Caterpillar	3516 TA	1,000	1,000	1990	2020
	DD4	diesel	Caterpillar	D399	700	700	1975	2005
	DD5	diesel	Caterpillar	3606	1,500	1,500	1996	2031
Mayo						7,400		
	MD1	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	MD2	diesel	Caterpillar	3516	1,000	1,000	1989	2019
	MH1	hydro	Dom Eng.	Francis	2,620	2,600	1957	none
	MH2	hydro	Dom Eng.	Francis	2,840	2,800	1951	none
Whitehorse						62,400		
	WH1	hydro	K.M.W.	Kaplan	5,800	5,800	1958	none
	WH2	hydro	K.M.W.	Kaplan	5,800	5,800	1958	none
	WH3	hydro	C.A.C.	Propeller	8,400	8,400	1969	none
	WH4	hydro	Dom Eng.	Propeller	20,000	20,000	1984	none
	WD1	diesel	Mirrlees	KV12	3,920	3,000	1968	2011
	WD2	diesel	Mirrlees	KV16	5,150	4,200	1968	2009
	WD3	diesel	Mirrlees	KV16	5,150	4,200	1970	2007
	WD4	diesel	EMD	20C	2,500	2,500	1975	2025
	WD5	diesel	EMD	20C	2,500	2,500	1975	2025
	WD6	diesel	EMD	20C	2,700	2,700	1990	2025
	WD7	diesel	Caterpillar	3612	3,300	3,300	1991	2026
	Haeckel Hill						810	
WW1		wind	Bonus	MARK III		150	1993	2013
	WW2	wind	Vestas			660	2000	2020
Mobile Diesels						1,450		
	YM1	diesel	Caterpillar	3516	1,400	1,300	1990	2015
	YM2	diesel	J Deere		150	150	1999	2024
Total Capacity						112,360		

4

3.2.1 Whitehorse Rapids Hydro Firm Capacity

5
6
7
8

The largest generating station in Yukon is the Whitehorse Rapids hydro plant. The output of the plant at full river flow conditions in summer is 40 MW, or slightly above. However, during low flow (i.e., drought) winter periods, the plant's firm output that can be relied upon is well below this level.

1 Whitehorse hydro is supplied by the flows of the Yukon River. The plant is largely “run-of-the-river”, but
2 there is some modest flow control via a control structure at the outlet of Marsh Lake (the Lewes Dam).
3 By managing the flow out of Marsh Lake in accordance with licence conditions, Yukon Energy can help
4 sustain Yukon River flows into the winter periods when system load requirements are highest. Absent this
5 control, the plant would have very low firm winter output. Although YEC has a modest level of flow
6 control on the river, there is very limited ability during winter to use the Whitehorse Rapids plant for
7 “load factoring” where the plant output might be materially varied on (say) a daily basis. In summary,
8 “load factoring” types of fluctuation in downstream flows at this plant during winter conditions can cause
9 ice break-up and ice jamming, and consequently flood low-lying areas of Whitehorse, as was reviewed in
10 detail by the YUB at the 1992 Resource Plan hearing.

11
12 The Whitehorse Rapids reliable firm capacity rating during low winter flows was reviewed in 1992 and in
13 follow-up at the 1993/94 GRA (as set out in Chapter 2). In short, at that time Yukon Energy and YECL
14 provided evidence that during drought years, a managed drawdown of Marsh Lake over six months can
15 provide 19 MW of consistent firm capacity under the lowest flows on record. However, Yukon Energy also
16 indicated that in 80% of the years (i.e., non-drought years), the plant could reliably provide 24 MW or
17 more during winter. In 1992, the Companies indicated that in drought years, if 24 MW of plant capacity
18 was required, up to 5 MW of diesel may be able to be temporarily leased for the winter to maintain a 24
19 MW reliable level of capability at this plant (over and above the capability provided by the plant’s existing
20 diesel units). As a result, since that time the hydro units at this plant have been assigned a winter reliable
21 capacity rating of 24 MW.

22
23 Yukon Energy has continued to refine its operation of the Whitehorse Rapids hydro plant, particularly in
24 the period since the closure of the Faro mine. Based on these more recent reviews, Yukon Energy can
25 now confirm that the drought-year capability of the Whitehorse Rapids plant is 24 MW under current load
26 conditions. This is achieved largely by being able to maximize Marsh Lake outflows, starting November, at
27 a stable level for the four coldest winter months, and at licenced minimum flows for the remaining two
28 winter months (when capacity is less of a concern on the WAF system). In addition, Yukon Energy can
29 manage Schwatka Lake levels to a small degree on a daily basis, drawing down the lake by about six
30 inches during the day and allowing it to refill at night.

31
32 Consequently, Yukon Energy continues to use 24 MW as the firm capacity of the Whitehorse Rapids
33 plant. Moreover, this full level is now achieved without the earlier concept of resorting to short-term
34 leased diesel units during drought conditions.

1 **3.2.2 Aishihik Hydro Capacity and Energy**

2 Unlike Whitehorse Rapids, Aishihik hydro capacity output is not limited by water storage or droughts. This
3 is because the multi-year Aishihik reservoir is large and quite flexible (with a seven foot restricted
4 operating range under the renewed licence), and can be dispatched largely as needed by Yukon Energy
5 to meet peak loads. For this reason, Aishihik's output can vary substantially during the day in winter as
6 loads change (compared to Whitehorse hydro, which is a very stable daily output). Aishihik's output also
7 varies materially on a seasonal basis, as summer use is minimized to allow the lake to re-fill for the
8 coming winter.

9
10 The maximum capacity output of Aishihik hydro is 30 MW today, based on 2 – 15 MW units. For the
11 reasons noted, this capability is available on a firm basis during winter low flow conditions.

12
13 Recent rewinds performed on AH1 indicate a potential to increase the rating on the units to 15.4 MW.
14 However, rewind work has not yet been performed on AH2 (scheduled for 2006) and until this is
15 completed and consequent coordinated testing done on the units, YEC will not be able to confirm the
16 slight increase in capacity ratings. Future potential also exists to re-runner the Aishihik units to
17 theoretically increase the mechanical capacity output by as much as 20%; however this initial indication
18 requires significant further work to confirm that the electrical system and various physical components
19 (such as wicket gates and turbine bearings) can handle the increase in output. This preliminary
20 assessment work is ongoing.

21
22 In terms of annual energy capability, due to the multi-year characteristics of the Aishihik plant and how it
23 is used, the long-term annual energy output of Aishihik is dependent upon a combination of (a) long term
24 average flow conditions, (b) load requirements on WAF, and (c) the constraints relating to the facility's
25 capacity and its water licence terms and conditions. For the purposes of this Resource Plan, Yukon
26 Energy has retained the Aishihik long-term average output at 105 GW.h/year consistent with previous
27 plans. As noted below, this capability is expected to increase slightly should sufficient major new
28 industrial loads be placed on the system; however, under such increased load conditions, Aishihik's
29 energy long term average capability is currently estimated to be about 3 GW.h/year lower than it would
30 have been had the previous licence conditions (nine foot unrestricted operating range) been maintained.

- 31
- **Current WAF Load Conditions:** At present, given surplus hydro energy on WAF due to
32 current load conditions, Aishihik Lake is being maintained in a substantially full condition near
33 the top end of its licence limits, so any major increase in need to drawdown the lake (such as
34 for major new loads) will allow high output for some time before the stored energy is

1 consumed (similarly, drought conditions at Aishihik today can be addressed by a period of
2 drawdown to maintain long-term average generation levels despite low inflows). Under these
3 conditions, the earlier long-term average energy capability does not appear to be materially
4 affected by the new Water Licence terms and conditions.

- 5 • **Major Industrial Load Additions:** At such time as sufficient large new industrial load
6 develops on WAF, similar to the Faro Mine loads in the past (or greater), it is to be expected
7 that Aishihik Lake would tend over a few years to be drawn-down to within the mid-range of
8 its licenced operating range. After such drawdown, Aishihik's long-term average annual
9 energy output is expected to increase slightly above 105 GW.h/year and to reflect licence
10 conditions. In the event that sufficiently higher WAF industrial loads occur, this long-term
11 average energy capability is expected to be somewhat further increased, but also to be as
12 much as 3 GW.h per year lower under the current seven foot restricted operating range than
13 would be expected under the nine foot unrestricted operating range of the reservoir with the
14 previous Water Licence.

15 3.2.3 Mayo Hydro Capacity

16 The capacity of the Mayo hydro plant has traditionally been listed as 5 MW based on 2-2.5 MW turbines.
17 However, there has not been sufficient load on this system for many years to make use of this full
18 capacity.

19
20 Due to the age of the units, in the last few years Yukon Energy has re-runnered and rewound the units
21 which has enabled an increase in individual unit performance (now rated at 2.6 and 2.8 MW
22 respectively). For planning purposes, Yukon Energy has assumed the combined 5.4 MW can be generated
23 at the plant. It is important to note, however, that there is not sufficient load today to bring both units
24 simultaneously up to full load to determine whether the full 5.4 MW can be achieved. This testing cannot
25 occur until further load growth occurs on the Mayo-Dawson system. The increase in capacity is also
26 forecast to increase the long-term average energy from 40 to 42 GW.h/yr.

27 3.2.4 Whitehorse Diesel Capacity

28 As noted in Section 3.1, there are immediate issues with respect to determining the future of the
29 Whitehorse diesel plant in light of requirements to either retire or invest substantially in the Mirrlees
30 diesel units WD1, WD2, and WD3.

1 In the interim, the three units are not in a condition that can sustain a Maximum Continuous Rating
2 (“MCR”) for planning purposes to the full nameplate ratings of these units. As a result, Yukon Energy has
3 based its near-term planning on a “de-rated” MCR for these units of 4.2 MW (WD 2 and WD3, nameplate
4 ratings of 5.15 MW) and 3.0 MW (WD1, nameplate rating of 3.92 MW).

5
6 Should some form of life extension project be undertaken on these units, that project would need to re-
7 assess the ability to bring these units back up to the full nameplate MCR.

8 **3.2.5 Fish Lake Hydro (YECL) Capacity**

9 YECL maintains a small two unit hydro facility on the WAF system called Fish Lake, rated at 1.3 MW. Fish
10 Lake hydro is neither dispatched nor monitored by Yukon Energy, and cannot be readily adjusted to
11 match load conditions on a daily basis.

12
13 Fish Lake has traditionally been included in the Yukon planning process as firm capacity on the WAF
14 system, at 1 MW. However, recent reports on the output of Fish Lake indicate winter flows cannot be
15 relied upon to sustain outputs higher than about 400 kW, as was the case through the monthly averages
16 during the winter of 2003/04 (December of that year dropped to a monthly average output of 389 kW),
17 with many recent winters not recording average monthly outputs above about 600-700 kW.

18
19 Consistent with normal system planning practice of recognizing winter constraints, as is done for Yukon
20 Energy’s assets, the YECL Fish Lake facility are considered in this Resource Plan to be reliable firm winter
21 capacity at a maximum of 400 kW.

22 **3.3 CAPACITY PLANNING CRITERIA REVIEW**

23 The Yukon system capacity planning criteria are the sets of rules used by YEC to determine how much
24 firm generation capacity is required on the various Yukon systems and when additions to generation
25 capacity are required. Criteria are applied separately for each power system in Yukon, e.g., the WAF
26 system versus each isolated diesel system.

27
28 Changes to the Yukon systems since 1992, as well as the pending retirement of the three Mirrlees diesel
29 units at Whitehorse, prompted a re-examination of the capacity planning criteria, focused particularly on
30 WAF. As a result of this re-examination, Yukon Energy has adopted new capacity planning criteria.

1 Adequate firm generation capacity is one component of providing reliable power. Overall reliability of
2 each BES system (generation and transmission) requires:

- 3 a) that there is adequate firm generation (and transmission) capacity installed on the
4 system;
- 5 b) that the installed system be properly protected;
- 6 c) that the installed system be properly maintained (including brushing of transmission
7 lines); and,
- 8 d) that the installed system is operated and dispatched in accordance with sound operating
9 criteria.

10
11 In addition, the reliability of service to customers served on the distribution system will also include
12 various factors relating to the reliability of that lower voltage system as well.

13
14 Standard utility reliability tests are intended to cover all of the recognized factors affecting system
15 generation supply reliability including load factor growth both on a system and on each feeder,
16 maintenance of equipment, regular and routine servicing and repair, assessing remaining life, planning
17 for end of life replacement, removal of danger tress, and a range of other specific factors that affect
18 reliability.

19
20 Capacity criteria in regards to long-term BES resource planning deals only with the first item in the above
21 list of factors affecting BES system reliability; namely, that there be adequate firm generation and
22 transmission capacity installed on each system.

23
24 In assessing capacity planning, it is recognized that Yukon Energy policy first interrupts secondary energy
25 service that is to be supplied by surplus hydro resources, and that no BES capability is planned to supply
26 secondary energy service. All remaining "firm" customer load requirements at the time of system
27 maximum load or peak (e.g., winter peak on WAF) are considered when assessing each system's capacity
28 planning requirements.

29 **3.3.1 Background and Overview on the Evolution of Capacity Planning**

30 Planning of a utility system must provide both for system growth and for operation after a component
31 failure. Systems vary greatly in size and complexity but the ability of each system to maintain service is
32 compared by using established and recognized criteria.

1 In general, throughout various systems these planning criteria have evolved gradually into more defined
2 ratios as systems have grown bigger and more complicated. Where relevant, transmission reliability has
3 also been addressed where it directly affects generation reliability.

4
5 The criteria used by NCPC were developed to indicate the required amount of firm generating capacity to
6 cover relatively small isolated systems, and were consistent with utility planning standards of that era.
7 NCPC had started with a multiple of small isolated systems, some of which continue, but others had
8 grown to the point where multiple sources were interconnected.

9
10 Yukon Energy (and its then manager, YECL), as the operator succeeding NCPC for the Yukon, initially
11 followed the practice of NCPC. It was quickly found that the continuing small isolated installations were
12 reasonably covered by the NCPC criteria but that the larger systems with multiple sources needed more
13 detailed analysis to be secure:

- 14 • The small systems were considered to be adequately protected if the generating capacity
15 with the largest single unit out of service was at least 110% of the anticipated peak load.
16 This approach is continued today.
- 17 • For the larger “grid” systems, it becomes necessary to consider not only the possible loss of a
18 single generator (in the case of WAF, a single “wheel” at Aishihik), but also the likelihood that
19 at least one of the major WAF diesels would be unavailable at the same time. Consequently,
20 the Resource Plan in 1992 introduced recognition of the diesel-related effect on Yukon
21 Energy’s ability to serve any particular WAF load by adding a “10% of installed diesel”
22 reserve on top of the Aishihik hydro reserve.

23
24 Under the NCPC capacity planning criteria and the 1992 Resource Plan criteria, the transmission system
25 availability was not considered at all.

26
27 In the meantime, other integrated utilities developed a statistical approach to the potential interruption of
28 service for any customer. This is often evaluated as the Loss of Load Expectation (“LOLE”) and it is
29 measured in hours per year². Most of the various Canadian utilities have come to apply an LOLE range
30 from one to two hours per year as their capacity planning standards. Where relevant, certain utilities
31 have incorporated transmission into this assessment where generation reliability is directly and materially
32 affected by transmission. Specific recent experience with Northwest Territories Power Corporation has

² Other terms are also used to describe the probabilistic measures, such as the BC Hydro criteria of Loss of Load Probability (“LOLP”) or Newfoundland and Labrador Hydro’s Loss of Load Hours (“LOLH”).

1 also applied, in parallel with LOLE criteria a second test to ensure that customers are protected against
2 failure of any single system component.

3
4 Yukon Energy has recently examined the LOLE approach and tested it against the operating history of its
5 WAF system. This review has shown that the WAF system has substantial hydro generation availability
6 that is directly affected by certain transmission, and that the WAF system also has been trending to an
7 increasing probability of longer outages as it expands (particularly with expansion of residential and
8 commercial loads and major reductions in industrial load). Yukon Energy has therefore now incorporated
9 the LOLE approach, with recognition of transmission reliability where relevant, into its system planning
10 criteria to better protect all of its firm customers from generation-related outages.

11
12 At the same time, Yukon Energy has recognized that the LOLE function is an average that does not
13 indicate how long any particular outage will last, and that any extended outage on its grid systems during
14 the winter peak could be very adverse and serious, particularly for affected residential and commercial
15 customers. Yukon Energy has addressed this concern by considering in parallel with LOLE a second test
16 as part of its planning criteria, namely the effect of the failure of any individual bulk electrical system
17 component and the ability of the system to continue to serve its firm residential and commercial
18 customers without the failed component (i.e., a test described as “surviving the first failure” or “operating
19 in the N-1 condition where “N” is the normal system complement). As an example, the biggest loss of
20 generation on WAF today at winter peak would be 30 MW following a failure of the Aishihik transmission
21 line; this loss would be far greater than the loss during winter peak of the biggest generator (which
22 currently is a 15 MW generator at Aishihik)³.

23
24 The previous criteria, the recent review and the revised criteria now adopted by Yukon Energy are each
25 reviewed in more detail below.

26 **3.3.2 Yukon Energy's Previous Capacity Planning Criteria (prior to late 2005)**

27 The Yukon systems were previously planned with criteria (as reviewed in 1992) using a single formula for
28 specifying its required firm generation capacity on each type of system. This deterministic criteria was
29 outlined in the 1992 Resource Plan.

³ The largest single unit on the WAF system is WH4, one of the hydro units at Whitehorse. However, as Whitehorse has four hydro units (WH1 at 5.8 MW, WH2 at 5.8 MW, WH3 at 8.4 MW and WH4 at 20 MW), but only 24 MW of firm flows in winter in drought conditions, a loss of WH4 would only effectively reduce the available capacity by 4 MW (as the other three units would still be available), which is smaller than the loss of 15 MW via one of the units at Aishihik.

- 1 • For **Isolated Diesel Communities**, the criteria required each system to have installed
2 generation capacity sufficient to meet 110% of the forecast peak load with the largest
3 generation unit out of service.
- 4 • For the **WAF grid**, the required system generation capacity was determined as follows:
- 5 1. The installed generation system, less a "Generation Reserve Requirement", must be able
6 to meet the forecast WAF winter peak loads. For simplicity, this approach was used to
7 define the Maximum Allowable Peak Load ("MAPL") for the WAF system at any time, i.e.,
8 the installed capacity at that time less the applicable Generation Reserve Requirement.
- 9
- 10 2. The Generation Reserve Requirement was the reserve needed to meet forecast winter
11 peak load with the loss of the single largest winter unit (one of the Aishihik units at 15
12 MW) plus the loss of 10% of the installed diesel capacity.
- 13
- 14 • For **individual communities on the WAF grid**, there was no generation capacity planning
15 criteria in place. In practice, communities over about 300 people other than Faro and
16 Whitehorse typically have local diesel generation installed to serve a dual purpose: overall
17 grid support similar to major diesel installations at Whitehorse or Faro, as well as local supply
18 during transmission outages. This applied at Ross River, Carmacks, Haines Junction, and
19 Teslin, but has not been traditionally applied at Carcross. It was also not applied at smaller
20 centres below 300 people.

21

22 With respect to Faro, there has traditionally been a major diesel plant well in excess of the
23 town requirements, but below the requirements of the Faro mine. Today, Faro maintains a
24 diesel plant of 5.3 MW, which serves as a major diesel anchor point for the grid as well as for
25 local supply in the case of transmission outages.

26

27 For Whitehorse, there were no criteria regarding generation capacity requirements. In
28 practice, however, Whitehorse has traditionally had sufficient generation (hydro plus diesel)
29 installed in the local area to supply the community in the case of major transmission outages.
30 This condition has now changed with recent growth in Whitehorse and the pending
31 retirement of the Mirrlees units.

- 32
- 33 • For the **MD grid**, there was previously no approved capacity planning criteria. Previously, the
34 Mayo system criteria had been based on supplying 110% of the peak load with the hydro

1 units out of service. The separate Dawson system had been planned as an isolated diesel
2 community (prior to the Mayo Dawson transmission development).

3
4 For both of the grid systems, the generation assets were included in the past capacity planning criteria
5 calculation, but transmission assets were not considered. As a result, the possibility of transmission
6 failure was not accounted for.

7
8 The MD Transmission Line was brought into service in 2002 to use surplus hydro at Mayo to offset diesel
9 generation in Dawson City. The Dawson diesel plant is still in service in Dawson as back-up capacity well
10 in excess of the community's peak loads (it had been installed to meet the Isolated system standard).
11 There are also two diesel units in Mayo that together approximate the local Mayo firm peak loads.
12 Consequently, the WAF grid was the focus during the examination of the capacity planning criteria.

13
14 Table 3.4 depicts the generating complement and Maximum Peak Load under the previous planning
15 criteria for WAF. The result is that a WAF load of 68.7 MW can be allowed under these criteria without
16 exceeding the calculated capability of the current generating units in service.

1
2
3
4
5

**Table 3.4:
Current WAF Generating Complement and
Maximum Allowable Peak Load (MAPL)
under Previous Planning Criteria**

Unit	Rating (MW)
Whitehorse Hydro (winter - for all units)	24.0
Whitehorse diesel #1	3.0
Whitehorse diesel #2	4.2
Whitehorse diesel #3	4.2
Whitehorse diesel #4	2.5
Whitehorse diesel #5	2.5
Whitehorse diesel #6	2.7
Whitehorse diesel #7	3.3
Faro diesel #3	1.0
Faro diesel #5	1.3
Faro diesel #7	3.0
Aishihik #1	15.0
Aishihik #2	15.0
Carmacks diesel (YECL)	1.3
Haines Junction diesel (YECL)	1.3
Teslin diesel (YECL)	1.3
Ross River diesel (YECL)	1.0
Fish Lake hydro (2 units - YECL)	<u>0.4</u>
Total	87.0
Less: 15 MW hydro Reserve	-15.0
Less: 10% Diesel Reserve	<u>-3.3</u>
Maximum Allowable Peak Load (MAPL)	68.7

6

3.3.3 Previous Yukon Criteria Compared with Criteria for Other Jurisdictions

8 Yukon Energy's previous capacity criteria do not identify any specific BES system capacity requirement
9 that can be readily compared with criteria adopted in other jurisdictions for integrated systems. This was
10 because the previous Yukon criteria only dealt with the concept of a "reserve" rather than actually
11 assessing the likelihood (or probability) that the generation available will be insufficient to supply the load
12 at any given point in time, which has been adopted by the majority of Canadian utilities. The previous
13 Yukon criteria are described as "deterministic" in that a set test is adopted for each system as a proxy

1 intended to ensure adequate capacity – however, to assess the adequacy of this proxy, it was necessary
2 to compare Yukon’s situation with criteria adopted in other jurisdictions.

3
4 Reliability experts were hired from the University of Saskatchewan in 2004 (under the direction of Dr. Roy
5 Billinton) to study and determine the probabilities inherent in the existing Yukon capacity planning
6 criteria. NWT Power Corporation has used Dr. Billinton as an advisor in the development of their Snare-
7 Yellowknife system planning criteria, and received approval from its regulator for their revised criteria in
8 November of 2004.

9
10 The review confirmed that a comparison of Yukon’s previous criteria with criteria typically adopted by
11 major Canadian utilities cannot be readily undertaken. However, in terms of the maximum peak load that
12 can be supported, the review indicated that WAF generation was not adequate to supply the 68.7 MW
13 peak (as would be allowed under the existing criteria (see Table 3.4)) within any reasonable reliability
14 standard adopted elsewhere in Canada⁴.

15
16 Generation Adequacy (capacity) criteria in Canada today are typically derived by looking at the probability
17 of an outage occurring due to having inadequate generation installed. This “probabilistic” approach looks
18 at the likelihood of different load levels over the year and the likelihood of this load not being met due to
19 unplanned outages of generation units or (in some limited cases) transmission facilities. The resulting
20 criteria are expressed for a system as LOLE (stated as average number of hours or days per year that the
21 BES system would be inadequate due to unplanned events) and Loss of Energy Expectation (LOEE,
22 stated in MWh/yr of energy desired by customers that would go unserved). The review indicated that
23 criteria commonly used in the NWT and southern Canada are LOLE between about one and two hours
24 per year. If applied to the Yukon system (including consideration of constraints posed by the reliability of
25 the Aishihik transmission line), the review indicated that such standards would only allow a maximum
26 peak on the current WAF system of about 60.1 MW to 62.9 MW (compared to 68.7 MW under the
27 previous criteria).

28
29 The review also indicated several key findings with regard to the previous WAF criteria, as follows:

⁴ The work by Drs. Billinton and Karki reflects an evaluation of the WAF system with some minor overall differences from the capacity values indicated in Table 3.4. For example, Drs. Billinton and Karki did not consider Fish Lake as a reliable supply resource (the load data available was net of Fish Lake outputs, so the resource was effectively already accounted for in the loads) and used a higher assumed Haines Junction diesel output of 1.7 MW. Subsequent investigations indicate this assumed capacity for Haines Junction was too high. The net result, however, of these variations is minimal on the overall conclusions of the report.

- 1 1. **The WAF Deterministic Criteria was adequate in 1996/97** – The previous WAF
2 capacity criteria provided excellent capacity reliability for residential and commercial
3 customers in 1996/97 when the Faro Mine was in operation, with an LOLE of 0.008 hrs/year
4 (based on the Faro Mine being the first customer to be interrupted). The reliability for
5 industrial customers was considerably less at that time at about 9.4 hours per year.
6 However, even in the event of a major shortage of WAF generation, the mine would still have
7 typically received substantial supply from the Faro diesel plant (13.6 MW at that time).
8
- 9 2. **The WAF Deterministic Criteria is not adequate today based on LOLE** – The previous
10 WAF capacity criteria provide poor capacity reliability today with an LOLE of about 5.9 hrs/yr
11 at the peak load level allowed by the past criteria. The LOLE is considerably higher than it
12 was in 1996, and also well above the normal range of one to two hours per year adopted by
13 other Canadian utilities. Since there are currently no major industrial customers on WAF, this
14 assessment in effect addresses the current capacity reliability for residential and commercial
15 customers on WAF.
16
- 17 3. **Aishihik transmission line is key capacity constraint** – The transmission line from
18 Takhini to Aishihik (L171 line) accounts for about 80% of the total LOLE today for WAF, and
19 is thus the key WAF capacity constraint. This transmission line connects 31.3 MW of capacity
20 to the Whitehorse area (as well as loads at Haines Junction). Were it not for this exposure to
21 transmission outages, the LOLE would drop from 5.9 to 1.2 hours per year. The effect of
22 considering the transmission line reliability is a reduction of 8.0 MW of load carrying
23 capability at the two hours per year LOLE level.
24
- 25 4. **Previous criteria not adequate to track impacts of WD retirements** – The previous
26 capacity criteria did not keep pace from a reliability standpoint with the planned retirement of
27 Whitehorse capacity (WD1, WD2 and WD3). This is because retirement of 4.2 MW of diesel
28 units at Whitehorse only reduced the MAPL by 3.8 MW (due to the 10% diesel reserve). The
29 recent review however indicated that load carrying capability at an LOLE of two hours per
30 year reduced by at least 4.2 MW upon a retirement of a unit of this type (in some cases
31 slightly more than 4.2 MW).
32

33 In addition to LOLE generation criteria, some utilities (including NWT Power Corporation for its
34 Yellowknife grid) also adopt a further emergency standard to ensure each major BES system can meet its
35 peak winter loads with loss of its largest single transmission component (called “N-1” criteria). The

1 previous Yukon criteria do not address the N-1 emergency criteria for systems such as WAF because the
2 transmission facility loss was not considered in the capacity planning criteria. The overall result was to
3 potentially expose Whitehorse area customers in particular to loss of adequate generation if the Aishihik
4 line suffers a sustained failure at the time of system peak. In practice, this risk exposure was not
5 material so long as there was adequate generation (including diesel units) in the Whitehorse area to
6 reliably supply this area's loads; however, this situation is changing through growth in Whitehorse area
7 loads and pending retirement of diesel units at the Whitehorse Rapids Diesel plant.

8 **3.3.4 New Criteria Adopted by Yukon Energy**

9 The new capacity planning criteria now adopted by Yukon Energy are as follows:

- 10 1. **WAF and MD System-wide capacity planning criteria:** Each system (WAF and MD)
11 should not exceed a LOLE of two hours per year. The two hour measure is the same as that
12 adopted in NWT and is comparable to the lower end of standards commonly used in southern
13 Canada (which are typically from one to two hours per year LOLE).

14
15 Although determining the LOLE requires sophisticated computer modelling, in practice the
16 LOLE approach can generally be applied on WAF by benchmarking the two hours per year
17 LOLE to a WAF overall "load carrying capability" of 62.9 MW. In rough terms, this load
18 carrying capability changes by about 1 MW for every MW of non-Aishihik line generation that
19 is added or retired (e.g., a retirement of 4 MW from the Whitehorse diesel plant will reduce
20 this load carrying capability by about 4 MW, vice versa for additions). The benchmarking is
21 also based on a rough assumption that the load carrying capability would be increased by
22 about 8.0 MW if the current Aishihik transmission line constraint was removed. This could be
23 done by twinning the line (i.e., creating a second line to allow access to Aishihik generation
24 resources in the event of failure of the existing line).

25
26 For MD, this criteria is well exceeded today. MD is well below two hours/year LOLE and also
27 satisfies an N-1 condition in all locations.

- 28
29 2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Yukon's grids
30 are small and isolated from major power grids, with single transmission lines connecting
31 generation to load centres. Consequently, it was also determined to be appropriate to
32 incorporate a standard to address the potential for sustained emergency conditions. In order
33 to be able to address major emergencies, each system (WAF and MD) should be able to carry
34 the forecast peak winter loads (excluding major industrial loads) under the largest single

1 contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the
2 loss of the system's single largest generating or transmission-related generation source. For
3 the case of the WAF system, the largest possible loss would currently be the Aishihik line,
4 which connects 31.3 MW of capacity (30 MW from Aishihik, and 1.3 MW of Haines Junction
5 diesel).

6
7 This N-1 criteria on WAF equates to a current load carrying capability (non-industrial) of 55.7
8 MW (excluding Haines Junction load, as it would not need to be served from the Whitehorse
9 end of the Aishihik transmission line in the event that transmission line is out of service).

- 10
11 3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any
12 location with a load large enough to justify a diesel unit of about 1 MW or more should be
13 considered as a preferred location for new diesel units if that community does not already
14 have back-up from another source (e.g., having an existing diesel unit). The new diesel
15 units would provide grid support, and in times of line failures would provide local generation
16 for the communities where they are located.

17
18 For isolated diesel communities no change has been adopted for the capacity planning criteria.
19 Accordingly, the previous criteria is maintained for isolated diesel systems of being able to meet 110% of
20 the community peak with the largest unit out of service.

21 **3.3.5 Rationale for Adopting a Two-Part Criteria on WAF and MD**

22 The two-part capacity planning criteria adopted by Yukon Energy for the WAF and MD systems is
23 essentially the same as the capacity criteria approved by the regulator for the Yellowknife system⁵. This
24 approach ensures that two different concerns are addressed on an ongoing basis.

25
26 The LOLE criteria provide an overall system measure that assesses the normal balance of the system
27 including industrial loads, and the probabilities of experiencing outages due to having inadequate
28 generation (and transmission) installed on the system. For Yukon, a standard approximately comparable
29 to that used in Yellowknife (at about the lower end of planning standards used in southern jurisdictions in
30 Canada), was viewed as reasonable. The LOLE standard in effect indicates the probability that the
31 installed BES resources will be inadequate to supply the load for the total load on the system (including

⁵ The only exception is that the Yellowknife N-1 criteria (called "minimum diesel") is slightly more stringent, in that 105% of the forecast winter peak loads must be carried under the N-1 condition, not simply 100% of the forecast peak as adopted by Yukon Energy.

1 industrial). In effect, it measures the balance between generation and loads (under normal probabilities
2 of each system generating and key transmission units failing) and indicates how likely or unlikely it is that
3 the balance will be unable to be maintained. This part of the criteria ensures that system capacity is
4 planned on an ongoing basis to meet standards adopted and approved for other similar utilities in
5 Canada.

6
7 However, the severity of a potential outage for non-industrial customers is not accounted for in the LOLE
8 model. For example, despite an LOLE of two hours per year, it is entirely possible to have sustained
9 outages (due to generation and transmission inadequacy, primarily related to the Aishihik line which is
10 the largest single system constraint) for much longer than this under extreme winter conditions.

11
12 An emergency criteria was determined to be a necessary complement, given the potential seriousness of
13 a sustained outage of the critical component of the system in winter (e.g., the Yukon system peak occurs
14 in the coldest months of winter, when there is the least amount of sunlight to effect repairs such as to
15 transmission facilities). This is to address the “surviving the first failure” consideration noted above (the
16 N-1 test). YEC is incorporating this second level of testing into its capacity planning along with the LOLE
17 criteria already described. As an example, the current biggest single winter generator on the WAF system
18 is a single Aishihik wheel at 15 MW but the current biggest single potential loss of supply would be 30
19 MW following a failure on the Aishihik transmission line⁶.

20
21 The N-1 criteria will not be extended to major industrial customer loads who typically maintain sufficient
22 on-site diesel for their own emergency purposes (these customers would be informed that they would not
23 receive full supply should the Aishihik line be out-of-service during the coldest days of winter).

24
25 Yukon Energy considered the NWT approach of requiring the system to meet the N-1 condition to a full
26 105% of forecast peak loads (slightly more stringent than a strict N-1) as a “safety factor for load
27 forecast error”⁷. Given a WAF peak in 2005 of about 55.4 MW (excluding Haines Junction, which is not
28 part of the N-1 criteria as it is on the western end of the Aishihik transmission line), such a “reserve” on
29 WAF would equate to 2.8 MW. As the load today on WAF is only forecast to grow by about 1 MW per
30 year (about 1.85%) and diesel capacity can be added relatively quickly if new capacity is seen to be
31 required from unusual load growth, such a reserve for load forecast error was not considered necessary.

⁶ The WAF system would also lose access to the 1.3 MW of generation installed at Haines Junction, but would similarly lose the need to supply the Haines Junction load from remaining WAF capacity (Haines Junction would be supplied by its own diesels) so there would be no impact on WAF of this additional loss.

⁷ NWT Public Utilities Board Decision 14-2004, page 25.

1 The N-1 criteria will effectively govern the need for WAF system capacity requirements in the near term.
2 However, this may not always be the case. As an example, if the Aishihik line was to be twinned, the N-1
3 condition would then only exclude 15 MW (the second largest single contingency on the WAF system is a
4 loss of one Aishihik turbine) and it is likely that the LOLE condition would then govern the need for WAF
5 system capacity. In addition, the LOLE condition may drive the need for new generation in the event of
6 large new industrial loads, although these loads will have no impact on the N-1 criteria. It is important to
7 ensure that ongoing capacity planning therefore addresses both concerns identified in the adopted two-
8 part criteria approach.

9 **3.3.6 Implications of the Adopted Criteria**

10 The net effect of the new criteria adopted by Yukon Energy is a 2005 WAF system condition that is
11 basically at the limits for all retail/wholesale loads (with approximately 300 kW of surplus in 2005). In
12 short, any further wholesale or retail growth on WAF will be required to be met with new generation, as
13 well as all future WAF system diesel unit retirements (see *Table 3.5, WAF Peak and Capacity Surplus*
14 *(Shortfall) as Whitehorse Diesels are Retired (MW)*).

15
16 New capacity requirements of 18.7 MW are forecast for WAF for 2012 based on the adopted N-1 criteria
17 as compared with only 12.5 MW based on the adopted LOLE criteria of two hours per year. Consequently
18 the N-1 criteria has governed assessment today of new WAF capacity requirements. In contrast, the
19 previous WAF criteria would indicate that no new WAF capacity would be required until 2010, and by
20 2012 only 5.5 MW of new capacity would be needed. These forecasts are based on current estimates of
21 system load growth, excluding new industrial loads.

22
23 In contrast, MD generation under the new criteria adopted by Yukon Energy is well in excess of required
24 levels in the absence of new major industrial loads. The same criteria can be applied to the MD system as
25 capacity constraints arise on that system. However, at this point in time it is clear that MD is well below
26 two hours per year LOLE and satisfies an N-1 condition in all locations.

Table 3.5:
WAF Peak and Capacity Surplus (Shortfall)
as Whitehorse Diesels are Retired (MW)

Year	Retirements	Previous Criteria			LOLE Criteria			N- 1 Criteria		
		Peak (WAF wide, including loads served by Fish Lake)	Load Carrying Capability	Surplus/ (shortfall)	Peak (WAF wide, including loads served by Fish Lake)	Load Carrying Capability 2 hours/ year LOLE	Surplus/ (shortfall)	Peak excluding Haines Junction (assumed to be 1 MW)	N – 1 criteria load carrying capability	Surplus/ (shortfall)
2005		56.4	68.7	12.3	56.4	62.9	6.5	55.4	55.7	0.3
2006		57.4	68.7	11.3	57.4	62.9	5.5	56.4	55.7	(0.7)
2007	WD3	58.5	64.9	6.4	58.5	58.7	0.2	57.5	51.5	(6.0)
2008		59.6	64.9	5.4	59.6	58.7	(0.9)	58.6	51.5	(7.1)
2009	WD2	60.6	61.1	0.5	60.6	54.5	(6.1)	59.6	47.3	(12.3)
2010		61.7	61.1	(0.6)	61.7	54.5	(7.2)	60.7	47.3	(13.4)
2011	WD1	62.9	58.4	(4.4)	62.9	51.5	(11.4)	61.9	44.3	(17.6)
2012		64.0	58.4	(5.5)	64.0	51.5	(12.5)	63.0	44.3	(18.7)

As long as the WAF system with the current Aishihik line (i.e., no twinning of this line) can meet the wholesale/retail peak under the N-1 criteria, up to 6-7 MW of major industrial loads can be served without driving new generation investment for capacity reasons.

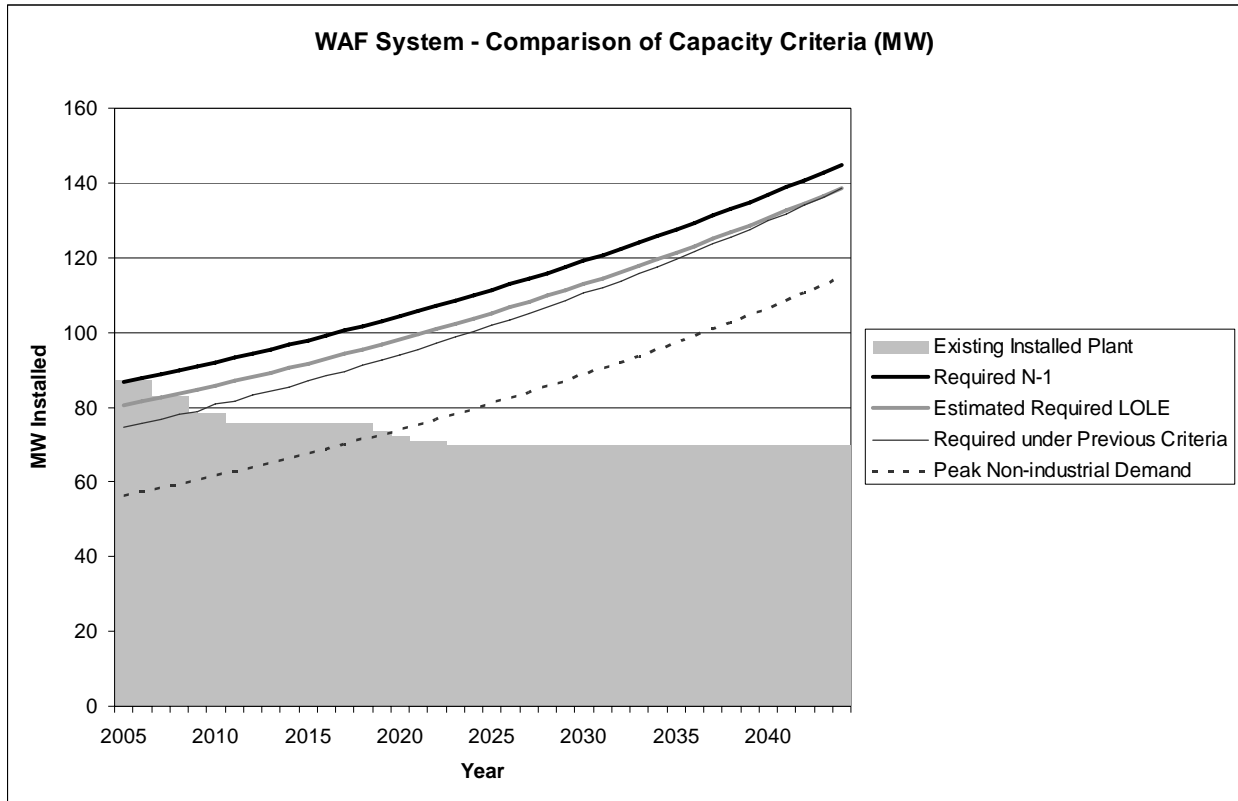
Adoption of the revised planning criteria was required to plan and develop infrastructure in Yukon. The new criteria indicate a need to have WAF generation additions occurring in the next 12-24 months. This may drive a requirement for capital investment in excess of \$3 million in the near-term.

Figure 3.1 WAF System – Comparison of Capacity Criteria depicts Yukon Energy’s need for new capacity through to 2045 under the N-1, LOLE, and previous criteria. Forecast WAF peak load (non-industrial) is depicted by the dashed line. Required capacity is shown based on the forecast peak load and the three different capacity planning criteria examined in Table 3.5 – this analysis assumes continuation of the current WAF systems without any new investment (such as twinning of the Aishihik line) to remove of the current Aishihik transmission line constraint. Forecast existing installed plant reflects retirement assumptions as noted in Figure 3.1. In effect, the analysis assumes that all new capacity requirements are met with diesel installed at Whitehorse.

Of note is that even under the existing capacity planning criteria, the planned retirement of the Mirrlees combined with expected load growth over the next five to six years will require new capacity to be installed on the WAF system. However, with adoption of the new criteria noted above, this requirement will lead to the need for new capacity to address all planned Mirrlees retirements plus basically all load growth from 2005 forward.

1
2
3

**Figure 3.1:
WAF System – Comparison of Capacity Criteria**



4

3.4 SUMMARY: REVISED CAPACITY PLANNING CRITERIA

The following revised capacity planning criteria have been adopted by Yukon Energy:

1. **WAF and MD System-wide capacity planning criteria:** Each system (WAF and MD) will be planned not to exceed a Loss of Load Expectation (or LOLE) of two hours per year.
2. **Emergency (or "N-1") WAF and MD system capacity planning criteria:** Each grid system (WAF and MD) will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related generation source.
3. **WAF and MD "community" criteria:** For communities on the WAF or MD grids, any location with a load large enough to justify a diesel unit of about 1 MW or more will be considered as a preferred location for new diesel units if that community does not already

18

1 have back-up from another source (e.g., having an existing diesel unit). The new diesel
2 units would provide grid support, and in times of line failures would provide local generation
3 for the communities where they are located.

4

5 For isolated diesel communities no change has been adopted for the capacity planning criteria (which
6 requires being able to meet 110% of the community peak with the largest unit out of service).

1 **4.0 NEAR TERM REQUIREMENTS**

2 “Near term” requirements address Yukon Energy generation and transmission commitments required
3 before 2009 for major investments with anticipated costs of \$3 million or more. Given the time needed
4 for possible construction, the assessment examines possible in-service needs to meet loads out to 2012.

5
6 This chapter focuses on opportunities for enhancements to existing hydro stations as well as cost-
7 effective resource supply alternatives capable of meeting the 15 to 27 MW of new capacity required
8 within the defined near term period. The sections for this chapter are as follows:

- 9 • Section 4.1: Planning Approach and Timeline
- 10 • Section 4.2: Requirements
- 11 • Section 4.3: Options
- 12 • Section 4.4: Assessment
- 13 • Section 4.5: Proposed Actions

14 **4.1 PLANNING APPROACH AND TIMELINE**

15 Potential major investments in the near term for new generation or transmission relate to opportunities to
16 enhance existing system assets, and to address WAF system capacity shortfalls. As reviewed in Section
17 4.2, the WAF shortfalls are forecast to be between 15 and 27 MW within the next five to six years. In
18 contrast, with material surplus hydro generation on both the WAF and MD systems, there is no apparent
19 near term requirement or opportunity for major new energy-related investments. There is a near term
20 opportunity to extend the WAF grid to supply two possible new mines in the Carmacks to Pelly Crossing
21 region using available surplus hydro generation (see *Section 4.2: Requirements*).

