

**CRANFIELD UNIVERSITY**

**SHARAAZ HOSEIN**

**A NATIONAL ENERGY POLICY PROPOSAL  
FOR TRINIDAD AND TOBAGO:  
NATURAL-GAS COGENERATION**

**SCHOOL OF MECHANICAL ENGINEERING**

**PhD THESIS**

ProQuest Number: 10820994

All rights reserved

INFORMATION TO ALL USERS

The quality of this reproduction is dependent on the quality of the copy submitted.

In the unlikely event that the author did not send a complete manuscript and there are missing pages, these will be noted. Also, if material had to be removed, a note will indicate the deletion.



ProQuest 10820994

Published by ProQuest LLC (2018). Copyright of the Dissertation is held by Cranfield University.

All Rights Reserved.

This work is protected against unauthorized copying under Title 17, United States Code  
Microform Edition © ProQuest LLC.

ProQuest LLC  
789 East Eisenhower Parkway  
P.O. Box 1346  
Ann Arbor, MI 48106 - 1346



**CRANFIELD UNIVERSITY**

**SCHOOL OF MECHANICAL ENGINEERING**

**PhD THESIS**

**Academic Year 2001 – 2002**

**SHARAAZ HOSEIN**

**A national energy policy proposal for Trinidad and Tobago: natural-gas  
cogeneration**

**Supervisor: O Badr**

**January 2002**

© Cranfield University, 2002. All rights reserved. No part of this publication may be reproduced without the written permission of the copyright holder.

## Abstract

This thesis looks at energy policy in Trinidad and Tobago (T&T) by focusing on a single policy measure, *natural-gas cogeneration*, to learn about energy policy in general. It investigates natural gas as it is in the ascendancy, both locally and globally, and because oil is on the decline in T&T. The research further focuses on cogeneration in the *industrial sector*. It then approximately extrapolates results from the industrial sector to the entire country. The aim can thus be described as assessing natural-gas cogeneration's potential as a policy measure, using the industrial sector as an example. LNG, another major natural-gas use, provides a reference point for locating natural-gas cogeneration in the overall energy policy framework.

The industry-wide cogeneration evaluation groups the 1,967 industrial electricity customers in 1998 according to similarity in electricity-use characteristics into 15 subgroups. This allows a study of one or more representatives from each subgroup to apply to the whole subgroup, and thus covers the whole spectrum of industrial electricity customers. This is a fundamental assumption of the research. The research thus essentially becomes a series of cogeneration feasibility studies at individual sites, needing data gathered from extensive fieldwork, and an analysis model constructed in MS Excel, which applies a standard business project-appraisal procedure.

The analysis determines that industrial cogeneration in 1998 delivers conservative natural-gas savings of 2.2 billion kWh, or 13.5% of the natural gas used to generate the entire country's electricity in that year. The dollar value of these savings over 20 years is US\$0.2 billion, using LNG's natural-gas resource valuation. Considering that a single LNG train uses 48.1 billion kWh natural gas per annum and delivers US\$6 billion in revenues over 20 years, cogeneration is a minor policy measure compared to the petrochemical industry, and similarly in an overall natural-gas policy. However, cogeneration's significance to the electricity sector, and its importance in promoting a nationwide natural-gas infrastructure for the future, where the population *directly* benefits from the resource, renders it an important energy-policy measure.

*Sincere thanks to the Commonwealth Scholarships Commission for kindly sponsoring this research.*