22
23 Near term opportunities in respect of existing hydro assets focus on both the Whitehorse and Aishihik
24 generating stations. In each case, the projects have been reviewed over many years in different
25 variations. These projects fit with similar initiatives in other jurisdictions such as BC Hydro’s “Resource
26 Smart” program focusing on means to provide additional energy or capacity “through physical or
27 operational modifications to existing facilities”, and similar Supply Side Enhancement programs at
28 Manitoba Hydro.

29
30 In respect of capacity requirements, as reviewed below capacity shortfalls on WAF under the new
31 capacity planning criteria begin to arise as soon as 2006, even before any Whitehorse diesel units are
32 retired, and become sufficiently material in 2007 to require overall spending commitments exceeding the

1 \$3 million level. Consequently, planning activities for the near term focus on supply options that are
2 sufficiently well-defined to make commitments and begin the necessary licencing or construction activities
3 by, at the latest, late 2006 to early 2007.

4
5 The planning approach for near term requirements follows the general planning approach set out in
6 Chapter 1:

- 7 1. **System capability** (part of Section 4.2: Requirements) over the intended “near term”
8 horizon (in this case, as explained above, to about 2012) is reviewed, particularly noting
9 planned retirement of generating capacity.
- 10 2. **System capacity requirements** (part of Section 4.2: Requirements) are reviewed over the
11 near term based on the new capacity planning criteria, focused on non-industrial load
12 forecasts plus potential loads from reasonably well-defined industrial load options that might
13 emerge in the near term; sensitivities are examined with regard to different possible load
14 forecasts.
- 15 3. **Forecast New Facilities Requirements** (part of Section 4.2: Requirements) are reviewed
16 over the near term based on system capacity requirements, opportunities to enhance existing
17 hydro generation facilities and, in the event loads are sufficiently high, opportunities to
18 displace diesel-based energy production.
- 19 4. **Resource Options** (Section 4.3: Options) are reviewed over the near term, focused on
20 potential resources of sufficient definition, size and timing for in-service to meet the near
21 term requirements for new facilities.
- 22 5. **Assessment of Resource Options** (Section 4.4: Assessment) are reviewed over the near
23 term, focused on technical feasibility (including timing), cost efficiency, reliability, and risk (in
24 particular, risks related to “markets” or future loads developing differently than indicated by
25 forecasts today).

26
27 Key considerations with respect to system capability are reviewed in Chapter 3. Over the focused near
28 term to about 2012, one key system capability issue relates in large part to the planned retirement of the
29 three Mirrlees engines:

- 30 • **WD1:** A Mirrlees KV12, installed in 1968, currently rated at 3.0 MW MCR (nameplate 3.92
31 MW) with a planned retirement in 2011;
- 32 • **WD2:** A Mirrlees KV16 from 1968, currently rated at 4.2 MW MCR (nameplate 5.15 MW),
33 with a planned retirement in 2009; and,
- 34 • **WD3:** A similar Mirrlees KV16 dating from 1970, currently rated at 4.2 MW MCR (nameplate
35 5.15 MW) with a planned retirement in 2007.

1 The three Mirrlees engines have been planned for retirement for many years, including as far back as the
2 1992 Resource Plan hearing (when they were planned to be retired in 1998, 1998 and 2000 respectively).
3 By 1996, the planned retirement of these units had been extended by four years to reflect in part lower
4 running hours during the 1993-1995 closure of the Faro mine, as well as maintaining their running hours
5 at a very low level by maintaining the units at the bottom of the stacking order.

6
7 With the 1998 closure of the Faro mine, Yukon Energy was able to further extend the planned
8 retirements to the current schedule (WD1 by 9 years, WD2 by 5 years and WD3 by 3 years) based on
9 updated assessment of the relative condition of each unit, and continued minimal operation.

10
11 However, at the present time, it is clear that further delay of retirement of these units is not possible
12 without material investment in major tear-down overhaul work. This is further confirmed by the BC Hydro
13 Condition Assessment (see Section 2.1) which concluded that these units were at "end-of-life". In
14 addition, the Mirrlees are low-speed base load units (514 RPM) which are poorly suited to the current
15 operating regime of stop-and-start operation. Finally, Yukon Energy and others who maintain Mirrlees
16 engines of this vintage (including Northwest Territories Power Corporation) have substantial concern with
17 the ongoing ability of the current owner of Mirrlees to provide ongoing parts and technical support.

18
19 Any further delay in planning for an orderly retirement or, if possible, major refurbishment of the Mirrlees
20 units will in all likelihood substantially increase the risks of a major failure or inability of these units to
21 supply reliable utility standard service when required.

22 **4.2 REQUIREMENTS**

23 Yukon requirements for new capacity or energy resources in the near term result from the combined
24 effects of three factors within each system:

- 25 • forecast non-industrial load growth, particularly on WAF related most notably to growth in
26 the Whitehorse area;
- 27 • potential opportunities to connect new major industrial mine loads, including via new
28 transmission to supply potential mines in the Carmacks to Stewart Crossing area; and,
- 29 • changes in the capability of existing generation or transmission resources, including changes
30 related to new capacity planning criteria and planned retirements.

31
32 As set out in detail in Section 4.3, there are only two material new near term resource supply
33 opportunities and/or requirements on Yukon systems:

- 1 1. New firm WAF capacity required, due to WAF winter peak capacity exceeding the maximum
2 loads allowed on the system under new capacity criteria (however, this system has no need
3 for new firm energy capability due to ongoing surplus hydro energy generation of over 90
4 GW.h/yr, with about 21 GW.h/yr of this surplus being currently used to supply interruptible
5 secondary sales).
- 6 2. Opportunities to enhance existing WAF hydro generating assets to increase energy and/or
7 capacity outputs.

8
9 The MD system has surplus hydro energy generation of about 17 GW.h per year, and surplus winter peak
10 capacity with existing hydro and diesel generation. Consequently, as reviewed in Section 3.3, the LOLE
11 for the MD system is not likely to exceed 2.0 hrs per year for many years into the future, absent major
12 new industrial loads on this system. The MD system also satisfies the N-1 capacity criteria at each end of
13 the MD transmission line as well as at the community of Stewart Crossing.

14
15 With respect to WAF requirements, four near term load cases have been identified, and are set out in the
16 following sections. Each section includes graphs depicting the capacity and energy requirements under
17 each scenario as follows:

- 18 • **Forecast WAF generation capacity:** The MW capacity requirement at winter peak is
19 indicated, showing separately the capacity to meet N-1 Requirement and the LOLE
20 Requirement, as well as the projected winter peak generation load. The graphs also
21 illustrate the capability to meet this requirement from existing capacity, net of scheduled
22 retirements, and the forecast need for new required capacity. For the purposes of illustrating
23 requirements, the new capacity is portrayed in these “requirements” graphs based on a
24 consistent assumption that requirements will be met by new 4 MW diesel units.
- 25 • **Forecast WAF generation energy:** The MW.h per year from existing hydro and from
26 diesel are indicated separately. The energy graphs also show any surplus supplied as
27 Secondary interruptible energy up to the forecast maximum Secondary Load expected
28 (maximum of 30 GW.h per year). The forecasts show the generation expected to occur, and
29 therefore these graphs do not show the full surplus hydro energy generation capability
30 (which in many cases materially exceeds forecast Secondary sales).

31 **4.2.1 Basis for Non-Industrial Load Forecasts**

32 Yukon Energy’s near term non-industrial load forecasts for WAF are shown in Table 4.1, and are reviewed
33 in more detail below.

**Table 4.1:
Near Term Non-Industrial Load Forecasts**

Load Forecasts				
Population Increase	Source	Increase in Use/Customer	Combined Percentage Increase	Sensitivity
0.4%	Yukon Bureau of Statistics: Medium Growth Projection	0.5%	0.9%	Low
1.0%	City of Whitehorse Population Increase (4 year average)	0.5%	1.5%	Medium-Low
	Mid-point		1.85%	Medium
	Yukon Energy's 3-Year Average Recorded Increase in Consumption		2.2%	Medium-High
	Yukon Energy's Highest Annual Recorded Increase in Consumption		3.0%	High

Yukon Energy's long-term non-industrial load forecast is based on a review of sales over past periods (as far back as 1992 in some cases, but focused on the period since 1998 when the Faro mine last closed), readily available information on the Yukon economy and other relevant statistics, and in some cases review of load forecasting variables used by other Canadian utilities.

The Yukon landscape is such that forecasting long-term non-industrial loads with precision is considerably more difficult than in southern jurisdictions. Although electricity consumption in many cases follows trends typical of other places in Canada, the Yukon economy can be substantively impacted by single events that, in most cases, cannot be foreseen with any accuracy more than a very short period in advance of the event (this short period can be one to two years or less). Examples include the opening and closing of large resource projects, such as mines, and major changes to Government of Canada funding to the Yukon Government.

Since the 1992 Resource Plan, the most material change in the Yukon electricity load forecast landscape has been the closure of the Faro mine (previously 40% of Yukon's load). Not only did the closure reduce industrial loads by nearly 200 GW.h a year, but it also dramatically reduced the loads in communities local to the mine (such as Faro, which reduced from an average residential customer count of 478 in 1996 to an average of 189 in 2001) and also major centers such as Whitehorse (Yukon Energy wholesales to YECL declined from 232 GW.h in 1996 to 217 GW.h in 2001).

1 The 1998 Faro mine closure impacts appear to have been largely incorporated into the Yukon economy
2 and population by 2001. During this 1998-2001 period, out-migration of about 10% of the Yukon's
3 population occurred (over 3,000 people).

4
5 Since 2001, the Yukon's economy and electricity loads have begun to develop a more normalized pattern.
6 This is most evident in YECL's native load (Yukon Energy's wholesales to YECL plus YECL's own WAF Fish
7 Lake generation added back) which has been characterized by growth of about 2.2% per year (three
8 year average from 2001-2004) with one year growth as high as 3% in 2004. As a normal level of growth
9 in the major load centers in Yukon, this three year average growth rate is likely within a reasonable range
10 of forecasts for the near term period in question. This reflects three factors:

- 11 1. **Population growth:** Population in the major load center of Whitehorse has been recently
12 increasing by approximately 1% per year reflecting fertility and mortality rates, net in-
13 migration to Yukon and net in-migration to Whitehorse from other places in Yukon (both of
14 these net in-migration trends have been positive since 2001). From 2001 to 2004 the
15 resulting Whitehorse growth rate was in excess of 1% per year. Growth in customer numbers
16 is expected to be at about this same level if not slightly higher due to reduced average
17 number of persons per household, reflecting normal Canadian trends.
- 18 2. **Use per residential customer:** Use per customer for residential customers is assumed to
19 be increasing at about 0.5% per year. Changes in use per customer are typically small over
20 time, with Canadian utilities typically forecasting similar uptrends over the next 20 years for
21 non-heating loads. This uptrend reflects in part increased use of certain appliances (such as
22 internet connected computers and other electronic devices) offset by modest efficiency
23 improvements in certain appliance sectors (for example, fridges are now far more efficient
24 than in past years, but the stock of fridges typically changes quite slowly so is only a modest
25 incremental change each year).
- 26 3. **Use per commercial customer:** Use per customer for commercial customers is not
27 expected to vary materially from trends seen for residential customers, although growth may
28 be slightly higher reflecting the trend towards larger stores and facilities (such as the Argus
29 properties).

30
31 Based on the above assessment, Yukon Energy has based long-term load forecasts on a **base case** of
32 1.5% (medium-low) to 2.2% (medium-high) growth per year with 1.85% growth per year as the mid-
33 point. In order to ensure the impacts of potential extreme outcomes with respect to non-industrial loads
34 are considered, load forecast uncertainty to a range of 3.0% annual growth (High Sensitivity) and 0.9%

1 annual growth (Low Sensitivity) have been considered where these extremes have the potential to
2 materially change the recommendations for major new investments in power resources.

- 3 • The **high sensitivity** of 3.0% per year is based on the highest one year wholesale sales
4 growth rate experienced by YEC (2004). This was a period of very high growth, but given
5 that it is the very recent experience, it is necessary to consider the potential that this rate is
6 representative of a major new evolution with respect to Yukon electrical load.
- 7 • The **low sensitivity** of 0.9% per year based on a very nominal growth which is the
8 combination of strictly the growth in use per customer plus the Yukon Bureau of Statistics
9 population forecast growth assuming no in-migration (0.4%). This is consistent with the
10 Yukon experience of not having had any periods of sustained zero to negative growth in the
11 non-industrial system (and reflecting the fact that today's loads are not predicated on any
12 downside risks related to underlying industrial projects, as no major industrial customers are
13 currently receiving service in Yukon).

14 **4.2.2 Basis for Near Term Industrial Load Forecasts**

15 In order to address the current expectation that two new industrial loads may proceed in the area north
16 of Carmacks, two industrial load cases have been included in the near term analysis (a range of other still
17 more optimistic industrial development scenarios are examined separately in Chapter 5):

- 18 1. **No new industrial load**, and
- 19 2. **Industrial loads consistent with Minto and Carmacks Copper both being**
20 **developed in the near term**, or about 9-11 MW of new load (2-4 MW for Minto plus 7 MW
21 for Carmacks Copper) and 64 GW.h of annual energy. These mine projects are not expected
22 to be long-lived, at 12 years for Minto starting 2007 and 8.5 years for Carmacks Copper
23 starting 2008 (although these starting dates may be delayed by other processes and
24 development timelines).

25 **4.2.3 Near Term WAF Load – Cases Analyzed Based on Non-Industrial and Industrial** 26 **Requirements**

27 Based on the above near term non-industrial and industrial load forecasts, four near term WAF load cases
28 have been considered:

- 29 1. **Base Case:** The Base Case near term assumptions are based on non-industrial loads at the
30 mid-point base case level (1.85% per year) and no new industrial loads.
- 31 2. **Low Sensitivity Case:** This case maintains non-industrial loads at the low sensitivity level
32 (0.9% growth) and no new industrial loads.

1 3. **Base Case including Mines:** This case combines the Base Case assumption for non-
2 industrial (1.85% growth) plus near term development of the Minto and Carmacks Copper
3 loads at a combined 9 MW.

4 4. **High Sensitivity Case, including Mines:** As the largest near term growth scenario, this
5 case combines the high sensitivity non-industrial load growth (3.0%) with near term
6 development of the Minto and Carmacks Copper loads.

7 **4.2.4 Base Case Requirements**

8 Under the Base Case, forecast loads exclude any major industrial customers. Non-industrial load growth
9 is projected at 1.85% per year.

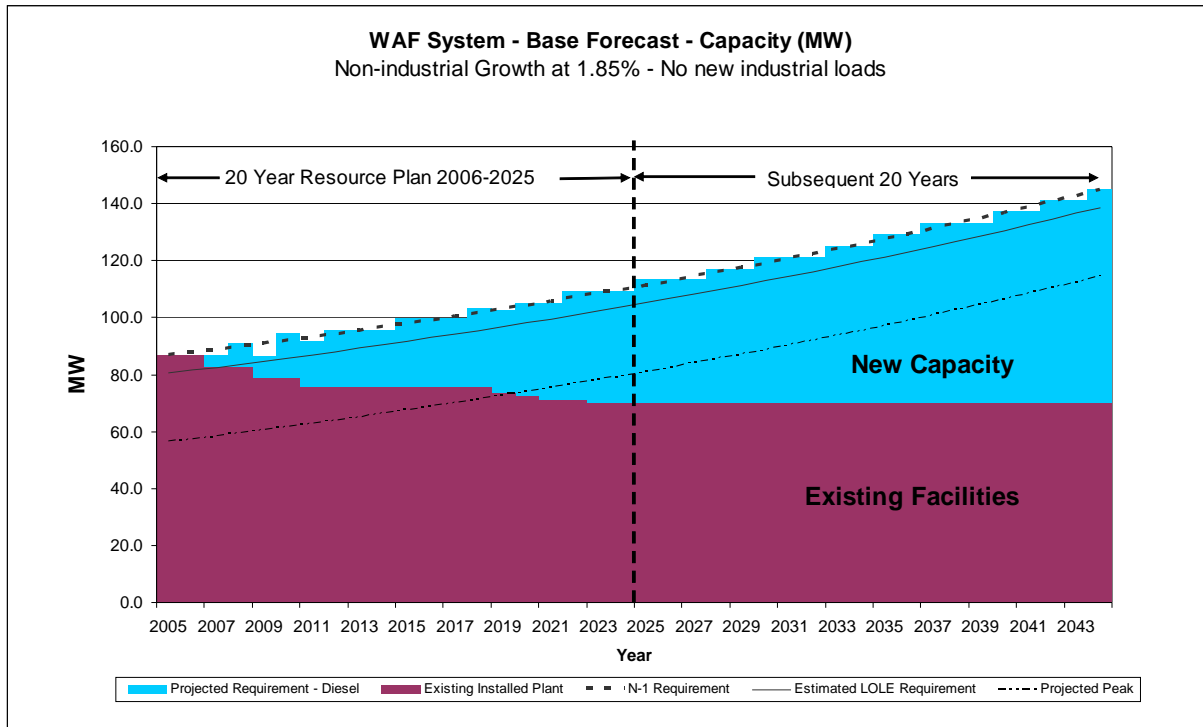
10
11 **Capacity:** Under the Base Case, there is a 0.7 MW capacity shortfall forecast for 2006, increasing to 18.7
12 MW by 2012 assuming that all three Mirrlees units (11.4 MW) have been retired by that time¹.

13
14 Figure 4.1 provides a 40 year horizon (20 years of Resource Plan plus the 20 subsequent years) and
15 indicates the capability of the existing facilities with planned retirements as well as the requirement for
16 new facilities to meet the proposed new planning criteria (LOLE and N-1, indicated by solid and dotted
17 lines respectively). In this figure, five new 4 MW diesel generation units (or equivalent 20 MW) are
18 assumed to be installed to meet the capacity shortfalls to 2012.

¹ Note that under the previous capacity criteria, the capacity shortfall in 2012 is 5.5 MW as noted in Section 3.3, and is entirely driven by the retirement of the 11.4 MW of current Mirrlees capacity.

1
 2

Figure 4.1:
WAF Base Case Capacity Requirements



3

4 **Energy:** The Base Case analysis as reviewed in Figure 4.2 indicates that diesel generation is not required
 5 to supply sustained loads (e.g., loads in excess of average annual hydro energy generation) until at
 6 earliest the end of the 20 year forecast planning period. Some diesel generation is required for peaking
 7 purposes (i.e., brief time periods during the winter peak months), but these peaking diesel generation
 8 requirements remain below 10 GW.h per year until after 2020 (i.e., near the end of the 20-year planning
 9 period), increasing to about 28 GW.h/year in 2025. Figure 4.2 also indicates the potential energy
 10 available for supplying secondary power up to the expected maximum annual program subscription of 30
 11 GW.h/year².

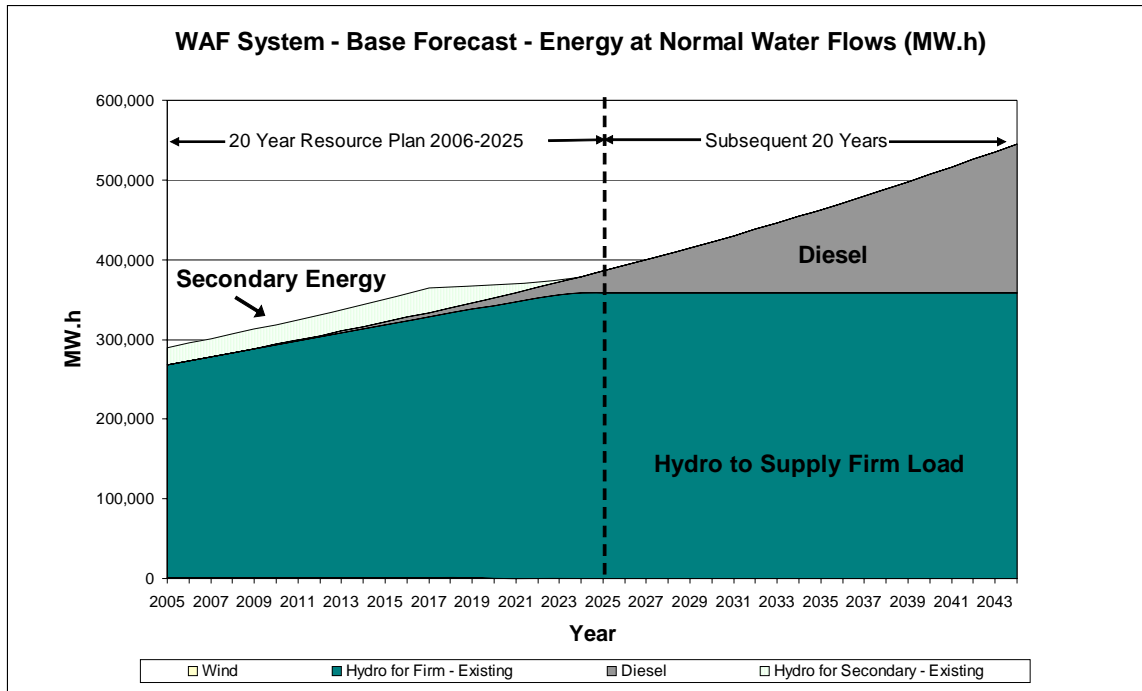
12

13 In summary, there is no opportunity under the Base Case near term forecast to develop new non-diesel
 14 generation to displace diesel fuel until near the end of the 20 year planning horizon.

² The analysis does not attempt to determine the secondary energy demanded that would go unserved due to short-term winter interruptions during periods of peaking diesel, i.e., the analysis determines only the annual impacts on energy available to service secondary loads. In reality, actual secondary sales would experience greater short term interruption as load growth increases the periods of peaking diesel operation during each year.

1
 2

Figure 4.2:
 WAF Base Case System Energy Requirements



3

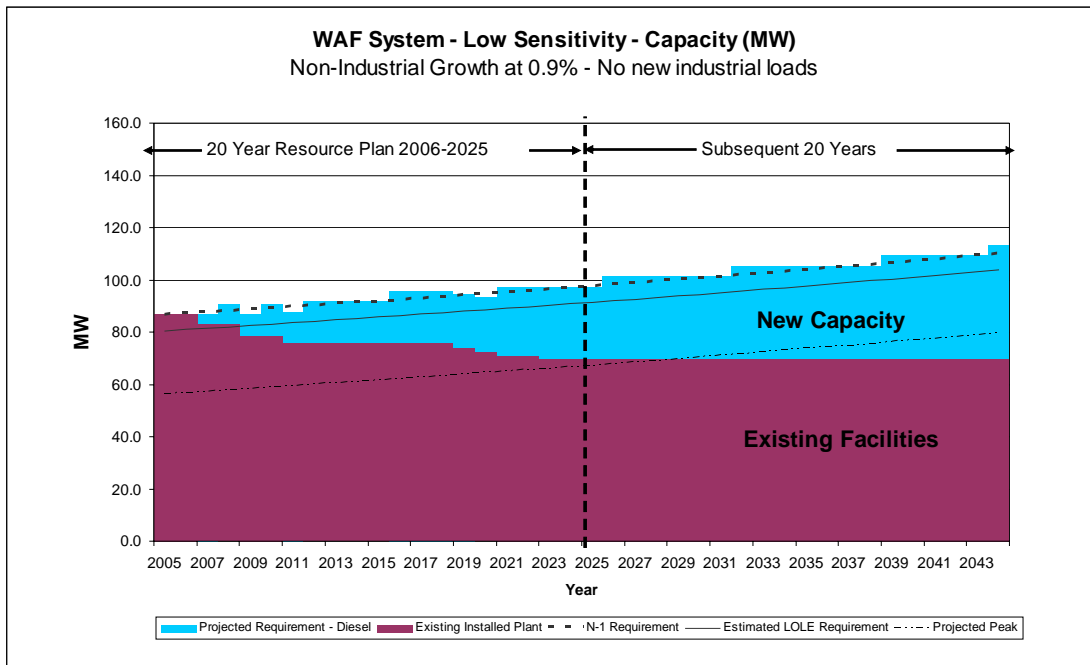
4 4.2.5 Low Sensitivity Case

5 The Low Sensitivity Case is based on non-industrial load growing at 0.9%/year and no new industrial
 6 loads.

7

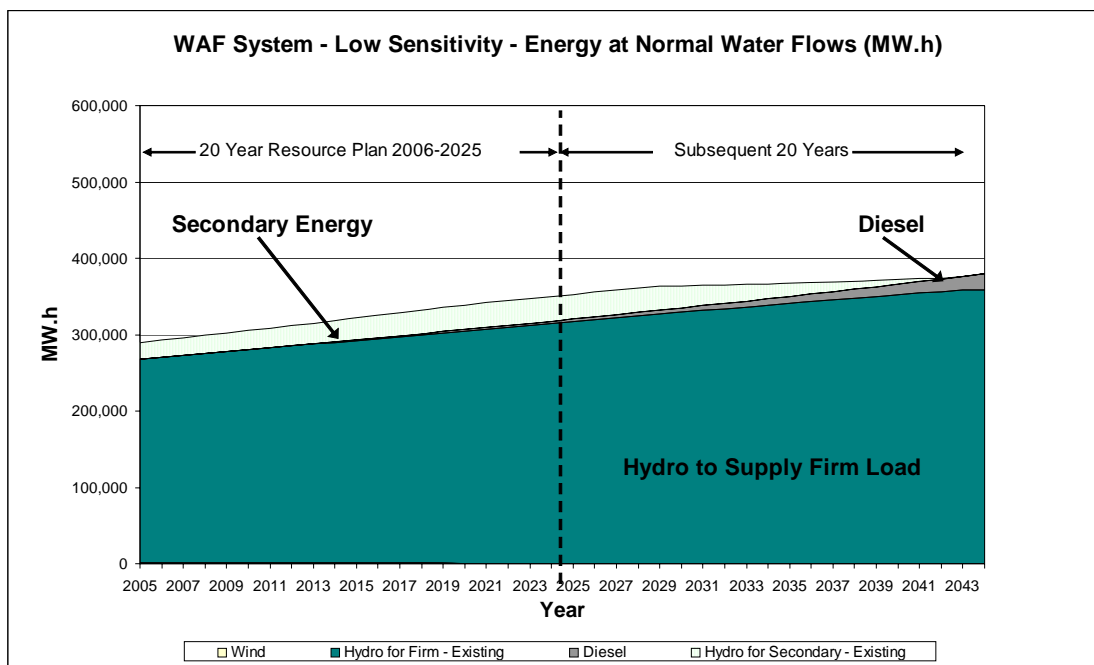
8 **Capacity:** Under this case, as reviewed in Figure 4.3, capacity shortfalls occur in 2006 of 0.2 MW with
 9 growing requirements thereafter driven primarily by retirement of diesel units (11.4 MW of retirements by
 10 2011). The Low Sensitivity Case forecast indicates 14.7 MW of capacity shortfall by 2012. Figure 4.3
 11 identifies a requirement by 2012 of four new 4 MW diesel units (16 MW).

Figure 4.3:
WAF Low Sensitivity Case Capacity Requirements



Energy: Under the Low Sensitivity Case (see Figure 4.4), as with the Base Case, there is no requirement for material diesel generation in the 20 year planning horizon.

Figure 4.4:
WAF Low Sensitivity Energy Requirements

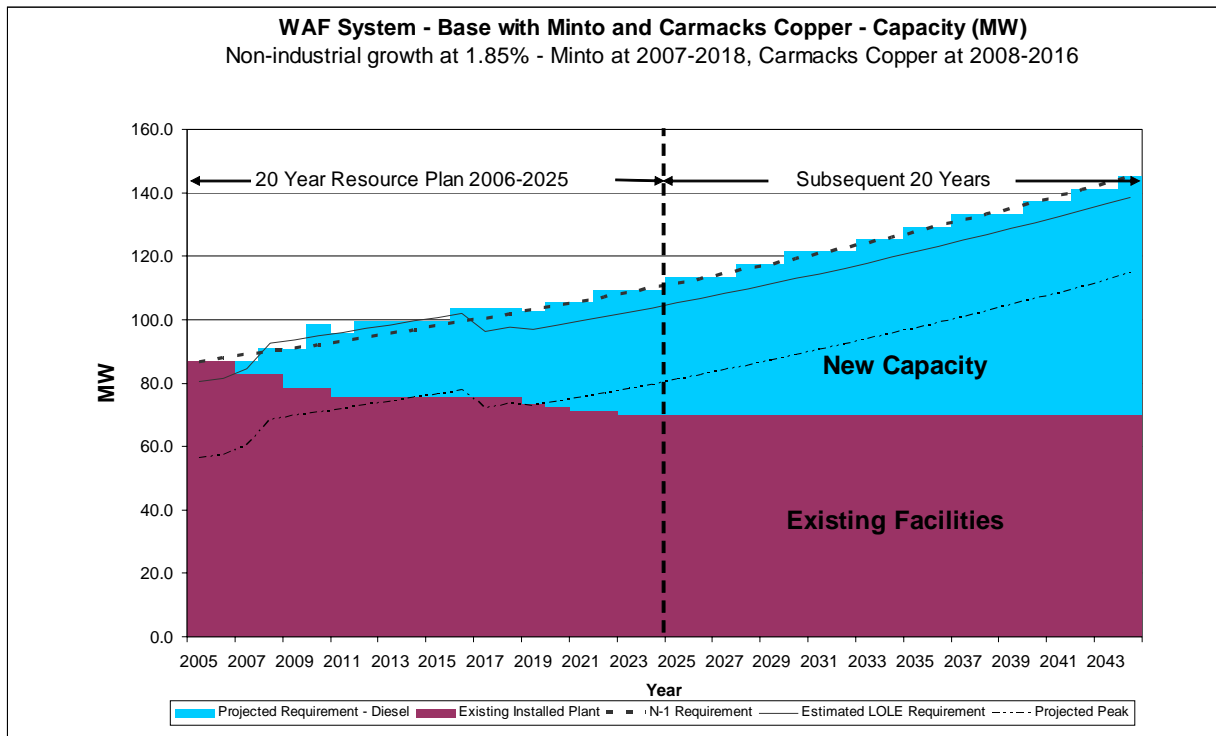


1 **4.2.6 Base Case with Mine Loads**

2 The Base Case with Minto and Carmacks Copper Mine loads includes the same non-industrial load growth
3 of 1.85% from the Base Case, plus an assumed near term connection of the Minto and Carmacks Copper
4 new mine loads to the WAF grid. This case presumes near term development of new transmission from
5 Carmacks to at least about Pelly Crossing with spurs to connect these two new mines.

6
7 **Capacity:** Under this case, capacity shortfalls of 0.7 MW arise in 2006, growing to 21.5 MW by 2012 (in
8 this case driven by the LOLE criteria instead of the N-1 criteria which drove capacity shortfalls for the
9 Base and Low sensitivity cases)³. The capacity shortfall is illustrated in Figure 4.5 below as six new 4 MW
10 diesel units (24 MW) assumed by 2012.

11 **Figure 4.5:**
12 **WAF Base Case with Mine Capacity Requirements**

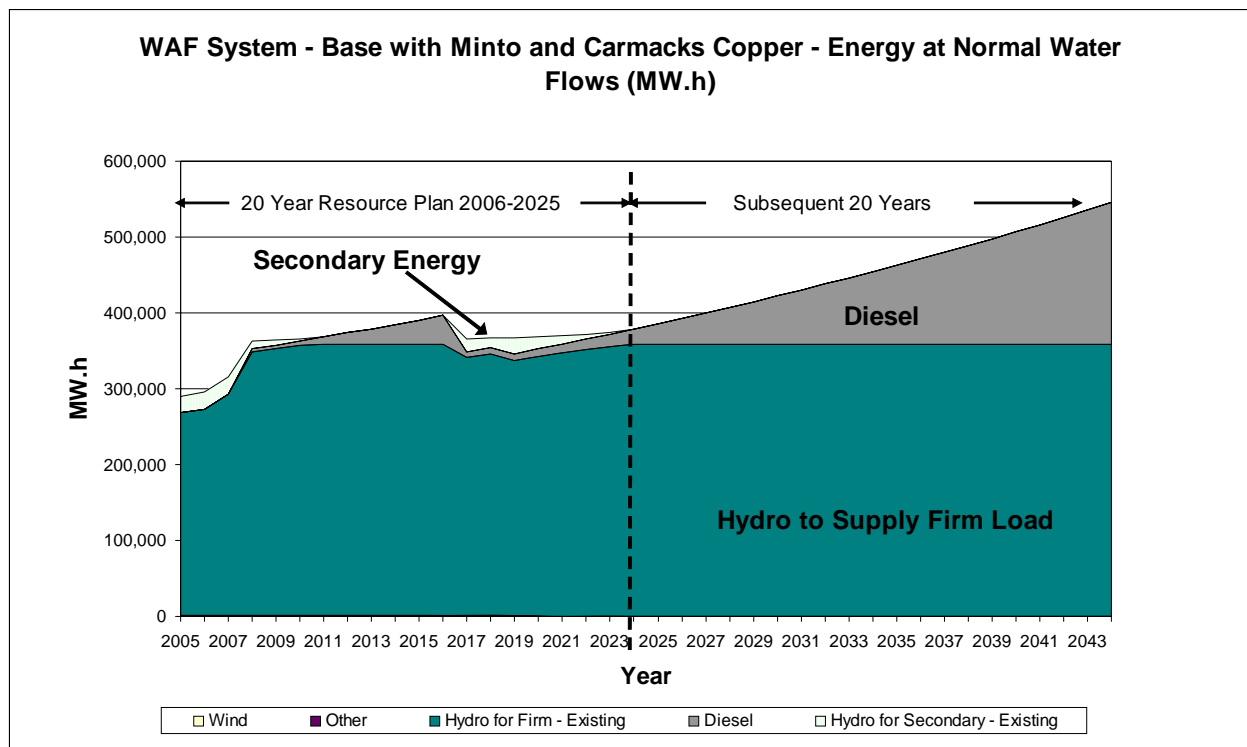


³ The combined mine loads in this scenario total 9 MW. Mine loads do not contribute towards peak loads for N-1 calculations but do contribute for LOLE (see Section 3.3). Under Base Case load scenarios, N-1 is requiring additions of capacity approximately 6.2 MW ahead of LOLE requirements. For this reason, the first 6.2 MW of industrial load do not drive any additional capacity requirements over and above the basic base load requirements. The result in this case with the added 9 MW of industrial load is an increase in capacity required compared to the Base Case (in order to serve the two mines) of only 2.8 MW (9 MW total load less 6.2 MW that can be served without additional capacity).

1 **Energy:** Under this scenario, as reviewed in Figure 4.6, the incremental mine load consumes largely
 2 hydro energy that would otherwise be surplus under the Base Case. However, with ongoing non-
 3 industrial load growth during the life of the mines, the WAF system begins to utilize diesel of up to about
 4 40 GW.h per year for modest base load generation (reflects WAF system hydro capability of about 358
 5 GW.h in a normal water year, with system energy requirements approaching 400 GW.h in about 2016 at
 6 the highest levels before mine closure). After the mine closures as assumed in this case, however, there
 7 would be a period of about seven years when excess hydro would return to the WAF system (along with
 8 the opportunity to make secondary sales) before normal non-industrial load growth would eliminate the
 9 hydro surplus (in 2024) and begin to drive new base load diesel requirements (beyond the current 20
 10 year Resource Planning horizon). Although this load pattern may give rise to the opportunity to consider
 11 very small hydro or other low variable cost generation within the 20 year horizon (perhaps up to a 2-3
 12 MW), the scale of any such generation would not materially affect the large capacity requirements (21.5
 13 MW) beginning in the very near term.

14
 15

**Figure 4.6:
 WAF Base Case with Mine Energy Requirements**



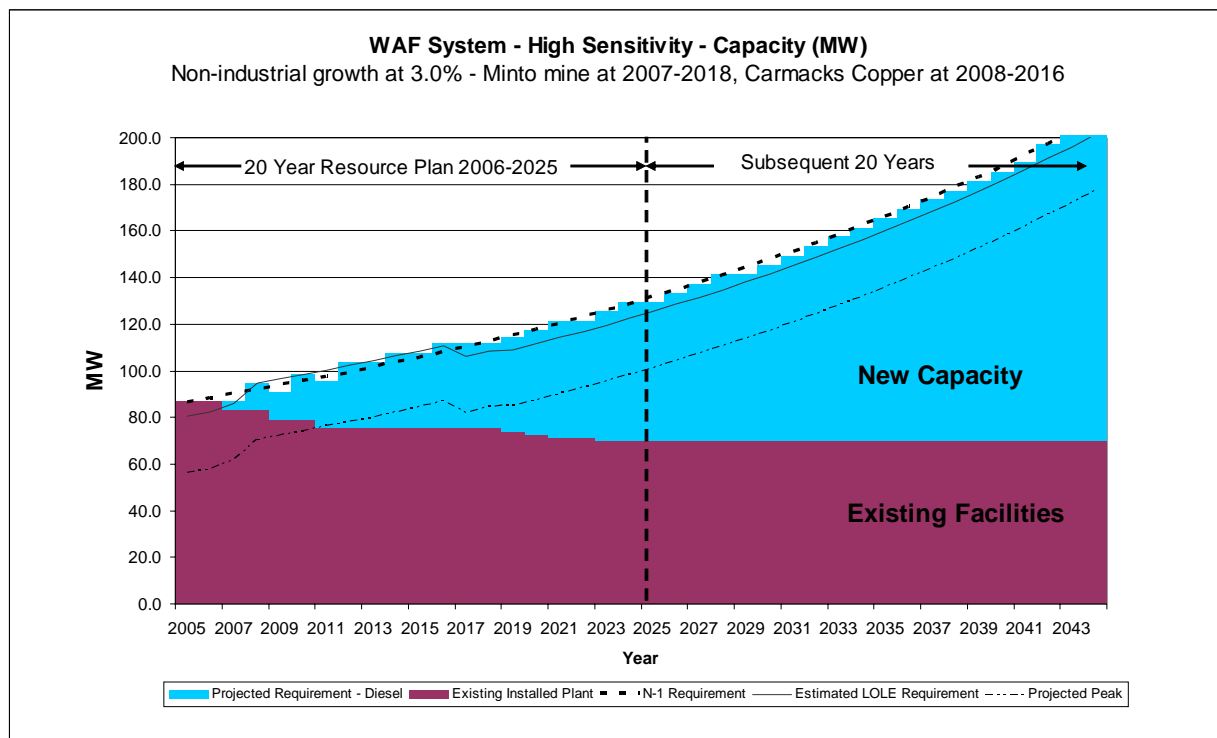
16

1 **4.2.7 High Sensitivity Case Including Mines**

2 In the High Sensitivity Case, the non-industrial load growth is forecast at 3.0% per year plus near term
3 addition of the Minto and Carmacks Copper mine loads (which presumes near term development of new
4 transmission from Carmacks to at least about Pelly Crossing with spurs to connect these two mines).

5
6 **Capacity:** Under this case, as reviewed in Figure 4.7, there would be material increases in the required
7 installed capacity to meet the loads, assuming that the new capacity criteria are adopted. Capacity
8 shortfalls in 2006 are at 1.4 MW, and by 2012 are at 26.7 MW (indicating the need in Figure 4.7 for an
9 assumed seven new 4 MW diesel units, or 28 MW)⁴.

10 **Figure 4.7:**
11 **WAF High Sensitivity Case with Mines Capacity Requirements**

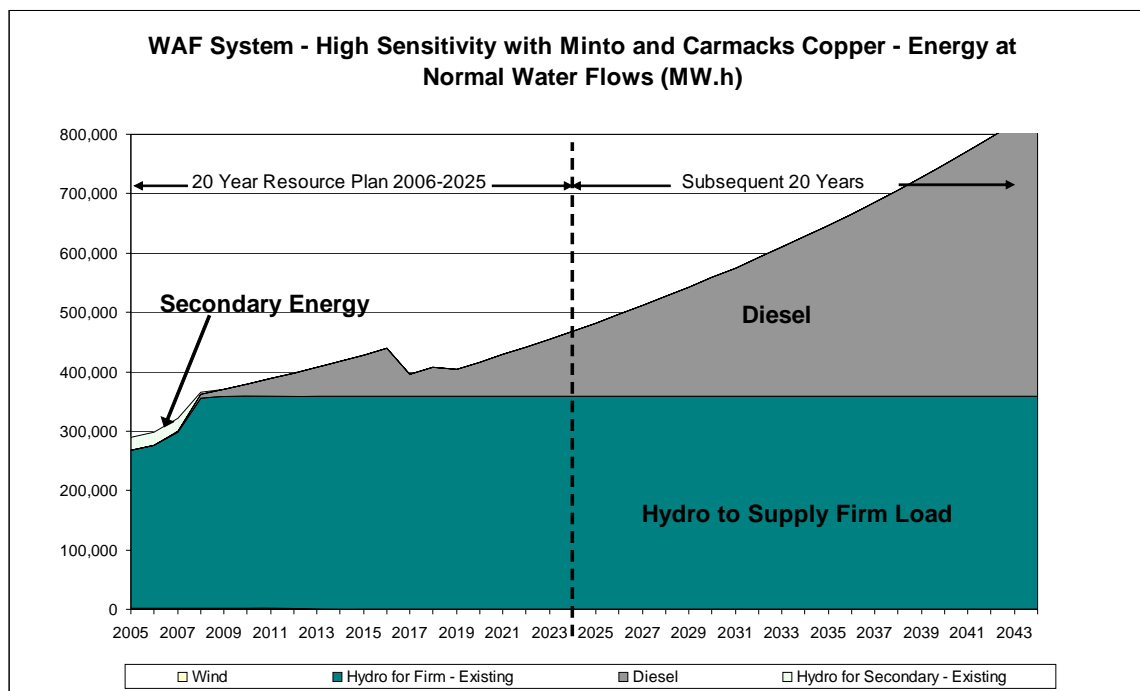


12
13 **Energy:** If the WAF system were to experience material sustained ongoing growth at the 3% level year
14 over year, as well as the near term opening of both the Minto and Carmacks Copper mines as assumed in
15 this high sensitivity case, the system will begin to experience base load diesel generation needs beginning

⁴ Without the two mines, the High Sensitivity Case capacity shortfall in 2012 is 24.1 MW.

1 in 2009⁵. This may present near term opportunities to examine new non-diesel (e.g., hydro) generation.
 2 However, on a sustained long-term basis as reviewed in Figure 4.8, the requirement for new generation
 3 such as hydro after the mines close as assumed in this case is only in the range of about 50 GW.h per
 4 year (due largely to load reductions upon the closure of the mines)⁶. This scale of generation is
 5 consistent with hydro sites of about 8 MW. Consequently, even if new baseload energy projects are
 6 enabled by this major load growth, they will not be of sufficient size to address the very material (27
 7 MW) new capacity requirements indicated under this scenario by 2012.

8 **Figure 4.8:**
 9 **WAF High Sensitivity Case with Mines Energy Requirements**



10
 11 Yukon Energy will also not likely be able to provide commitments to develop such capital intensive energy
 12 projects within the near term timeframes where capacity shortfalls begin to arise on the WAF system.
 13 This is because it would take a number of years to see loads develop at this high annual growth rate, as
 14 well as greater certainty with respect to mine loads, before capital intensive projects of this type would
 15 be suitable to consider. In addition, following appropriate commitments, hydro projects also typically
 16 require several years to plan, licence, design and construct.

⁵ Without the two mines, the High Sensitivity Case will begin to experience base load diesel generation only in 2017 (when no surplus hydro for secondary sales).

⁶ If 3% per year growth in non-industrial loads is sustained, as assumed in this case, diesel energy requirements grow to 124 GW.h by 2025.

1 **4.3 OPTIONS**

2 Based on the above requirements, three broad categories of project resource options are noted for the
3 period prior to 2012:

4 1. **Opportunities projects to enhance existing facility energy and/or capacity output**
5 or to allow better use of existing capabilities to ensure Yukon Energy has maximized the
6 potential from past investments in major generating facilities. There are three well-defined
7 near term project options in this regard:

8 a) **Aishihik 3rd Turbine project:** Facility enhancements at Aishihik via a third turbine of 7
9 MW costing over \$3 million to allow better ability to use the existing plant to meet peak
10 loads, as well as more efficient use of water when operating at low outputs.

11 b) **Marsh Lake Fall/Winter Storage project:** Improved water management at
12 Whitehorse via changes to the water licence for upstream storage not costing over \$3
13 million, in order to allow reduced discharge of water during the fall months to enhance
14 the ability to store water for winter.