*I dedicate this thesis to my parents.*

# Table of contents

## LIST OF FIGURES

## LIST OF TABLES

## NOTATION

## CHAPTER 1. INTRODUCTION 1

## CHAPTER 2. ENERGY POLICY 3

|              |                                                     |           |
|--------------|-----------------------------------------------------|-----------|
| <b>2.1</b>   | <b>REASONS FOR ENERGY POLICY</b>                    | <b>3</b>  |
| <b>2.2</b>   | <b>FORMULATING AN ENERGY POLICY</b>                 | <b>4</b>  |
| 2.2.1        | PLANNING HORIZON                                    | 6         |
| 2.2.2        | THE INEP PROCEDURE                                  | 7         |
| 2.2.3        | THE CASE AGAINST POLICY                             | 9         |
| <b>2.3</b>   | <b>ENERGY POLICY HISTORY IN TRINIDAD AND TOBAGO</b> | <b>10</b> |
| <b>2.4</b>   | <b>THE ENERGY-POLICY GREEN PAPER</b>                | <b>10</b> |
| 2.4.1        | INTRODUCTION                                        | 10        |
| 2.4.2        | GENERAL FRAMEWORK                                   | 10        |
| 2.4.3        | CURRENT ENERGY TRENDS AND PROJECTED FUTURES         | 11        |
| 2.4.3.1      | Current reserve structure                           | 13        |
| 2.4.3.2      | The energy-sector's importance                      | 14        |
| 2.4.3.3      | Sectoral trends – the primary-energy sector         | 14        |
| 2.4.3.4      | Sectoral trends – the transformation sector         | 14        |
| 2.4.3.4.1    | Refineries                                          | 14        |
| 2.4.3.4.2    | Electricity                                         | 15        |
| 2.4.3.4.3    | LNG plants                                          | 16        |
| 2.4.3.4.4    | Natural gas fuel supplies                           | 16        |
| 2.4.3.4.5    | Non-energy products                                 | 16        |
| 2.4.3.5      | Sectoral trends – energy consumption                | 17        |
| <b>2.4.4</b> | <b>GUIDELINES FOR ENERGY POLICY IMPLEMENTATION</b>  | <b>19</b> |
| 2.4.4.1      | Policy strategies and initiatives                   | 20        |
| 2.4.4.1.1    | Administration in the energy sector                 | 20        |
| 2.4.4.1.2    | Energy-supply security                              | 20        |
| 2.4.4.1.3    | Monetising the natural gas resources                | 21        |
| 2.4.4.1.4    | Promoting cleaner energy/alternative energy options | 21        |
| 2.4.4.1.5    | Protecting and preserving the environment           | 21        |

|           |                                    |    |
|-----------|------------------------------------|----|
| 2.4.4.1.6 | Training, research and development | 21 |
| 2.5       | ANALYSING THE GREEN PAPER          | 22 |
| 2.5.1     | SPECIFIC PROBLEMS WITH THE GP      | 23 |

### **CHAPTER 3. WORLD ENERGY** 27

|     |                                        |    |
|-----|----------------------------------------|----|
| 3.1 | GLOBAL ENERGY SUPPLY AND DEMAND TRENDS | 27 |
| 3.2 | ENERGY OUTLOOK                         | 31 |
| 3.3 | GLOBAL NATURAL GAS RESOURCES           | 33 |
| 3.4 | GLOBAL ENERGY AND THE ENVIRONMENT      | 34 |
| 3.5 | THE CASE FOR NATURAL GAS               | 36 |

### **CHAPTER 4. TRINIDAD AND TOBAGO ENERGY** 43

|       |                                      |    |
|-------|--------------------------------------|----|
| 4.1   | NATURAL GAS                          | 44 |
| 4.1.1 | COMPRESSED NATURAL GAS               | 45 |
| 4.2   | ELECTRICITY                          | 46 |
| 4.2.1 | ELECTRICITY RATE STRUCTURE           | 47 |
| 4.2.2 | INDUSTRIAL – D ELECTRICITY CUSTOMERS | 48 |
| 4.3   | FORECASTING T&T ENERGY               | 49 |

### **CHAPTER 5. COGENERATION** 51

|           |                                                    |    |
|-----------|----------------------------------------------------|----|
| 5.1       | POWER- AND HEAT-GENERATION FUNDAMENTALS            | 51 |
| 5.1.1     | COMBINING POWER- AND HEAT-GENERATION               | 52 |
| 5.2       | CONDITIONS FOR COGENERATION                        | 53 |
| 5.2.1     | ECONOMIC FACTORS                                   | 53 |
| 5.2.2     | LOCAL DEMAND PATTERNS                              | 53 |
| 5.2.3     | EXPORT                                             | 54 |
| 5.2.4     | OPERATION AND MAINTENANCE                          | 55 |
| 5.3       | COGENERATION HARDWARE                              | 55 |
| 5.3.1     | THE ENGINES                                        | 58 |
| 5.3.1.1   | Combustion process                                 | 58 |
| 5.3.1.2   | Engine characteristics in relation to cogeneration | 60 |
| 5.3.1.2.1 | Power output                                       | 60 |
| 5.3.1.2.2 | Power generation efficiency and heat output        | 60 |
| 5.3.1.2.3 | Fuels and their supply                             | 64 |
| 5.3.1.2.4 | Maintenance and service-loss                       | 65 |
| 5.3.1.3   | Adapting the engines to cogeneration               | 66 |
| 5.3.1.3.1 | Heat recovery                                      | 67 |
| 5.3.1.3.2 | Capital and operating costs                        | 68 |
| 5.3.2     | ALTERNATORS (AC GENERATORS)                        | 68 |
| 5.4       | OPERATION AND MAINTENANCE (O&M)                    | 69 |
| 5.4.1     | OPERATING STRATEGY OPTIONS                         | 69 |
| 5.4.1.1   | Choosing the control strategy                      | 69 |
| 5.4.2     | OPERATION                                          | 70 |