15 c) **Carmacks to Stewart Transmission project:** The opportunity to use Government of
16 Yukon infrastructure funding to develop new transmission costing over \$3 million to
17 interconnect the WAF and MD systems, including opportunities to connect to the WAF
18 two potential new mines north of Carmacks.

19
20 2. **Major capacity-related replacement and/or expansion projects** costing \$3 million or
21 more to address substantial impending and unavoidable capacity shortfalls on WAF
22 (approaching 15 MW to 27 MW by 2012) requiring new generation and/or transmission to
23 ensure sufficient firm capacity to supply forecast peak loads. As noted in Section 3.3, this
24 shortfall is driven in large part by exposure to Aishihik transmission line outages. Two main
25 concepts are explored in this regard:

26 a) **Maintain/Replace/Expand Whitehorse Diesel projects:** One concept seeks to
27 reduce exposure to the transmission line weaknesses through reducing the potential
28 *impact* of transmission line outages, focused on maintaining existing diesel (a major Life
29 Extension project on the Mirrlees units), or installing new diesel generation on the WAF
30 grid not dependent on the Aishihik transmission line (a major Whitehorse Diesel
31 Replacement and Expansion project).

32 b) **Aishihik 2nd Transmission Line project:** Alternatively, the Aishihik 2nd Transmission
33 Line Project concept seeks to reduce exposure to weaknesses through reducing the
34 potential *incidence and duration* of transmission line outages through developing
35 redundancy in the Aishihik transmission connection.

1 3. **Smaller supplemental projects** that may contribute towards meeting WAF supply
2 requirements, but are either not currently defined or not currently expected to cost at least
3 \$3 million, and do not independently offer sufficient capacity to play a major role in satisfying
4 the near term capacity shortfall requirements. Yukon Energy continues to evaluate
5 supplemental projects in the near term and on an ongoing basis, but the main near term
6 focus is on system enhancement opportunities and major replacement and/or expansion
7 projects that will be required based on the new capacity planning criteria.

8 Studies are ongoing with regard to each of the above major near term options. The Submission provides
9 a screening of projects based on current information (as summarized below), setting out the conditions
10 and requirements relevant to proceeding with each specific option as well as initial cost estimates
11 currently available for each option (which, aside from opportunity projects, remain preliminary and
12 subject to ongoing adjustment and refinement). Updates will be provided during the review of the
13 Submission to the extent that relevant new information is forthcoming for the ongoing studies of these
14 projects.

15 **4.3.1 Overview of “Opportunity” Project Options**

16 The implementation of supply side enhancement or Resource Smart projects reflects a sensible and
17 prudent approach to maximizing the value of existing resources. Such projects are routine in other
18 jurisdictions in Canada, and often offer the lowest cost sources of supply available (although the scale
19 can be modest in some cases).

20
21 Opportunities to put in place enhanced system assets can also be enabled by new loads or external
22 funding to offset capital costs so as to put no burden on ratepayers.

23
24 Yukon Energy has focused on three major opportunity projects in the near term:

- 25 • **Aishihik 3rd Turbine Project (7 MW; 5.4 GW.h/year):** Up to 7 MW of capacity could be
26 added to the existing Aishihik hydro plant through addition of a third turbine. This potential
27 project was reviewed in the 1992 Resource Plan hearing as a potential 5 MW unit, and
28 pursuant to YUB recommendations from that proceeding⁷, Yukon Energy pursued and
29 received environmental approvals for the unit in the new Aishihik Water Licence of up to 7
30 MW. The third turbine would yield an increase in long-term average hydro energy supply
31 from Aishihik of up to 5.4 GW.h/yr (if load conditions on the system are sufficiently high) but

⁷ The YUB recommended that Yukon Energy pursue a licence for “the maximum capacity that is economically, technically and environmentally feasible”.

1 in certain conditions prior to high WAF load conditions can allow displacement of diesel
2 generation in excess of this level due to the ability to allow added Aishihik generation at the
3 time of system winter peak (see Section 4.3.8). The 3rd turbine by itself is of no reliable peak
4 capacity value whatsoever under the N-1 criteria as it is subject to the same Aishihik
5 transmission line constraints as the existing units (unless an Aishihik 2nd Transmission Line
6 project is in-service) and is similarly of limited reliable peak capacity value (0.6 MW) under
7 LOLE criteria. Current investigations are updating capital costs and planning for this project.

- 8 • **Marsh Lake Fall/Winter Storage Project (about 1.6 MW; 7.7 GW.h/year):** There is
9 the potential with a Marsh Lake Fall/Winter Storage project to increase the firm winter
10 capacity of the Whitehorse Rapids hydro facility by about 1.6 MW and to increase its long-
11 term average hydro energy by about 7.7 GW.h/yr (actual enhancement depends on load
12 conditions assumed). The project involves seeking changes to the Whitehorse Rapids water
13 licence to allow Yukon Energy to reduce the amount of water it releases from Marsh Lake in
14 non-flood years from August 15 to the end of September, to allow that water to be used
15 instead during the peak winter generation period (during flood years, no change would be
16 made during August and September, until after flood levels subside). In all cases, the water
17 levels would remain within the lake level limits currently experienced (i.e., the peak
18 controlled level would be below the natural high water levels experienced in the lake).
19 Basically no new physical works are expected to be required for this project⁸.

- 20
21 • **Carmacks-Stewart Transmission Line Project (about 6 MW; 15 GW.h/year,**
22 **decreasing with time as MD load grows, plus opportunity to connect up to 2 new**
23 **mines):** Yukon Energy is currently using Yukon Government Infrastructure Funding to carry
24 out initial planning and permitting for this project; development of this project at this time is
25 contingent on commitment of the necessary Yukon Government Infrastructure Funding as
26 needed to ensure no adverse impacts on Yukon ratepayers. The development from Carmacks
27 to at least Pelly Crossing would provide the basis to supply potential mine loads at Minto and
28 Carmacks Copper with WAF surplus hydro energy. Development beyond Pelly Crossing to
29 Stewart Crossing would interconnect the WAF and MD grids, thereby accessing surplus MD
30 capacity for WAF in the near term. The full project with interconnection of the two grids
31 would provide about 6 MW and 15 GW.h/yr of hydro energy to WAF, with this contribution
32 decreasing as the MD load grows.

⁸ This project concept would increase the licensed full supply level by 0.3 meters. The lake would not experience water levels higher than are currently experienced. No environmental studies on this specific project concept have been completed to date.

1 **4.3.2 Aishihik 3rd Turbine**

2 The Aishihik 3rd turbine project (current capital cost forecast of \$7 million for 7 MW⁹) has long been
3 considered as a relatively cost-effective means to add material new capacity to the WAF system, as well
4 as a modest amount of new hydro energy.

5
6 Review of the system capacity constraints as part of the Capacity Planning Criteria review indicates that
7 the capacity value of Aishihik 3rd turbine is extremely modest (about 600 kW under an LOLE of 2
8 hours/year, 0 MW under N-1) in the absence of a second Aishihik transmission line. This is because there
9 is already a disproportionate amount of WAF generation at risk of an Aishihik transmission line outage,
10 and the firm load carrying capability of WAF (under a probability-based assessment approach such as
11 LOLE, or an N-1 approach) is not aided by further capacity development at Aishihik.

12
13 However, there remain two other enhancement aspects of the Aishihik 3rd turbine that cannot be ignored:

- 14 • First, there are certain circumstances where an Aishihik 3rd turbine could be valuable capacity
15 to WAF (most notably if an Aishihik 2nd transmission line were developed, but also with major
16 future generation development elsewhere on WAF which would reduce the relative weighting
17 of Aishihik in the generation mix).
- 18 • Second, and likely of greater near term value, the long-term energy value of the Aishihik 3rd
19 turbine (estimated at 5.4 GW.h per year under high load scenarios and new Water Licence
20 terms) can be of value to WAF and can potentially yield diesel unit cost savings to offset the
21 Aishihik 3rd turbine capital cost¹⁰.

22
23 The Aishihik third turbine also provides material added near term enhancement benefits in displacing
24 peaking diesel energy generation on the WAF system (as well as enhancing the ability to maintain
25 maximum secondary sales revenues) while WAF surplus hydro is still available. This is because the
26 presently installed firm winter hydro capability is only 54.4 MW (30 MW at Aishihik and 24 MW at
27 Whitehorse plus 0.4 MW for Fish Lake) with normal winter hydro capacities in the range of 56-58 MW
28 (i.e., in non-drought years). Consequently at the present time the maximum WAF load that can be
29 allowed before diesel units must be started (and secondary sales interrupted) is a maximum of about 54
30 MW or less. With the addition of 7 MW of new hydro capacity at Aishihik, the operation of peaking diesel

⁹ The \$7 million cost estimate is currently under active review and refinement to reflect current pricing.

¹⁰ The potential energy of 5.4 GW.h/yr represents an annual capacity factor of only 8.8% for the 7 MW unit; however, offset cost savings of about \$1 million or more per year will occur if this displaces diesel fuel generation at 65 cents/litre cost. Base Case loads are not sufficient to yield any material diesel fuel displacement in the near term, but this starts to occur before 2025. Peaking diesel savings, which are discussed separately, are also material during this period under Base Case assumptions.

1 (and interruption of secondary sales) will not occur until closer to 61 MW. This can lead to material
2 savings in WAF diesel generation starting when the unit comes into service (ranging under Base Case
3 conditions from 0.4 GW.h a year in 2009 to as high as about 6 GW.h per year over the period of the
4 Resource Plan). This effect also is expected to result in an increased number of hours of secondary sales
5 availability and consequently secondary sales revenues¹¹ (this benefit has not been quantified).
6

7 The Aishihik 3rd Turbine is already authorized in the renewed water licence. Approximately 20-24 months
8 are estimated to be needed from commitment until it comes into service (i.e., time needed for remaining
9 pre-decision final design and costing and tendering as well as for subsequent construction). It is assumed
10 that the project, if committed, would at the earliest come into service in 2009.

11 **4.3.3 Marsh Lake Fall/Winter Storage**

12 Although the Whitehorse Rapids hydro generating station is a largely run of river plant, there is some
13 modest storage available at Marsh Lake, controlled via the Lewes Dam (a control structure upstream of
14 Miles Canyon).
15

16 Various options have been reviewed over many years to enhance the output of Whitehorse Rapids by
17 increasing the ability to control Marsh Lake.
18

19 One option that was previously studied and not adopted in 1992 was a project called the "Marsh Lake
20 Top Storage Project" which YEC investigated in 1991-92 at the request of the YUB, to raise the licenced
21 maximum storage on Marsh Lake by five feet (as well as associated lake level impacts on Tagish and
22 Bennett Lakes). A study produced at that time for YEC estimated a requirement for only \$760,000
23 (1992\$) of physical works to the Lewes Dam control structure, but likely well over \$25 million (1992\$) in
24 mitigation costs related to significant adverse impacts on many properties and developments affected by
25 the higher water levels (YEC noted to the YUB that the company considered the study's estimates to be
26 low). Consequently, YEC recommended in the 1992 Resource Plan that it not proceed with the project,
27 and the YUB agreed with this recommendation in its 1992 Report.

28 The Marsh Lake Fall/Winter Storage project under consideration today is a fundamentally different project
29 than that considered in 1992. In this case, the project involves seeking changes to the Whitehorse Rapids
30 water licence to allow Yukon Energy to reduce the amount of water it releases from Marsh Lake under

¹¹ The impact on secondary sales quantities from hydro peaking resources such as the Aishihik Third Turbine has not been assessed. At certain loads, the Third Turbine may also reduce somewhat the availability of surplus power for secondary energy, as the water would be used to avoid baseload diesel and consequently no longer be "surplus hydro". However, this is not expected to occur until the system is near the full utilization of hydro capability and only for a limited number of years.

1 certain conditions in the fall and early winter, in order to enhance Yukon River flows during the coldest
2 months of winter¹². The effect of the revised water licence would be as follows:

- 3 • **In non-flood years:** The licence revision would allow Yukon Energy to reduce Marsh Lake
4 outflows from August 15 to the end of September, to allow that water to be used instead
5 during the peak winter generation period.
- 6 • **During flood years:** In years where Marsh Lake levels are at flood stages, no change would
7 be made during August and September until after flood levels subside. Similar to existing
8 rules, once the floods have subsided, water levels would be controlled to reduce further
9 spillage in fall and early winter months (at a level about one foot higher than presently
10 allowed), to allow the water to be used instead during the peak winter generation period. In
11 all cases, the water levels would remain within the lake level limits currently experienced
12 (i.e., the peak level that YEC is allowed to maintain by use of Lewes Dam would be below the
13 natural high water levels experienced in the lake during uncontrolled summer periods). There
14 would be no effect on the flood levels experienced on Marsh Lake.
- 15 • **During drought years:** Yukon Energy is currently permitted to help alleviate summer
16 drought levels on Marsh Lake through “early closures” of the Lewes Dam (as early as July 7
17 in extreme droughts). These provisions would remain, and would likely be adapted somewhat
18 to further alleviate summer drought conditions to ensure the lake reached the full controlled
19 supply level (as revised) in each year.

20
21 Environmental licencing activities for the project have not been initiated. Studies will need to confirm the
22 extent (if at all) to which the project may affect water levels in lakes that extend into BC.

23
24 The Marsh Lake Fall/Winter Storage project has the potential to enhance the output of the Whitehorse
25 Rapids hydro facility by about 1.6 MW and 7.7 GW.h/yr long-term average hydro energy (actual
26 enhancement will depend on load conditions assumed and revised maximum licence level allowed, which
27 is assumed here to be one foot). Basically no new physical works are expected to be required for this
28 project.

29
¹² During uncontrolled periods of summer and fall (when YEC has no control over the lake and it is operating under an entirely natural regime), Marsh Lake has been known to peak at two feet above the Yukon Energy “controlled maximum” level currently provided for in the water licence, and to typically peak at least one foot above the “controlled maximum” level. The specific revision sought to the water licence would be to change the licenced “controlled maximum” level that YEC can maintain at Marsh Lake upwards by likely in the range of one foot, i.e., the proposed licence revision will still be well within the normal natural levels experienced on the lake.

1 Costs of the project relate almost entirely to environmental licencing and mitigation, which are very
2 difficult to predict. Given the relatively limited potential for physical or environmental effects (but
3 recognizing the potential for notable public interest in ensuring full review of all potential effects) the
4 costs of the project are not expected to exceed \$1 million. Licensing and other pre-decision activities are
5 assumed to require a year such that the project could potentially come into service in 2007 (in time to be
6 of value in addressing the 2007/2008 winter peak).

7 **4.3.4 Carmacks to Stewart Transmission Line Project**

8 The proposed 138 kV Carmacks to Stewart Transmission Line would extend the WAF system north from
9 Carmacks generally along the Klondike Highway to at least Pelly Crossing, and potentially as far as
10 Stewart-Crossing in order to provide full interconnection with the MD system. Interconnection of the WAF
11 and MD grids would provide near term capacity and energy benefits to the WAF system.
12

13 If the project is developed from Carmacks to at least Pelly Crossing, potential new mine developments in
14 close proximity to the new transmission line could have access to service with WAF surplus hydro energy.
15 In particular, the Minto mine and the Carmacks Copper mine, located between Carmacks and Pelly
16 Crossing, are both located in areas that could be serviced with the proposed line. Development only to
17 Pelly Crossing, however, would not result in interconnection of the MD and WAF grids.
18

19 Costs to develop this project from Carmacks for full interconnection to Stewart-Crossing have been
20 estimated at about \$35 million (2005\$). It is not currently economic for Yukon Energy, as a regulated
21 utility, to develop this project since both the WAF and MD systems today have surplus hydro power and
22 the line would not at this time displace the level of diesel fuel or other high cost generation needed to
23 justify its costs. Accordingly, this project is being examined as a key Yukon territorial infrastructure
24 initiative to meet a specific window of opportunity related to two potential new mines (Minto and Western
25 Silver at Carmacks Copper) and current Yukon Government Infrastructure Funding.
26

27 The project is currently being advanced using Yukon Government funding for permitting and approvals
28 activities, including licencing under the new *Yukon Environmental and Socio-Economic Assessment Act*
29 (*YESAA*), as well as for finalizing project final design and costing. If critical planning does not proceed in
30 a timely way through 2006 using Yukon Government Infrastructure Funding, permits and other
31 preparatory work will not likely be done in time to enable the project to help in the development of these
32 two mines (based on the current planned development schedules for Minto in particular). Current
33 planning is seeking to protect a potential in-service date for this project between mid-2008 and mid-
34 2009.

1 The extent to which the ultimate project concept is developed in the near term will be determined based
2 on available Yukon Government Infrastructure Funding as well as the mine development that will actually
3 occur. The project's capital costs will not impact regulated utility rates to the extent that its costs are
4 funded through Yukon Government grant funding or through customer contributions from mines
5 connecting to the WAF grid. Rates charged to such mines for use of WAF power would need to be
6 approved by the YUB in accordance with OIC 1995/90 (which requires that such rates at least cover
7 utility costs of service evaluated on a Yukon wide basis).

8
9 Development of this project from Carmacks to Pelly Crossing is estimated to cost in the range of about
10 \$20 million (2005\$). This extent of development, in combination with the two proposed mines being
11 developed and connected (costs for "radial" lines to service Minto and Carmacks Copper sites will be
12 addressed via normal utility and customer investment policies), would fully utilize WAF surplus hydro in
13 the near term.

14
15 Extending the project fully from Carmacks to Stewart Crossing (a further likely capital cost (2005\$) of
16 about \$15 million over and above the cost for the project from Carmacks to Pelly Crossing) would provide
17 near term capacity and energy benefits for the WAF system related to interconnection of the WAF and
18 MD systems. It is estimated that such interconnection would provide in the near term about 6 MW of net
19 capacity benefit to WAF¹³ as well as another 15 GW.h/yr of net long-term average hydro energy; these
20 benefits would decrease in future as MD load grows (or if new industrial developments, such as
21 reopening of the UKHM mine, connect to the MD system). The surplus hydro made available can yield

22
23 WAF economic benefits during the planning period through both diesel unit cost savings and extended
24 maintenance of secondary sales revenues¹⁴.

25 In assessing various alternatives related to the Carmacks to Stewart Transmission Line project, Yukon
26 Energy is examining the net cost that could be funded through rates in order to make interconnection
27 cost competitive with other options. This is based on the assumption that if the project was to be
28 developed in the near term, the project's capital cost will be provided for through Yukon Government
29 Infrastructure Funding as required to ensure no impact on regulated utility rates.

¹³ This reflects 12 MW of installed MD firm capacity and MD peak load forecast (2008) of 5.9 MW.

¹⁴ The present value (2005\$) of these diesel cost savings and extended secondary sales revenues approximates only \$1.2 million over the 20 year planning period under Base Case conditions; under Base Case including Mines conditions (which are likely to be required, at least in part, if the interconnection is to be developed at this time), and excluding consideration of any other opportunity projects, this present value increases to \$4.7 million. (These present values assume a discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre for peaking and 3.9 kW.h/litre for baseload, diesel fuel prices at \$0.65/litre (2005\$), diesel O&M at \$0.016/kW.h (2005\$) and inflation at 2%/yr. No firm capacity benefit is included in these present values.)

1 Long term benefits from the Carmacks Stewart Transmission project connecting the two grids include:
2 encouraging economic development along the corridor of the new line and its extended environment;
3 enhancing overall power system reliability on these systems; and providing greater flexibility to
4 accommodate future load and generation interchange between the WAF and MD systems as they are
5 currently known. Potential benefits, for example, include the ability under certain load development
6 scenarios to move surplus WAF power to serve major new mine developments in the MD grid region
7 should they arise; or to move surplus MD power to the WAF grid region from potential new hydro
8 developments in the MD grid or Pelly Crossing regions, as well as from potential future Mayo hydro plant
9 enhancements.

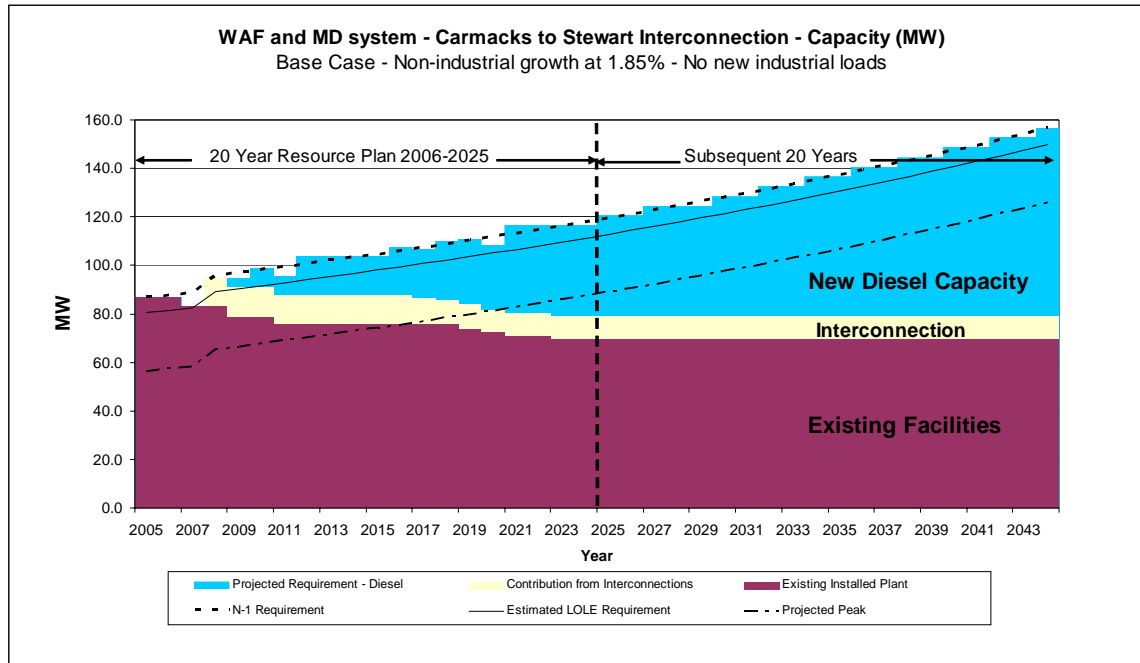
10

11 The Carmacks to Stewart Transmission Line project (full interconnection) impact on WAF firm winter
12 capacity, plus other new diesels as required to meet capacity requirements, is illustrated in Figure 4.9 (at
13 Base Case loads and excluding consideration of any other non-diesel capacity enhancements).

- 14 • The Base Case capacity shortfall in 2012 with interconnection of the MD and WAF grids is
15 approximately 13.1 MW, and is assumed in Figure 4.9 to be met through 16 MW of added
16 diesel units (4 MW in 2009, 4 MW in 2010, and 8 MW in 2012).
- 17 • Under other forecast conditions examined, the capacity shortfall in 2012 with the Carmacks
18 to Stewart Transmission Line project (full interconnection) is 8.7 MW (Low Sensitivity case),
19 about 15.8 MW (Base Case including Mines), and about 21.5 MW (High Sensitivity including
20 Mines).

1
 2

Figure 4.9:
Carmacks to Stewart Transmission Line in 2008



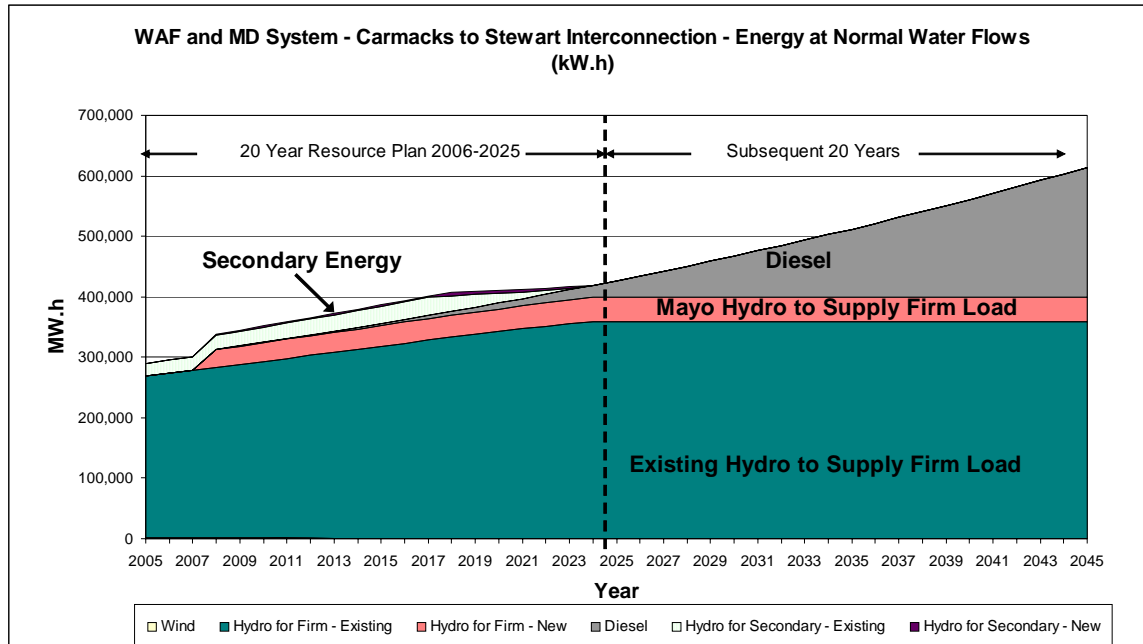
3

4 Figure 4.10 reviews the hydro and diesel energy loads under the Base Case forecast with interconnection
 5 of the MD and WAF grids, indicating surplus hydro remaining throughout the 20-year planning period.

- 6 • Under Base Case forecast conditions including the Minto and Carmacks Copper Mines, the full
 7 interconnection project has the same surplus hydro after the mines close in 2016 and 2018.
- 8 • Under the High Sensitivity case including these mines, the full interconnection project has no
 9 surplus hydro available after the mines close.

1
2
3

Figure 4.10:
Carmacks to Stewart Transmission Line in 2008



4

5 **4.3.5 Overview of Major Capacity-Related Project Options**

6 Under the new capacity planning criteria, the WAF system is facing a capacity shortfall in the very near
7 term. As reviewed in Section 4.2, the magnitude of the capacity shortfall depends in part on the load
8 growth that occurs over the next few years (including the extent to which new mine loads, if developed,
9 are connected to WAF through new transmission facilities). However, even under the lowest load growth
10 scenarios, the shortfall approaches 15 MW by 2012, which is a very material scale for the WAF system
11 (which peaks at about 56 MW today).

12

13 Facing this requirement, Yukon Energy has identified three major replacement and expansion project
14 options (beyond the “opportunity” project options already noted) that have the potential to largely or
15 entirely address major capacity shortfalls by 2012 on the WAF system:

- 16 • **Mirrlees Life Extension Project (14 MW):** One option that requires consideration is a
17 major refurbishment of the three existing Mirrlees units at Whitehorse to reclaim the full 14
18 MW nameplate ratings and extend the life of the units for 10 years or more. The project
19 would require a full “tear down” overhaul of the three units as well as upgrading to various
20 shared systems in the Whitehorse diesel plant. As the project would only provide 14 MW of
21 capability, it would need to be combined with other projects to meet the full 2012 shortfall

1 assumed based on retirement of these Mirrlees units (i.e., to achieve the full 15 MW to 27
2 MW under the various scenarios in Section 4.2). This option is reviewed in more detail below
3 (see Section 4.3.6).

- 4
- 5 • **Whitehorse Diesel Replacement/Expansion Project (unlimited MW):** This flexible
6 option is available to meet the full range of possible new capacity requirements in near term
7 (up to the full high load scenario requirements of 27 MW by 2012). New units of any type or
8 combination could be added to the system incrementally as required. In all likelihood the
9 units would be installed as replacements for the retired Mirrlees (in the bays vacated by the
10 retirements) and, if undertaken with large units such as modern 8 MW Wartsila gensets (or
11 larger, such as 11 MW units), could largely or entirely be accomplished within the confines of
12 the existing site. In addition, other major resource options that are not sufficiently large to
13 address the entire 2012 shortfalls may be combined with a smaller scale of new diesel
14 installation. This option is reviewed in more detail below (see Section 4.3.7).

- 15
- 16 • **Aishihik 2nd Transmission Line Project (15 MW under N-1 criteria, 8.0 MW under**
17 **LOLE criteria):** As discussed in detail in Section 3.3, the largest single factor influencing the
18 reliability and risk profile of the WAF system today is the non-redundant nature of the
19 Aishihik transmission line. A major rationale for maintaining substantial “stand-by” diesel in
20 Whitehorse is to address the risks of an Aishihik line failure. One project option that
21 consequently merits consideration is a “twinning” of the Aishihik transmission line to provide
22 required redundancy. Were such a facility to be put into service to provide complete
23 redundancy, the N-1 criteria would be revised to indicate 15 MW as the largest single
24 contingency (based on one of the hydro units at Aishihik, which are the largest single units
25 on the system) rather than 30 MW currently arising from a potential loss of the line. Under
26 the N-1 criteria, this would currently be a 15 MW benefit to the load carrying capability of the
27 system. Under the LOLE criteria, also as noted in Section 3.3, the benefit from a redundant
28 Aishihik transmission line would currently be about 8.0 MW. In addition, this option enables
29 the opportunity for additional firm capacity benefits related to other potential enhancements
30 at the Aishihik generating station such as the Aishihik 3rd Turbine, as well as the potential for
31 re-running (as discussed below). As the Aishihik 2nd Transmission line project would
32 currently only provide 15 MW of new load carrying capability, it would currently need to be
33 combined with other projects to meet the full 2012 shortfall (to achieve the full 15 MW to 27
34 MW under the various scenarios in Section 4.2). This option is reviewed in more detail below
35 (see Section 4.3.8).

1 Aside from relying only on diesel expansion/replacement, none of the above major options on its own is
2 likely to address the full WAF capacity shortfall expected in the near term (to 2012). For initial review
3 below, it is assumed that additional diesel engines are the default option to be used as required with
4 each of the other options in order to meet the full near term capacity shortfall. Later, in section 4.4,
5 optimum combination of these options is examined under a range of planning assumptions.

6 **4.3.6 Mirrlees Life Extension Project**

7 As noted in Section 4.1, the Whitehorse Diesel Units WD1, WD2 and WD3 are the three largest units in
8 the Whitehorse diesel plant. Although planned for retirement at an earlier date, Yukon Energy was able
9 to delay the retirement of the units largely as a result of the closure of the Faro Mine.

10
11 BC Hydro's Condition Assessment in 2004 recommended that the retirement of these units be seriously
12 considered if significant further use was anticipated (*Section 3.1: Current Facilities Condition*
13 *Assessment*). Assumptions regarding retirement of these units have at various times been based to a
14 greater or lesser extent on the following cited issues:

- 15 • The units' condition is becoming unacceptably poor, and would require substantial
16 investment to bring them back up to a utility quality condition;
- 17 • The units are poorly suited to the current operating regime of stop-and-start operation;
- 18 • Parts and technical support are lacking and expensive; and,
- 19 • The units are expensive to operate and maintain.

20
21 Despite these limitations, the retirement of the Mirrlees engines will necessitate major new capacity-
22 related investment in the near term (particularly under the new capacity criteria, but also to a lesser
23 degree even under the previous criteria). In addition, the YUB recommended in its 1992 Report on the
24 utilities' Resource Plan that before the Companies commit to the construction of a supply option they
25 should critically assess a number of factors including "the necessity for diesel retirements". As a result,
26 Yukon Energy is currently undertaking a critical assessment of the potential for a "Life Extension Project"
27 for the units. Such a project must, at a minimum, ensure the above concerns with respect to condition
28 can be fully addressed (including reclaiming the previous full 14 MW combined nameplate ratings).

29
30 If feasible, such an option would materially reduce capacity shortfalls in the next five to six years; it
31 would also materially reduce capital costs relative to those needed for any other available option to meet
32 WAF near term capacity requirements. Such an option, if practical, is expected to involve capital costs
33 (2005\$) potentially in the order of \$0.5 million to \$1.0 million for each unit (with material risks that costs
34 could not be readily estimated with any degree of certainty before the project is undertaken, as the

1 status of internal parts and mechanisms cannot be readily ascertained until the tear-down is underway).
2 In addition there would be substantial initial work in the order of \$1.0 million to \$1.5 million related to
3 shared aspects of the Whitehorse diesel facility systems requiring material improvements (such as cooling
4 systems, fuel delivery systems, foundation, etc.).

5
6 There remain two key concerns with the Mirrlees: the cost and availability of parts and support from the
7 manufacturer, and the suitability of the units to the current Yukon operating environment.

8
9 With respect to the manufacturer, it will not be prudent for Yukon Energy to proceed with any Mirrlees
10 Life Extension project unless Yukon Energy can receive clear and reliable assurances that the
11 manufacturer can provide full competent and cost-effective parts and technical support for these units for
12 the next 10-20 years. Recent Yukon Energy experience indicates this concern to be very material. Yukon
13 Energy is in the process of assessing the manufacturer's claims that they can continue to provide
14 competent support on these units, including discussing Yukon Energy's recent experiences with the
15 manufacturer, and seeking references from other utilities who have pursued a similar course of action.

16
17 With respect to the operating environment, despite a full tear-down overhaul, the Mirrlees units will
18 remain low speed base load units which are poorly suited to the current Yukon operating environment
19 (stop-and-go operating, limited running hours). This limitation cannot be fixed. However, it is not
20 sufficiently severe to rule out a Life Extension project option, given competitiveness on other grounds as
21 well as the expected use primarily for reserve rather than planned operation purposes (see Section 4.4
22 regarding "Assessment" below).

23
24 Yukon Energy is aware that Northwest Territories Power Corporation ("NTPC") has plans to retire their
25 two KV16 Mirrlees units in Yellowknife in the next number of years (NTPC has already retired a similar
26 unit in Inuvik; the Yellowknife units are similar in running hours to Yukon Energy's units, but about six to
27 seven years newer). The NTPC retirement plans are due primarily to two concerns: part and technical
28 support availability, and suitability to a stop-and-go unattended operating environment. Further
29 discussions with NTPC are planned to compare experiences on these two matters.

30
31 If the Mirrlees Life Extension project is pursued and 14 MW of capacity is restored for these units, by
32 2012 additional diesel capacity will still be required under the capacity planning criteria (capacity
33 shortfalls of 4.7 MW would exist under the Base Case, 0.7 MW under the Low Sensitivity Case, 7.5 MW
34 under the Base Case with mines, and 12.7 MW under the High Sensitivity Case with mines).

1 Overall, likely costs (2005\$) for the Mirrlees Life Extension project to 2012 can be estimated for screening
2 purposes as follows, assuming that added requirements beyond 14 MW are met though additional diesel
3 capacity¹⁵:

- 4 • **Base Case:** Mirrlees Life Extension at \$3.0 million to \$4.5 million, plus 4.7 MW requirement
5 for new diesel at \$0.8 million to \$0.9 million per MW, for a total ***\$6.8 million to \$8.7***
6 ***million.***
- 7 • **Low Load Sensitivity:** Mirrlees Life Extension at \$3.0 million to \$4.5 million plus 0.7 MW
8 requirement for new diesel at \$0.8 million to \$0.9 million per MW, for a total of ***\$3.6 million***
9 ***to \$5.1 million.***
- 10 • **Base Case with Mines:** Mirrlees Life Extension at \$3.0 million to \$4.5 million, plus 7.5 MW
11 requirement for new diesel at \$0.8 million to \$0.9 million per MW, for a total ***\$9.0 million to***
12 ***\$11.3 million.***
- 13 • **High Load Sensitivity including Mines:** Mirrlees Life Extension at \$3.0 million to \$4.5
14 million, plus 12.7 MW requirement for new diesel at \$0.8 million to \$0.9 million per MW, for a
15 total ***\$13.2 million to \$15.9 million.***

16
17 In summary, the capital cost (2005\$) of the Mirrlees Life Extension Project plus other diesels as required
18 to meet peak loads to 2012 is expected to cost in the range of \$6.8 million to \$8.7 million, with potential
19 under various load developments to range from \$3.6 million to as high as \$15.9 million.

20
21 Timing with respect to the Mirrlees Life Extension is expected to be quite flexible. Major tear-down
22 overhauls can likely be scheduled on six months notice, and major upgrades to common facilities can
23 likely be staged so as to meet in-service requirements of the overhauled units (although the lead times
24 will in all likelihood be slightly longer than for overhauls, due to design requirements). The project can
25 also likely be staged over a number of years (summers) if preferable. The project is assumed to be
26 suitably organized in an orderly fashion by sequencing one unit per year from 2007 to 2009 (starting with
27 the largest) with common facilities upgrades occurring in 2007. Work on the existing units and facilities
28 that disrupt current capability must occur during summer months (as the units are needed during winter
29 to provide firm capacity).

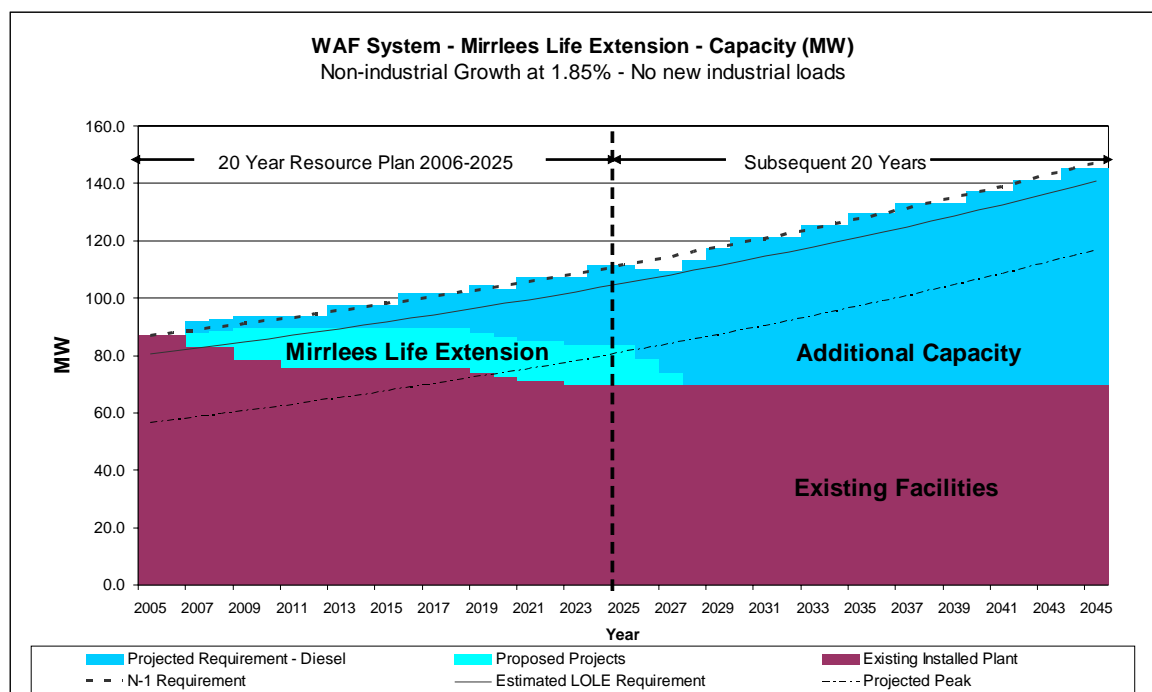
¹⁵ See Section 4.3.7 for a more detailed review of costs for additional diesel units. As a rough measure for screening purposes, diesel units installed for capacity reserve purposes without a need for major "Green Field" support systems (e.g., fuel tanks, substations, control systems) are estimated to cost (2005\$) in the range of \$800,000 to \$900,000 per MW (e.g., \$3.2 to \$3.6 million for a 4 MW unit). Under the Mirrlees Life Extension option the Whitehorse diesel plant facilities would be utilized for the Mirrlees units, and costs for additional diesels therefore may tend to be higher than otherwise assumed, particularly if a new diesel generation site would need to be developed for these added units.

1 For the added diesel units that are assumed to be required, issues also arise with respect to locating such
 2 diesel units if the entire Mirrlees Life Extension project is pursued. Were the three Mirrlees to be retired,
 3 the three “bays” of the existing diesel plant would allow three new units to be installed (units of 8 MW
 4 are expected to fit readily into the existing bays, allowing for up to 24 MW of new capacity; units of 11
 5 MW or larger may also fit, but require further consideration). However, if the Life Extension is pursued,
 6 these bays will be in use by the Mirrlees and new units will require modifications or expansions to the
 7 existing building, or pursuit of other options with respect to unit location.

8
 9 The Mirrlees Life Extension project impact on WAF capacity, plus other diesels as required to meet
 10 capacity requirements, is illustrated in Figure 4.11 (at Base Case loads). This figure focuses on a Life
 11 Extension project to add 20 years to the lives of the Mirrlees units. Under this forecast scenario, one new
 12 diesel unit (about 4 to 5 MW) would be required in 2007.

13
 14 One potential variation on implementing the Life Extension project could involve Life Extension of the two
 15 largest Mirrlees units (10 MW total) combined with replacement of the smaller third Mirrlees unit (4 MW)
 16 with a larger 8 or 11 MW new unit. Under this variation, there would be no need for any other new
 17 diesel unit by 2012.

**Figure 4.11:
Mirrlees Life Extension**



1 **4.3.7 Whitehorse Diesel Replacement/Expansion Project**

2 The Whitehorse Diesel Replacement/Expansion project encompasses various potential concepts of
3 meeting all capacity requirements (including those driven by Mirrlees retirements) using new diesel units
4 at Whitehorse. This could include various combinations of unit sizes (e.g., approximately 4 MW or 8 MW
5 or potentially others such as 11 MW or 15 MW) sequenced as needed to meet load requirements as well
6 as other implementation practicalities. Ongoing investigations are examining issues and costs related to
7 alternative ways to implement this generic option, including common plant upgrade requirements.

8
9 Purchase of new diesel units is likely the most flexible approach possible to addressing capacity shortfalls,
10 as units can be sourced that are properly suited to standby use in a wide range of sizes and
11 specifications. However, due to presently high worldwide demand for new diesel units, lead times for new
12 orders from initial commitment through to in-service (including engineering, manufacture, delivery,
13 installation and commissioning) can be on the order of 18 months, which is well above the traditional
14 lead time for new units. As note earlier, work on the existing units and facilities that disrupts current
15 capability must occur during summer months (as the existing units are needed during winter to provide
16 firm capacity).

17 Diesel units installed at the current Whitehorse plant, without the need for major "Green Field" support
18 systems (e.g., fuel tanks, substations, control systems), are estimated to cost (2005\$) in the range of
19 \$800,000 to \$900,000 per MW¹⁶. Estimated capital costs (2005\$) to 2012 for screening purposes of the
20 Whitehorse Diesel Replacement/Expansion Project are as follows:

- 21 • **Base Case:** 18.7 MW requirement for new diesels at \$0.8 million to \$0.9 million per MW, for
22 a total of ***\$15.0 million to \$16.8 million***.
- 23 • **Low Load Sensitivity:** 14.7 MW requirement for new diesels at \$0.8 million to \$0.9 million
24 per MW, for a total of ***\$11.8 million to \$13.2 million***.
- 25 • **Base Case with Mines:** 21.5 MW requirement for new diesels at \$0.8 million to \$0.9 million
26 per MW, for a total of ***\$17.2 million to \$19.4 million***.
- 27 • **High Load Sensitivity including Mines:** 26.7 MW requirement for new diesels at \$0.8
28 million to \$0.9 million per MW, for a total of ***\$21.4 million to \$24.0 million***.

¹⁶ By way of example, based on prices recently quoted to YEC and estimates for costs to install and commission at Whitehorse, a 4.3 MW EMD 16-265H using 6.9 kV generators has been estimated to cost (2005\$) about \$730,000 per MW (\$3.1 million), and a 7.8 MW new 7.8 Wartsila 18V32 using 13.8 kV generators has been estimated to cost (2005\$) about \$740,000 per MW (\$5.8 million). In addition, common plant upgrade costs of \$1.0 million have been estimated to apply in each case (assuming installation at the current Whitehorse plant to replace the Mirrlees units, which are assumed to be removed and replaced with from 12 to 24 MW, depending on the unit size selected). Together, these costs average at between \$786,000 and \$808,000 per MW (depending on the units size selected).

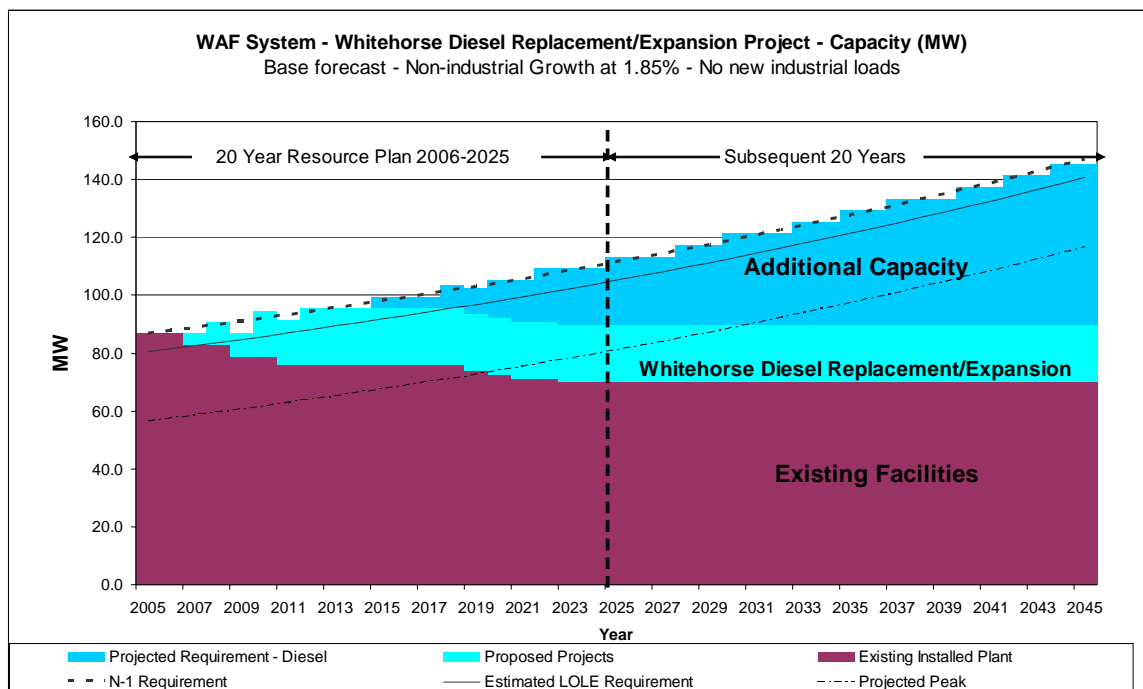
1 In summary, the capital cost (2005\$) of the Whitehorse Diesel Replacement/Expansion Project as
 2 required to meet peak loads to 2012 is expected to be in the range of \$15.0 to \$16.8 million, with
 3 potential under various load developments to range from \$11.8 million to as high as \$24.0 million.

4
 5 For the first three units installed, there is little issue with space or support systems at the current
 6 Whitehorse diesel plant, as the three bays vacated by the retired Mirrlees are of sufficient size to
 7 accommodate the noted 4 MW or 8 MW units and perhaps up to 11 MW or larger.

8
 9 However, issues begin to arise if either a) more than three units are required in the sequence to 2012 (as
 10 would occur with new units of 4 MW rather than 8 MW, or would occur under the High Load Sensitivity
 11 Scenario with Mines which requires more than three 8 MW units) or b) units are required at a rate faster
 12 than the Mirrlees are planned to be retired. If this arises, modifications or expansions will be required to
 13 the existing building, or other options required regarding unit location.

14
 15 The Whitehorse Diesel Replacement/Expansion Project impact on WAF capacity is illustrated in Figure
 16 4.12 (at Base Case loads and assumed increments generally at 4 MW units). Under this forecast scenario,
 17 an added diesel unit would be required in 2007, another 4 MW unit would be required in 2008, an 8 MW
 18 unit would be required in 2010, and a further 4 MW unit in 2012.

19
 20 **Figure 4.12:**
 21 **Whitehorse Diesel Replacement and Expansion**



1 **4.3.8 Aishihik 2nd Transmission Line Project**

2 The Aishihik Transmission Line is a key component of the WAF 138 kV system. It connects 30 MW of
3 hydro generation from Aishihik to major load and generation centers at Whitehorse and beyond. The
4 Aishihik 2nd Transmission Line Project is a near term option for potential development under the new
5 capacity planning criteria if the existing Mirrlees diesel units at Whitehorse are confirmed to be retired.
6 The project concept is to establish a redundant circuit for Aishihik generation to reach the remainder of
7 the WAF system at Whitehorse.

8
9 The net effect of this project under forecast loads would be a reduction in the N-1 capacity planning
10 criteria "reserve" currently of about 15 MW, approximately equal to adding 15 MW of new diesel units.
11 Under the LOLE criteria, the Aishihik 2nd Transmission Line project benefit currently is 8.0 MW. However,
12 under the Base Case forecasts with current facilities, the N-1 criteria is the key factor in requiring new
13 capacity in the near term¹⁷. Subject to timing issues for its in-service, the project would eliminate the
14 need for any new capacity under Base Case load forecasts until 2012.

15
16 Pending results of the current Mirrlees Life Extension investigations, Yukon Energy has not proceeded
17 with material work to date on potential routing options for the Aishihik 2nd Transmission Line project.
18 There exist a number of options to connect to any of 3 substations in the Whitehorse area, or
19 alternatively potentially to the WAF grid line north to Carmacks. Regardless of the routing, the project
20 requires that full redundancy on the delivery of power to the Whitehorse is to be established, including
21 substation components and Whitehorse area transmission connections.

22
23 Preliminary costing (2005\$) indicates a transmission line development cost (planning, permitting, design
24 and construction) for the simplest project alternative roughly paralleling the existing line on the order of
25 \$16 to \$19 million. The total costs (2005\$) to meet capacity requirements to 2012 with the Aishihik 2nd
26 Transmission Line project are therefore currently estimated for screening purposes as follows:

- 27 • **Base Case:** Aishihik 2nd Transmission Line at \$16 to \$19 million, plus 4.5 MW requirement
28 for new diesel at \$0.8 million to \$0.9 million per MW, for a total of ***\$19.6 million to \$23.1***
29 ***million.***
- 30 • **Low Load Sensitivity:** Aishihik 2nd Transmission Line at ***\$16 to \$19 million*** fully satisfies
31 the capacity requirements to 2012.

¹⁷ In contrast, if the Aishihik 2nd transmission line was to be built, the LOLE criteria would become the driving factor by 1.1 MW.

- 1 • **Base Case with Mines:** Aishihik 2nd Transmission Line at \$16 to \$19 million, plus 13.5 MW
2 requirement for new diesel at \$0.8 million to \$0.9 million per MW, for a total of ***\$26.8***
3 ***million to \$31.2 million***. The substantial diesel requirement over and above the Base Case
4 is due to the fact that with 9 MW of mining loads, the LOLE criteria becomes the driving
5 consideration in new capacity, which only credits the Aishihik 2nd transmission line project
6 with 8.0 MW rather than the 15 MW under the N-1 criteria.
- 7 • **High Load Sensitivity including Mines:** Aishihik 2nd Transmission Line at \$16 to \$19
8 million, plus 18.7 MW requirement for new diesel at \$0.8 million to \$0.9 million per MW, for a
9 total of ***\$31.0 million to \$35.8 million***.

10 In summary, the capital cost (2005\$) of the Aishihik 2nd Transmission Line Project plus additional new
11 diesel units as required to meet peak loads to 2012 is expected to be in the range of \$19.6 to \$23.1
12 million, with potential under various load developments to range from \$16 million to as high as \$35.8
13 million. In particular, costs under this scenario (without examining any other potential benefits noted
14 below) are materially increased by the presence of the potential mining loads.

15
16 The Aishihik 2nd Transmission Line project would somewhat reduce operating costs compared to diesel in
17 the near term as the project would allow for greater flexibility to keep Aishihik on-line during line
18 maintenance activities which may serve to reduce diesel energy generation that would otherwise be
19 required. In contrast, an equivalent 15 MW of diesel units would require some new spending on diesel
20 fuel in order to maintain and exercise the units regularly.

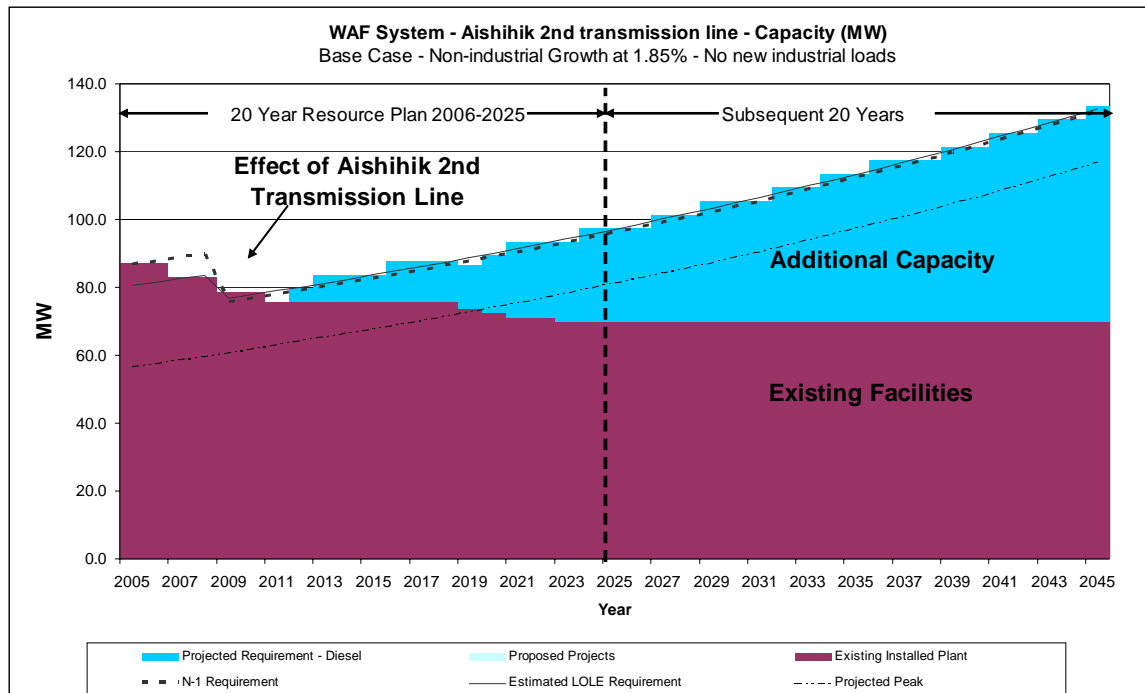
21
22 The development of the new transmission line would involve much longer lead times from commitment to
23 in-service than the other options noted above (potentially three years or more after a commitment to do
24 detailed planning and construction), as well as be less flexible in the near term given the impact of an
25 addition of 15 MW all at one time (compared to diesels which can be added in selected increments as
26 desired). For the purposes of planning, it is not expected that an Aishihik 2nd Transmission Line could be
27 in service any earlier than 2009, which would additionally raise concerns over capacity shortfalls in the
28 2006-2008 period (under the assumption that under Base Case conditions it may not be sensible to install
29 sufficient new diesel engines (8 MW) to address this two to three year capacity shortfall).

30
31 In addition, due to the nature of transmission line contracting, it would not be possible to develop a
32 materially more reliable estimate of the capital costs until such time as permitting and environmental
33 approvals were completed, final tenders were received and contracts concluded (likely requiring a
34 planning cost expenditure of about 10% of the capital cost, or about \$1.6 to \$1.9 million to get to this
35 stage).

1 Figure 4.13 below illustrates the capacity criteria benefits of twinning the Aishihik line. Under Base Case
2 assumptions, new diesel (about 4 to 5 MW) would not need to be added to the system until 2012.

3
4
5

**Figure 4.13:
Aishihik Second Transmission Line 2009**



6

7 In addition to ensuring existing Aishihik capacity can remain substantially more reliable to the system, the
8 Aishihik 2nd Transmission Line project also has the benefit of enhancing the opportunity provided by two
9 projects to provide additional capacity at Aishihik:

- 10 1. The 7 MW Aishihik 3rd Turbine.
- 11 2. A re-runnering of the existing Aishihik turbines for potentially up to 6 MW of added capacity.

12

13 The Aishihik 3rd Turbine is discussed in detail in section 4.3.2. At this time, there is insufficient definition
14 on the potential Aishihik re-runnering project to determine likely costs and practical full capabilities;
15 however, re-runnering projects in other jurisdictions are frequently pursued as cost-effective sources of
16 new capacity and/or energy.

17

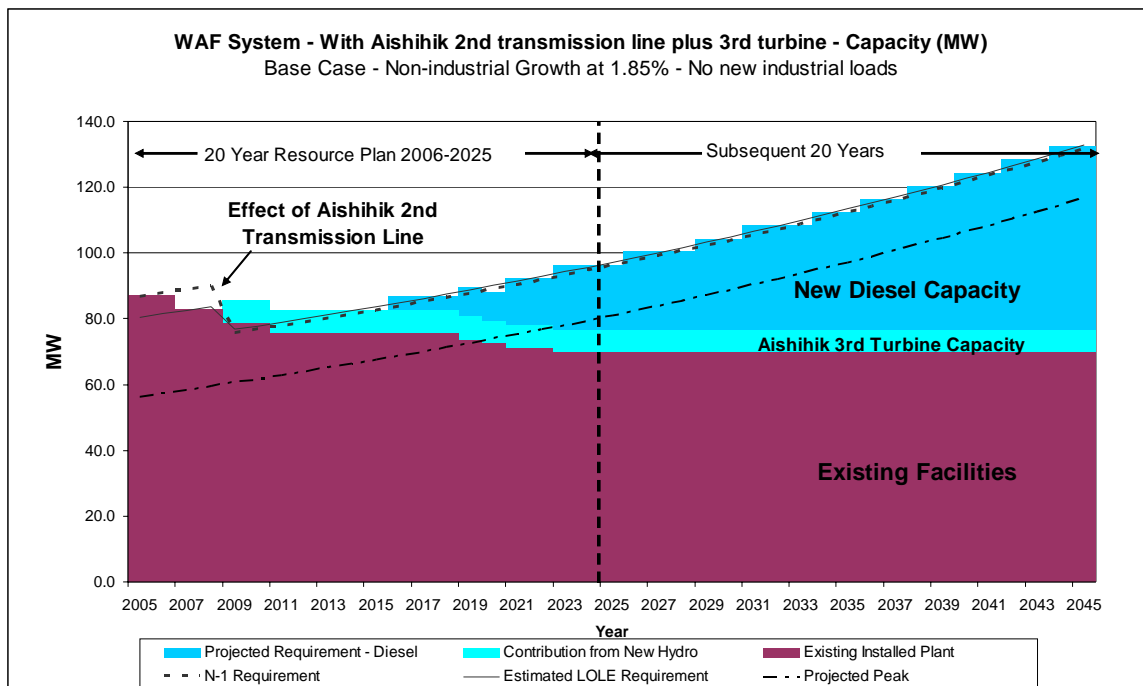
18 In the event the Aishihik 3rd Turbine project is pursued independently as an “opportunity” project in the
19 near term, development of the Aishihik 2nd Transmission line (under Base Case load conditions) would
20 provide 22 MW of firm capacity, which would allow for a full retirement of the Mirrlees engines and defer

1 until 2016 the need for any new diesel units on the WAF system. However, without an Aishihik 2nd
2 Transmission line, the Aishihik 3rd Turbine project cannot be considered reliable capacity under the N-1
3 criteria and only 0.6 MW of the 7 MW can contribute to the Load Carrying Capability under the LOLE
4 criteria. Accordingly, the added capacity value of the Aishihik 2nd Transmission Line become 22 MW under
5 the N-1 criteria and 14.4 MW under the LOLE criteria¹⁸.

6
7 Figure 4.14 below notes, under Base Case assumptions, the added benefit of a third turbine separately
8 from new diesel (in this case the 3rd Turbine is assumed to be placed in service in 2009, with new diesel
9 not required until 2016)¹⁹.

10
11
12

**Figure 4.14:
Aishihik Second Transmission Line in 2009 (with Aishihik 3rd Turbine in 2009)**



13

¹⁸ Under N-1 criteria with the Aishihik 2nd Transmission Line, a full 37 MW (30 MW existing plus 7 MW for 3rd Turbine) is now recognized at Aishihik (versus no MW recognized without the 2nd Transmission line), less 15 MW for loss of one unit (which once again becomes the largest single contingency event at the time of winter peak), resulting in a net firm capacity gain due to the 2nd line of 22 MW. Under LOLE criteria, the Aishihik 2nd Transmission Line benefit is 8.0 MW regarding the existing Aishihik capacity plus 6.4 MW regarding the Aishihik 3rd Turbine (0.6 MW of the 7 MW would be recognized without the 2nd transmission line), resulting in a net firm capacity gain due to the 2nd line of 14.4 MW.

¹⁹ Approximately 20-24 months are estimated to be required from commitment of the Aishihik 3rd Turbine project until it comes into service. Accordingly, this project could, if so required, be brought into service by as early as during 2008.

1 **4.3.9 Supplemental Project Options**

2 Supplemental project options can serve to complement the major “opportunity options” as well as the
3 major replacement and expansion options noted above. These supplemental project options have the
4 potential to increase capacity, but are not of a sufficient size to materially address the near term capacity
5 shortfall forecast for WAF. These options also remain relatively undefined at this time.

6 a) **Other facility enhancements that are preliminary and likely far too small to**
7 **address the entire forecast shortfall:** Supply-side enhancement opportunities are
8 limited by site and/or unit specific opportunities to increase winter peak capacity.
9 Examples under consideration include re-running of the two existing Aishihik units
10 (although any new capacity would be subject to the same N-1 constraints as the existing
11 units), and re-running of Whitehorse hydro units WH3 and WH4.

12 b) **Projects without sufficient definition to pursue in the near term:** A range of
13 possible longer-term projects related to the Southern Lakes, as well as Atlin Lake Top
14 Storage have the potential to increase capacity and energy outputs of the Whitehorse
15 Rapids plant (as well as potentially to establish new generation south of Whitehorse).
16 However, these projects are not considered to be potential options to meet near term
17 capacity focused needs, as they are not sufficiently defined or studied at this time. Yukon
18 Energy is currently undertaking a study to update and refine its knowledge of the specific
19 hydrology of the southern lakes area, but until this work is completed, it is difficult to
20 know the potential for cost-effective water management (or hydro generation) structures
21 in the region.

22 c) **Projects with no reliable capacity contribution:** New wind generation, small scale
23 run-of-river hydro generation, solar, major new DSM initiatives or various other potential
24 new generation technologies are not typically considered by utilities to provide reliable
25 capacity towards meeting near term capacity shortfalls of the type forecast in Yukon.

26 d) **Projects that require major energy load to be economic:** New storage hydro
27 projects, biomass generation (e.g., wood), and coal generation are not considered to be
28 feasible cost effective options to meet near term capacity focused needs. These projects
29 can only typically be developed when systems require both capacity and sustainable new
30 energy that would otherwise need to be supplied by higher cost options; in Yukon’s case
31 past experience has shown that these projects can only be developed on a cost-effective
32 basis when there is sufficient energy being generated with diesel, and substantial
33 certainty that this diesel generation would continue well into the future absent a major
34 capital intensive new generation development of this type (see Chapter 5).

- 1 e) **Addition of new diesel generation capacity at Carcross (likely by YECL) of**
2 **about 1 MW:** Carcross and the connections to Tagish are the only WAF communities of
3 reasonable size (over about 300 people) which do not have local diesel generation
4 installed. In the event that new diesel generation is required on WAF, it may be prudent
5 to locate a small portion of this generation (likely about 1 MW) in the Carcross or Tagish
6 area.

7 **4.4 ASSESSMENT**

8 Assessment of the above near term major project options (i.e., options costing \$3 million or more for
9 commitment before 2009) focuses on system optimization and economics for opportunity projects, and
10 on requirement to address the new capacity planning criteria for capacity-related projects.

- 11 • **Opportunity Projects:** Assessment of the three identified opportunity projects is set out in
12 Section 4.4.1 below. These three projects reflect both qualitative benefits from maximizing
13 the use of existing investments and infrastructure, as well as quantitative economic benefits
14 from enhanced hydro energy and/or capacity availability to serve loads.
- 15 • **Capacity-related projects:** Assessment based on the revised capacity planning criteria, as
16 described in Chapter 3 (Section 3.4), is set out in Section 4.4.2 below. Under these criteria,
17 and assuming retirement of the Mirrlees units, new capacity is needed on WAF under the
18 Base Case in 2006 (0.7 MW), with an 18.7 MW forecast shortfall in 2012²⁰. The MD system
19 has no forecast capacity shortfalls by 2012 under the revised capacity planning criteria in the
20 absence of new major industrial loads.

21
22 There is no economic opportunity in the near term to develop new capital intensive energy projects such
23 as hydro or coal (without major new industrial loads at the level discussed in Chapter 5) outside of the
24 identified opportunities regarding enhancements to existing facilities.

25
26 Resource options are assessed and/or screened over the near term and beyond, based on technical
27 feasibility (including timing), cost efficiency and effectiveness, reliability, and risk (in particular risks
28 related to future load requirements developing differently than indicated by current forecasts). Section

²⁰ Assessment based on the previous capacity planning criteria is not addressed. Under the previous criteria, and assuming retirement of the Mirrlees units, no new capacity would be needed on WAF under the Base Case until 2010 (0.6 MW), with a 5.6 MW forecast shortfall in 2012. Meeting these requirements would not require cost commitments by Yukon Energy of \$3 million or more before 2009. However, even if the previous capacity planning criteria were still in place, it would remain relevant to assess the feasibility of 10 to 20 years Life Extension for the three Mirrlees diesel units at Whitehorse as a cost effective way to retain 14 MW of capacity capability on WAF.

1 4.4.3 below examines the expected effects of preferred near term projects on overall utility costs and
2 rates.

3 **4.4.1 Assessment of Opportunity Projects**

4 There are three ways that the identified major opportunity projects can provide qualitative and
5 quantitative benefits to Yukon power systems:

- 6 • **Peaking diesel fuel use reductions:** Although WAF loads today are at a level where surplus
7 hydro exists on this system, peaking diesel is becoming required on the coldest days of the year
8 and a reasonably high load growth rate is driving the system towards further requirements for
9 peaking diesel each year. Expansion of Aishihik capacity is particularly beneficial in this regard
10 until load growth in effect removes most of the opportunities for secondary sales.
- 11 • **Firm winter capacity benefits:** Certain enhancements to existing facilities can provide
12 additional firm capacity to aid in meeting the WAF firm capacity shortfalls noted above. This
13 applies to the Marsh Lake Fall/Winter Storage project and to the Carmacks to Stewart
14 Transmission Line project, but does not apply to the Aishihik 3rd Turbine in any material way
15 unless and until the Aishihik 2nd Transmission Line is developed.
- 16 • **Long-term average hydro energy benefits:** Finally, over the long-term, projects that bring
17 new long-term average hydro energy can provide the ability to displace diesel fuel once loads
18 grow to the point of diesel being required for baseload purposes (either through retail customer
19 load growth or the addition of new industrial customers). This benefit applies to all three of the
20 identified "opportunity" projects.

21
22 Table 4.2 provides a summary of the near term opportunity projects, including capital costs, in-service
23 timing. Capacity and energy benefits, and present value assessments (for at least two options) of the
24 long-term net diesel costs savings after consideration of project capital and operating costs.

1
2
3

**Table 4.2:
Summary of Near Term Opportunity Projects to 2012 (2005\$ millions)**

PROJECT ²¹	BASIS FOR PROJECT	PROJECT CONTRIBUTION ²²
IN PROJECT PLANNING STAGES (PRE-CONSTRUCTION ACTIVITIES, INCLUDING YUB REVIEW)		
Aishihik 3rd Turbine (2009) Capital cost: \$7 million	Economic opportunity for "Supply Side Enhancement" to existing facilities.	<ul style="list-style-type: none"> Hydro peaking capability (7 MW). Long-term energy enhancement (5.4 GW.h/year). no contribution to required firm capacity criteria without 2nd Aishihik Transmission. Long term net diesel cost savings of \$4.1 million (NPV, 2005\$) under Base Case load forecasts
COMMITTED PROJECTS PROCEEDING TO PROJECT PLANNING STAGES (INCLUDING YUB REVIEW)		
Marsh Lake Fall/Winter Storage (2007) Capital cost: up to \$1 million	Economic opportunity for "Supply Side Enhancement" to existing facilities.	<ul style="list-style-type: none"> 1.6 MW of firm capacity toward criteria, plus Hydro peaking capability, plus 7.7 GW.h/year long-term energy. Long term net diesel cost savings of \$10.0 million (NPV, 2005\$) under Base Case load forecasts.
Carmacks to Stewart Transmission Line Project (2008) Capital cost: \$35 million funded by YTG as required to ensure no adverse rate impacts.	Expansion of WAF system to interconnect WAF and MD, and to link two mine projects to WAF hydro surplus. (YTG funding of capital cost to ensure no adverse rate impact).	<ul style="list-style-type: none"> Enhance near term link for new mines to WAF hydro surplus. No new MD supply to WAF unless connect WAF and MD systems. Once connected, up to 6 MW of enhanced capacity for criteria, and up to 15 GW.h/year added hydro energy (decreasing over time).

²¹ Table 4.2 is in 2005\$. This table does not indicate the discounted present value of capital costs given in-service dates, the life of each option, or the rate-related impacts of depreciation, interest and return on equity.

²² NPV long-term net diesel savings reflects ratepayer NPV diesel savings less NPV for capital and operating costs of the project. Present values are assessed over an assumed 65 year life based on the assumed in-service dates, a discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre (peaking) and 3.9 kW.h/litre (baseload), diesel fuel prices at \$0.65/litres (2005\$), diesel O&M at \$0.016/kW.h (2005\$) and inflation at 2%/yr. No firm capacity or secondary sales benefits are included. See Appendix C for NPV long-term net diesel savings for the Aishihik 3rd Turbine Project (without and with Marsh Lake Fall/Winter Storage).

1 The costs and time requirements for the identified “opportunity” projects vary significantly, and are
2 material when assessing each option. Based on Table 4.2, the following summary observations are
3 provided:

- 4 • **Marsh Lake Fall/Winter Storage:** The least costly option (up to \$1 million estimated cost)
5 and potentially fastest to implement option (potential in-service by fall 2007) is the Marsh
6 Lake Fall/Winter Storage project, where the only major work required is to secure the
7 relicensing as needed. Under these circumstances, it is readily apparent that, once
8 developed, the project’s economic benefits materially exceed its economic costs during the
9 20-year planning period as well as during the longer-term. Table 4.2 indicates long term net
10 diesel savings of \$10.0 million (NPV, 2005\$) under Base Case loads.
- 11 • **Aishihik 3rd Turbine:** In contrast, even though the necessary licensing is in place, the
12 Aishihik 3rd Turbine project requires both material costs (estimated currently at about \$7
13 million) as well as material time to implement (earliest likely in-service may be 2008, but
14 more reasonably scheduled for 2009). Under these circumstances, more detailed economic
15 and financial assessments are needed to determine whether the project is likely to yield net
16 economic benefits during the planning period (even though long term net benefits are likely
17 to occur, based on assessments done in the past). Table 4.2 indicates long term net diesel
18 savings of \$4.1 million (NPV, 2005\$) under Base Case loads.
- 19 • **Carmacks to Stewart Transmission Line:** This project will proceed only if Yukon
20 Government funding ensures no adverse impact on ratepayers. Accordingly, costs are not a
21 driver in its assessment in this Resource Plan, i.e., if developed under these terms, its costs
22 will be required to be competitive with the least cost options then available to meet system
23 requirements. The project is in the early project planning stages and at the earliest could be
24 in service between mid-2008 and mid-2009.

25
26 More detailed assessment reviews are provided below of each project.

27 **4.4.1.1 Aishihik 3rd Turbine Project**

28 Under Base Case or higher loads without other sources of new hydro energy, the present value savings
29 from displaced diesel for the Aishihik 3rd Turbine option are expected to offset fully its capital costs.
30 Specific economic assessment cases are reviewed below (see Appendix C for more detailed tables setting
31 out the economic and financial present value assessments by year over the 65 year assumed economic
32 life of this project):

- 1 • **Base Case with no other projects:** Under Base Case conditions, assuming a 2009 in-
2 service the present value (2005\$) over the 20 year planning period of these diesel cost
3 savings is approximately equal to the costs that would be imposed on ratepayers of the third
4 turbine (depreciation, interest, return on equity, O&M) based on diesel prices at \$0.65/litre
5 (2005\$); this present value is beneficial by \$4.1 million over the 65 year life of the project²³.
6 – This reflects a NPV of diesel fuel and O&M savings of \$11.2 million (2005\$, largely
7 increasing throughout the period) and a NPV cost of the project (capital plus O&M) of
8 \$7.1 million.
9 – It ignores benefits from increased ability to make secondary sales²⁴.
10 – Under this scenario, the project would require 8 years from in-service until it was a net
11 positive impact on annual rates (to 2017)²⁵.
12 – The impact on YEC’s revenue requirement in any given year over the 20 year planning
13 period would vary from about negative \$0.67 million (first year) to a savings of about
14 \$1.44 million (2022) without including any secondary sales benefits in the near term.
15
16 • **Base Case with Mines:** If Aishihik 3rd turbine is developed concurrently with about 10 MW
17 of new mining load (the “base case with mines” scenario), the project net benefits over the
18 20 year planning period total \$3.7 million (NPV, 2005\$) and \$7.9 million over the 65 year life
19 of the 3rd turbine project. In this case, the project is a positive impact on revenue

²³ Assuming a nominal discount rate of 7.52%/year, diesel unit efficiency at 3.48 kW.h/litre for peaking and 3.9 kW.h/litre for baseload, diesel fuel prices at \$0.65/litres (2005\$), diesel variable O&M at \$0.016/kW.h (2005\$) and inflation at 2%/yr. Depreciation over 65 years is consistent with the “waterwheels, turbines and generation” category of assets as approved in the 2005 Required Revenues and Related Matters Application.

²⁴ Yukon Energy does not presently have sufficient load data to analyze the potential revenue benefits related to increased number of hours of secondary sales availability. In rough terms, winter secondary sales average at about 3 MW, or about \$198/hour at the current 6.6 cents/kW.h rate effective January 2006 (the rate approved by the YUB in Order 2005-12 was 5.2 cents/kW.h, effective January 2005 with ongoing quarterly adjustment to reflect changes in hearing oil prices). The Aishihik 3rd turbine will reduce the number of hours of diesel generation required on the system by about 127 hours in 2009 (first year of in-service) to about 1004 in 2021. In practice, secondary sales are interrupted for much longer than actual diesel generation time, as these sales can be interrupted for 24-48 hours in advance of expected cold weather. Even at the 127-1004 hour range of actual diesel generation, added secondary revenues would approximate \$25,000 to \$199,000 per year over the period (prior to WAF requiring base load diesel, which would lead to a total secondary sales interruption year round).

²⁵ Were Marsh Lake Fall/Winter Storage developed separately in advance of the Aishihik 3rd turbine (in 2007), the NPV of the project under Base Case loads over 20 years would become negative \$1.0 million, and positive \$3.1 million over the life of the project (ignoring secondary sales benefits), with 9 years required from a 2009 in-service to net annual cost savings to ratepayers (by 2018). Under this scenario, and without further development of mine loads or additional load growth, a delay of 1-2 years may be advisable (decision to proceed in 2009 for in-service in 2011) which would reduce the number of years of adverse rate impact back to 7, with an NPV over the period to 2025 (reflecting only 15 years of project service to that time) of negative \$0.3 million (lifetime NPV savings of \$3.8 million, compared to \$3.1 million if developed at 2009 after Marsh Lake, or \$4.1 million if developed at 2009 with no Marsh Lake).

1 requirement by year 3, with the annual impact varying from negative \$0.10 million (first
2 year) to \$1.44 million (2022)²⁶.

3
4 In summary, the Aishihik 3rd turbine project is an economically viable upgrade to the existing system that
5 can be economically pursued in the near term. The project economics are enhanced to the degree that
6 mine loads arise in the near term. The Resource Plan reflects commitment to this project for an in-service
7 of 2009 (requiring major design and tendering, as well as a YEC Board of Directors decision to construct,
8 to occur in late 2007/early 2008)²⁷. Projects assessed in subsequent sections of this Chapter presume
9 successful implementation of this project by fall 2009.

10 4.4.1.2 Marsh Lake Fall/Winter Storage Project:

11 The Marsh Lake Fall/Winter Storage project provides three sources of benefits:

- 12 1. **firm capacity** (1.6 MW towards both N-1 and LOLE),
- 13 2. **ability to avoid peaking diesel** (via extra 1.6 MW of hydro available at peak times before
14 YEC must run diesels), and
- 15 3. **increase to long-term average energy** (7.7 GW.h but varies somewhat based on system
16 loads).

17
18 As a source of new capacity alone, the expected costs of the project are not expected to be more than \$1
19 million (primarily related to environmental licencing and mitigation works) and equate to \$0.625
20 million/MW (compared to \$0.8 to \$0.9 million/MW for new diesel).

21
22 However, the capability to enhance the system with added peaking ability as well as added long-term
23 average energy equally justifies the Marsh Lake project (at an expected net present value of \$10.0 million
24 in diesel savings to ratepayers (2005\$) over the life of the project (at Base Case loads) with \$1.9 million
25 (2005\$) of these savings occurring during the period of the Resource Plan to 2025).

²⁶ Were Marsh Lake Fall/Winter Storage developed separately in advance of the Aishihik 3rd turbine (in 2007) under the Base Case with Mines load forecast, the NPV of the Aishihik 3rd Turbine project over 20 years would become positive \$2.6 million, and positive \$6.7 million over the life of the project, with three years required from a 2009 in-service to net annual cost savings to ratepayers (by 2012). This assessment is not adversely affected if the Carmacks-Stewart Transmission Project is also developed in 2008 (see Appendix C).

²⁷ In the event that Marsh Lake Fall/Winter Storage is pursued, mine loads are not proceeding towards commitment, and WAF loads are below forecast through 2006 and 2007, it may become necessary to delay the decision to construct by one to two years or more, depending on load conditions and forecasts at that time, in order to minimize potential adverse rate impacts in the early years of the project.

1 Accordingly, the Resource Plan reflects commitment to proceeding to the licencing and detailed technical
2 stages with this project for in-service by August 2007 or August 2008. Projects assessed in subsequent
3 sections of this Chapter presume successful implementation of the Marsh Lake Fall/Winter storage project
4 by August 2007.

5 **4.4.1.3 Carmacks to Stewart Transmission Project:**

6 This project is being examined using Yukon Government funding, on grounds separate from near term
7 WAF capacity needs.

8

9 As Yukon Energy cannot independently justify the interconnection on any reasonable current economic
10 grounds based on specific diesel savings or capacity benefits, the proposal to proceed with the project is
11 solely linked to external factors related to Yukon Government funding and the development of the two
12 mines. Accordingly, assessment of other project options in this Resource Plan does not presume
13 development of this interconnection.

14

15 The portion of this project from Carmacks to at least Pelly Crossing is likely to be in place if and when the
16 Minto and/or Carmacks Copper mines are supplied with WAF grid power²⁸. Accordingly, if and when it
17 becomes clear that these mine loads will develop for WAF, extension of this transmission project from
18 Pelly Crossing to Stewart Crossing (to provide full interconnection of the MD and WAF grids) is likely in
19 any event to be a technical option to provide WAF access to additional capacity (about 6 MW) and
20 surplus hydro energy (about 15 GW.h).

21 • The cost effectiveness of this interconnection option will continue to depend on Yukon

22 Government funding to ensure that there is no net cost to Yukon Energy or Yukon ratepayers
23 beyond what would be required for any other option to provide required capacity and energy.

24 • In this situation, assessments will need to consider the extent to which the surplus hydro
25 made available under this load situation will yield WAF economic benefits during the planning
26 period that serve to offset at least some of the capital costs through both diesel unit cost
27 savings and extended maintenance of secondary sales revenues.

28 • Full assessment of this option will also need to address risks related to re-opening of the
29 UKHM mine (or other new industrial developments) which would reduce or eliminate the MD
30 surplus hydro, as well as potential new opportunities provided by the interconnection, such

²⁸ Together, these mines are currently expected to require between 9 and 11 MW of peak power, and up to about 60 GW.h/yr of energy. The added net peak load imposed on WAF by these mines will depend on the extent to which these new mining operations develop their own on-site diesel plants either for backup or other reasons (potentially including interim operation prior to the arrival of utility power, or for benefits associated with waste heat during certain seasonal operations).

1 as potential additional enhancements for the existing Mayo hydro facility (including enhanced
2 peaking capability) or other new generation opportunities in the MD area.

3 **4.4.2 Assessment of Capacity-Related Projects**

4 With the adoption of new capacity planning criteria, major investments in the near term are required to
5 adequately serve forecast WAF loads. This conclusion is consistent over a wide range of possible load
6 forecast conditions, which indicate WAF capacity shortfalls beginning in 2006 and increasing to between
7 15 MW and 27 MW by 2012 for the current customer classes plus potential mining operations. In
8 contrast, the MD system has no forecast capacity shortfalls by 2012 under the revised capacity planning
9 criteria in the absence of new major industrial loads.

10
11 Based on assessment of the “opportunity” projects reviewed in Section 4.4.1 above, the Resource Plan
12 assumes commitment to the Aishihik 3rd Turbine project for in-service at 2009 and to the Marsh Lake
13 Fall/Winter Storage project for an in-service date of August 2007. Accordingly, these projects are
14 assumed to be in-service at the noted dates for the purposes of assessing the requirement for capacity-
15 related projects. However, because the proposal to proceed with the Carmacks to Stewart Transmission
16 Line project is solely linked to external factors related to Yukon Government funding and the
17 development of the two mines, assessment of capacity-related project options does not presume
18 development of this interconnection. Accordingly, the possibility of the Carmacks to Stewart Transmission
19 Line project (as an option) is included in the assessment of the capacity-related project options.

20
21 Table 4.3 summarizes the capital cost (2005\$) estimates outlined in Section 4.3 for screening purposes
22 related to the near term major resource options to address capacity shortfall requirements. These initial
23 screening cost estimates assume additional diesel units as the default option to provide any remaining
24 capacity needed beyond that provided by the major project option, as well as the opportunity projects
25 presumed to be in place (Aishihik 3rd turbine at 2009 and Marsh Lake Fall/Winter Storage at 2007)²⁹.

²⁹ Capacity required over and above major project options are lower than noted in *Section 4.3 Options* due to the assumed in-service of Marsh Lake Fall/Winter Storage in 2007 and Aishihik 3rd turbine (where relevant) in 2009.

1
2
3
4
5
6

Table 4.3:
Comparison of Near Term Capacity-focused Options to 2012
Assuming Marsh Lake Fall/Winter Storage in 2007 and Aishihik 3rd Turbine in 2009
Without Carmacks to Stewart Transmission Project Interconnection of WAF and MD
(Capital costs (2005\$ millions) - No present value assessments)

MAJOR PROJECT OPTIONS	ADDITIONAL DIESEL REQUIREMENT BY 2012 and costs if met with new diesel capacity ³⁰						TOTAL COSTS TO 2012
	Base Case Loads		<i>Low Sensitivity</i>		<i>High Sensitivity with Mines³¹</i>		
	Capacity	Cost	<i>Capacity</i>	<i>Cost</i>	<i>Capacity</i>	<i>Cost</i>	
Mirrlees Life Extension (14 MW; \$3.0 to \$4.5 million)	3.1 MW	\$2.5 to \$2.8 million	<i>0 MW (0.9 MW surplus)</i>	<i>\$0</i>	<i>10.5 MW</i>	<i>\$8.4 to \$9.5 million</i>	Base Case: \$5.5 - \$7.3 million Range: \$3.0 - \$14 million
Whitehorse Diesel Replacement/ Expansion (expected maximum of 33 MW ³²)	17.1 MW	\$13.7 to \$15.4 million	<i>13.1 MW</i>	<i>\$10.5 to \$11.8 million</i>	<i>24.5 MW</i>	<i>\$19.6 to \$22.1 million</i>	Base Case: \$13.7-\$15.4 million Range: \$10.5 - \$22.1 million
Aishihik 2nd Transmission Line in 2009 (22 MW at N-1 and 14.4 MW at LOLE; \$16.0 to \$19.0 million) ³³	0 MW (4.1 MW surplus)	\$0	<i>0 MW (8.1 MW surplus)</i>	<i>\$0</i>	<i>10.1 MW</i>	<i>\$8.1 to \$9.1 million</i>	Base Case: \$16.0 - \$19.0 million Range: \$16.0 - \$28.1 million

7

³⁰ Costs to meet calculated shortfall in capacity, at \$0.8-\$0.9 million per MW (2005\$) – assessment does not reflect optimization of unit size increments. Estimates assume Carmacks to Stewart Transmission is not developed (with development of this project, capacity shortfalls to be supplied by additional diesel would be reduced by about 5 to 6 MW in 2012).

³¹ The Base Case with Mines capacity shortfalls in 2012 are 5.2 MW less than shown here for High Sensitivity with Mines.

³² Capital costs at \$0.8-\$0.9 million per MW (2005\$); 33 MW is expected to be possible at the existing Whitehorse Rapids diesel plant using 3 - 11 MW units. Beyond 33 MW, consideration is required of site options given limitations of existing building and site.

³³ If an Aishihik 2nd transmission line is constructed, the WAF system capacity requirements become driven by the LOLE criteria not the N-1. Consequently, although the Aishihik 2nd transmission line provides 22 MW load carrying capability under the N-1 criteria, and 14.4 MW under the LOLE criteria, the net effect of constructing the line under the Base Case conditions is 21.2 MW (from a 17.1 MW shortfall to a 4.1 MW surplus at 2012), reflecting that with the 2nd line the LOLE criteria rather than the N-1 criteria creates the ultimate capacity requirement.

1 Assessment of options to address near term requirements remains dependent upon ongoing
2 investigations to define in more detail each option's conditions and costs. The major Resource Plan near
3 term options to address capacity shortfalls are assessed below in light of current information and the
4 revised capacity planning criteria requirements. The assessment is addressed under two main situations
5 regarding the technical feasibility of the Mirrlees Life extension option, assuming that it will be
6 determined within the next few months to be either feasible or not feasible.

7 **4.4.2.1 Assuming Mirrlees Life Extension Project is Technically Feasible**

8 If the Mirrlees Life Extension project is technically feasible, this is the clear least cost option to provide 14
9 MW of reliable near term capacity. At \$3.5 to \$4.5 million for all three units, this option costs from
10 \$250,000 to \$321,000 per MW. These costs are well below those needed for diesel
11 replacement/expansion (at \$800,000 to \$900,000 per MW), or the costs for an Aishihik 2nd transmission
12 line. Mirrlees Life Extension can also be developed incrementally as needed.

13

14 Notwithstanding these obvious advantages, serious technical issues are still being addressed to determine
15 if this option is feasible and capable of providing full life extension of 10-20 years (including all required
16 parts and technical support from the manufacturer). It is expected that an initial decision will be made in
17 first quarter of 2006 based on an assessment of the capability of the manufacturer to provide technical
18 resources and support, references of other utilities who have pursued life extension options with similar
19 Mirrlees units, and refined expected costs of the option based on further assessment of both overhaul
20 requirements and shared facility requirements (which are ongoing).

21

22 If the Mirrlees Life Extension option is determined to be feasible and acceptable on technical grounds, a
23 series of steps and assessments will remain to address the expected near term capacity shortfalls and
24 other near term resource development opportunities. These assessments are set out below:

25 1. **Proceed with initial Mirrlees 5 MW Unit Life Extension project in 2007:** The first
26 step will involve Yukon Energy contracting out a first "teardown" level of overhaul on one of
27 the units to occur during the summer of 2007 (focusing likely on the 5 MW unit to be retired
28 currently in 2007). The common diesel plant upgrade work would also be undertaken at the
29 same time (at an estimate cost of \$1.0 to \$1.5 million). Yukon Energy is proposing this
30 schedule in light of the current expectation that the maximum cost commitment for this first
31 unit would not exceed \$2.5 million (2005\$). Under this scenario, the WAF system would
32 experience an expected capacity shortfall during the winter of 2006/07 of about 0.7 MW prior
33 to the planned capacity work in 2007.

- 1 2. **Proceed with the other two Mirrlees unit Life Extensions in 2008 and 2009:** The
2 other two unit Life Extension projects would be proceeded with on a timely basis. Prior to
3 proceeding with each of these projects, which are currently expected to cost up to \$1.0
4 million (2005\$) per unit, Yukon Energy would review the experience gained from Life
5 Extensions carried out to date.
6
- 7 3. **Preferred Options to meet the Remaining Capacity Shortfall on WAF (3.1 to 10.5**
8 **MW):** Even with provision of 14 MW from the Mirrlees Life Extension project, Yukon Energy
9 will still need under the Base Case load conditions to develop at least an additional 3.1 MW
10 new capacity by 2012 (and this added requirement could range up to 10.5 MW under the
11 high load cases examined). Adoption of the Life Extension option will affect the assessment
12 of the other remaining options to provide the balance of the capacity requirement (based on
13 the assessments below, the Carmacks to Stewart Transmission Line Project, if developed with
14 Yukon Government funding, could provide a preferred way to provide up to about 6 MW of
15 added firm capacity):
- 16 a) **Whitehorse Diesel Expansion options would be limited - may need to assess**
17 **other locations for additional diesel unit units as a default option:** The option of
18 developing Whitehorse Diesel Expansion might not be feasible within the current building
19 or even potentially at the current plant site under these conditions, and it may be
20 necessary to assess other locations for any additional diesel unit options. Costs for diesel
21 expansion at a new location as a default planning option involving 4 MW or larger units
22 are likely to approximate \$1 million per MW. A variation that may merit consideration is
23 Life Extension on the two larger (5 MW nameplate) Mirrlees units, plus replacement of
24 the smaller Mirrlees unit (4 MW nameplate) with an 8 or 11 MW new unit to secure the
25 needed capacity.
- 26 b) **2nd Aishihik Transmission Line not likely to be cost effective option:** The
27 Aishihik 2nd Transmission Line project by itself is not likely to be cost effective in the
28 near term under these conditions, given its cost (currently estimated at \$16 to \$19
29 million) and its “lumpy” delivery of 22 MW of effective capacity all at one time.
- 30 c) **Carmacks to Stewart Transmission Line can be attractive with Minto and**
31 **Carmacks Copper Mine Loads:** The portion of this project from Carmacks to at least
32 Pelly Crossing is likely to be in place if and when these mines are connected to the WAF
33 grid. Accordingly, if and when it becomes clear that these mine loads will develop for
34 WAF, extension of this transmission project from Pelly Crossing to Stewart Crossing (to
35 provide full interconnection of the MD and WAF grids) is likely in any event to be a

1 technical option to provide WAF access to additional capacity (about 6 MW) and surplus
2 hydro energy (about 15 GW.h); the cost effectiveness of this option may also be resolved
3 based on Yukon Government funding to ensure no adverse effect on ratepayers relative
4 to any other option. (See Section 4.4.1.3 for further review of this option.³⁴)

5 **4.4.2.2 Assuming Mirrlees Life Extension is Not Technically Feasible**

6 If the Mirrlees Life Extension project is not technically feasible and the Mirrlees units must be retired, the
7 key initial decision becomes whether or not to develop the Aishihik 2nd Transmission Line Project. As
8 noted in Table 4.3, the Aishihik 2nd Transmission Line fully addresses the capacity requirements of the
9 Base Case loads.

10
11 In summary the near term choice under these conditions is between the Aishihik 2nd Transmission Line
12 Project (22 MW of near term capacity benefits under N-1, 14.4 MW under LOLE)³⁵, versus reliance on
13 major Whitehorse Diesel Replacement/ Expansion for at least the same amount of new near term
14 capacity (17.1 MW, with potential to range from 13.1 MW to 24.5 MW). As reviewed below, current
15 information does not necessarily indicate a clear preferred approach under these conditions. Ongoing
16 investigations will continue to assess these options if it becomes clear that the Mirrlees Life Extension
17 option is not technically feasible.

18
19 Technical, cost and risk issues assessed with regard to this choice (see below) underline the nature of the
20 problems and opportunities associated with selecting the Aishihik 2nd Transmission Line option at this
21 time rather than pursuing Whitehorse Diesel Replacement/Expansion on an incremental basis in the event
22 that the Mirrlees Life Extension is not feasible:

- 23 **1. Cost effectiveness of capacity benefits for Aishihik 2nd Transmission Line option is**
24 **affected by several factors:** Initial review of capital costs per MW indicates that the
25 Aishihik Transmission Line option is likely to cost from \$0.73 to \$0.86 million per MW (2005\$)
26 under the N-1 condition (from \$16 to \$19 million, to provide 22 MW) or from \$1.11 to \$1.32
27 million per MW (2005\$) under the LOLE condition (for 14.4 MW firm load carrying capability).

³⁴ Assuming Mirrlees Life Extension is implemented, the Carmacks to Stewart Transmission Line would displace up to about 6 MW (depending on the load case assumed) of new diesel expansion capacity costing about \$1 million per MW (2005\$).

³⁵ Given that the Aishihik 3rd Turbine is economic on its own for energy-related reasons in the near-term, the benefits of the Aishihik 2nd Transmission line are 22 MW under N-1 (i.e., if Aishihik 3rd Turbine is already built prior to the line, the line would serve to reduce the "N-1" factor from 37 MW (the total capacity output of Aishihik) to 15 MW (the largest single wheel at Aishihik).

1 2. The cost effectiveness of this option is affected by several factors:

- 2 • Transmission Line Capital Cost is lower than comparable Diesel Replacement/Expansion
3 Capital Cost under non-industrial scenarios: This transmission project capital cost under
4 N-1 is estimated to be slightly lower than the capital cost (2005\$) expected for
5 Whitehorse Diesel Replacement/Expansion (\$0.8 to \$0.9 million per MW). This however
6 ignores the addition risks related to transmission line cost estimating compared to new
7 diesels, as set out below.
- 8 • Transmission Line Capital Cost is higher than diesel if LOLE criteria applies with sufficient
9 mine development: The cost competitiveness of the Aishihik 2nd Transmission Line option
10 is eroded in the event that mine development is sufficient to reduce its effective capacity
11 contribution to only 14.4 MW (in the event that the LOLE criteria becomes dominant over
12 the N-1 criteria).
- 13 • Added Offset benefits possible from Aishihik 2nd Transmission Line if develop future
14 Aishihik capacity via re-runnering: The Aishihik 2nd transmission line enables the
15 opportunity for other potential capacity-related projects at Aishihik (as yet relatively
16 undefined) focused principally on re-runnering the existing units for added capacity
17 output of potentially up to 6 MW. Although this potential future project has not been
18 costed or had sufficient technical or environmental analysis (such as flow velocities), re-
19 runnering is often viewed in other jurisdictions as a cost-effective way to enhance the
20 existing system for added capacity (and/or energy). Without the Aishihik 2nd
21 Transmission Line project, it is unlikely that rerunnering at Aishihik would be economic
22 (sicne it would not provide any effective ability to contribute to firm WAF capacity during
23 the winter peak).

24

25 3. **Timing and Cost Risk Concerns with Aishihik 2nd Transmission Line options:** Key
26 concerns with regard to the Aishihik 2nd Transmission Line Project include the timing and
27 substantial costs needed to deal with planning, permitting, and approvals prior to receiving
28 solid capital cost estimates via the tendering process. If a preliminary commitment to the
29 project was in place in 2006, planning and firm cost estimates would not likely be completed
30 until well into 2007 at the earliest and the transmission line's in-service would in all likelihood
31 be no earlier than 2009. During the period to 2009, capacity shortfalls on the WAF system
32 would grow to 7.1 MW (related to both load growth and retirement of the first Mirrlees
33 WD3). On these matters (timing, and the delayed certainty with respect to cost estimates,
34 and the risks of capacity shortfalls in the interim) the Whitehorse Diesel
35 Replacement/Expansion option is expected to have a clear advantage.

- 1 4. **Load Risk Concerns with Aishihik 2nd Transmission Line options:** The potential cost
2 effectiveness of the Aishihik 2nd Transmission Line combined with the Aishihik 3rd Turbine
3 project is dependent on load conditions. This is because the project provides more capacity
4 than is required at 2012 under the Base Case and Low Sensitivity scenarios, but is of lesser
5 capacity value under the very high sensitivity case scenarios with mines (14.4 MW, compared
6 to 22 MW under N-1) which clearly exceed Base Case forecasts³⁶ while also not becoming so
7 high due to new industrial mine loads as to cut back the effective capacity benefits³⁷.
8
- 9 5. **Issues regarding 2nd Transmission Line Overlap with Carmacks to Stewart Project:**
10 Concurrent development of the Carmacks to Stewart Transmission Line project with the
11 Aishihik 2nd Transmission Line Project could create adverse overlap issues for Yukon Energy
12 with regard to planning, permitting, design and construction if the Carmacks to Stewart
13 project is proceeding as reviewed in 4.4.1. Conversely, in the even of the Base Case with
14 Mines loads, the two project could together meet the overall capacity shortfall by 2012³⁸.
15
- 16 6. **Carmacks to Stewart Transmission Line can be attractive with Minto and
17 Carmacks Copper Mine Loads:** The portion of this project from Carmacks to at least Pelly
18 Crossing is likely to be in place if and when these mines are connected to the WAF grid.
19 Accordingly, if and when it becomes clear that these mine loads will develop for WAF,
20 extension of this transmission project from Pelly Crossing to Stewart Crossing (to provide full
21 interconnection of the MD and WAF grids) is likely in any event to be a technical option to
22 provide WAF access to additional capacity (about 6 MW) and surplus hydro energy (about 15
23 GW.h); the cost effectiveness of this option may also be resolved based on Yukon
24 Government funding to ensure no adverse effect on ratepayers relative to any other option.
25 (See Section 4.4.1.3 for further review of this option.)³⁹.

³⁶ This option is clearly not cost effective even when assessed over 40 years to 2045 under the Low Sensitivity case. Even under Base Case loads, securing 40-year net present value benefits can be very sensitive to assumed costs and diesel saving magnitudes.

³⁷ Net benefits over 40 years, for example, will be minimal under some cost and diesel saving assumptions at 25 MW mine loads.

³⁸ Under such joint development without Mirrlees Life Extension, the Carmacks to Stewart Transmission would displace about 5 MW of new diesel costing about \$0.8 to \$0.9 million per MW (2005\$).

³⁹ Regardless of the selection of Aishihik 2nd Transmission project or Diesel Replacement/Expansion (assuming Mirrlees Life Extension is not implemented), in the event that the Minto and Carmacks Copper mines are developed the Carmacks to Stewart Transmission Project would appear likely to displace by 2012 up to about 6 MW of new diesel costing \$0.8 to \$0.9 million per MW.

1 **4.4.3 Schedule and Sequencing of Alternatives**

2 Based on the review of opportunity and capacity-related projects above, the potential scheduling and
3 sequencing of these near term projects is illustrated in Figure 4.15.

4
5 As indicated in Figure 4.15, both opportunity projects and capacity-related projects are required to be
6 initiated and pursued in the near term to address constraints (Marsh Lake Fall/Winter Storage and
7 Capacity-Related projects to address capacity shortfalls; Carmacks-Stewart Transmission Line to address
8 opportunity to service mines in the region, as well as access YTG infrastructure funding).

9
10 The exception to current timing constraints is the Aishihik 3rd turbine. This project has some flexibility
11 regarding the scheduling and in-service date (as it does not contribute to firm capacity shortfalls). As
12 indicated in Appendix C, the economics of the project are considerably improved if it is in service as of
13 the start of any new mining loads. However, without new industrial loads and with Marsh Lake
14 Fall/Winter Storage proceeding, it may be advantageous to delay Aishihik 3rd turbine by about two years
15 compared to the timing in Figure 4.15; this decision can be part of the late 2007 assessment by YEC as to
16 whether to proceed with the project at that time.

17 **4.4.4 Rate related Impacts of Near Term Options**

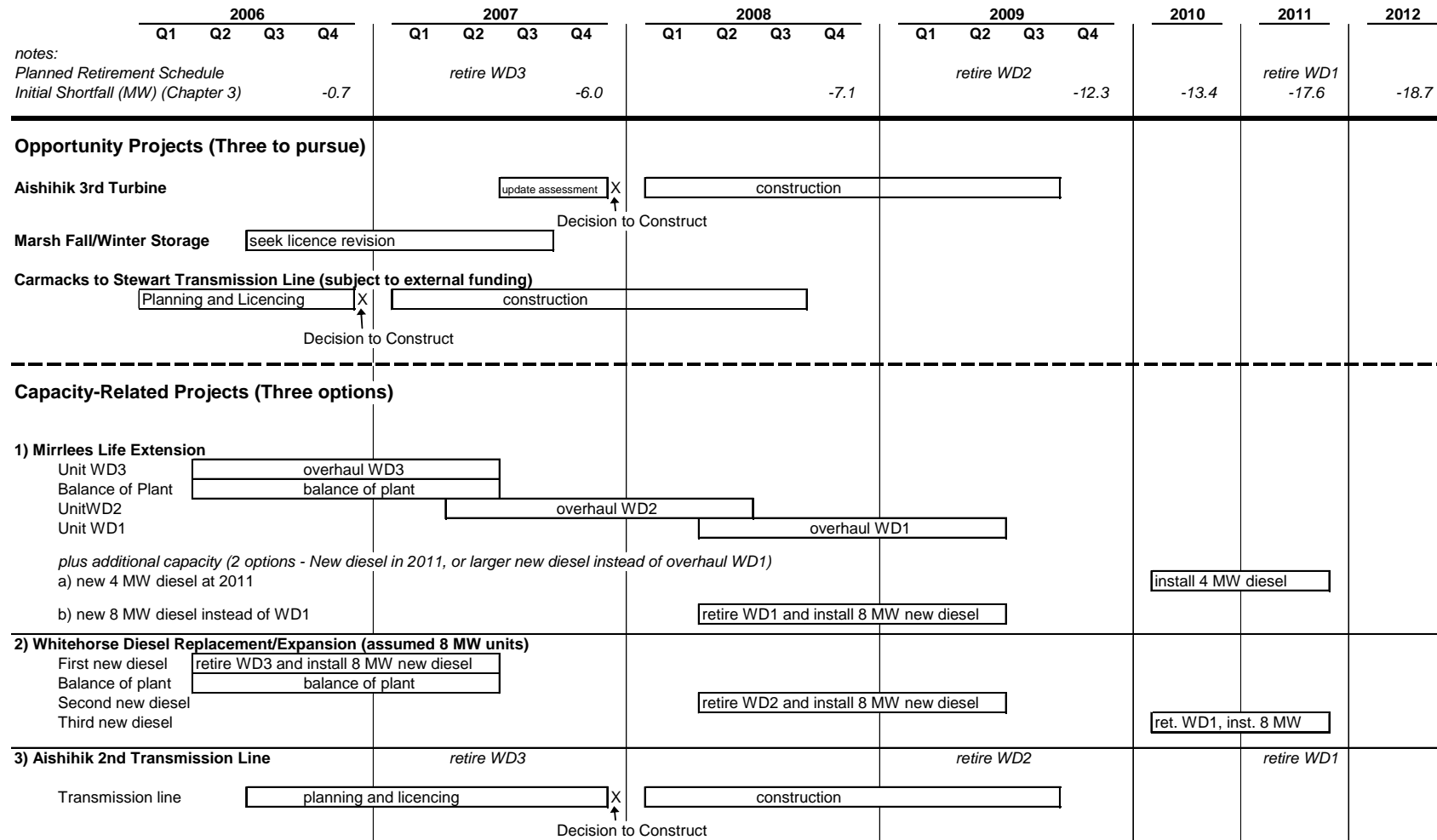
18 This section provides a brief examination of the expected effects of preferred near term projects on
19 overall utility costs and rates.

20
21 Separate financial assessment is required of the effect of any project on rates, as rates for any given year
22 are set based on annual costs (including depreciation, interest and return on equity) rather than the
23 lifetime long-term costs of projects in service. For capital intensive projects such as hydro or
24 transmission, these annual costs tend to be at a maximum in the first few years of the project (when rate
25 base balances are highest) while benefits can in many cases extend and grow many years into the future
26 (50-100 years in some cases).

27
28 Under current rates and OIC 1995/90, Yukon-wide rate impacts are likely to arise of about 1% if utility
29 costs (revenue requirements) are increased in any one year by \$360,000 compared to alternatives.

1
2
3

**Figure 4.15:
Timing and Sequencing of Opportunity and Capacity-Related Projects**



1 Two key aspects of rate impacts arise with respect to the near term projects:

2 1. **Opportunity Projects seek to put in place economic assets that provide long-term**

3 **benefits:** The relative rate impacts of the three opportunity projects vary depending on the
4 particulars of the project:

5 a) **Aishihik 3rd turbine:** As reviewed in *section 4.4.1*, the Aishihik 3rd turbine project
6 provides long-term rate benefits. In the first years of the project, however, there is the
7 potential for adverse rate impacts (see Appendix C for more detailed tables):

8 i. **Base Case Assumptions:**, Under Base Case assumptions, much like other capital
9 intensive hydro projects, the annual costs of the project will outweigh the annual
10 benefits for a number of years (until offset by inflation and load growth). At a
11 maximum (year 1 if developed in 2009) this impact will be less than 2%, which
12 declines through 2017 (2018 if develop Marsh Lake Fall/Winter Storage first) after
13 which it becomes a positive and growing rate benefit.

14 ii. **Base Case with Mines:** If about 10 MW of new industrial loads are connected to
15 the system in the near term (consistent with the two mines now proposed north of
16 Carmacks), the maximum adverse rate impact (year 1 if developed in 2009) will be
17 0.3% (0.9% if Marsh Lake Fall/Winter Storage previously developed), and by year 3
18 will be a positive and growing rate benefit compared to the situation without the
19 project (year 4 if Marsh Lake Fall/Winter Storage previously developed).

20
21 In this case, some benefits of the capital intensive Aishihik 3rd turbine increase each
22 year as the value of diesel displaced increases with inflation or other upward fuel
23 price drivers. However, the Aishihik 3rd turbine project imposes the highest costs on
24 ratepayers in the early years.

25
26 In summary, although very attractive economically over the long-term, the Aishihik
27 3rd turbine project will result in adverse rate impacts in the first year of the project
28 under all near term cases assessed (0.3% to almost 2%), with this impact lasting 2-8
29 years (this is similar to the MD Transmission Project, which was forecast to be a
30 beneficial project for ratepayers over its life, but did result in the need to address
31 what would otherwise have been adverse rate impacts in the first two years via
32 flexible debt financing from YDC).

33 b) **Marsh Lake Fall/Winter Storage:** This project brings firm capacity, peaking capacity
34 and long-term energy benefits. The costs of the project (estimated at no more than \$1
35 million) reflect a maximum cost for the firm capacity of \$0.625 million/MW, which is

1 cheaper than new diesel (assuming all capital costs of the Marsh Lake project are
2 calculated in the cost/MW, ignoring energy benefits). Ignoring energy benefits, the
3 capital-related costs of Marsh Lake at the maximum \$1 million level would drive annual
4 depreciation costs of \$0.016 million plus interest and return on equity costs in the first
5 year of about \$0.078 million plus O&M costs of about \$0.005 million. At a maximum, the
6 project will be an upward rate driver of about 0.28%, offset by the savings in peaking
7 diesel (which exceed this level by 2013).

8 c) **Carmacks-Stewart interconnection:** This project will only be developed if funded via
9 no-cost capital (e.g., Yukon government funding) to a level that ensures no adverse rate
10 impacts on ratepayers. The value of a potential Carmacks-Stewart interconnection will
11 erode over time if the surplus hydro energy and installed capacity available for exchange
12 between the two grids from this project reduce over time with load growth (or new
13 industrial loads) on either system (as will occur at some point if load growth continues
14 without development of new lower cost capital intensive energy resources). However,
15 this limit only occurs to the extent that the flexibility provided by the interconnection
16 does not enable development of attractive new generation projects (such as facility
17 enhancements at the existing Mayo plant or other hydro opportunities in the MD area).

18
19 2. **Cannot avoid investment in new capacity, which will tend to be upward rate**
20 **driver:** The adoption of the revised capacity planning criteria requires that under Base Case
21 load assumptions a material investment in new capital spending will be required by 2012
22 assuming Mirrlees life extension is implemented, and higher investment if other alternatives
23 are pursued. This amount is over and above normal utility capital amounts for re-investment
24 and facility renewal (which tend to have a relatively stable impact on rates). The major new
25 capacity-driven capital spending to 2012 results in relatively little change to other utility
26 costs. The resulting rough estimations of gross impacts on rates at 2012 are as follows for
27 the screening options noted in Table 4.3⁴⁰:

28 a) **Mirrlees Life Extension:** With a \$5.5 million to \$7.3 million capital investment by 2012
29 (2005\$), resulting revenue requirements are likely to be increased by about \$0.6 million
30 to \$0.8 million (at about 30 years depreciation on diesel assets and 7.52% average cost
31 of capital) or in the range of 1.7% to 2.2% impact on rates.

⁴⁰ The calculations do not reflect estimated rate base values at 2012, which would be higher than simple capital cost estimates due to inflation between 2005\$ and the actual date of in-service, and be reduced by depreciation from the date of in-service to 2012.

- 1 b) **Whitehorse Diesel Replacement/Expansion:** At an estimated Base Case
2 requirement for \$13.7 million to \$15.4 million capital investment by 2012 (2005\$),
3 resulting revenue requirements are likely to be increased by about \$1.5 million to \$1.7
4 million (at 30 years depreciation on diesel assets and 7.52% average cost of capital) or
5 in the range of 4.1% to 4.6% impact on rates.
- 6 c) **Aishihik 2nd transmission line:** Base Case costs of \$16.0 million to \$19.0 million
7 (2005\$) by 2012 (at 50 years depreciation for transmission line, 7.52% average cost of
8 capital) with resulting annual costs of \$1.5 million to \$1.8 million, or rate impacts in the
9 range of 4.2% to 5.0%.

10

11 The gross impacts noted above are full impacts to address capacity shortfalls to 2012 under
12 the revised criteria. These gross impacts do not address the fact that major capital spending
13 is required by 2012 even under the previous capacity planning criteria to address a shortfall
14 of 5.6 MW under Base Case loads⁴¹.

15 **4.5 PROPOSED ACTIONS**

16 Four separate major investments are proposed for Yukon Energy generation and transmission
17 commitment before 2009, three with anticipated costs of \$3 million or more. These proposed major
18 projects will address near term requirements and opportunities to 2012 and together will provide over 21
19 MW of new WAF firm winter capacity by 2012 (i.e., enough new firm capacity to meet WAF capacity
20 shortfalls that would otherwise be expected by 2012 of 18.7 MW under the Base Case forecast and 21.5
21 MW under the Base Case forecasts plus the Minto and Carmacks Copper mine loads). The four major
22 proposed projects are reviewed below, along with contingency provisions and other proposed actions
23 before 2012:

- 24 **1. Aishihik 3rd Turbine Project:** This project, which was initially reviewed in the 1992 YUB
25 Resource Plan hearing, will provide 7 MW of added peaking capability⁴² and about 5.4
26 GW.h/yr of long-term average hydro energy supply at the existing Aishihik generation station
27 at a capital cost of about \$7 million (2005\$). Under Base Case loads without any new
28 industrial developments, this project is expected to be economic within the planning period to

⁴¹ If full Mirrlees Life Extension is pursued under Base Case loads under the previous criteria (to secure 14 MW of capacity by 2012, but worth 12.6 MW under the existing capacity planning criteria due to 10% diesel reserve factor, securing a 7.0 MW surplus and ensuring the units are not lost to disrepair and neglect), an estimated \$3.0 to \$4.5 million in capital costs would be expected to be incurred, for an annual rate impact cost of about \$0.3 to \$0.5 million or 0.9% to 1.4%.

⁴² Without twinning of the Aishihik Transmission Line, none of this added Aishihik capacity is recognized under the N-1 WAF capacity planning criteria, and only 0.6 MW is recognized under the LOLE WAF capacity planning criteria.

1 2025 based solely on its diesel operating cost saving benefits for the WAF grid, including
2 displacement of peaking and then baseload diesel as WAF loads increase. Yukon Territorial
3 and environmental approvals for the project were received in the new Aishihik Water Licence.

4 a) Accordingly, this project will proceed with final planning activities to enable a final
5 decision during 2007 to start construction for in-service by October 2009.

6 b) If Marsh Lake Fall/Winter Storage is developed without any additional non-industrial load
7 growth or new industrial loads emerging, the final decision to start construction is
8 proposed to be deferred until late 2009 for in-service in 2011 or 2012.

9
10 **2. Marsh Lake Fall/Winter Storage licence revision:** This project, which was not reviewed
11 in the 1992 Resource Plan hearing, will increase the firm winter capacity of the Whitehorse
12 Rapids hydro facility by about 1.6 MW and increase long-term average hydro energy from
13 this facility by about 7.7 GW.h/year at a capital cost of no more than \$1 million.⁴³ Yukon
14 Energy will undertake the project planning activities, including consultation and
15 environmental licensing, as required to seek amendment of the Whitehorse Rapids water
16 licence to enable modified operation of Marsh Lake within its current lake levels to enhance
17 fall/winter storage. Basically no new physical works are expected to be required for this
18 project. Project approval is forecast by August 2007 (although provision is made in the event
19 that the new Yukon environmental licencing regime requirements delays completion of the
20 licence amendment to 2008). The effects of the proposed licence amendment are
21 summarized as follows:

22 a) **Remain within current lake level limits:** In all cases, the water levels with the
23 amended licence will remain within the lake level limits currently experienced (i.e., the
24 peak controlled level would be below the natural high water levels experienced in the
25 lake).

26 b) **Licence amendment changes the "controlled maximum" level:** The proposed
27 amendment would change the licenced "controlled maximum" level that YEC can
28 maintain upwards by about one foot; however, during uncontrolled periods of summer
29 and fall (when YEC currently has no control over the lake and it is operating under an
30 entirely natural regime), Marsh Lake has been known to peak at two feet above the YEC
31 "controlled maximum" level. The effects of the proposed change are as follows
32 depending on water conditions:

⁴³ This estimated capital cost is made up of the costs for licencing, any required mitigation works and any potential facility modifications

- 1 i. **Non flood year operation other than a drought:** This project would allow Yukon
2 Energy to reduce the amount of water it releases in non-flood years from August 15
3 to the end of September, to allow that water to be used instead during the peak
4 winter generation period. No effect is to occur under these conditions in any year
5 prior to August 15, other than under drought conditions (see below).
6 ii. **Flood year operation:** During flood years, there would be no change in the flood
7 levels experienced on Marsh Lake, and no change to operations would be made
8 during August and September until after flood levels subside.
9 iii. **During drought years:** Current licence provisions to help alleviate summer drought
10 levels on Marsh Lake through “early closures” of the Lewes Dam would remain, and
11 would likely be adapted to alleviate further summer drought conditions to ensure the
12 lake reached the full supply capacity level in each year.
13
14 3. **Carmacks-Stewart Transmission Line Project:** This project will fully interconnect the
15 MD and WAF grids as well as facilitate WAF transmission access to potential new mine loads
16 at Minto and Carmacks Copper, providing 5.6 MW of additional firm near term capacity and
17 15 GW.h/year of additional near term energy for WAF⁴⁴. Development of this project, which
18 is estimated to cost about \$35 million (2005\$), is subject to provision of Yukon Government
19 funding to ensure that there is no net cost to Yukon Energy or Yukon ratepayers beyond
20 what would be required for any other option to provide required capacity and energy. Based
21 on external funding to assure no adverse impact on ratepayers from project development,
22 planning activities will proceed with the Carmacks-Stewart project to enable a decision to
23 proceed with construction early in 2007 for an in-service date in approximately late 2008.
24
25 4. **Mirrlees Life Extension Project:** Subject to confirmation of technical feasibility that is
26 expected to be determined within the first quarter of 2006, the Mirrlees Life Extension Project
27 will conclude final planning activities in 2006 in order to provide in-service during 2007
28 through to 2009 to provide an additional 14 MW of firm WAF capacity at a cost of up to \$4.5
29 million (2005\$).

⁴⁴ Added capacity and energy supplied to WAF by this interconnection are subject to MD loads, and will decline as MD loads increase. Reopening of the UKHM mine or other new industrial developments on MD, for example, would reduce MD surplus capacity and hydro energy available to WAF. In contrast, potential additional enhancements at the existing Mayo hydro facility or other new generation opportunities in the MD area could enhance overall WAF/MD power supply in the event of Carmacks-Stewart Transmission line development.

1 a) **First Mirrlees unit in service by October 2007:** By the summer of 2006 planning
2 work and commitments for construction/implementation will begin on the first Mirrlees
3 unit (5MW) at a cost of up to \$2.5 million (2005\$)⁴⁵ in order that in-service will occur
4 before October 2007.

5 b) **Other two Mirrlees units by October 2008 and 2009:** Life Extension for the other
6 two Mirrlees units will proceed thereafter for expected in-service in 2008 and 2009,
7 subject to review of the experience gained from Life Extension of the first unit and the
8 possible Yukon Energy consideration of replacing the third Mirrlees unit (4 MW) with a
9 larger capacity new diesel unit (e.g., 8 MW or 11 MW unit).⁴⁶

10
11 5. **If Mirrlees Life Extension is not technically feasible, implement diesel**
12 **replacement/expansion and/or other project options as appropriate:** Without the
13 Mirrlees Life Extension option providing 14 MW of firm capacity, the key near term choice is
14 between the option involving Whitehorse Diesel Replacement/Expansion (capability for three
15 units with combined capacity of up to at least 33 MW) versus the Aishihik 2nd Transmission
16 Line (providing 22 MW under N-1 criteria and about 14.4 MW with LOLE criteria)⁴⁷.

17
18 Although the expected capacity shortfall can technically be met with the Aishihik-related
19 option, this is not expected to be the lowest cost option to 2012 under Base Case loads and
20 also this is not the lowest cost long-term option under higher loads including mines. The
21 Aishihik-related option also exposes the WAF grid to near term and growing capacity
22 shortfalls until it is completed.

23
24 Accordingly, the Diesel Replacement/Expansion option will be implemented as follows in the
25

⁴⁵ This cost includes a "teardown" level of overhaul and the common diesel plant upgrade work necessary to undertake the Mirrlees Life Extension Project.

⁴⁶ In the event that Mirrlees Life Extension proceeds but the Carmacks-Stewart Transmission Line is not developed in the near term, replacing the third Mirrlees unit with an 11 MW new diesel would more than replace the capacity that otherwise would have been provided by the Carmacks-Stewart Transmission Project.

⁴⁷ In this context, the Aishihik-related option has been examined for possible implementation assuming that it is feasible to commit development of the Aishihik 2nd Transmission Line by 2009 at the latest; under this option, material near term capacity shortfalls would still occur until the Aishihik 2nd Transmission Line was in service.

1 event that Mirrlees Life Extension is not technically feasible⁴⁸:

2 a) **First Diesel Unit (8 to 11 MW) needs to be installed by October 2007** Yukon
3 Energy will need under these circumstances to proceed with final planning work on this
4 project by summer 2006, including orders for the necessary engine unit (with
5 cancellation provisions) in order that the unit can be installed by October 2007 at a
6 capital cost (2005\$) of up to about \$7.2 million (8 MW) or \$8.8 million (11 MW). This will
7 include updating any common diesel plant systems necessary for connection of a new
8 unit.

9 b) **Other Diesel Units:** Once the first unit is committed, it is expected that up to two
10 additional diesel units (depending on the unit size selected) will be implemented
11 thereafter as required for in-service before 2012.

12
13 6. **Ongoing monitoring of existing customer load forecasts and new industrial**
14 **development opportunities:** In order to facilitate ongoing assessment of generation and
15 transmission options and requirements, Yukon Energy monitoring of annual customer class
16 load trends (peak capacity and seasonal energy) on each grid is required. In addition, Yukon
17 Energy will continue to monitor directly with developers and government specific new
18 industrial development opportunities for grid power service, including assessment of any
19 mine site power contribution to the supply of reliable grid peak capacity.

20
21 7. **Other Small Enhancement Projects:** Continued routine utility investment is
22 recommended in assessing and proceeding with projects to enhance existing facilities at a
23 cost less than \$3 million. This includes:

- 24 • study of the hydrology of the Southern Lakes, and potentially pursuing small water
25 control structures in this region (new generating stations to manage water plus generate
26 hydro power would, if proposed in the future, exceed \$3 million);
- 27 • continued pursuit of opportunities to cost-effectively rewind or re-runner existing hydro
28 generating units at Whitehorse and Aishihik; and,
- 29 • assessing need and timing for a potential 1 MW diesel unit installation at Carcross/Tagish
30 (likely by YECL).

⁴⁸ Diesel Replacement/Enhancement will also be the option pursued as required in the event that other major projects do not proceed as proposed, e.g., the Carmacks-Stewart Transmission Line Project (which is assumed to provide 5.6 MW by late 2008) and/or the Marsh Lake Fall/Winter Storage (which is assumed to provide 1.6 MW by fall 2007 or 2008). In the event that mine loads are connected to WAF without completion of the Carmacks-Stewart Transmission, Yukon Energy will review the feasibility of the Aishihik 2nd Transmission Line project.

1 5.0 INDUSTRIAL DEVELOPMENT SCENARIOS AND OPPORTUNITIES

2 This chapter addresses planning activities that Yukon Energy may be required to carry out in order to be
3 able to start construction on generation and transmission projects before 2016 (beyond those projects
4 noted in Chapter 4 for commitment in the near term before 2009), largely to meet the needs of potential
5 major industrial customers.

6
7 Industrial development scenarios and opportunities include possible new mines, or other major potential
8 developments in Yukon including the Alaska Highway Natural Gas Pipeline project. This chapter focuses
9 on project resource options that have the potential to meet the new capacity and energy needs
10 associated with four potential industrial development scenarios (10 MW, 25 MW and 40 MW industrial
11 development scenarios, and the Alaska Highway Pipeline).

12
13 The sections for this chapter are as follows:

- 14 • Section 5.1: Planning Approach and Timeline
- 15 • Section 5.2: Requirements
- 16 • Section 5.3: Options
- 17 • Section 5.4: Pre-Assessment and Screening
- 18 • Section 5.5: Proposed Actions

19 5.1 PLANNING APPROACH AND TIMELINE

20 Planning activities to proceed with other generation or transmission projects beyond 2009 and before
21 2016 are being driven by the potential needs of a diverse range of possible major industrial developments
22 and the possible energy requirements and/or opportunities related to such developments¹.

23
24 Chapter 4 has shown that new near term industrial loads of up to 10 MW within the 20 year planning
25 period typically give rise to capacity-focused resource options². In contrast, new industrial loads above 10
26 MW within the 20 year planning period may create opportunities for energy-focused resource projects.

¹ Section 4.2.4 shows, under Base Case loads (without new industrial loads), WAF diesel generation remains below 10 GW/h/year until after 2020, and increases only to 28 GW.h/year in 2025. Near term development of the Aishihik 3rd Turbine and Marsh Lake Storage as proposed in Chapter 4 would reduce this Base Case WAF diesel generation, e.g., to about 15 GW.h/year in 2025.

² Near term WAF industrial loads of up to about 10 MW could increase this Base Case WAF diesel generation to about 40 GW.h by about 2016 (with development of Aishihik 3rd Turbine and Marsh Lake Storage as proposed in Chapter 4, this WAF diesel generation would be about 25 GW.h/year in 2016); however, in Section 4.2.6 such new near term mine loads are not expected to be sustained beyond about 10 years (i.e., beyond about 2017 if mine developments occur in 2007/2008).

1 Chapter 5 examines these energy opportunities in the context of the different possible load situations
2 outlined in Chapter 1 (Figure 1.2), the significant uncertainties associated with such load possibilities, and
3 the lead times and other needs associated with Yukon Energy protecting appropriate resource options
4 related to these different possible loads.

5
6 The planning approach in this Chapter parallels that used in Chapter 4; namely:

- 7 1. **System capability** (part of *Section 5.2: Requirements*) over the intended 20-year horizon
8 as well as to 2045 is reviewed.
- 9 2. **System requirements** (part of *Section 5.2: Requirements*) are reviewed over the 20-year
10 plan horizon and to 2045, focusing on key characteristics for each of the four representative
11 industrial load scenarios.
- 12 3. **Forecast New Facilities Requirements** (part of *Section 5.2: Requirements*) are reviewed
13 over the 20 year planning term and implications to 2045, focusing on opportunities to
14 develop new capital intensive energy projects with potential to displace future diesel-fuel
15 generation required under each industrial load scenario.
- 16 4. **Resource Options** (*Section 5.3: Options*) to meet energy requirements under each
17 industrial load scenario are identified and summarized to the extent that representative non-
18 diesel generation resource projects can be defined today.
- 19 5. **Assessment of Options** (*Section 5.4: Pre-Assessment and Screening*): given the limited
20 degree of information available today on most resource options, preliminary pre-assessment
21 and screening of the identified options focuses primarily on “technical” considerations (how
22 well various project sizes and location fit each scenario’s potential load requirements). Where
23 available, screening also considers to a limited degree “economic pre-assessment” of these
24 options based on available information about the likely Levelized Cost of Energy or “LCOE” of
25 each generation component.

26
27 This chapter sets out the actions that Yukon Energy proposes to take during the planning period to
28 prepare for potential industrial development scenarios and opportunities beyond the near term, and to
29 protect future opportunities to develop generation and transmission in a timely but cost-effective way.
30 The planning activities proposed in this chapter are intended to strike a balance between the
31 opportunities and risks associated with bulk power resource options selected to supply future Yukon
32 industrial development.

1 **5.1.1 Need to Consider and Balance Several Key Factors**

2 Yukon and other experience in Northern Canada dramatically demonstrate how past industrial
3 developments provided the opportunity to develop new generation and transmission infrastructure in a
4 cost effective way, and how that infrastructure continues to yield sustained lower cost energy benefits to
5 local residential and commercial power users long after the initiating industry has been closed³.

6
7 The existing hydro at Aishihik and Mayo and the 4th wheel at Whitehorse were all linked directly with
8 industrial developments which are now closed, as were the major hydro developments at Snare, Bluefish
9 and Taltson in NWT (developed to service either mines that are now closed, or in the process of closing).
10 Only areas in Northern Canada that have had industrial customer mining load have the benefits today of
11 access to significant low-cost hydro.

12
13 Yukon and other Northern Canada experience also demonstrates that power resource planning regarding
14 specific industrial developments can involve long pre-development timelines as well as considerable
15 uncertainty and risk.

16
17 Accordingly, Yukon Energy needs to maintain a balanced approach to planning for grid power service to
18 major new industrial loads. In particular, the approach must ensure that Yukon Energy is sufficiently
19 prepared so as to “protect” feasible options to proceed with its own desirable resource projects quickly as
20 needed should new industrial loads develop, while at the same time not spending more than is prudent to
21 protect and advance such resource projects by, for example, proceeding to detailed feasibility stages
22 based on mere load speculation or industrial development scenarios that are highly uncertain. Overall,
23 this balance must be struck between two basic considerations:

24 **a) Readiness and Timing in relation to supplying new loads:** Due to industrial
25 development planning and construction constraints, there may be limited time after a
26 development’s load uncertainties are resolved for Yukon Energy to proceed with the new
27 generation and transmission needed to supply a new industrial load development with grid-
28 based power. In particular, planning, designing, licencing and constructing new generation or
29 transmission can, in many cases, take at least as long if not longer than similar planning,
30 commitment and construction for a new industrial development such as a mine. If not

³ Section 2.1.1 in Chapter 2 reviews how today’s hydro generation and transmission facilities, developed in the past often in response to specific industrial mine-related load opportunities, are the key factor causing Yukon power costs today to typically be lower than those found in Alaska or the NWT.

1 sufficiently prepared and ready, new grid-based power service opportunities will be missed,
2 likely in favour of on-site generation by the industrial customer. The potential significance of
3 each such opportunity to Yukon's power system in the near and long-term merits careful
4 consideration, along with assessment of the requirements to be sufficiently prepared and
5 ready.

6 **b) Costs, timelines and Risks for resource project planning:** The planning phases for
7 new generation or transmission can be costly and require many years of work prior to Yukon
8 Energy being in any position to undertake final commitments to proceed with construction
9 (with corresponding risks that potentially substantial spending on planning studies will
10 indicate a project is not feasible). Understanding the likely costs, timelines, and risks
11 associated with planning specific power resource options is an important precondition to
12 assessing the likely requirements to be sufficiently prepared and ready.

13
14 As noted, when considering grid-based power supply options to new industrial loads, the key factors to
15 be balanced in this regard relate both to the industrial development under consideration and to Yukon
16 Energy:

- 17 • **Industrial Development factors:** Considerable uncertainty often persists as to timing and
18 prospects to start and complete construction for a major new industrial development; even
19 after successfully developed, material risks and uncertainties can remain as to the length of
20 time for ongoing operation as well as the ability to meet ongoing financial obligations. Key
21 factors in this regard include:
 - 22 – **Non-power uncertainty and risk factors:** In general, the key planning considerations
23 and uncertainties for specific industrial developments derive from market, resource or
24 other factors not related to power supply. Although power can be a cost factor that
25 needs to be considered by potential industrial operations, such as mines or pipelines, it is
26 often just one factor among many key considerations (such as financing, markets,
27 licencing, or facility design).
 - 28 – **On-site power considerations:** Many major industrial developments if needed can
29 rely upon on-site diesel generation or even (in some instances) their own fuel resource
30 supply (e.g., coal for a coal mine, wood waste for a pulp mill, or natural gas for a natural
31 gas pipeline) and will if required proceed without waiting upon development of access to
32 utility grid-based power supply. In some instances, on-site generation may even provide
33 opportunities to utilize waste heat or waste resources that can be used to supply energy;
34 on-site generation capability may also provide critical requirements during construction or
35 be needed as reliable backup to grid power during operation.

1 on-site generation capability may also provide critical requirements during construction or
2 be needed as reliable backup to grid power during operation.

- 3 – **Short operating life and/or small scale power need:** In instances where a short
4 operating life of (say) five to ten years is expected or at risk, or where the scale of the
5 development involves relatively small power requirements, the incentive to incur material
6 up front capital costs for connection to grid-based power may be severely reduced.
- 7 – **Cases where access to grid power is critical:** In some special cases, the feasibility
8 of a specific industrial development may also be critically dependent upon access to grid-
9 based power that is supplied at costs materially less than diesel fuel generation. In such
10 instances, joint planning with the utility will be a key consideration to the industrial
11 development's ability to proceed.

- 12
- 13 • **Yukon Energy factors:** Yukon Energy can also face a range of its own specific uncertainties
14 and risks related to supplying grid power to major industrial developments. Key factors in this
15 regard include;

- 16 – **Inability to select or "forecast" in advance which industrial development**
17 **scenario will unfold:** Based on current information, Yukon Energy cannot select or
18 "forecast" in advance on any reliable basis (sufficient, for example, to commit material
19 planning resources on any prudent basis) what level or scope or type of major industrial
20 development is likely to occur by any specific time period under review in this Resource
21 Plan.
- 22 – **Limited value to current information:** Until uncertainties are resolved for a specific
23 industrial development, it is typically also not practical or cost effective based on
24 currently available information (regarding both the industrial development and the power
25 resource options to supply its needs) to plan and assess in any detail how Yukon Energy
26 may serve that development. If and when a development proceeds, its specific energy,
27 power capacity and timing requirements (and the costs and needs for resource options to
28 supply such requirements) in many cases are likely to vary significantly from current
29 estimates.
- 30 – **Limited time to respond to a new development once its major uncertainties**
31 **are resolved:** As noted above, Yukon Energy will typically have only a very limited time
32 to respond after uncertainties are resolved for a new industrial development before it
33 becomes necessary to undertake power supply commitments; in many instances, as
34 noted above, an industrial development will also simply proceed to use on-site diesel
35 generation if Yukon Energy cannot commit on a timely basis to supply grid-based power.

- 1 – **Costs and time to develop new bulk power supply resources:** Yukon Energy may
2 need to develop at least some new bulk power resources to supply grid power in
3 response to a new industrial development. Opportunities to supply grid power that are
4 contingent on planning, permitting and developing material new transmission and/or
5 capital intensive non-diesel fuel generation resources are likely to require many years of
6 work involving major capital costs prior to Yukon Energy even being in a position to
7 make final commitments to proceed with construction of the needed resource projects –
8 and capital intensive construction projects may then require several additional years (and
9 cost risks) before coming into service.
- 10 – **Need to assess, and secure YUB approval of, ongoing rates:** Yukon Energy needs
11 also to examine in advance the likely ongoing rate implications and risks, both for the
12 potential industrial customer and for other Yukon ratepayers, and to secure YUB approval
13 of any rate to be charged with regard to commitments to supply any new “major
14 industrial customer” (as defined in OIC 1995/90).
- 15 – **No market value to power if developed but not needed in Yukon:** Unlike many
16 southern jurisdictions with export connections, Yukon Energy cannot secure any
17 economic value from projects except from sales to customers in Yukon, due to the lack
18 of grid interconnections with external markets. In this regard, there is considerably more
19 risk today to developing capital intensive bulk power projects in Yukon than in, say,
20 Manitoba or British Columbia. This is because failure of local loads to develop as planned
21 in Manitoba or BC can be offset by the opportunity to sell more power on export markets
22 than otherwise would be the case. In contrast, once Yukon commits to a major capital
23 intensive resource supply project, if the load does not develop or remain as planned the
24 resource project has the potential to have zero or very limited value⁴.
- 25 – **Resource Projects of a scale at or beyond Yukon Energy’s current capability:** In
26 some industrial development scenarios examined in this Resource Plan, the magnitude of
27 required new generation and transmission opportunities may be at or beyond the current
28 capability of Yukon Energy, or other Yukon entities, to finance and construct. For
29 example, Yukon Energy presently has about \$57 million in equity, while some of the

⁴ This exact situation occurred with the construction of Whitehorse unit #4 in the 1980s. This unit basically provides almost exclusively summer energy, which was only of value at that time if the Faro mine was operating. However during construction of unit #4 the Faro mine closed, such that at the time of commissioning, the unit provided no economic value to the system. Since that time, substantial periods of operation of the Faro mine have provided opportunities to capture good economic value from unit #4. However, had the mine shut for good in the 1980s, unit #4 may have not been of any material value to the WAF system for decades after it was commissioned. Today, limited quantities of surplus hydro can be sold at lower secondary rates, however the potential is somewhat limited and is of lower value than full firm energy sales.

1 resource options considered in this Chapter approach \$500 million to \$600 million capital
2 costs for generation alone (plus amounts for substantial transmission upgrades), and
3 would involve the need to assess financial approaches and partnerships, potentially
4 including participation by the Governments of Yukon and Canada. Such additional
5 complications would likely increase planning timeframes and would also likely involve
6 assessing options regarding sharing of risks associated with the projects.

7 **5.1.2 Regulatory and Policy Framework**

8 As a regulated utility, Yukon Energy's planning and developments occur within a regulatory and policy
9 framework relating to its power supply developments and regulated rates charged to recover utility costs
10 of service.

11
12 Where new industrial customers are located within areas presently served by Yukon Energy grid power,
13 Yukon Energy must take into consideration its typical utility "obligation to serve" new loads that request
14 electrical service. In contrast, Yukon Energy is not automatically required to serve new industrial loads
15 that are located far away from the current Yukon grids unless the customer (or government) is prepared
16 to fund directly the transmission costs and risks required for Yukon Energy to connect the new load to
17 the grid⁵. In this regard, it is broadly assumed that major new industrial customers located materially
18 away from the current grids would not be added to the Yukon grid systems due primarily to the
19 constraints of incremental transmission connection costs. Without such connections, it is also assumed
20 that a new major industrial load would typically be supplied by isolated on-site diesel generation with all
21 costs being excluded from YUB consideration for the purpose of Yukon wide regulated rate setting (in
22 accordance with OIC 1995/90).

23
24 The existing WAF system today can provide substantial (approximately 90 GW.h/year under normal water
25 flows) attractive low-cost surplus hydro power to new industrial customers. The clear implication is that
26 new industrial customers in reasonable proximity to WAF currently have major opportunities to secure
27 material cost savings by purchasing WAF power supplies rather than using on-site diesel generation.
28 Securing new industrial customers on WAF to allow sale of this surplus power at firm rates will also be a
29 beneficial rate driver for all existing Yukon Energy and YECL firm customers, not only on WAF but
30 throughout Yukon (due to the rate directive provisions of OIC 1995/90 which in effect integrate all utility

⁵ As with new connection to WAF or MD by new non-industrial customers, transmission or distribution costs driven by new industrial customers are assumed to be funded by the industrial customer themselves (or by government), except to the extent that there is a cost effective case for Yukon Energy to invest in hooking up new industrial customers at a benefit to current ratepayers (pursuant to principles established in the Electric Service Regulations).

1 costs to equalize retail customer class rates through Yukon)⁶.

2
3 However, the current WAF hydro power surplus is being reduced by ongoing normal growth in non-
4 industrial customer firm loads, such that Secondary Energy sales on WAF that rely on surplus hydro
5 power are expected to be fully curtailed by 2023 under the Base Case load forecast reviewed in Chapter
6 4 (see Figure 4.2).

7
8 Larger or longer-term new industrial power loads connected to WAF or MD that require energy materially
9 beyond available surplus hydro power would, absent the development of new power resource options,
10 drive major new diesel generation on these grids. Accordingly, Yukon Energy needs to identify and
11 consider carefully the options and impacts to service such new industrial developments. For example, it
12 may not be sensible to develop new transmission to service a mine (with associated transmission line
13 losses) if the power is being largely generated via diesel at Whitehorse, when the same power could
14 likely be generated at the mine site using diesel without the associated transmission losses. New grid
15 extensions will similarly have limited long term value to the extent that they end up being used to
16 transmit diesel generated power rather than hydro or other lower cost based power. Overall, looking at
17 longer-term implications, such new industrial loads are likely to be attractive economically to the existing
18 grid system only if they allow development of new capital intensive low-cost generation, such as occurred
19 with the original opportunities to develop Mayo or Aishihik.

20
21 Accordingly, for new bulk power projects that may be developed in response to industrial development
22 opportunities, Yukon Energy needs to assess the economics of the project (including attendant risks), the
23 potential rate impacts on other utility customers as well as for the new industrial customer, and overall
24 Yukon policy objectives.

25
26 On the matter of overall policy objectives, in other jurisdictions various broad policy objectives regarding
27 resource development guide electrical system expansions⁷. In Yukon, the traditional energy policy
28

⁶ Up to 30 GW.h of this surplus hydro may currently be sold to secondary energy customers; however, interruption of such secondary sales (as well as use of the balance of the current hydro surplus) to service firm industrial loads will secure much higher revenues for Yukon Energy without incurring material increases in its costs. Under regulated rates, the net benefits of such rate revenue improvements will therefore flow through to reduce overall regulated rates below levels that would otherwise apply. Yukon Energy and YECL customers will accordingly benefit to the extent that rate reduction savings do not simply serve to reduce Rate Stabilization Fund subsidies funded by the Yukon Government.

⁷ An example is the BC government directive that BC Hydro not develop nuclear power. In contrast, at times Newfoundland has had a moratorium on developing new small hydro.

1 objectives have been focused on development, where economically feasible, of local resources compared
2 to imported diesel fuel. Consequently, at times since it was established, Yukon Energy (along with Yukon
3 Development) has assessed, requested proposals, and in some cases conducted research and
4 development projects on the following: Eagle Plains crude oil, wind generation, diesel/coal combined
5 cycle generation (based on coal from Division Mountain), new hydro (including small Independent Power
6 Producer (IPP) hydro projects), diesel/solar hybrid, biomass generation and geothermal resources (many
7 of these at scales well below that needed to supply industrial customers). Planning for major new supply
8 continues to reflect largely the broad “development of local resources” objective where economically
9 feasible.

10 **5.1.3 Planning Framework**

11 The planning framework in this chapter focuses on information that is currently available and on activities
12 Yukon Energy (and the YUB) can control – monitoring potential loads as they develop, conducting
13 appropriate screening and pre-feasibility work on potentially attractive generating and transmission
14 options, and conducting phased and managed feasibility work where appropriate in advance of industrial
15 developments becoming firmly committed to ensure Yukon Energy “protects” the ability to respond when
16 necessary within the timelines required.

17
18 To ensure that relevant longer-term service implications are considered, Yukon Energy examines load
19 scenario requirements in this chapter out to the year 2045; however, the analysis addresses only those
20 generation or transmission supply options that may be required to commence development before 2016.

21
22 The analysis and project options identified in this chapter build on the Chapter 4, assuming commitment
23 prior to 2009 for resource projects proposed in Chapter 4. In particular, capacity requirements noted in
24 this Chapter reflect adoption of the revised capacity planning criteria (as set out in Section 3.4) as well as
25 prior commitment to and completion of a Mirrlees Life Extension Project (at 14 MW) plus about 4 MW
26 new diesel capacity by 2012 pursuant to the primary contingent recommendations of Chapter 4 to
27 address “Base Case” loads. This chapter also presumes near term development of Marsh Lake Fall/Winter
28 Storage (1.6 MW of added firm capacity) as well as the Aishihik 3rd Turbine project as proposed in
29 Chapter 4⁸, without the Aishihik 2nd Transmission Line project (such that the Aishihik 3rd Turbine has no
30 effect on meeting the N-1 capacity planning criteria and only 0.6 MW towards the LOLE criteria), and
31

⁸ In addition to any capacity-related impacts, Marsh Lake Storage and the Aishihik 3rd Turbine as proposed in Chapter 4 together add about 13 GW.h/year to long-term average WAF hydro energy supply (assuming sufficient WAF loads).

1 takes into consideration the possible near term development of the Carmacks to Stewart Crossing
2 Transmission as reviewed in Chapter 4.

3 As noted, Chapter 5 identifies four representative industrial development “scenarios” (rather than
4 “forecasts”) in order to identify basic planning options for the Resource Plan to consider with regard to
5 different ranges of potential industrial load sizes (as well as load timing, expected life and general
6 location). Individual industrial development opportunities and/or resource supply projects, however, are
7 not the focus of the Chapter 5 analysis.

8

9 Four key factors are simultaneously considered in the Chapter 5 screening of potential new resource
10 supply options for each WAF industrial load scenario:

11 1. **Generation cost of energy supplied by new resource (LCOE):** A primary consideration
12 is the basic generation cost of energy supplied by output from any new resource (with typical
13 focus on overall unit cost per kW.h as opposed to cost per MW of capacity). For the purposes
14 of initial screening, “levelized costs of energy” or LCOE can be used to determine the unit
15 costs/kW.h at the project site of energy produced. Levelized costs reflect the costs of the
16 plant amortized over its life (all kW.h units available to be produced by the plant) assessed
17 on real dollar (2005\$) economic terms (i.e., assuming the levelized unit cost after 2005
18 increases with inflation each year).

19 • LCOE focuses only on key generation cost components for a resource option as needed
20 to screen or compare alternative resource options.

21 • LCOE for hydro supply projects accordingly focuses in most instances only on capital
22 costs, as these tend to establish the primary overall generation cost for this option.
23 Operating and maintenance costs for large projects can be quite modest (0.5% of capital
24 cost based on BC Hydro estimates) which would tend to increase the LCOE by about
25 9.4%. Smaller hydro project operating and maintenance costs may vary up to 1.0% to
26 1.5% of capital cost, which can increase LCOE by 18.8% to 28.3% over the levels
27 estimated in this chapter.

28 • In the case of other resource options which involve material fuel operating costs (e.g.,
29 diesel generation, or thermal generation using coal, wood biomass or natural gas) it is
30 also necessary that the LCOE reflect fuel as well as capital costs (if the capital costs are
31 also likely to be a key part of the option’s overall costs).

32 • LCOE automatically takes into consideration variations in the economic lives of alternative
33 resource options.

34 • LCOE implicitly assumes that all energy generated over the economic life of a resource
35 option is sold at rates that fully recover the LCOE costs, i.e., this screening tool does not

1 address the extent to which a resource option may be oversized to meet forecast loads,
2 or otherwise mismatched with forecast loads (in terms of, say, seasonal consideration).
3

4 2. **Location of supply and cost of transmission to loads:** If attractive supply options (such
5 as hydro) can be identified that offer lower levelized generation costs of energy (LCOE) than
6 diesel power generation, it is necessary also to screen separately based on location, as low-
7 cost supply options that are materially away from existing transmission systems may not be
8 able to support the costs of major new transmission to connect to the system (particularly for
9 small plants). Similarly, in some cases supply options that are too remote will result in
10 transmission losses that undermine otherwise attractive LCOEs.
11

12 3. **Load fit with resource option supply:** Despite a new low cost source of supply being
13 available to Yukon Energy (as assessed based on LCOE per kW.h as well as on location
14 relative to the forecast loads), the overall economics of a resource option also depend
15 ultimately on the supply having actual economic value to the system (such as by displacing
16 energy that otherwise would have needed to be generated using diesel fuel). If some or all of
17 the power provided by a new supply source is surplus to system firm load requirements (e.g.,
18 becomes spilled hydro) even very low cost resource options can be uneconomic to the overall
19 power system. Key considerations for section 5.4 on “pre-assessment and screening”
20 therefore focus on “load fit”, or how well any given resource project might fit the load
21 requirements (energy in particular) over the next 40 years, how many years of surplus
22 energy may arise if a resource project were to be constructed, and the market risks
23 associated with potential pre-mature closure of industrial customers.
24

25 4. **Other associated charges, such as “water rentals” and taxes:** For hydro resource
26 projects that are developed in BC, additional annual charges will be levied on the project that
27 would not be in place if the project was located in Yukon. It is therefore relevant to consider
28 these additional charges when screening such projects in the Resource Plan.
29

30 Other major screening factors must separately be considered within the process for evaluating,
31 developing and constructing new power generation facilities, such as environmental factors which may
32 preclude certain developments, or drive material added capital or operating costs (such as for
33 environmental mitigation activities).

1 The organization and approach adopted in Chapter 5, with its focus on four different industrial load
2 scenarios, reflect the overall importance of “load fit” within the resource option screening process. As
3 reviewed in Sections 5.3 and 5.4, the scale of the industrial loads associated with each scenario drives
4 the identification of relevant resource option technologies. Based on initial screening for this basic “load
5 fit”, further screening can then be carried out in accordance with the four key factors noted above.

6 **5.2 REQUIREMENTS**

7 There is a diverse range of industrial development opportunities that could develop in the Yukon during
8 the 20 year planning period, providing an equally diverse range of potential opportunities to develop new
9 energy resources.

10

11 At present, base metal prices in particular are at high levels and mining exploration in Yukon has
12 expanded. Yukon Energy has worked with the Government of Yukon Mineral Development Branch to
13 identify potential future mining industrial customers based on specific prospects and proponents, as well
14 as based on the nature of the development, its expected life, and its location in relation to developed grid
15 power.

16

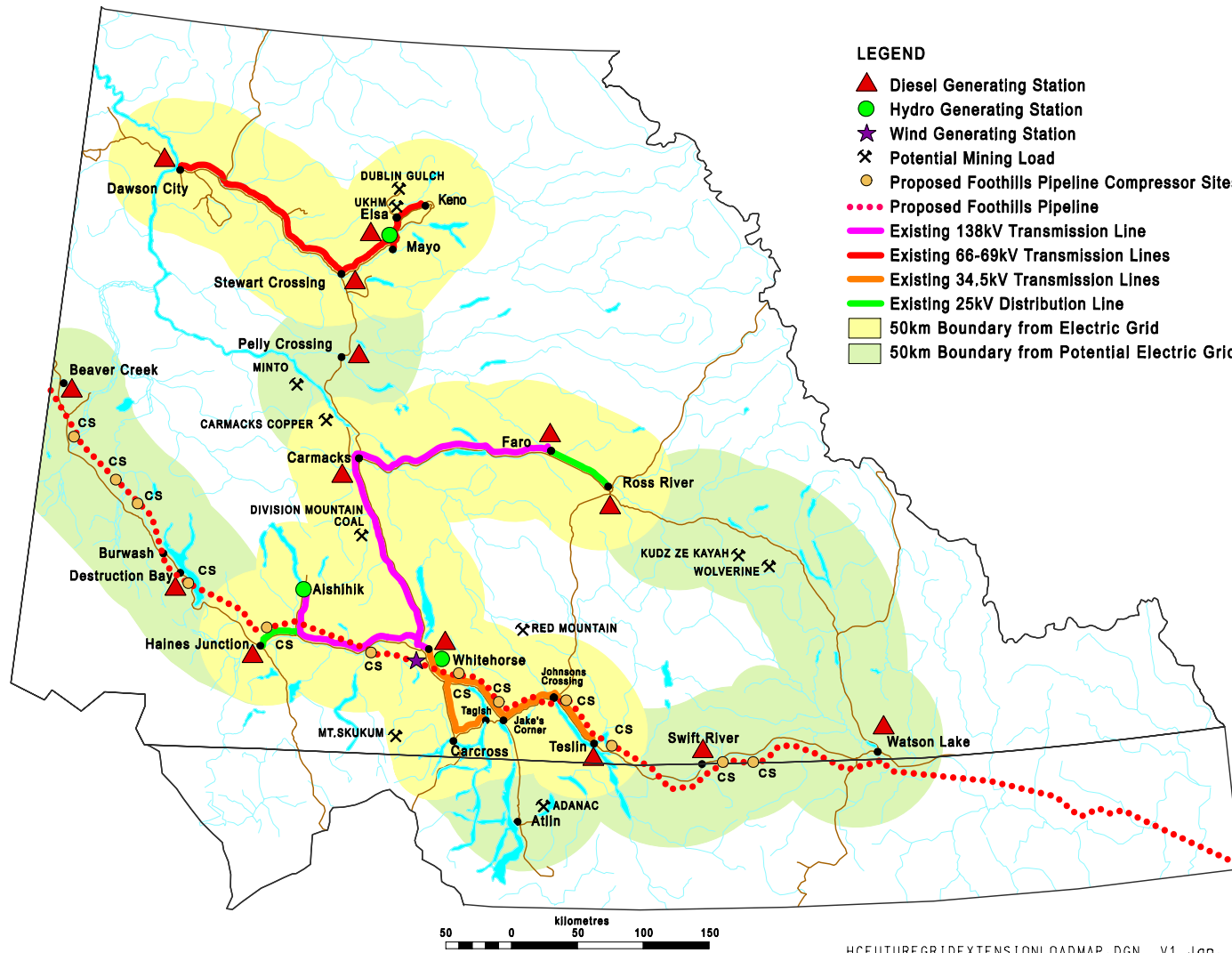
17 Larger opportunities may be presented by an Alaska Highway Pipeline, and information on the potential
18 loads for pipeline pumping (which could be served by electricity under certain circumstances) has been
19 included in the planning exercise.

20

21 Potential industrial developments considered in this chapter are detailed in *Table 5.1 Industrial*
22 *Development Opportunities*. Locations of these potential developments are indicated in *Figure 5.1: Map*
23 *of Industrial Development Opportunities and Power Infrastructure*.

Figure 5.1:
Map of Industrial Development Opportunities and Power Infrastructure

EXISTING TERRITORIAL POWER INFRASTRUCTURE AND POTENTIAL LOADS



1
2
3
4
5
6
7
8
9
10

1
2
3
4

**Table 5.1:
Industrial Development Opportunities**

Project	Proponent	Location	Grid	Commodity	Road Access	Distance To Grid (km)	Peak Demand (MW)	Annual Energy (GW.h)	Project Life	Assumed In-Service Date
Alaska Highway Pipeline, WAF 120 MW to 360 MW¹										
Kluane Compressor	Foothills Pipeline	kmp 214 Destruction Bay	WAF	Natural Gas	Alaska Highway	147.2	30	223.4	30	2012-15
Champagne Compressor	Foothills Pipeline	kmp 378 Stony Creek	WAF	Natural Gas	Alaska Highway	3	30	223.4	30	2012-15
Marsh Lake Compressor	Foothills Pipeline	kmp 455.8 Marsh Lk. Outlet	WAF	Natural Gas	Alaska Highway	30	30	223.4	30	2012-15
Rancheria Compressor	Foothills Pipeline	kmp 739.2	WAF	Natural Gas	Alaska Highway	330	30	223.4	30	2012-15
Potential Mine Developments, WAF 11 to 20 MW										
Division Mountain Coal	Cash Minerals Ltd.	Braeburn	WAF	Coal	Klondike Highway	20	15	105	15	2010
Red Mountain	Tintina Mines Ltd.	80 km NE of Whitehorse	WAF	Moly	no road access	83	11 to 20	81 to 126	20	2009
Adanac	Adanac	124 KM SE of Whitehorse (in BC)	WAF	Molybdenum	road via Altin	approx. 120	15	Unknown	20	2010
1 to 10 MW										
Minto Property	Sherwood Mining Corp.	100 km NW of Carmacks	WAF	Cu, Ag, Au	Klondike Highway	98	2	14	12	2007
Carmacks Copper	Western Silver Corp.	28 km NW of Carmacks	WAF	Cu, Ag, Au	Freegold Road	53	7	50	8.5	2008
Wolverine	Yukon Zinc	130 km SE Ross River	WAF	Cu, Pb, Zn, Ag, Au	Robert Campbell	273	5.1	37	9	2009
Kudz Ze Kayah	Teck	110 km SE Ross River	WAF	Cu, Pb, Zn, Ag, Au	Robert Campbell	218	8.8	63	11	2011
Mt. Skukum	Tagish Lake Gold Corp	40 km W of Carcross	WAF	Au, Ag	Annie Lake Road	47	1.5 to 2.7	11 to 20	8	2008
Potential Mine Developments, MD 1 to 10 MW										
Dublin Gulch Property	Strata Gold Corp.	40 km N of Mayo	MD	Au	road north of Elsa	27	4	20	10	2009
UKHM	Under YTG Management (in due diligence)	Elsa	MD	Ag, Zn, Pb	Elsa	0	2	14	5	2007

1-The initial four compressor stations are shown here. Up to eight additional compressor stations (each with similar 30 MW potential load) could be added within the following four to five years.
The pipeline electrical loads in this table assume use of electric power rather than natural gas from the pipeline to run these compressor stations. There will also be some ancillary pipeline power loads in any event (not shown here) even if the compressor stations use natural gas.

5
6

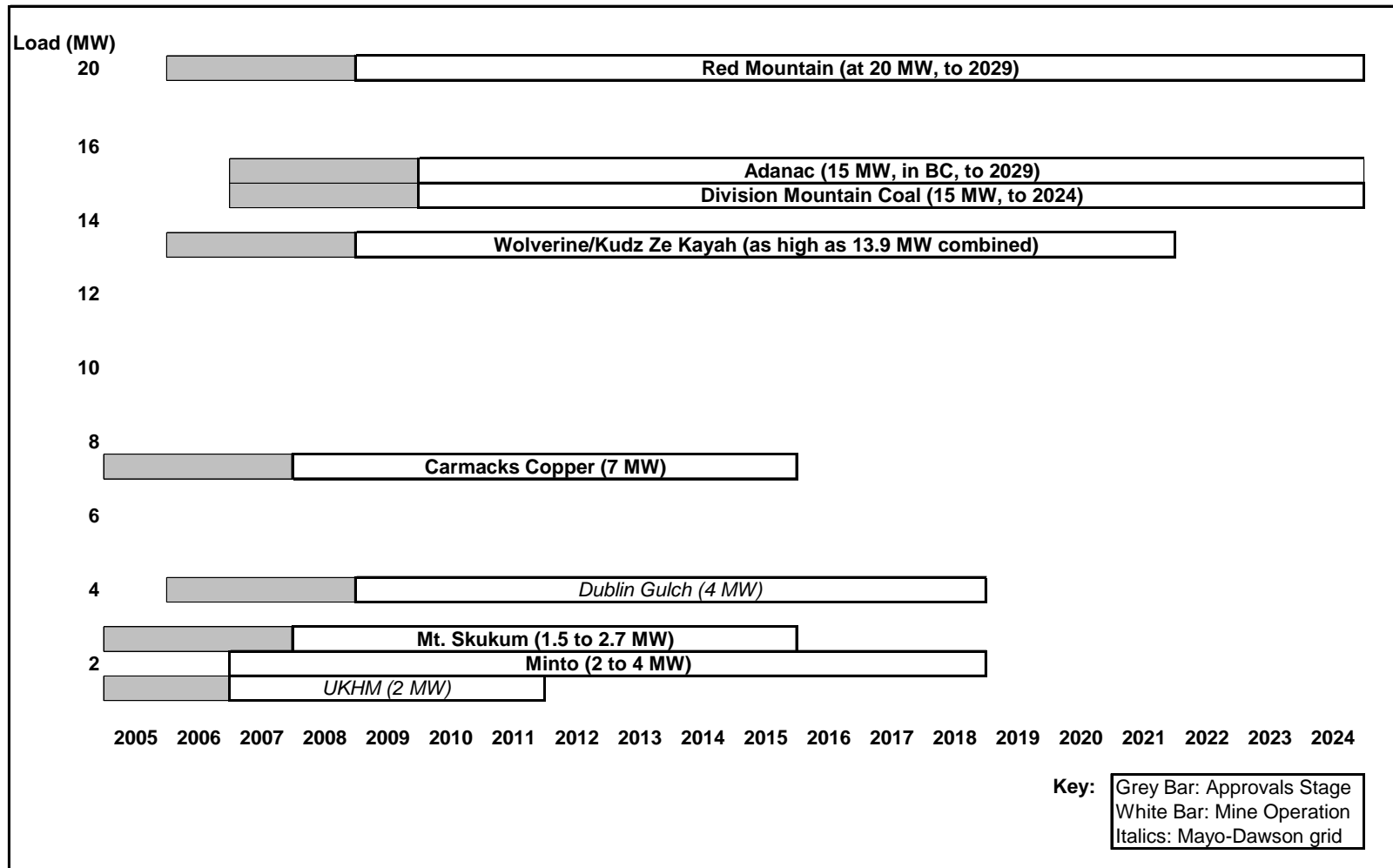
1 *Figure 5.2 Earliest In-Service Dates and Power Loads for Potential Mine Developments* illustrates the
2 currently estimated potential timelines associated with mining load opportunities being considered.

3
4 Individual industrial developments noted in Table 5.1 and Figure 5.2 could result in possible new
5 generation projects starting construction before 2016, based on industrial load requirements ranging from
6 2 MW to 360 MW and energy requirements ranging from 11 GW.h to 2,680 GW.h per year, and with
7 service lives ranging from 5 to 30 years or more.

8
9 Many of the potential industrial mine loads considered in this chapter are well beyond the bounds of
10 existing transmission, which may limit opportunities for grid service unless other outside funding (such as
11 YTG) is available to enable the connection and eliminate potential adverse rate impacts. The mine
12 developments noted in this chapter are within 273 km of either the WAF or MD grids (see Table 5.1).

13
14 When considering the potential “start dates” and development uncertainties for any of the mine projects
15 considered in this chapter it is relevant to note that many of the industrial developments being
16 considered today have been under active consideration as “near term development” prospects for some
17 time. Yukon Energy’s internal Resource Plan update process in 1996/97, for example included many of
18 these projects as “advanced mineral projects” relevant at that time for possible power requirements,
19 including Minto, Kutz Ze Kayah, Dublin Gulch, UKHM and Carmacks Copper as projects then engaged in
20 environmental permitting (with all of these developments then expected to use on-site diesel, except for
21 Carmacks Copper and UKHM which were then expected to secure grid power), and including Division
22 Mountain Coal (grid power) and Mt. Skukum (on-site diesel) as projects with anticipated environmental
23 review. Rates approved by the YUB from the 1996/97 GRA included a “New Mine Rider” (Rider K) to
24 address adjustment of retail rates throughout Yukon in the event either Carmacks Copper (WAF) and/or
25 UKHM (Mayo system) was connected to a system in 1996 or 1997.

1
2
Figure 5.2:
Earliest In-Service Dates and Power Loads for Potential Mine Developments



3

1 To address forecasting uncertainty regarding these industrial development opportunities, four “scenarios”
2 have been selected related to industrial development. Given the range of potential development options,
3 the four scenarios allow Yukon Energy to identify basic planning options relevant to consider in the
4 Resource Plan. If and when specific loads of a certain magnitude develop, Yukon Energy can at that time
5 refine and develop specific plans for serving the load.

6
7 Industrial Development Scenarios and Opportunities identified for this Resource Plan focus on the WAF
8 grid (includes possible MD supply options if the Carmacks-Stewart Transmission project is developed) and
9 include:

- 10 • **Scenario 1: A 10 MW WAF Industrial Scenario:** This scenario includes one to two
11 smaller mines, which are represented in the analysis by the addition of the Minto (2 MW to 4
12 MW) and Carmacks Copper (7 MW) mines.
- 13 • **Scenario 2: A 25 MW WAF Industrial Scenario:** This scenario includes multiple major
14 developments comparable overall to the traditional load impact of the Faro Mine when it was
15 operating. This scenario is roughly based on the development of three mines, focused on:
16 Minto (2 MW to 4 MW), plus Carmacks Copper (7 MW) and either Red Mountain (11 MW to
17 20 MW) or Division Mountain coal for export markets (15 MW).
- 18 • **Scenario 3: A 40 MW WAF Industrial Scenario:** A larger 40 MW scenario is considered
19 to focus on a potential major mining industry development scenario in Yukon. This scale of
20 mining power load would be in excess of the loads experienced when the Faro mine was
21 operating. As an example, such a scenario could be enabled by the development of Minto (2
22 MW to 4 MW), plus Carmacks Copper (7 MW) plus Red Mountain at the largest load level
23 assumed to date Mountain (11.3 MW to 20 MW, likely at larger end of scale) plus Division
24 Mountain coal for export markets (15 MW).
- 25 • **Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline Scenario:**
26 This largest scenario is based on the development of an Alaska Highway Natural Gas Pipeline
27 in the 2012-2015 period and assumes that this development elects to use electricity for
28 pipeline compression. The magnitude of power use is based on an initial four compressor
29 stations at 30 MW each, ultimately being expanded over time to 12 compressor stations at 30
30 MW each, each with a life of 30 years.

31
32 All scenarios forecast non-industrial loads at the Base Case level from Chapter 4 and reflect schedule in-
33 service of projects recommended in Chapter 4 including Aishihik 3rd Turbine, Marsh Lake Fall/Winter
34 Storage and Mirrlees Life Extension. For simplicity, it is also assumed that additional diesel capacity
35 (about 3-4 MW) is developed to meet the balance of the Base Case capacity required by 2012; as noted

1 in Chapter 4, Base Case options in this regard include replacing the smaller third Mirrlees unit (4 MW)
2 with a larger new diesel unit (8-11 MW).

3
4 The following Chapter 5 requirements analysis also initially assumes reliance on new diesel generation to
5 supply additional new capacity required to meet new industrial loads.

6 **5.2.1 Scenario 1: A 10 MW WAF Industrial Scenario**

7 Within the next number of years, there is a credible scenario of Yukon Energy potentially connecting
8 service to two mining loads at Minto (Sherwood Mining Corporation) and Carmacks Copper (Western
9 Silver Corporation). Analysis of a 10 MW load scenario, however, is applicable for other potential load
10 developments of a similar scale (including potentially Mt. Skukum gold at 2 MW, Red Mountain in its
11 smallest form at 11 MW, or major expansion of transmission along the Robert Campbell highway to
12 connect Kudze Kayah at 8.8 MW or Wolverine at 5.1 MW should other non-utility funding be available to
13 develop transmission along this route).

14
15 Focusing on the development of Minto and Carmacks Copper, the projects together would likely have a
16 capacity requirement of 9 MW to 11 MW, and up to 64 GW.h of annual energy sales (about 70 GW.h of
17 annual generation). The projects are not expected to be long-lived. Minto is expected to start in 2007
18 and run for 12 years. Carmacks Copper is expected to start in 2008 and run for 8.5 years. These starting
19 dates may be delayed by other processes and development timelines.

20
21 The Scenario 1 loads are equivalent to the "Base Case with Mine Loads" discussed in detail in section
22 4.2.6 of Chapter 4, except that the Chapter 5 approach to determining requirements presumes previous
23 near term completion (before 2012) of the Mirrlees Life Extension and installation of 3-4 MW of additional
24 diesel generation, as well as near term development of Marsh Lake Fall/Winter Storage (by 2008) and the
25 Aishihik 3rd Turbine (2009).

26
27 **Capacity:** Based on the revised capacity planning criteria (see Chapter 3), up to 6-7 MW of mining load
28 can be added to the WAF system without driving a need for any new capacity. Even the addition of 10
29 MW of mining load may not drive any need for new capacity if this new load is either matched with some
30 degree of on-site diesel capability at the mines, or peaks at times other than the current coincident peaks
31 of residential and commercial customers on the coldest days of the year⁹. However, absent any on-site

⁹ Assuming only modest on-site diesel in each case (about 20-40% of the peak load), there would be no incremental requirement for capacity on the YEC system in order to serve this scale of mining load.

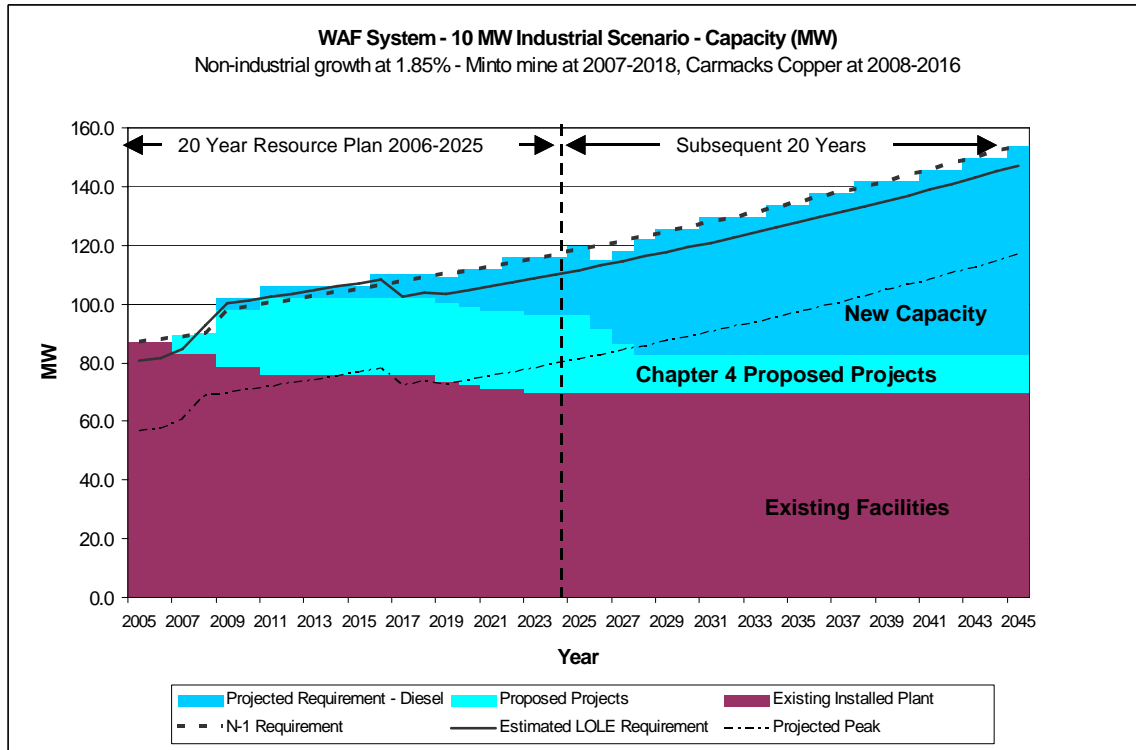
1 diesel at the mines, development of this scale will drive an added capacity requirement of up to about 2-3
2 MW by 2012 compared to the Base Case¹⁰.
3
4 The WAF integrated system peak loads once the two mines are connected would approach the 65-70 MW
5 level, growing to about 78 MW by the end of the mine life¹¹,
6
7 With the current installed plant (and including the proposed 7 MW of hydro from the Aishihik 3rd Turbine
8 and 1.6 MW of new capacity with the Marsh Lake Fall/Winter Storage), YEC can reliably supply about 62
9 to 63 MW of peak load with hydro (higher in some winters depending on Yukon River flows).
10 Consequently, Yukon Energy would need to rely at times on dispatching up to 15 to 16 MW of diesel
11 capacity during a relatively limited number of hours at the coldest times of the winter to meet peak loads.
12 This is well within the system capability from a reliability/capacity perspective.

¹⁰ Based on the earlier more detailed review in Section 4.2.6, prior to addition of the Aishihik 3rd turbine and Marsh Lake Fall/Winter Storage, the two mines add 2.8 MW to the firm WAF capacity needed (assuming no on-site mine diesel capacity). This is because the mines are assumed at 9 MW (2 MW for Minto plus 7 MW for Carmacks Copper) but 6.2 MW of this load can be carried under the LOLE criteria without driving a need for new capacity (once the mines are connected, the LOLE criteria drives new capacity additions, not N-1). However, later in Chapter 4, the Aishihik 3rd turbine project is proposed to proceed, which adds 0.6 MW to LOLE load carrying capability, so the incremental effect of the mine loads drops to 2.2 MW. Accordingly, the incremental impact on capacity requirements in 2012 due to these two mines would be about 2.2 MW. However, it is noted that a portion of the 2.2 MW requirement may be met by either on-site diesel, or by Chapter 4 projects that add capacity beyond the strict amounts required through 2012. (Chapter 4 assumed, to meet Base Case loads, 18.7 MW is installed separately through implementation of the Chapter 4 proposed actions regarding Marsh Lake Fall/Winter Storage at 1.6 MW, Mirrlees Life Extension at 14 MW plus at least 3.1 MW of new diesel at Whitehorse to address the remaining shortfall. As noted in Chapter 4, a 4 MW new diesel unit may be installed (resulting in a surplus of 0.9 Mw at 2012 under Base Case conditions), the third (4 MW) Mirrlees unit might be replaced by new diesel at from 8 to 11 MW (resulting in surplus capacity under Base Case of between 0.9 and 3.9 MW), or the Carmacks to Stewart Transmission might be developed (providing surplus capacity under Base Case conditions of 1.9 to 2.9 MW of added capacity).)

¹¹ Chapter 5 assumes that new mine loads are consistent throughout the winter, even at very low temperatures – this may not be correct as some mining operations are limited in terms of the activities they can pursue once temperatures drop to very cold levels.

1
2

Figure 5.3:
Scenario 1: WAF Capacity Requirements



3

4 **Energy:** Under this scenario, surplus WAF hydro would provide most of the incremental energy needs if
5 the mines are connected to WAF. From an energy perspective, the development of Minto and Carmacks
6 Copper are well suited to the current scale of system surplus hydro. At the assumed time of their
7 expected connection (2007-2008), basically the entire loads of these two customers can likely be served
8 with surplus hydro for most of the year (with the relatively minor exception of winter peaking as noted
9 above, subject to receiving further confirmation regarding the seasonality of the loads).

10

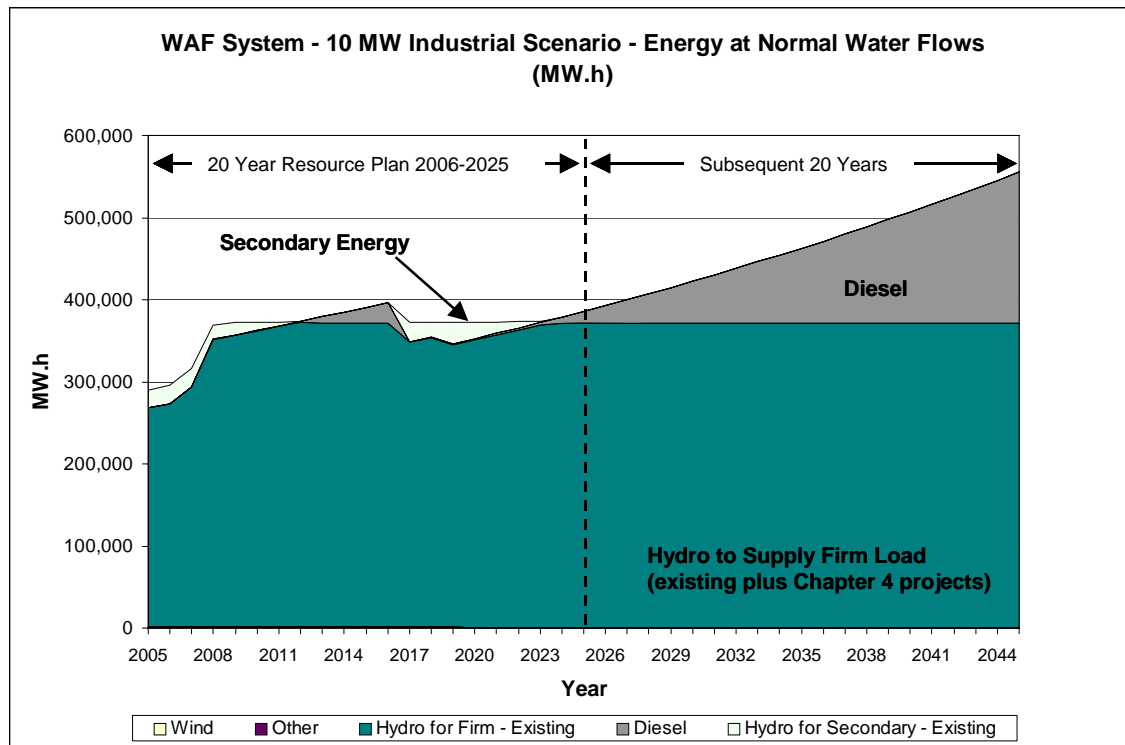
11 However, diesel generation use would increase throughout the period while the mines are connected.
12 Assuming development of Marsh Lake Storage and the Aishihik 3rd Turbine (as proposed in Chapter 4 to
13 capture energy benefits as noted), diesel generation of 2 GW.h to 25 GW.h per year would arise in the
14 period 2012-2016 (prior to the expected closure of Carmacks Copper in 2017)¹². After 2017, surplus

¹² Over the life of the two mines as assumed in Scenario 1, about 10% of the incremental energy requirement is supplied by diesel generation in Figure 5.3.

1 hydro would return to the system for about 7 years to 2023, when base load diesel would again be
2 required, in this case due to non-industrial load growth.¹³

3
4
5

**Figure 5.4:
Scenario 1: WAF Energy Requirements**



6
7
8
9
10
11
12
13

The load balance information above notes a small incremental requirement for diesel generation under this scenario. However, over the next 20 years (the period of the current Resource Plan) the maximum diesel requirements at normal water flows in any year is about 25 GW.h/year, with only 4 of the 20 years above 10 GW.h/year. Diesel requirements for the remaining 16 years vary from about 0.1 GW.h/year to 8 GW.h/year and average about 2 GW.h/year. Under this load scenario, it would be difficult to justify even considering new energy projects for commitment before 2016 based on mine loads of up to 10 MW that are not sustained well beyond 2016¹⁴.

¹³ See Appendix C, Table C.5 for a review of diesel requirements by year assuming these two mine loads as well as development of Marsh Lake Fall/Winter Storage and the Aishihik 3rd Turbine.

¹⁴ Variations on Scenario 1 might change this conclusion, i.e., if the same mine development was delayed until about 2016, sustained levels of diesel generation into the future 20 years and beyond would be much higher. However, this type of variation provides minimal guidance to Yukon Energy Resource Plan activities during the next several years.

1 **5.2.2 Scenario 2: A 25 MW WAF Industrial Scenario**

2 The 25 MW industrial scenario focuses on a larger load development, based on service to Minto and
3 Carmacks Copper via new transmission north from Carmacks, plus additional major industrial load in the
4 10-20 MW range, with serious potential candidates being Division Mountain coal (15 MW, at Braeburn on
5 existing WAF transmission) or Red Mountain (11.3 MW - 20 MW, north of Johnson's Crossing, requiring
6 70-100 km or more of new major transmission).

7

8 The scenario is examined assuming development of Minto, Carmacks Copper per the loads in Scenario 1,
9 plus Division Mountain coal (15 MW load assumed at 105 GW.h/year from 2010 for 15 years). Overall
10 supply requirements are similar to what existed to supply the Faro mine loads when it was last operating,
11 and approximate 180 GW.h/year of incremental generation when all three mines are operating.

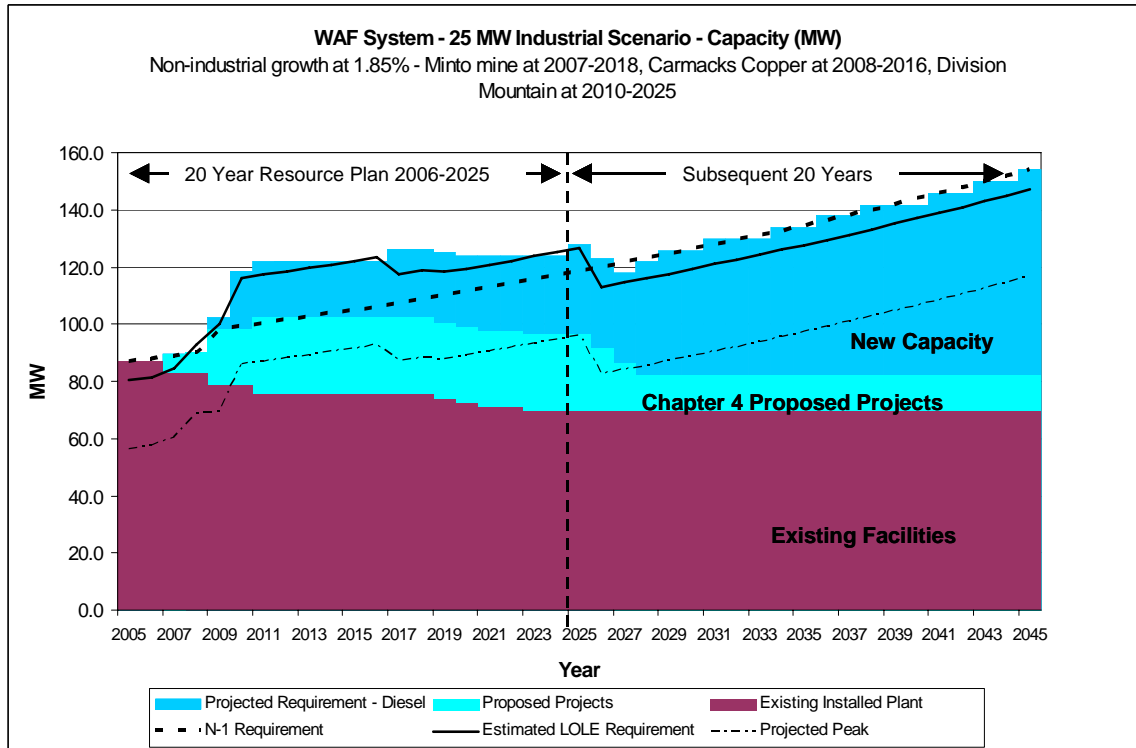
12

13 **Capacity:** If this scenario were to arise, Yukon Energy would face substantial requirements for new
14 capacity in excess of that indicated in Chapter 4. This added capacity required for these industrial loads
15 would potentially be up to an additional 17.2 MW of new diesel units or equivalent capacity, assuming
16 minimal on-site diesel installations at the three mines¹⁵.

¹⁵ As noted in the summary of requirements, the scenario case is modeled using a maximum 24 MW of industrial load. Of this amount, and assuming development of the Aishihik 3rd Turbine, 6.8 MW of industrial load may be carried under the LOLE criteria without a need for new capacity (over Base Load N-1 requirements), and 17.2 MW of new capacity is therefore required.

1
 2

Figure 5.5:
 Scenario 2: WAF Capacity Requirements



3

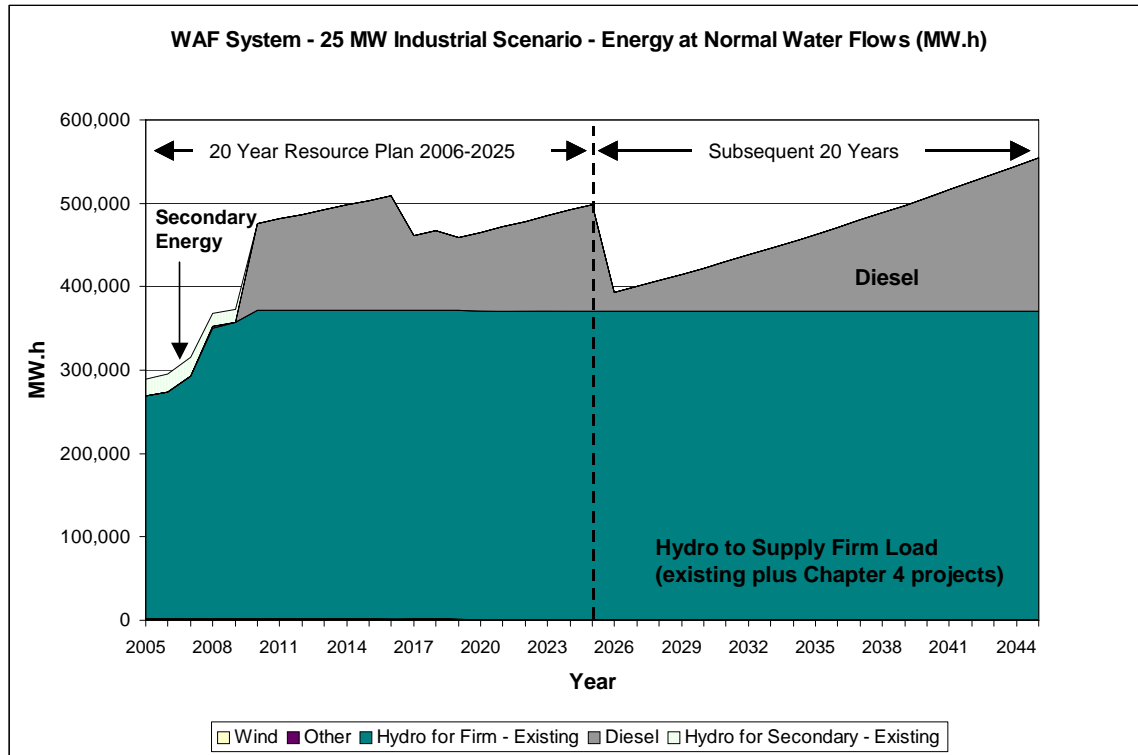
4 The WAF integrated system peak loads once the two mines are connected would approach the 85-95 MW
 5 level during the mine lives under the assumptions adopted. However, given the scale of the mine loads in
 6 this case and without development of new non-diesel generation, the WAF diesel units would be
 7 operating for basically the entire year (similar to when Faro was in operation) so “peaking diesel” would
 8 no longer be a relevant concept for the YEC WAF system.

9

10 **Energy:** This scenario gives rise to major new requirements for diesel baseload generation, which over
 11 the life of the mines would supply about 70% of the mine load incremental generation. Without new
 12 development of hydro or other capital intensive generation, WAF diesel fuel generation required would
 13 range from about 90 to 140 GW.h/year for a period of 16 years (from 2010 to 2025); thereafter, as the
 14 new industrial loads close, diesel generation would approximate 21 GW.h/year (growing each year by 7
 15 to 8 GW.h as WAF non-industrial load grows) and not reaching the 100 GW.h per year level again for 10
 16 years (until 2036), well outside the horizon of the current Resource Plan.

1
2

Figure 5.6:
Scenario 2: WAF Energy Requirements



3

4 **5.2.3 Scenario 3: A 40 MW WAF Industrial Scenario**

5 This scenario is based on an assumption that Yukon Energy is able to connect service to numerous new
6 mining developments and that these developments coincide in the next 10 years. A larger scenario in
7 excess of the Faro mine, this scenario could potentially include the same mines identified in the 25 MW
8 industrial scenario, with the development of the Red Mountain mine. Other possible development
9 combinations in this scenario (but more distant from current grids) including Adanac (15 MW) and Kutz
10 Ze Kayah and Wolverine (8.8 and 5.1 MW) should other non-utility funding enable transmission
11 development along this route.

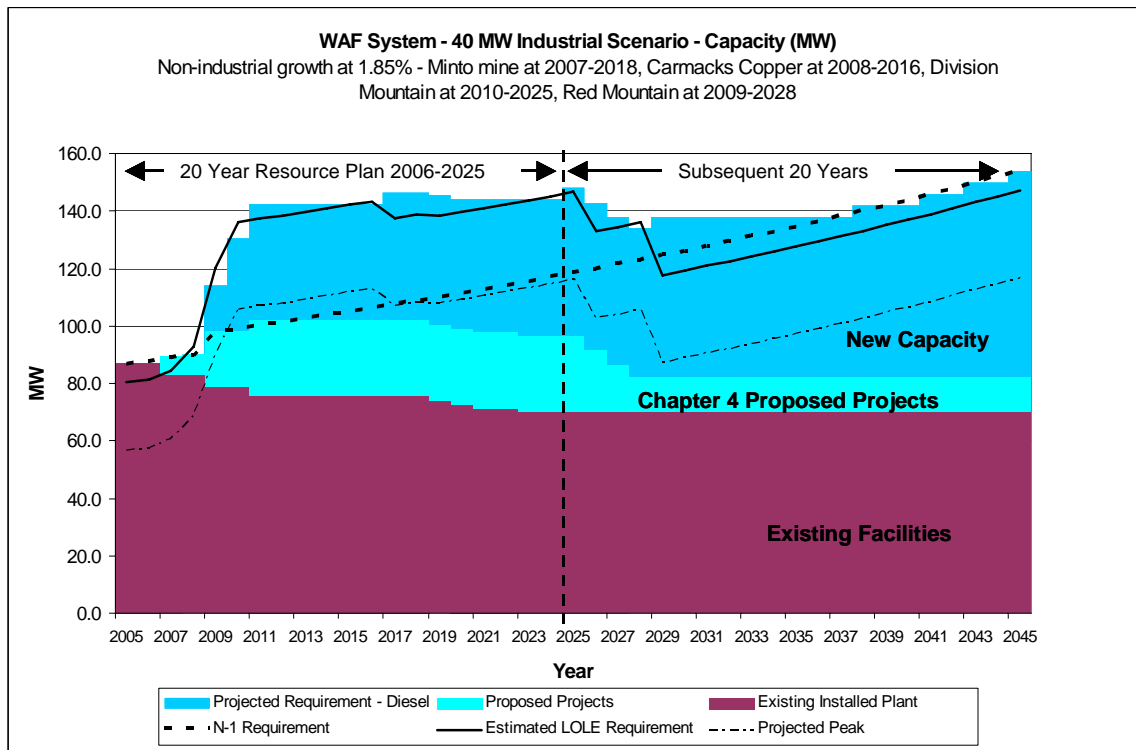
12

13 The specific scenario developed for analysis assumes four new mines all coming into service no later than
14 2010. These mines include Minto, Carmacks Copper, and Division Mountain per Scenario 2 (the 25 MW
15 scenario), plus Red Mountain assumed to be developed at 20 MW and 126 GW.h/year from 2009 for 20
16 years (also requiring 70-100 km or more of new major transmission). Without new development of hydro
17 or other capital intensive generation, overall generation supply requirements would approximate 315
18 GW.h/year when all four of these mines are operating.

1 **Capacity:** The scale and duration of development of this major combination of mining loads is such that
2 material increases in system installed capacity are required to service the loads. Yukon Energy would
3 face substantial requirements for new capacity in excess of that indicated in Chapter 4. This added
4 capacity required with these industrial loads would be more than 35 MW of new diesel units or equivalent
5 capacity, assuming minimal on-site diesel installations at the four mines¹⁶.

6
7
8

**Figure 5.7:
Scenario 3: WAF Capacity Requirements**



9

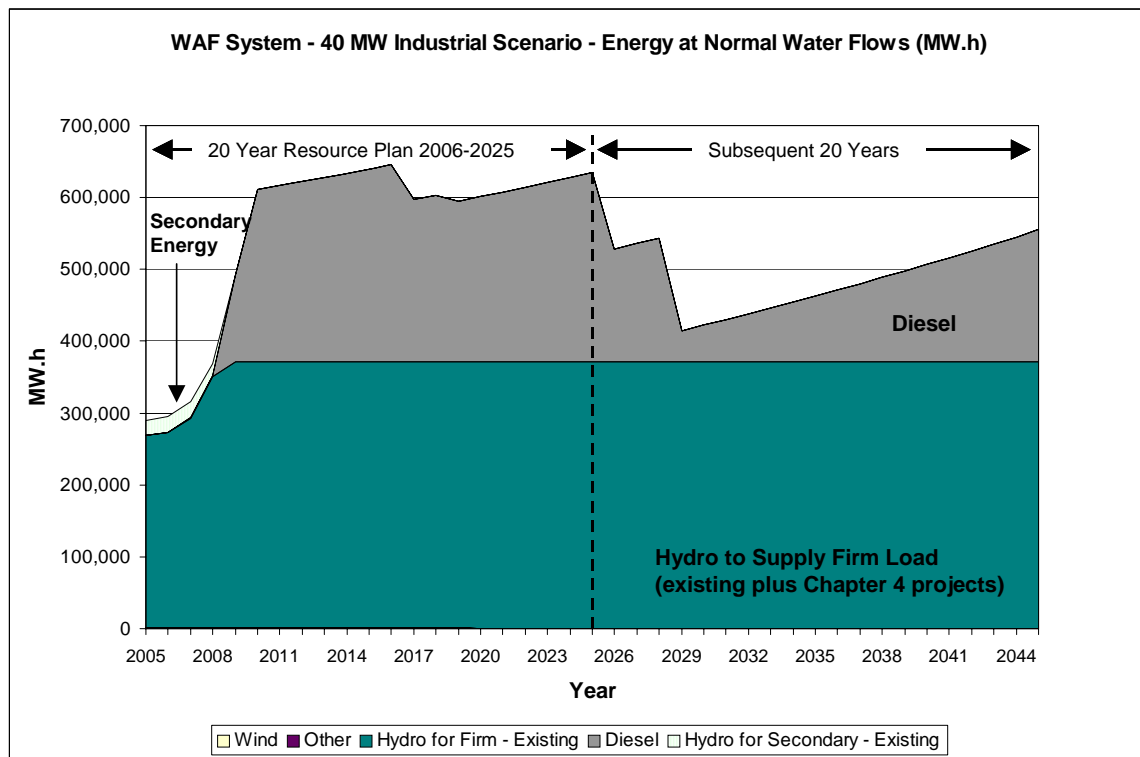
10 **Energy:** From an energy perspective, the development of 40 MW of industrial load well exceeds the
11 current scale of system surplus hydro. For a period of 16 years, the magnitude of diesel generation under
12 this scenario (if all new energy was supplied by diesel fuel generation) would range from 220 to 275
13 GW.h at normal water flows, with four additional "shoulder" years before and after the peak averaging
14 120 to 170 GW.h. Without new development of hydro or other capital intensive generation, over the life
15 of the mines diesel generation would supply about 85% of the mine load incremental generation.

¹⁶ As noted in the summary of requirements, the scenario case is modeled using a maximum 44 MW of industrial load. Of this amount, and assuming development of the Aishihik 3rd Turbine, 6.8 MW of industrial load may be carried under the LOLE criteria without a need for new capacity (over Base Load N-1 requirements), and 37.2 MW of new capacity is therefore required.

1 After the period of mine closures (assumed here at 2029), the WAF system under this scenario would be
 2 back down to a non-industrial load level that requires all the existing hydro output plus about 44 GW.h of
 3 diesel generation, and it will take approximately 13 years (assuming no additional new industrial
 4 developments) before it increases back to the 150 GW.h of diesel generation level (to 2042). This period
 5 is well beyond the current 20 year Resource Plan framework.

6
 7
 8

Figure 5.8:
Scenario 3: WAF Energy Requirements



9

10 **5.2.4 Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline**

11 The largest potential industrial power load in the near-term in Yukon is the Alaska Highway Pipeline. For
 12 the purposes of current planning, Yukon Energy is working with initial plans that four compressor stations
 13 each potentially requiring 30 MW and 223 GW.h/year for 30 years may require service (totalling up to
 14 120 MW and 894 GW.h/year). The earliest in-service date for the first four compressors is assumed to be
 15 in the 2012-2015 period, assuming development of the pipeline by this time as well as use of electric
 16 power rather than natural gas from the pipeline to run these compressor stations. Up to eight additional

1 30 MW compressors could be added within the following four to five years (potential total 360 MW and
2 2,680 GW.h/year for this scenario).

3
4 Under normal circumstances, a natural gas pipeline operating in remote areas will power compressor
5 stations with direct drive natural gas compressors without the use of electricity. In areas where there is
6 access to low cost electrical power, pipelines have been converting to electrically powered compressors.
7 In Yukon, the terms of the current agreement relating to this pipeline state that the proponent will be
8 required to use electric compression if it can be provided on a “reasonably economic” basis. Accordingly,
9 the Scenario 4 potential power load is contingent not only on the pipeline being developed as assumed,
10 but also on Yukon Energy being able to establish that it can provide a “reasonably economic” electricity
11 option for the pipeline to use electric compression.

12
13 Capacity and energy graphs indicating existing supply versus new 120-360 MW loads for Scenario 4 are
14 not meaningful, given the current installed winter capacity for the entire WAF grid at only 87 MW.

15 **5.3 OPTIONS**

16 New generation options to supply future industrial developments focus on energy rather than capacity
17 requirements.

18
19 New industrial WAF power loads beyond Scenario 1 levels would lead to increased reliance on available
20 diesel generation to meet incremental baseload energy requirements¹⁷, and high costs associated with
21 non-peaking diesel energy generation would thereby create opportunities to develop new supply
22 resources to displace the need for incremental diesel energy generation. In each scenario, non-diesel
23 energy resource development opportunities are shaped by the magnitude and duration (seasonal and
24 multi-year) of the incremental baseload energy that would otherwise need to be supplied by available
25 diesel generation.

26
27 Yukon Energy has identified on technical grounds an initial list of potential generation options to examine

¹⁷ “Baseload” here means annual energy generation other than “peaking” energy generation. “Peaking” energy generation is generation that occurs in any year only over short-term periods (hours or days) to aid in meeting the peak demand (MW) for electricity, typically during business day hours in winter; peaking generation units accordingly will typically operate only a small percent of the time in any year (e.g., say up to 10% to 15% of total annual hours). In contrast, typical baseload generation units will typically operate for most of the time in any year, e.g., Whitehorse Rapids hydro units (40 MW capacity) on a long-term basis will generate about 246 GW.h/year, implying average annual operation at about 70% of annual capacity. Due to seasonal as well as peaking operation, long-term average annual energy generation at Aishihik approximates only about 40% of the plant’s 30 MW capacity.

1 for each of the four WAF industrial development scenarios (in addition to diesel generation as a standard
2 default option, and transmission required to connect new industrial loads and/or new generation under
3 each scenario).

4

5 At this stage, further to discussions related to the 1992 YUB hearing, the Resource Plan also considers
6 briefly potential development of resource options by IPPs.

7 **5.3.1 Overview of Resource Supply Options**

8 Major power resource supply technology options considered in this chapter for possible commitment
9 before 2016 fall into one of three categories: hydro, thermal (coal, or potentially biomass), or natural
10 gas. Potential interconnection to the BC grid is also considered with the pipeline scenario.

11

12 For the major supply options considered, the relevant technology characteristics of each type are critical
13 to considering its suitability to the loads to be served during the planning period. Beyond the major
14 supply technology options considered in this chapter, a number of other technology options have been
15 reviewed and determined to not provide the necessary characteristics for major development options in
16 Yukon at this time. Details on the following additional technology options are set out in *Appendix A:
17 Generation Technologies*), along with review of the major technologies addressed below in this chapter:

- 18 • Wind
- 19 • Coal-bed methane
- 20 • Hydrogen
- 21 • Nuclear
- Biomass
- Geothermal
- Solar
- DSM

22

23 Before reviewing supply options specific to each of the four WAF industrial development scenarios, the
24 technology characteristics for each of the major supply technology options considered in this chapter are
25 highlighted separately below. In addition, potential consideration of IPPs to develop these major resource
26 options is also reviewed.

27

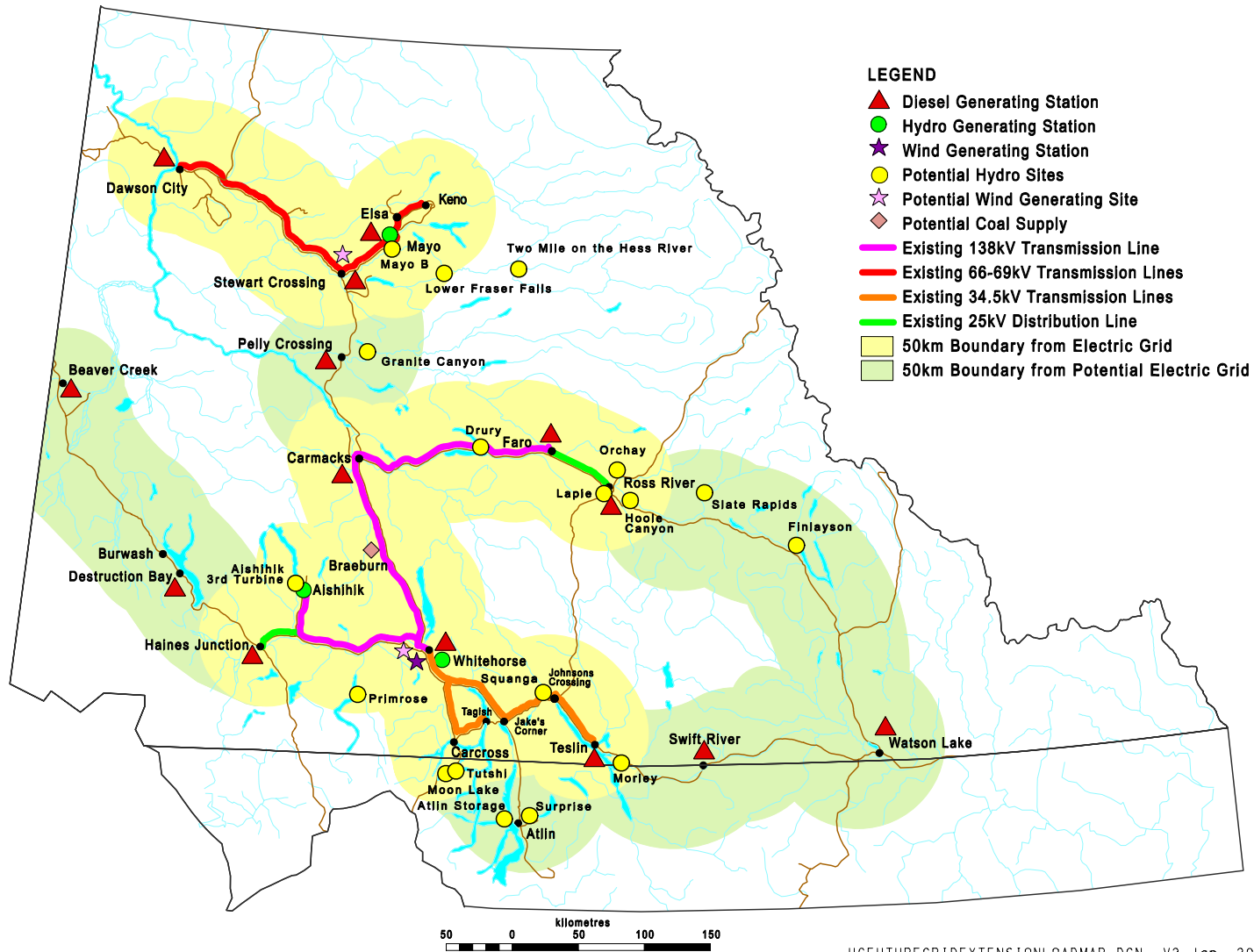
28 *Figure 5.9: Map of Potential Supply Option Sites* provides an overview of hydro and coal site option
29 locations examined in this chapter in the context of the current WAF and MD power supply infrastructure,
30 identifying as well areas within a 50 km boundary from current and potential electric grids.

1
2
3
4

Figure 5.9:

Map of Potential Supply Option Sites

EXISTING TERRITORIAL POWER INFRASTRUCTURE AND POTENTIAL SUPPLY OPTIONS



5.3.1.1 Hydro Technology Characteristics

The potential hydro supply options identified in the Resource Plan for the Yukon are detailed in *Table 5.2: Potential Hydro Resource Options* as well as in *Appendix B: Hydro Project Options*.

**Table 5.2:
Potential Hydro Resource Options¹**

	Grid	Installed MW	GWh	Capital Cost (2005\$millions) (excl. trans.)	Trans. Distance (km)	Protected under Yukon land claims	In BC	Capital Cost LCOE (cents/KWh) excl. trans (2005\$ real)
Existing Hydro Enhancements								
Aishihik Diversions	WAF	0	total of 24	n/a	0	X		n/a
Atlin Storage	WAF	2	9	n/a	0		X	n/a
Very Small Hydro Projects (1-4 MW)								
Drury	WAF	2.6	23	31	0	X		7.2
Squanga	WAF	1.75	8.3	12	5			7.7
Orchay	WAF	4.2	27	47	15			9.2
Morley	WAF	4	22	31	30	X		7.5
Lapie	WAF	2	10	14	8			7.4
Small Hydro Projects (5-10 MW)								
Moon	WAF	8.5	50	51	66		X	5.4
Surprise	WAF	8.5	50	50	100		X	5.3
Tutshi	WAF	7.5	50	79	25		X	8.4
Mayo B	MD	10	48	101	0			11.2
Medium Hydro Projects (10-30 MW)								
Primrose	WAF	28	141	191	100			7.2
Finlayson	WAF	17	129	179	230			7.4
Large Hydro Projects (30-60 MW)								
Hoole	WAF	40	275	412	100			8.0
Slate	WAF	42	252	422	172			8.9
Two Mile Canyon on the Hess	MD	53	280	380	n/a	X		7.2
Very Large Hydro Sites (60+ MW)								
Granite	WAF	80 (up to 250)	660	706	125	X		5.7
Fraser Falls	MD	100 (up to 450)	613	555	n/a			4.8
Yukon River (such as Rink Rapid, Eagles Nest, Five Fingers)	WAF	various 75-240	n/a	n/a	n/a			n/a

¹ See Appendix B for more information on specific hydro options and for review of Capital Cost LCOE (2005\$).

Hydro resource options exist under each of the four industrial development scenarios, addressing new energy requirements that emerge when loads develop sufficiently to fully utilize the current hydro generation surplus on each grid. Hydro is a proven technology in Yukon and considerable effort has been spent over the years to assess and catalogue potential for hydro throughout the territory. Key characteristic of hydro generation include the following:

- **High initial cost of plant, with very low to zero variable costs:** This key characteristic of hydro derives from the nature of the “fuel” – running water. Consequently, once hydro

1 plants are constructed, they need for economic reasons to be used on a sustained ongoing
2 basis (unless intermittent use is done simply to store water for more cost effective future
3 peaking, seasonal or other use) as there are very little cost savings if the plant is not in use.
4 This leads to situations such as now exist on WAF, where hydro fixed costs are shared across
5 less energy sales than would be the case if the existing hydro assets could be fully utilized by
6 higher firm loads. This is also the economic basis for current WAF and MD secondary sales,
7 essentially to help spread the fixed costs of the hydro plant across more kW.h output units.
8 Consequently, it is difficult to justify hydro projects unless maximum use can be made of the
9 entire output in as many years as possible. The convenient corollary is that hydro project
10 costs are largely incurred up front as capital outlays, so over time the annual expenses
11 accounted for hydro facilities tend to be very stable (with real or constant dollar costs
12 tending to decline¹⁸) compared with diesel or coal, where nominal fuel costs do tend to
13 increase over time with inflation (among other factors).

- 14 • **Very long project lives:** In conjunction with very low variable costs, hydro projects tend to
15 have a very long economic life (in some cases 100 years or more) and accordingly economic
16 justifications for such projects typically also assume sustained and effective use throughout a
17 correspondingly long economic life. As a result the exposure risks related to market
18 requirements or other factors for new hydro projects extend farther into the future than
19 facilities that are expected to provide similar benefits over shorter economic lives.
- 20 • **Long lead times for permitting, approvals and construction, with substantial**
21 **investment in planning studies required in advance of determining full project**
22 **feasibility and making commitments:** The time required to assess, licence and construct
23 a hydro project is much lengthier than for most other generation technologies. The 1992
24 Resource Plan reviewed in detail the planning stages for a typical hydro project that might
25 have been considered at that time.

26

27 Hydro generation project feasibility in each instance is sensitive to certain key factors:

- 28 • **Water availability:** Knowledge of dependable flows; head under natural (run of river)
29 water conditions; potential options for reservoir storage and/or diversions; availability of
30 water throughout the year, particularly during winter peak periods; and opportunities for
31 seasonal or multi-year reservoir storage.

¹⁸ By way of example, consider that the bulk of the initial Whitehorse Rapids hydro plant was built in the 1950s for \$7.2 million. Today's costs for this plant include depreciation on the \$7.2 million as well as interest on the undepreciated component of this original capital cost.

- 1 • **Generation site:** Foundation conditions; general terrain; and access during construction
2 and operation.
- 3 • **Project location:** Distance from existing and expected future loads; and transmission
4 requirements.
- 5 • **Regulatory approvals:** Environmental and socio-economic impacts; and mitigation
6 requirements.

7
8 When undertaking hydro project planning, there is a need for sequential planning stages given the
9 relatively high potential planning costs for each potential site. Experience establishes that project
10 selection should be in clearly defined stages in order to control time and cost commitments, to account
11 for environmental regulatory requirements as well as technical, economic and financial issues, and to
12 allow for an orderly project screening and assessment before commitment and construction of any
13 project without unnecessarily committing excessive capital for assessing multiple sites to the same level
14 of detail.

15
16 The 1992 Resource Plan set out three levels or stages for hydro project planning and selection in Yukon,
17 with the need for any site to proceed successfully through all three stages before any commitments may
18 be considered.

- 19 • **Level 1/Stage 1 – River Reconnaissance/Inventory (all sites):** Air reconnaissance to
20 locate/evaluate potential sites; existing water flow data. In the 1992 Resource Plan, Level 1
21 was estimated to cost \$20,000 per site (resulting cost estimates considered to be within +/-
22 50%). Yukon Energy has developed an inventory of many sites in Yukon and in northern BC
23 that have been studied in the past (primarily by NCPC or Government of Canada, and
24 reviewed from time to time by Yukon Energy). Based on inventory of sites studied in the
25 past, Yukon Energy has identified certain sites in this Resource Plan with the potential to
26 meet the forecast electricity needs of Yukon under each of the four industrial development
27 scenarios.
- 28 • **Level 2/Stage 2 – Site Reconnaissance/Pre-Feasibility:** Field investigations to
29 evaluate foundation conditions, preliminary hydrological studies, preliminary office studies
30 (power availability, structural lay-outs and capital costs at +/- 25% accuracy), confirm or
31 reject some of the key initial assumptions in an inventory study and provide some data
32 needed for further studies if justified. In the 1992 Resource Plan, Level 2 was estimated to
33 cost \$80,000 per site. Level 2 was achieved at a minimum for all sites reviewed in the 1992
34 Resource Plan report.

- 1 • **Level 3/Stage 3 – Feasibility Studies:** Further field investigations (geological reports,
2 foundation investigations through test pitting and drilling, construction material investigations
3 to finalize sources), site topography (scale 1:20,000 or 2 m contours), updated hydrology,
4 environmental and socio-economic studies, consultations with First Nations and others,
5 detailed office studies (to determine structure sizing and location, final concept, power
6 availability, and project capital cost at +/-20% accuracy). In the 1992 Resource Plan, Level
7 3 was estimated to cost \$400,000 per site. Level 3 should be substantially completed prior to
8 any decision to proceed to licensing; required for regulatory submissions, construction
9 contract packages, financing arrangements. Level 3 review was started on only some of the
10 projects examined in the 1992 Resource Plan report (only some of the small scale projects).

11
12 The cost today to carry out each Stage/Level of site specific planning would be higher than indicated in
13 the 1992 Resource Plan, both to reflect current day dollars and to reflect any current projects that are
14 larger or more complex than those considered in 1992. Costs to proceed through full scale feasibility
15 studies, licencing/permitting and final design/costing prior to any final commitments for even a “small”
16 hydro project (5-10 MW) might, for example, range from \$5 to \$10 million¹⁹.

17
18 Yukon Energy will only proceed with the final design and construction of sites (effectively Level 4 or
19 Stage 4) that are required (based on load growth, or commitments by industrial customers), that can be
20 successfully licensed in a timely manner, and that are not expected to have a long-term adverse impact
21 on ratepayers relative to other available options.

22 **5.3.1.2 Coal and other Thermal Technology Characteristics**

23 Environmentally sound coal generation is considered in this chapter consistent with past reviews in Yukon
24 based on a presumed pre-development of local supplies (Division Mountain). Coal development solely for
25 power generation, and associated costs of mine development, is not considered.

26
27 Coal generation has been reviewed a number of times for application in Yukon. Coal in particular as a fuel
28 source has also been examined in many other jurisdictions beyond Yukon, and is a major generation
29 option that is subject to extensive ongoing technology development to address emissions controls as well
30 as other features (see also Appendix A). Key characteristics of coal relevant to the WAF system are as
31 follows:

- 32 • **Economics very sensitive to size of plant:** Repeated assessment of coal potential in
33 Yukon has focused on 20 MW size, as that is the largest single unit that WAF could handle

¹⁹ Estimate based on 10% of estimated capital costs from Table 5.2.

1 within operating reliability considerations. Economic preference exists for larger plants up to
2 50 MW or more to secure lower costs per kW.h of output. This size sensitivity extends to
3 capital costs and operating costs (i.e., largely need same material staff complement for 20
4 MW plant as for 50 MW²⁰). However, energy output from larger potential sizes of plant at
5 perhaps 360 GW.h per year (50 MW) are well in excess of most WAF scenario requirements
6 other than the Pipeline.

- 7 • **Technologies for use of coal have been advancing at a rapid pace**, particularly with
8 regard to reducing emissions. Any coal generation plant would have to be environmentally
9 sound in order to be considered by Yukon Energy.
- 10 • **Facility life of 20-30 years can be well suited to Yukon loads:** The industrial loads in
11 Yukon can allow for large loads of limited life, with risks of major reductions at the end of the
12 life of the mine(s). With a hydro development, the long life of the facility can increase the
13 exposure to this market risk, while the 20-30 year life of coal or other thermal plants is better
14 suited to the timelines of mine life for many developments and to the mitigating of risks of
15 load decreases when the mine closes.

16
17 Similar to coal, biomass generation (i.e., wood waste) is subject to the same economic constraints.
18 Specifically, the fixed costs (including fixed operating and maintenance costs) do not vary dramatically
19 with the size of the operation or the load. In these circumstances, economic viability hinges on relatively
20 large and virtually constantly run facilities. As a general principle, however, biomass generation in Yukon
21 would not typically become economic unless three key conditions are met (these same conclusions have
22 also recently been cited as preconditions for biomass electricity generation in Alaska - see Appendix A):

- 23 1. The fuel (typically wood) must be available from a source that would otherwise have to pay
24 to dispose of it. Economic biomass generation is not typically possible even outside Yukon
25 with a wood product that has a cost to harvest. Biomass generating facilities at a minimum
26 typically need a secure source of forestry waste biomass such as sawdust or bark waste from
27 a pulp mill that is in close proximity to the biomass generating plant or even (in at least some
28 cases) that can be delivered to the plant for free; for this precondition to apply, there often
29 has to be savings achieved from avoided disposal costs.
- 30 2. The wood-fired power displaces diesel power.
- 31 3. The waste heat from the biomass generation also must be of economic value on-site, or be
32 able to be sold.

33

²⁰ An earlier study for YDC indicated that 13 staff FTE would be required to operate a 20 MW plant. This number was not sensitive to size (in the extreme, a 1 MW plant was considered and determined to still require 12 staff FTE).

1 To date, proposals discussed in Yukon do not meet any of these three key criteria, and accordingly the
2 thermal biomass option is not considered likely to be economically feasible for commitment prior to 2016
3 for any of the industrial development scenarios being considered.

4 **5.3.1.3 Natural Gas Technology Characteristics**

5 Natural gas generation is a major supply option to southern utilities (as well as NWT in Inuvik) that may
6 become an option in Yukon if the Alaska Highway Pipeline project proceeds. The current expectation is
7 that any pipeline developed along the Alaska Highway will allow access for at least the major centers to
8 natural gas for local distribution. However, there appears to be uncertainty as to pricing regimes for bulk
9 gas delivered to Yukon.

10
11 In terms of the Resource Plan, potential for Natural Gas availability focuses on three major areas:

- 12 • **Natural Gas used by the pipeline for compression:** As reviewed earlier in Section 5.2.4,
13 under normal circumstances a natural gas pipeline operating in remote areas will power
14 compressor stations with direct drive natural gas compressors without the use of electricity.
15 In areas where there is access to low cost electrical power, pipelines have been converting to
16 electrically powered compressors. In Yukon, the terms of the current agreement relating to
17 this pipeline state that the proponent will be required to use electric compression if it can be
18 provided on a “reasonably economic” basis. Outside of compressors, pipelines have
19 reasonably material other electrical loads (including potentially cooling loads) that may be
20 ideal candidates for grid power service even if compressor loads are determined to be better
21 served directly by natural gas.
- 22 • **Natural Gas for Yukon power generation:** Regardless of whether the pipeline operator
23 uses natural gas or electrically powered compression, the pipeline will likely create
24 opportunities for natural gas based power generation in Yukon. Evidence from southern
25 jurisdictions and NWT indicates that natural gas generation is a major technology option for
26 new power generation and can be well ahead of diesel in terms of costs, reliability and
27 impact on the environment. In addition, unlike coal, natural gas generation is more readily
28 “scalable” to sizes suitably for Yukon as well as more suited to timely regulatory review and
29 approvals and flexibility to operate in response to load variations.
- 30 • **Natural gas availability to Yukoners for heating supply:** Natural gas will become a
31 heating supply option for residential and commercial customers under the pipeline scenario.
32 In 1977 Foothills did include a proposal to provide natural gas to communities along the
33 pipeline route including Beaver Creek, Burwash Landing, Destruction Bay, Haines Junction,
34 Whitehorse, Teslin, Upper Liard, and Watson Lake. Although electrical heating is no longer

1 considered to be a major component of Yukon Energy's loads, there is likely to be some
2 reduction in load (including winter peak loads) from electrical heating customers converting
3 to natural gas.

4 **5.3.1.4 Independent Power Producers**

5 Power delivered to a grid (e.g. through purchases by Yukon Energy) from IPPs rather than generated
6 from assets owned and operated by regulated utilities typically follows the underlying technology
7 characteristics for the generation source used, e.g., IPPs developing hydro sites have some of the same
8 characteristics as utility-developed hydro site projects noted above.

9
10 IPPs in certain instances can offer specialized skill, experience, or knowledge that may allow a specific
11 supply option to be cost effectively developed by the IPP to meet utility requirements as stipulated in its
12 contract with the IPP; such contracts are also intended to provide the IPP with unregulated profit
13 incentives to be efficient and effective in supplying such generation outputs. However, there are some
14 unique non-technology characteristics of IPPs that were reviewed in some detail at the 1992 Resource
15 Plan hearings, and that merit specific attention as they may potentially drive material additional risks to a
16 utility and its ratepayers compared to regulated utility power supply projects:

- 17 • **Unit pricing, including issues of levelized costs and sharing of benefits from diesel**
18 **displacement:** As of 1992, the last major YUB review of IPP matters, there remained
19 significant issues outstanding in regards to approaches to pricing for potential IPPs in Yukon.
20 Major issues relate to how to determine the "value" of the IPP to the system (typically based
21 on avoided costs for the system, which can be difficult to calculate for various supply types),
22 how to share between the IPP developer and the utility ratepayers the "benefits" associated
23 with developing lower cost generation, and the potential use of "levelized" nominal prices for
24 IPPs (which tend to provide higher real prices in the near-term and lower real prices over the
25 long-term, and are typically preferred by IPP developers). At a basic level, it is likely that
26 hydro supply projects that can effectively displace regulated utility diesel generation will yield
27 material avoided cost savings within Yukon; however, while almost all such savings will
28 typically go to the benefit of ratepayers when such hydro projects are developed by a
29 regulated utility, the IPP development option introduces a separate step whereby some (or
30 perhaps even all) of the avoided costs savings can be captured by the IPP developer.
- 31 • **Take-or-pay contracts:** Similar to other Yukon generators, IPP developers would likely
32 have no market for their power other than the utility. Financing for such IPP projects is
33 expected to require the utility to commit to a "take-or-pay" contract that means the utility will
34 be committed to buy most or all of the project's output at full prices, whether the utility

1 requires the power or not and perhaps even whether the IPP is able to sustain production of
2 the power. As a result, market and likely other risks of the development can in effect be fully
3 borne by the utility rather than by the IPP developer, even though the IPP may capture most
4 or all of any avoided cost benefits when the facility is able to displace diesel generation.
5 Under some potential IPP arrangements, avoided costs benefits may be locked in for the IPP
6 developer (and paid for by ratepayers as though the diesel savings were in fact occurring)
7 regardless as to whether in fact any such diesel cost savings are being realized by the utility.

- 8 • **Delivery of power/reliability:** If an IPP project on a system in Yukon is not functioning at
9 any point in time, regardless as to whether or not the utility must still make payments to the
10 IPP, there is the separate risk that the utility (due to default by the IPP) may not be able to
11 meet its committed supply of power to its ratepayers. However, the utility itself typically has
12 little or no control over the IPP facility, its maintenance activities, emergency procedures, or
13 scheduling and thus can run into problems with the continuity of supply to its customers. For
14 this reason, it is difficult for a regulated utility to treat IPP or other generation not under
15 utility control as “firm” supply for a regulated utility system²¹. A utility also has no control
16 (beyond penalties) over the construction of IPP projects and whether the IPPs can in fact
17 meet key contracted commitments such as in-service date.

- 18 • **Financial guarantees:** IPP producers typically seek external bank financing for portions of
19 the capital cost of their facilities. For this reason, these producers typically require power
20 purchase contracts from the regulated utility with strong terms in favour of the IPP and may
21 also include various guarantees from the utility, ultimately focusing the lender’s assessment
22 of their risks onto the financial strength of the utility. The end result can be effective
23 requirements for the utility to backstop or guarantee the risks of the private investor to
24 further disproportionately focus the risks of any development on the utility itself and its
25 ratepayers.

26
27 Consequently, as discussed in the 1992 hearing, it is difficult to establish an IPP arrangement in Yukon
28 that would reflect a fair sharing of the risks between the utility (and its ratepayers) and the private IPP
29 developer. Yukon Energy in 1996 did complete a major call for “Expressions of Interest” including for IPP
30 supply,. This call yielded some potential focused opportunities for future investigation of small IPPs
31 should material loads develop and base load diesel become an ongoing requirement. However, as noted

²¹ As an example, the Snare-Yellowknife system in NWT has a hydro facility that was previously owned and operated by one of the mines. NTPC had a supply agreement with the mine to meet their peak loads in the event the hydro site was not producing. Consequently, when the capacity criteria was assessed for the entire grid, this hydro station was not considered firm capacity for the purposes of planning the system. In 2003 NTPC purchased this station and, now that it no longer is owned and operated as an IPP, it is now included in the new firm capacity planning approach for the system.

1 in the 1992 hearing, IPP focus in Yukon to date has been on small projects - other than small hydro
2 projects, it remains unclear how difficult it will be in Yukon to develop or negotiate an IPP arrangement to
3 suitably share risks on resource projects of any material size.

4 **5.3.2 Options for Scenario 1: A 10 MW WAF Industrial Scenario**

5 A 10 MW industrial scenario would not likely require the addition of capacity or energy projects. Up to
6 6-7 MW of industrial load can be added to the system without driving a need for new capacity.
7 Depending on the seasonality of the load and quantity of on-site diesel generation installed by the mines,
8 it is possible that all of the 10 MW in new load could be served without driving a need for new capacity.

9
10 There is also a current ability to serve about 90 GW.h per year of energy from existing surplus hydro,
11 decreasing as non-industrial load grows over the life of the mines. Under this scenario, there remains
12 some diesel generation required for peaking and, as the non-industrial load grows, some requirements
13 for baseload diesel. However there is limited value to any new hydro or thermal generation to displace
14 diesel fuel, as the number of hours per year of diesel requirements remains quite limited.²² In addition,
15 the specific early mine developments considered in Scenario 1 are of relatively short duration (i.e., mine
16 shutdowns are assumed to occur in 2016 and 2017), with the result that surplus hydro is expected to
17 remain under this scenario for half of the 20 year planning period (from 2006 to 2009, and from 2017 to
18 2022).

19
20 As a result, any opportunities for new generation developments are likely limited to existing hydro
21 enhancements (including those identified in Chapter 4, Section 4.3.6) and/or possibly the smallest of the
22 hydro sites identified in Yukon, at most, and likely only those that can provide both capacity and energy
23 benefits. A list of "very small hydro projects" (1-4 MW) is provided in Table 5.2 and in *Appendix B: Hydro*
24 *Project Options*. Among these options, only Drury is considered to be reasonably well defined at this
25 time.

26 **5.3.3 Options for Scenario 2: A 25 MW WAF Industrial Scenario**

27 A 25 MW industrial scenario, which would be similar to WAF loads experienced when the Faro mine was
28 operating, would provide opportunities for the addition of both capacity and energy. Without new
29 development of hydro or other capital intensive generation, incremental WAF diesel generation required
30 under the Scenario 2 case examined in Section 5.2.2 would range from about 90 to 140 GW.h/year for a

²² Over the life of these two mines with the timing assumed in Scenario 1, only about 10% of the incremental energy requirement would need to be met by generation beyond that available from current hydro surplus resources (assuming average long-term flows).

1 period of 16 years (from 2010 to 2025) out of the 180 GW.h/year of overall increased energy required
2 due to the new industrial developments.

3
4 Under the Scenario 2 case examined in Section 5.2.2, if no new capital intensive generation was
5 developed and the WAF system had to be served solely with incremental diesel, the assumed industrial
6 loads would only be supplied about 30% with surplus hydro and about 70% with incremental diesel
7 generation over their life. Under these conditions, (i.e., if diesel generation is to be relied upon to supply
8 the incremental energy requirement), there is no apparent basis for Yukon Energy developing any new
9 transmission interconnections to the bulk of this mine load (with the associated risks and transmission
10 losses) rather than the mines simply using isolated diesel plants at their mine site.

11
12 However, this scale of industrial load on the WAF system would provide material potential opportunities
13 to develop new capital intensive generation on WAF. If the assumed industrial loads arise, diesel
14 requirements over the life of the industrial loads (absent new capital intensive generation) would
15 approximate 90-140 GW.h/year; however, after the mines close, diesel generation on WAF would fall
16 back to about 21 GW.h/year, growing at about 7 to 8 GW.h/year as non-industrial load grows.
17 Accordingly, the size range of new capital intensive generation suitable for this magnitude of load is likely
18 to be about 50 GW.h per year, or about 7-10 MW of reasonably high capacity factor generation (such as
19 those reviewed in 1992 when the Faro mine was operating)²³. If such development could be pursued,
20 there would remain 7-10 MW of other new "reserve" capacity required (for largely peaking or standby)
21 where low capital costs are the driving economic factor (i.e., likely new diesel units) over and above the
22 commitments recommended in Chapter 4.

23
24 Hydro projects in excess of about 7-10 MW size would impose risks of substantial periods of surplus
25 hydro after the planned closure of the mines (with 10 years required for diesel consumption to move
26 back up to 100 GW.h/year from 2026 to 2036) outside of risks related to premature closure of one or
27 more mines under this scenario.

28
29 In contrast, as reviewed below, the scale of diesel generation displacement offered by Scenario 2 appears
30 to be too small to support any feasible thermal coal supply options, even though the overall mine life
31 assumed better fits thermal than hydro supply alternatives.

²³ At that time, projects up to about 8 MW per year and 50 GW.h/year were considered (implied annual capacity factor of 70%).

1 **Hydro:** Options can include those identified for the 10 MW scenario (very small hydro projects), as well
2 “small hydro projects” (5-10 MW) and Existing Hydro Enhancements noted in Table 5.2 and *Appendix B:*
3 *Hydro Project Options*. Aside from Drury, each of these options is considered to be relatively undefined at
4 this time.

5
6 The projects identified reflect a lack of suitable hydro sites identified to date in this size range in Yukon.
7 The primary supply options considered in 1992 in this size range (such as Moon Lake as well as Surprise
8 Lake) are in BC and consequently attract significant additional charges for water rental fees and taxes.

9
10 **Thermal – Coal:** There are no credible opportunities to develop coal generation at this scale. As
11 reviewed earlier, the practical minimum size coal development considered for Yukon has been 20 MW,
12 which roughly equates to 144 GW.h/year or well in excess of the requirements under this scenario (other
13 proposals have focused on coal generation in excess of this range up to 50 MW).

14 **5.3.4 Options for Scenario 3: A 40 MW WAF Industrial Scenario**

15 Under the 40 MW scenario, as under the 25 MW scenario, any loads connected to the WAF clearly push
16 the system well onto diesel. Without new development of hydro or other capital intensive generation,
17 incremental WAF diesel generation required under the Scenario 3 case examined in Section 5.2.3 would
18 range from 220 to 275 GW.h/year for a period of 16 years, with four additional “shoulder” years
19 averaging about 120 to 170 GW.h/year. After these mines close (assumed to be 2029), diesel generation
20 on WAF for non-industrial loads would fall back to about 44 GW.h/year, growing at about 7 to 8
21 GW.h/year as non-industrial load grows.

22
23 If diesel was relied upon to supply loads of this magnitude, the industrial loads in effect would only be
24 supplied about 15% with existing surplus hydro and 85% with incremental diesel generation over their
25 life. As noted above for the Scenario 2 case, if WAF diesel generation is to be relied upon there is no
26 apparent basis for Yukon Energy developing any new transmission interconnections to the bulk of this
27 mine load (with the associated risks and transmission losses) rather than the mines simply using isolated
28 diesel plants at their mine site. Consequently, if such loads are to be considered for connection to WAF, a
29 major focus is required on developing new capital intensive generation larger than the 50 GW.h/year (7-
30 10 MW) examined under Scenario 2 options.

31
32 New capital intensive energy projects in the range of 50 GW.h/year (about 7-10 MW) would be expected
33 to be fully utilized in each year of this scenario. In contrast, long-term capital intensive energy projects in
34 the range of 150 GW.h/year (in the range of 20-30 MW if baseload) would experience about 13 years or

1 more of surplus energy after the closure of the mines until non-industrial load growth consumed the
2 excess output. Projects in excess of this level would see about 20 years of sustained use, then significant
3 periods where they far exceed system requirements.
4

5 Overall, hydro project options above about 100 GW.h per year may be difficult to justify unless there is
6 substantial expectation of subsequent industrial loads after 2024, and solid measures to address
7 downside risks of premature mine closings. Thermal coal project options, however, with levels of energy
8 generation of about 150 GW.h/year that are focused on a 20-year life may become feasible at this scale
9 of mine loads. Each of these options is reviewed below, and is considered to be relatively undefined at
10 this time.
11

12 **Hydro:** Hydro projects to supply the 40 MW scenario result in significant issues with respect to load
13 stability and economic value of power over their life after the planned closure of the mines (outside of
14 risks related to premature closure). This is because hydro projects are very long-term investments that
15 can produce power well beyond the expected life of the mine being considered.
16

17 At this size range, options can include those identified for the 5-10 MW scenario (small hydro projects),
18 as well "medium hydro projects" (10-30 MW) noted in Table 5.2 and *Appendix B: Hydro Project Options*.
19

20 At this size range, projects can support some costs for new transmission, so generation sites within about
21 50-100 km or more of the established 138 kV grid become worthy of investigation.
22

23 **Thermal – Coal:** Under the 40 MW scenario, the scale of new requirements increase to a point where
24 opportunities may arise to develop coal or other thermal generation. The practical minimum size coal
25 development considered earlier (1992) for Yukon has been 20 MW which roughly equates to 144
26 GW.h/year or in the range of the new energy requirements under this scenario. As coal plants have a life
27 more consistent with the mine lives being considered (often assessed for project planning and feasibility
28 at 25 years, although many plants outlive this), the technical fit of a coal plant to the loads under this
29 scenario is better than hydro in this size range.
30

31 The economics of coal generation are very sensitive to the price of the coal, as well as to the quality of
32 the coal and emissions standards, which can materially impact the capital costs required for the plant (for
33 example, ash handling and dealing with sulphur in the coal). A 1995 assessment of coal power generation
34 prepared for YDC by H. A. Simons Ltd. using Division Mountain coal determined a \$50 million capital cost
35 (1995\$) excluding mine development costs, as well as about \$2 million (1995\$) for non-fuel annual

1 operating and maintenance costs (including 13 staff positions). Further assessment in 1996 focused on
2 the potential for coal at \$30/tonne to allow for power generation (using a 20 MW plant) at 8 cents/kW.h
3 (1996\$).

4
5 Based on these earlier 1995/96 estimates, a coal plant could be constructed and operated on the
6 following basis:

- 7 • 25 year life at 20 MW, 144 GW.h (a 20 year life is also assessed below).
- 8 • \$61 million capital cost (2005\$), \$2.5 million per year non-fuel operating cost (2005\$)
9 excluding taxes.
- 10 • Coal requirements of 102,000 T per year at \$37/T (1995 estimate of \$30/T inflated to
11 2005\$).
- 12 • Oil requirement of 2.3 million litres at \$0.65/litre (2005\$) – based on 1995 estimate of 2,220
13 T/year²⁴.

14 The result is an 8.3 cents/kW.h LCOE (2005\$, real), excluding transmission and taxes (but in this case
15 including operating and maintenance costs, unlike hydro LCOE costs quoted above, given substantial
16 O&M costs for coal generation)²⁵.

17 **5.3.5 Options for Scenario 4: A 120 to 360 MW WAF Alaska Highway Natural Gas Pipeline** 18 **Scenario**

19 Compared to the existing Yukon WAF system (firm non-industrial load of about 270 GW.h per year,
20 installed winter capacity of about 90 MW), the pipeline loads for the first four stations at 120 MW and
21 894 GW.h/year, are massively in excess of system capability or conditions experienced to date.

22
23 Little work has been done since the 1950s and 1960s on hydro sites of the size relevant to this scenario.
24 Any such hydro generation development would involve concurrent major transmission development
25 needs which have not been assessed or costed to date in any detail, although some preliminary
26 transmission concepts have been reviewed.

27
28 Timing needed for planning and licensing major generation and transmission projects is likely in excess of
29 ten years, given the need at the outset for extensive and costly pre-feasibility and feasibility studies. This
30 suggests that the pipeline would be operating for many years before the new hydro generation would be

²⁴ Based on the 1996 study, oil is required to supply the facility during start-up and back up duty. Given increases in the cost of oil since this study was completed, a newer coal plant may have a revised optimal balance between oil and coal, but this has not been assessed.

²⁵ Coal generation developed to supply a 20 year project life would result in the LCOE being increased to 8.7 cents/kW.h compared to 8.3 cents/kW.h for a 25 year project life (2005\$, real)

1 available. The need for the pipeline operator to install gas compressors at the outset will further reduce
2 the cost effectiveness of the new hydro options. However, previous reviews in Yukon (including the Lysyk
3 inquiry) noted the key importance of the pipeline operator installing stations that can be readily
4 converted to electrical service at a later date if power cannot be coordinated for delivery from the outset
5 of pipeline operation.

6
7 The range of potential options for Scenario 4 is reviewed below.

8
9 **Hydro:** Hydro projects to supply the Pipeline scenario are of a magnitude not well understood or recently
10 studied in Yukon. At this size range, options can include more modest “large hydro projects” (30-60 MW)
11 noted in Table 5.2 and *Appendix B: Hydro Project Options* for supply to one or more individual stations,
12 or “very large hydro projects” (60+ MW) for major integrated supply to multiple compressor stations.

13
14 At this size range, major redevelopment of Yukon transmission would be required, so transmission is an
15 unresolved issue for all potential generation sites.

16
17 **Thermal – coal:** Power generation from coal can reasonably provide the magnitude of power required
18 to service the pipeline. However, no serious work has been completed in Yukon regarding potential coal
19 developments of this scale. In addition, at least initially coal is not likely to be considered economically
20 viable as supply to electrical compression for the pipeline, as electrical compression is typically attractive
21 to pipeline operators only in low cost hydro-based jurisdictions where rates can be below 6 cents/kW.h to
22 as low as almost 3 cents/kW.h or lower depending on interruptibility (but not typically resorting to
23 electrical compression in higher priced non-hydro jurisdictions dominated by coal).

24
25 **Interconnection with the BC Grid:** There are limited attractive projects in Yukon that have the
26 capability to serve the full power needs of the pipeline. It is possible that such potential new loads would
27 form the basis for BC to extend transmission from BC that would connect Yukon (near Watson Lake) with
28 generation assets located in BC. This option could radically change power supply costs and options in
29 Yukon to the extent that major load centres (e.g., WAF and MD as well as Watson Lake) were linked to
30 this new grid connection.

31 **5.4 PRE-ASSESSMENT AND SCREENING**

32 The options identified under the various scenarios above reflect potential opportunities to put in place
33 capital intensive but overall lower cost sources of supply than alternatives of grid-based diesel supply or
34 isolated diesel supply to the mines.

1 In assessing grid-based diesel supply, current diesel price forecasts indicate about \$0.70/litre to
2 \$0.75/litre for Whitehorse for 2010 (based on \$50 to \$55 US per barrel, 2010\$ for NYMEX light sweet
3 crude, reflecting current oil futures markets), equating to about \$0.21/kW.h to \$0.22/kW.h (2010\$, or
4 \$0.20/kW.h in 2005\$)²⁶ including modest variable operating and maintenance costs (such as lube),
5 assumed at 0.016/kW.h in 2005\$. These costs provide a benchmark for assessing the potential cost
6 competitiveness of any other resource option. These costs also provide an indication of potential
7 ratepayer impacts relating to connection of major new industrial loads if in the end these loads must be
8 supplied through incremental diesel generation.

9

10 Based on the information now known to YEC, all potentially feasible generation options noted in the
11 previous sections including their associated transmission, can potentially be economically developed as an
12 alternative to diesel, so long as system loads allow full to near-full use of their output over the life of the
13 project.

14

15 There are two major areas of uncertainty, however, that limit ability to develop full detailed assessment
16 of options and conclusions regarding economic and technical feasibility at this time for any specific
17 industrial development scenario:

- 18 • There is not sufficient definition of the loads and timing of industrial customers (outside of
19 perhaps Minto at 2-4 MW).
- 20 • All project supply options identified above to address these scenarios are at best moderately
21 defined, and most remain relatively undefined. In terms of the hydro project staging, few
22 projects are at Level 2 (Site Reconnaissance/Pre-Feasibility) while most are at Level 1 (River
23 Reconnaissance/Inventory) and in many cases (especially for medium to large projects) even
24 the Level 1 work was completed many decades ago under different expected generation
25 concepts and constraints so is of limited value. Thermal projects are at a similarly early
26 stage in conceptual planning.

27

28 The focus of the following pre-assessment and screening is initially on technical pre-assessment and load
29 fit (i.e. how well does the project fit the load requirements under any specific load scenario). As noted,
30 cost effective opportunities to displace diesel generation require full to near-full effective energy use of a
31 resource option's output over its life.

²⁶ For modeling purposes, fuel costs have been assumed at 65 cents/litre for 2005, inflating at 2% per year, to total 71.77 cents/litre in 2010.

1 Subsequently, economic pre-assessment is also considered to look at the screening options with respect
2 to economic factors. Within the economic pre-assessment, diesel generation is assumed to be the default
3 source for all energy not supplied by hydro or other resource options under the 10 MW, 25 MW and 40
4 MW scenarios, as diesel generation provides supply with relatively limited risk related to timing and/or
5 capital costs. Diesel generation is not a reasonable supply option under the pipeline scenario, where the
6 alternative to electrical compression is natural gas driven compression.

7 **5.4.1 Technical Pre-Assessment and Load Fit**

8 The assessment of how well various supply options fit the load requirements focuses around options of
9 various types and size ranges. The analysis focuses on scale of loads relative to scale of various resource
10 project options; however, as noted in Section 5.3, the assumed timing of loads as well as their duration
11 can also be of critical importance in assessing resource options²⁷.

12
13 The load fit assessment is provided separately below for each different supply option technology and
14 scale grouping:

15
16 **Hydro – Enhancements (Aishihik diversions at no capacity, 1.8-17.7 GW.h/year; Atlin
17 Storage at 2.0 MW, 9.0 GW.h/year; also other potential options being assessed in Southern
18 Lakes; potential planning costs for these projects are estimated to be about \$100,000 to
19 \$200,000 per project):** These projects involve maximizing the value from the existing investments.
20 Under the industrial development scenarios, each focuses on the potential to provide energy as well as in
21 some cases capacity. The projects are all likely to be of relatively modest size that could be relevant
22 under basically all potential industrial scenarios. The planning costs for these projects are estimated to
23 be between \$300,000 and \$600,000.

24
25 **Hydro – Very Small (1-4 MW, 5-30 GW.h/year, \$12-\$47 million; potential planning costs of
26 \$1.2 to \$4.7 million prior to decision to proceed with project):** The projects in this size range

27

²⁷ By way of example, a ten year delay in the Scenario 1 mine loads would enhance opportunities to develop at least very small hydro projects (to the extent that non-industrial loads would then have grown sufficiently to sustain long term use of the new energy supply). Similarly, the duration assumed for each mine development load examined is of critical importance in the assessment of resource supply options, e.g., capital intensive supply options can much more easily accommodate loads of 40 years duration than loads of only 10 years duration. In this regard, Scenario 2 and 3 load opportunities relate as much to assumed mine duration (at 15 to 20 years) as to the assumed level or scale of these loads; Scenario 4 load opportunities, with 30 year durations, also elate to more than only scale.

1 (Drury at 2.6 MW or larger, Squanga at 1.75 MW, also Morley (4 MW), Lapie (2 MW) and Orchay (4.2
2 MW)) are likely beyond the limits of what can be enabled by the 10 MW industrial development assumed
3 in Scenario 1. The technical assessment of these projects relies on serving a role to supply energy in
4 excess of existing system hydro capability, in order to displace diesel related to serving incremental mine
5 loads while they are in operation, and to displace diesel serving non-industrial loads once the mines close
6 at about 2016-2018. However, absent mine development at or above 10 MW extending through to at
7 least 2020, it is not apparent that the load fit is sufficiently consistent to enable projects of even this very
8 small size range to be feasible. Should they be developed, these projects are well within the financial
9 capability of Yukon Energy/YDC to pursue, including measures to protect against downside market or
10 load related risks.

11
12 **Hydro – Small (5 -10 MW, 30-70 GW.h/year, \$50-\$101 million; potential planning costs of**
13 **\$5.0 to \$10.1 million prior to decision to proceed with project):** Projects in this size range (Moon
14 at 8.5 MW, Tutshi at 7.5 MW, Mayo B at 10 MW) can be enabled by industrial developments in the 25
15 MW range with relatively limited downside risk outside of premature mine closures over a life of at least
16 15 to 20 years²⁸. These projects are in a size range that can be financed under traditional structures by
17 YEC and YDC, and that YDC likely has the financial capability to “backstop” with respect to various
18 market-related risks. Ongoing current efforts in the southern lakes area may yet identify further potential
19 in this size range for other projects or comparable sized enhancements to the Whitehorse Rapids facility
20 by way of water management projects.

21
22 **Hydro – Medium (10-30 MW, 70-150 GW.h/year, \$179-\$191 million; potential planning costs**
23 **of \$17.9 to \$19.1 million prior to decision to proceed with project):** Sites in this size range
24 (including Primrose at 19-30 MW and Finlayson at 17 MW) only fit the WAF load profile under the largest
25 40 MW mining scenarios discussed (Scenario 3), which focused on the opening of four mines
26 simultaneously (Minto, Carmacks Copper, Division Mountain and Red Mountain) with lives of 15 to 20
27 years for most of the load. However, even under these conditions the hydro projects are likely much too
28 large for the system after the closure of the mines (assuming mine closure prior to about 2035), and as
29 such would rely on either new mining loads at that time to sustain the level of WAF energy 20-25 years
30 from now, or would have substantial surplus for likely far many years. In this regard, projects in this size
31 range may also have a difficult time competing with coal with respect to load fit compared to the life of
32 the generating station²⁹.

²⁸ Appendix B, Figure B-2 provides a review example of load fit for Moon Lake hydro and the 25 MW Industrial Scenario 2.

²⁹ Appendix B, Figure B-3 and Figure B-4 provide a review example of load fit for Primrose hydro and the 25 MW Industrial Scenario 2 and 40 MW Industrial Scenario 3.

1 Serious issues also arise with respect to “market”-related risks in this case such as premature mine
2 closings and even delays in initial development. In addition, these projects are likely at the limits of what
3 YEC/YDC can finance within the existing financial structure. At these limits of the financial capability of
4 YDC and YTG, it would become necessary to identify and/or develop suitable mechanisms within Yukon
5 to “backstop” the downside market risks associated with projects of this size.

6
7 **Hydro – Large (30-60 MW, about 150-300 GW.h/year, \$380-\$422 million; potential planning**
8 **costs of \$38.0 to \$42.2 million prior to decision to proceed with project):** These projects exceed
9 the size required for any credible mining load or combination of loads examined in this Resource Plan and
10 would require well in excess of 40 MW of new mining loads – no such loads or load combinations have
11 been identified to date. Project options in this range focused on Hoole at 40 MW, Slate at 41.6 MW, and
12 Two Mile Canyon on the Hess at 53 MW. There may be options to develop these sites for portions of a
13 pipeline load (1-2 compressors of the planned 4-12 compressor pipeline development), but in all
14 likelihood the economics of a pipeline case will more readily facilitate projects in the 60+ MW range and
15 not multiple projects in the 30-60 MW range. In addition, these projects appear to be at or beyond the
16 absolute limits that Yukon Energy and Yukon Development could potentially finance under any conditions
17 without potential external support or guarantees, such as from Canada.

18
19 **Hydro – Very Large (60 MW+, over 500 GW.h/year, \$555 million+; potential planning costs**
20 **in excess of \$50 million prior to decision to proceed with project):** These projects cannot be
21 considered for any practical development without a committed pipeline load (or equivalent) using
22 electricity for compression, and without major transmission system development or redevelopment to
23 handle this scale of generation. The projects identified to date include Granite at 80-250 MW, Fraser Falls
24 at 100-450 MW, and various Yukon River sites at 100-500 MW. Yukon Energy would also need to
25 address financial capability to even plan and carry out pre-construction activities on these projects, as
26 costs for even these pre-development stages would likely exceed Yukon Energy’s ready financial
27 capability. Costs for development would require either major financial partners or government debt
28 guarantees from Canada as commitments are likely beyond the capability of Yukon to guarantee.

29
30 **Thermal – Coal:** Development of environmentally sound coal in a size range of 20 MW or more cannot
31 be seriously considered on the WAF system, given current technology, outside of major industrial
32 developments in the range of 40 MW or higher (i.e., well in excess of the Faro Mine when it was
33 operating). In the event very large industrial mine developments do arise in the 40 MW range, however,
34 coal may be a better fit to the life of the load than hydro, and would therefore merit further consideration
35 at that time.

1 Coal may provide opportunities within the 25 MW scale of industrial load development (similar to Faro-
2 sized load) if constraints on technical feasibility and cost for coal generation projects smaller than 20 MW
3 can be in some way be addressed. Earlier proposals that considered a technology for 15 MW combined
4 coal/oil system have since been abandoned. However, it will remain relevant to monitor technology
5 developments in this area. The capital costs of a coal facility are in a size range that can be financed
6 under traditional structures by YEC and YDC, and YDC likely has the financial capability to “backstop”
7 with respect to various market-related risks.

8
9 Coal options must be environmentally sound to be considered. The feasibility of coal generation will
10 depend to some extent on the cost of employing state of the art technologies to reduce emissions.

11
12 Coal options also need to address directly who would be responsible for providing this resource, and
13 under what terms and conditions would Yukon Energy secure such supplies. In the event that a coal
14 mining project is developed for export markets, the coal for local thermal markets may become readily
15 available. It is not clear how such supplies could be economically secured, however before such time as a
16 coal mining project is developed for export markets. Other relevant aspects also require further
17 considerations, including ash disposal.

18
19 **Thermal – Biomass:** In the event that Yukon develops a source for waste wood, of sufficient scale and
20 duration, that would otherwise have a cost associated with disposal (e.g., someone willing to pay Yukon
21 Energy or an IPP to dispose of it) there may develop an option for biomass generation. Currently, no
22 such source of biomass supply is apparent in the time period for this Resource Plan. However, given
23 similar fixed cost constraints as for coal, even if such a source was secured it is not likely that this type of
24 generation would fit the load profiles under any but the largest industrial development scenario (e.g., a
25 20 MW plant enabled by 40 MW of industrial load).

26
27 **Natural Gas:** The pipeline scenario (Scenario 4) will likely create opportunities for natural gas based
28 power generation in Yukon.

29
30 Evidence from southern jurisdictions and NWT indicates that natural gas generation is a major technology
31 option for new power generation and can be well ahead of diesel in terms of costs, reliability and impact
32 on the environment.

33
34 In addition, unlike coal, natural gas generation is more readily “scalable” to sizes suitable for Yukon as
35 well as more suited to timely regulatory review and approvals and flexibility to operate in response to

1 load variations. Natural gas generation is also likely to be located near to the main load centres, and thus
2 not subject to the same transmission costs and risks as noted for many other supply options.

3
4 It is premature at this time, however, to assess likely charges that will apply for natural gas supplies
5 when they become available³⁰.

6 **5.4.2 Economic Pre-Assessment**

7 Given a solid load fit in technical pre-assessment, Yukon Energy has an ability to consider in a preliminary
8 way the likely economics of projects to assist in any screening effort. Four key factors come into
9 consideration in this pre-assessment:

- 10 1. **Preliminary Generation Capital and fuel-related Levelized Cost/kW.h (LCOE):** At a
11 simple preliminary level, the LCOE noted above can provide a useful screening tool for the
12 various options under consideration.

13
14 Compared to assumed prices for solely the variable cost of diesel at 20 cents/kW.h in 2005\$,
15 all supply projects reviewed above have substantial opportunities to produce power over the
16 long-term at a cost lower than diesel.

- 17
18 2. **Transmission Required to access main WAF Grid:** For hydro projects in particular,
19 investment in transmission to connect remote sites with the established transmission system,
20 and associated losses, can be a material factor in project economics. Transmission costs that
21 begin to exceed about 10%-15% of the project costs can be difficult to overcome.

22
23 Rough assumptions to date are that projects in the 1-4 MW range cannot support any
24 material transmission costs beyond simple connection (i.e., must be basically on the
25 established transmission, preferably 138 kV) while 5-10 MW projects may be able to support
26 transmission of 50 km (to perhaps as high as 100 km at a maximum). Projects in the 10-30
27 MW range may be able to allow for transmission somewhat over 100 km.

28
29 For the large to very large projects (30-60 MW and 60+ MW) there has not been any serious
30 effort to screen based on incremental transmission costs, as this can only likely be usefully
31 considered once loads have been identified and required upgrades or additional circuits to

³⁰ The Mackenzie Valley Pipeline proponents currently have a proposal before the National Energy Board that includes plans to provide access to gas from the pipeline for use by communities in the NWT along the pipeline route. This proposal, and the current NEB review, may provide guidance as to possible future charges applicable in Yukon after pipeline development in this area.

1 existing transmission can be incorporated into the assessment – such planning is not possible
2 in the absence of further information about potential loads.

- 3
4 **3. Extra Fees, Charges or Process costs related to hydro developments in BC:** For
5 hydro projects in BC, there is a material additional cost and risk associated with both
6 licencing due to interprovincial processes, as well as water rentals and taxes.

7
8 In Yukon, Yukon Energy does not pay and has complete future protection against any water
9 rentals that may be levied by the federal government for use of waters for power generation.
10 However, such fees are commonplace in other jurisdictions and can result in material costs
11 for the utility (in Manitoba, water rental rates are 0.3 cents/kW.h for generation; rates in BC
12 have been as much as 0.5 cents/kW.h but have recently been under review – the BC charges
13 also include additional amounts for storage of water, as well as taxes). The economics of
14 projects located in BC will require close monitoring of these rates to ensure that these costs
15 are fully included in planning assessments of BC project economics.

- 16
17 **4. Impacts on rates:** Separate economic assessment is required of the effect of any projects
18 on rates, as rates for any given year are set based on annual costs (including depreciation,
19 interest and return on equity) rather than the lifetime long-term costs of projects. Past Yukon
20 experience with the Faro mine well indicates that even long-term economic investments
21 (such as Whitehorse turbine #4) can result in substantial rate impacts in some years when
22 loads drop below the point where the assets are providing economic value³¹. Based on
23 examples in Appendix B, major new hydro projects that have otherwise attractive lifetime
24 LCOE costs can give rise to the potential for serious rate impact risks in some years if loads
25 decline.

26
27 A separate issue with respect to capital intensive projects such as hydro is that annual costs
28 which drive rates are at a maximum in the first few years of the project (when rate base
29 balances are highest). However, the benefits of capital intensive projects tend to increase
30 over time as the value of any diesel displaced increases with inflation or other upward fuel

³¹ Past experience with the Faro mine and Whitehorse #4 indicate rate impacts of 20-40% are possible when the Faro mine experienced shut downs in 1993 and 1997/98. This level of rate impact, however, likely understates the true full potential rate impact from major mine closures (i.e., closures for mines that account for a dominant share of WAF loads as was the case with the Faro mine when operating), as in the case of Whitehorse #4 the Government of Canada (via the Canada Flexible Term Note) retained most of the risks with respect to such loads. Absent this mechanism, the rate impact of the 1998 Faro closure would have been about \$1 million higher than ultimately experienced (almost 3% higher than the 18.74% increase that ratepayers experienced).

1 price drivers (this is similar to the Mayo-Dawson Transmission project which will achieve
2 material savings for ratepayers over its life, but did result in the need to address what would
3 otherwise have been adverse rate impacts in the first two years via flexible debt financing³²).
4 Projects reviewed in the 1992 Resource Plan indicated potential for one to three year adverse
5 impact on rates before savings compared to diesel begin to arise for ratepayers (using a
6 diesel price of \$0.26/litre), while Mayo-Dawson Transmission project initial reviews had at
7 times determined the potential for five to ten year adverse impact on rates absent YDC
8 flexible financing (ultimately the flexible financing was only required for 2003 and 2004).

9
10 However, due to the higher price of diesel fuel today, rate impacts from each of the resource
11 supply option projects identified above are expected to be positive in year 1 assuming the full
12 output is available to offset diesel generation. For example, Drury at a capital cost of \$31
13 million (2005\$) has the potential to offset 23 GW.h of diesel (\$4.6 million per year, based
14 diesel on \$0.20/kW.h in 2005\$). The year 1 costs of Drury (2005\$) will total approximately
15 \$2.3 million for interest and return on equity (7.52% cost of capital times \$31 million³³) plus
16 about \$0.6 million for depreciation (using an aggregate life of hydro-related assets for
17 depreciation of 50 years, and no reserve for salvage). In short, the capital costs of Drury
18 would drive a \$1.7 million lower overall system costs in year 1 than supplying this same 23
19 GW.h with diesel (this ignores what would likely be a relatively small operating and
20 maintenance cost for Drury, but also ignores capital cost benefits from the 2.6 MW of
21 capacity Drury brings to the system avoiding some investment at times in diesel engines).

22
23 For Level 2 projects (at this time only includes Drury), full economic assessment can be
24 undertaken once certainty is developed with respect to sustained industrial loads beyond
25 Minto (i.e., Minto is not sufficient to justify any scale of new capital intensive generation).

26 **5.5 PROPOSED ACTIONS**

27 Yukon Energy proposes planning activities as set out below to address a wide range of potential industrial
28 development scenarios beyond the near term, and to protect future opportunities to commit development
29 of additional generation and transmission projects before 2016 in a timely and cost-effective way in the

³² At this point in time, overall average retail rate increase impacts are likely to be about 1% if utility regulated costs are increased in any one year by \$360,000. Rate impacts need to be assessed in this regard by comparing a specific resource option to the available alternative resource options. It is relevant to note that this assessment may prove a resource option to save money relative to diesel, thereby allowing lower rates than would be required with diesel generation, while in reality (due to the need to develop new generation in any event to serve major new loads) overall rates are still being increased.

³³ Note also that Drury has very limited transmission costs required for the facility.

1 event that one or more of these industrial development scenarios materialize. Planning activities are
2 organized by industrial development load scenario, identifying proposals as to how to approach each load
3 scenario should it arise. "Pre-commitment" activities are also addressed which encompass planning
4 activities Yukon Energy proposes to carry out prior to any certainty or commitment on the part of
5 potential new industrial loads.

6 **5.5.1 Proposed Activities Regarding Scenario 1: A 10 MW WAF Industrial Scenario**

7 This industrial development scenario (which provides for near term development and operation between
8 2007 and 2018 of the Minto and Carmacks Copper mines) supports commitment of modest existing hydro
9 enhancements, but does not support commitment of any new hydro site development before 2016 unless
10 mine loads of at least 10 MW are sustained well beyond 2016. Consideration of the smallest hydro site
11 options (1-4 MW) could potentially be supported in the event that 10 MW mine load development extends
12 through to at least 2020. In this context, the following planning activities are recommended in the event
13 these mine loads are seriously being considered for development prior to 2016:

- 14 • **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-
15 term recommendations, planning should then proceed to commit the Aishihik 3rd Turbine, the
16 Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements
17 indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work,
18 and existing WAF hydro plant upgrade assessments.
 - 19 – If not already committed, Aishihik Diversions and Atlin Storage should then be advanced
20 to Level 2 studies, including system-wide water and load dispatch modeling, to quantify
21 the energy benefits under this scenario.
 - 22 – Ongoing assessment of the Southern Lakes should be completed to identify additional
23 water control or small hydro opportunities to enhance Whitehorse Rapids output.
- 24 • **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission line is
25 developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible
26 enhancements at the existing Mayo hydro facility, including enhanced peaking capability.
- 27 • **New WAF hydro site development:** If industrial and overall load development
28 commitment is such that both new capacity and baseload diesel generation energy are
29 required through to at least 2020 (and there is no clear indication of more major industrial
30 development scenarios emerging during the 20 year planning period), planning activities
31 should be carried out to enable commitment of a very small hydro site development (1-4
32 MW, 5-30 GW.h/year)³⁴ able to provide new capacity and displace diesel energy.

³⁴ Present estimates of the costs are \$12-\$47 million generation capital cost (2005\$) with potential generation planning costs of \$1.2-\$4.7 million prior to a decision to proceed with construction.

- 1 – Based on current information, this would indicate that the hydro site at Drury should at
2 that time be advanced to full Level 3 studies that include consideration of variations that
3 maximize capacity.
4 – Possible consideration might also be given to Level 2 studies for Squanga as a utility
5 project or IPP, and/or for Morley, as potential alternatives for comparison to Drury.
6 – Consideration must include means to mitigate downside risks should industrial loads
7 close prematurely.
8 – Actual development in each or these cases will involve investments greater than \$3
9 million, or long-term contract commitments in excess of \$3 million present value to IPPs,
10 and therefore YUB review will be sought prior to project commitment.
11 • **Other activities regarding DSM:** If loads of this scale and duration develop, further
12 consideration will be given to DSM programming focused primarily on reduction of system
13 peak demand.

14 **5.5.2 Proposed Activities Regarding Scenario 2: A 25 MW WAF Industrial Scenario**

15 If industrial loads are committed on WAF before 2016 for development of more than 10 MW (70
16 GW.h/year) but less than about 20-25 MW (comparable to the Faro mine) for a period through to at least
17 2025, planning activities should be carried out to enable commitment to develop new hydro site
18 resources to provide approximately 50 GW.h per year to WAF.

19

20 For potential hydro projects, key options to be considered at such time as greater load certainty develops
21 regarding this level and duration of industrial load are as follows:

- 22 • **WAF hydro system enhancements:** If not already committed pursuant to Chapter 4 near-
23 term recommendations, planning should proceed to commit the Aishihik 3rd Turbine, the
24 Marsh Lake Fall/Winter Storage and any other feasible existing hydro enhancements
25 indicated to date by the Aishihik Diversion assessments, the Southern Lakes hydrology work,
26 and existing WAF hydro plant upgrade assessments (see proposals for Scenario 1).
27 • **Mayo hydro system enhancements:** If the Carmacks to Stewart transmission is
28 developed to interconnect the WAF and MD grids, assess and develop as appropriate feasible
29 enhancements at the existing Mayo hydro facility (including any feasible enhanced peaking
30 capability).
31 • **New hydro site development:** If industrial and overall load development commitment on
32 WAF before 2016 is such that WAF baseload diesel generation energy of more than 10 MW
33 (70 GW.h/year) is then required through to at least 2025 (and there is no clear indication of
34 more major industrial development scenarios establishing new WAF industrial loads in excess

1 of about 20 MW (about 125 GW.h/year) emerging during the 20 year planning period and
2 extending beyond 2025, planning activities should then be carried out to enable commitment
3 of a small hydro site development (7-10 MW, about 50 GW.h/year³⁵) able to provide diesel
4 displacing energy to WAF.

- 5 – New hydro options focused on Yukon-based projects, if available, would be the
6 preference.
- 7 – However, given limited attractive projects in this size range identified in Yukon to date,
8 further Level 1 and 2 activity should be undertaken if timing permits in areas within 50
9 km of existing 138 kV WAF transmission focused initially on scans of the various
10 inventory studies completed by NCPC or others.
- 11 – Sites in BC, including Moon Lake and Tutshi³⁶, should have Level 2 studies updated in
12 preparation for this possible load scenario, particularly focusing on the costs and risks
13 associated with interprovincial licencing requirements and water rentals. Level 3 studies
14 should then proceed if warranted.

- 15 • **Coal supply possibilities:** In the event that the loads of this scale develop and coal also
16 becomes available from developed Yukon sources, coal generation technology should be
17 reviewed in the event that timing permits to determine the potential for an economic and
18 environmentally sound coal development at sizes below 20 MW, sized as appropriate to fit
19 the industrial loads being developed at that time.
- 20 • **Other activities regarding DSM and wind:** If loads of this scale and duration develop,
21 further consideration will be given to DSM programming focused on both the reduction of
22 system peak demand and energy conservation, and development of new wind generation (if
23 attractive sites near established utility grids can be identified).

24
25 Actual development of new hydro sites (or any other new generation site) in each case will involve
26 investments greater than \$3 million, so YUB review will be sought prior to project commitment. In
27 addition, for larger scale developments, planning and feasibility work may exceed the \$3 million level, so
28 there is the potential for YUB review at this earlier stage as well.

29 5.5.3 Proposed Activities Regarding Scenario 3: A 40 MW WAF Industrial Scenario

30 If industrial loads are committed on WAF before 2016 of more than about 20-25 MW (150 or more
31 GW.h/year) for a period through to at least 2030, resulting in forecast baseload WAF diesel generation

³⁵ Present estimates of the costs are \$50-\$100 million generation capital cost (2005\$) with potential generation planning costs of \$5-\$10 million prior to a decision to proceed with construction.

³⁶ No further work should proceed on Surprise Lake so long as the community continues its plans to develop micro-hydro at the site.

1 energy of more than about 150 GW.h/year to be required until at least 2030, then planning activities can
2 reasonably proceed to consider commitments before 2016 to develop new hydro site or coal generation
3 resources of 20-30 MW to provide 130-150 GW.h per year of long-term energy (20 or more years) to
4 WAF.

- 5 • **Load uncertainties and low probabilities today:** The industrial loads required to reach
6 the above levels at this time involve significant uncertainties and low probabilities.
- 7 • **New medium scale hydro site development (20-30 MW, 130-150 GW.h/year):** The
8 development of generation and transmission to serve these loads, based on currently
9 identified potential hydro sites (Primrose and Finlayson), would involve substantial generation
10 capital costs (\$179-\$191 million (2005\$), excluding transmission, as well as very large
11 planning costs (about \$20 million) prior to a decision to proceed with construction. Such
12 costs are likely at or beyond the limits of YEC's current financial capabilities and involve
13 material costs and risks related to investments in feasibility and planning long before final
14 decisions to proceed can occur or plants brought on-line.
- 15 • **Coal supply thermal generation possibilities:** Coal resource options of this scale could
16 involve far less capital than comparable new hydro sites, provided that coal supply as such
17 was otherwise available from developed Yukon sources. The scale at 20 MW
18 (140/GW/h/year³⁷), however, is still very small for coal thermal technology and would require
19 careful Level 2 and 3 screening and feasibility assessments to confirm its potential feasibility.

20
21 For potential generation projects related to the above scales, it is not apparent today that there is
22 sufficient likelihood of this major development scenario arising to justify major investment at this time in
23 planning and feasibility studies for medium new hydro or small coal plants. Accordingly, no specific
24 planning activities are recommended at this time. Future decisions with respect to the level of effort and
25 expense in this area will reflect YEC's ongoing assessment of the probabilities of the required loads
26 developing. For projects of this scale, even early planning and feasibility work (at least on hydro sites)
27 will exceed the \$3 million level, in which case YUB review will be sought before proceeding with specific
28 planning commitments of \$3 million or more.

29 **5.5.4 Proposed Activities Regarding Scenario 4: A 120 to 360 MW WAF Pipeline Scenario**

30 The Scenario 4 pipeline loads at this time involves significant uncertainties as regards timing and
31 magnitudes. However, given the implications of this industrial development for all aspects of Yukon
32 power utility activities, and its clear possibility to come into service within the 20-year period for the

³⁷ The present estimate of the costs are \$ 61 million thermal plant capital cost (2005\$), excluding transmission or coal resource development costs, with potential generation planning costs of \$6 million or more prior to a decision to proceed with construction.

1 current Resource Plan, one key activity recommended for the near-term regarding Scenario 4 involves
2 continued active monitoring of this development as well as active planning to identify and assess all
3 potential related material impacts, options and opportunities, including:

- 4 • Major power supply options for the pipeline for compression (focusing initially on short listing
5 and assessing at Level 1 knowledge large scale hydro site options and related transmission
6 requirements).
- 7 • More modest power supply opportunities focused on compressor station “station service”
8 loads.
- 9 • Options to use natural gas for power generation to serve cost effectively other incremental
10 industrial loads.

11
12 The development of generation and transmission to serve these pipeline loads is likely well beyond the
13 limits of YEC’s current financial capabilities as well as involving material costs and risks related to
14 investments in feasibility and planning long before final decisions to proceed can occur or plants brought
15 on-line. Accordingly, prior to carrying out any planning activities beyond Level 1 assessment of any
16 specific site or technology specific studies, it is proposed that Yukon Energy identify and assess options
17 that would address this constraint, e.g., joint venturing with others, and/or options to secure external
18 government or other financing.

19 **5.5.5 Proposed “Pre-commitment” activities**

20 Prior to any certainty developing regarding the industrial scenarios that may arise, it is proposed that
21 Yukon Energy remain focused on certain key planning activities to ensure protection of the options to
22 address new load requirements. Yukon Energy proposes the following activities in this regard:

- 23 • **Monitoring of Industrial load developments:** Yukon Energy will continue to monitor
24 closely potential load development and related spin-off residential and commercial impacts,
25 including necessary discussions with mineral exploration companies active in Yukon, key
26 officials in Yukon government working with mines and other industrial developments, and
27 relevant industry associations. Separately, YEC will maintain ongoing monitoring of potential
28 Alaska Highway pipeline developments and factors that may impact electrical loads in Yukon
29 (including potential for electrical compression).
- 30 • **Southern Lakes hydrology assessments:** Continued assessment and studies of the
31 hydrology of the southern lakes area, including identification of potential for water control
32 structures to enhance output of Whitehorse Rapids, as well as potential hydro generation
33 sites.

- 1 • **Other existing hydro facility enhancements:** Continued focus on projects to enhance
2 output of existing hydro generation facilities at Aishihik, Whitehorse and in certain cases,
3 Mayo. This includes full Level 3 and 4 studies on the Aishihik 3rd turbine and updating Level
4 2 studies on Aishihik diversions. Where suitable, activities should be carried out in
5 conjunction with other normal Supply Side Enhancement planning by Yukon Energy, such as
6 re-runnering.
- 7 • **Level 1 and 2 assessments to identify preferred 5-30 MW scale Yukon hydro sites:**
8 There is an option to invest in further surveying the potential of other Yukon based hydro
9 generation sites to try to identify good sites in the 5-10 MW range (within about 50 km of
10 existing high voltage transmission) and to advance credible candidates in the 5-30 MW range
11 through Level 2 assessments (including ongoing monitoring of hydrology) in order to identify
12 more clearly preferred sites to develop for possible loads within this range. However, this
13 activity is costly and may require assessment of a number of sites. No activities in this regard
14 are recommended today; however, in the event that at least one large industrial load (such
15 as Red Mountain or Division Mountain) proceeds to advanced licencing and likely
16 commitment stages, it is proposed that this initial work should proceed quickly to determine
17 if the sites identified to date are indeed the best candidates or if there are other Yukon-based
18 sites that should be seriously considered, and to identify specific projects for Level 3
19 feasibility assessments.
- 20 • **Ongoing monitoring of hydrology:** Active hydrology monitoring will proceed where
21 feasible for all hydro sites likely to be serious candidates for future development within the
22 20 year planning period. The monitoring may be periodic (seasonal flow information, current
23 cost of \$1,000 per year per site) up to a full-time recording station (at a current cost of
24 \$30,000 (initial costs) plus ongoing costs of between \$10,000 to \$15,000 per year).