|           |                                                     |    |
|-----------|-----------------------------------------------------|----|
| 5.4.3     | MAINTENANCE                                         | 72 |
| 5.4.3.1   | Condition monitoring                                | 75 |
| 5.5       | SCALE OF COGENERATION                               | 75 |
| 5.5.1     | SMALL-SCALE COGENERATION                            | 75 |
| 5.5.1.1   | Small-scale cogeneration technology                 | 75 |
| 5.5.1.1.1 | Operating and control strategy                      | 77 |
| 5.5.1.2   | Small-scale cogeneration maintenance                | 77 |
| 5.5.1.3   | Conclusions about small-scale cogeneration          | 77 |
| 5.5.2     | LARGE-SCALE COGENERATION                            | 78 |
| 5.5.2.1   | Performance monitoring for large-scale cogeneration | 86 |
| 5.5.2.2   | Maintenance                                         | 86 |
| 5.6       | GAS TURBINE SMALL-SCALE COGENERATION                | 87 |
| 5.6.1     | THE HARDWARE                                        | 87 |
| 5.6.1.1   | Recuperator                                         | 88 |
| 5.6.1.2   | Alternator and power conditioning                   | 89 |
| 5.7       | COGENERATION AND ENERGY POLICY                      | 89 |

## **CHAPTER 6. LIQUEFIED NATURAL GAS 91**

|         |                                        |     |
|---------|----------------------------------------|-----|
| 6.1     | WORLDWIDE LNG POTENTIAL                | 91  |
| 6.2     | WORLDWIDE LNG TRADE                    | 93  |
| 6.2.1   | WORLDWIDE LNG IMPORTS AND EXPORTS      | 94  |
| 6.3     | LNG TECHNOLOGY                         | 96  |
| 6.3.1   | LNG-PROCESS DEVELOPMENTS               | 96  |
| 6.3.2   | LNG TECHNOLOGY DEVELOPMENTS            | 100 |
| 6.4     | LNG ECONOMICS                          | 100 |
| 6.4.1   | LNG'S DELIVERED VALUE                  | 102 |
| 6.4.2   | THE COST OF SUPPLYING LNG              | 103 |
| 6.4.3   | NGL CREDITS                            | 105 |
| 6.4.4   | NET COST/BENEFIT BALANCE               | 107 |
| 6.4.5   | SUMMARISING LNG ECONOMICS              | 109 |
| 6.5     | THE TRINIDAD AND TOBAGO LNG EXPERIENCE | 111 |
| 6.5.1   | ATLANTIC LNG                           | 111 |
| 6.5.1.1 | ALNG Trains 2 & 3 expansion            | 112 |
| 6.5.2   | THE COUNTRY'S CONCERNS                 | 112 |
| 6.6     | LNG IN T&T FROM A POLICY PERSPECTIVE   | 114 |

## **CHAPTER 7. ABSORPTION COOLING 117**

|         |                                   |     |
|---------|-----------------------------------|-----|
| 7.1     | THE VAPOUR-COMPRESSOR CYCLE       | 117 |
| 7.2     | THE ABSORPTION CYCLE              | 119 |
| 7.3     | COEFFICIENT OF PERFORMANCE (COP)  | 123 |
| 7.4     | ABSORPTION SYSTEM CHARACTERISTICS | 124 |
| 7.4.1   | HEAT SOURCE                       | 124 |
| 7.4.1.1 | Source heat stream temperature    | 124 |
| 7.4.2   | COOLING LOAD                      | 125 |
| 7.4.3   | HEAT SINK                         | 125 |

|            |                                                   |            |
|------------|---------------------------------------------------|------------|
| <b>7.5</b> | <b>THE LITHIUM BROMIDE-WATER ABSORPTION CYCLE</b> | <b>126</b> |
| 7.5.1      | SINGLE-EFFECT ABSORPTION PROCESS                  | 126        |
| 7.5.2      | SINGLE-EFFECT ABSORPTION MACHINE CONFIGURATION    | 128        |
| 7.5.3      | DOUBLE-EFFECT ABSORPTION PROCESS                  | 129        |
| 7.5.4      | DOUBLE-EFFECT ABSORPTION MACHINE CONFIGURATION    | 132        |
| 7.5.5      | COMPARING SINGLE- AND DOUBLE-EFFECT SYSTEMS       | 133        |
| <b>7.6</b> | <b>PART-LOAD OPERATION</b>                        | <b>134</b> |
| <b>7.7</b> | <b>HEAT RECOVERY</b>                              | <b>136</b> |
| <b>7.8</b> | <b>ABSORPTION SYSTEM BENEFITS</b>                 | <b>137</b> |
| <b>7.9</b> | <b>ABSORPTION SYSTEM ECONOMICS</b>                | <b>138</b> |
| 7.9.1      | FIRST COSTS                                       | 138        |
| 7.9.2      | OPERATING COSTS                                   | 139        |
| 7.9.3      | MAINTENANCE COSTS                                 | 139        |

## **CHAPTER 8. FIELDWORK** **141**

|            |                                               |            |
|------------|-----------------------------------------------|------------|
| <b>8.1</b> | <b>FIELDWORK METHOD</b>                       | <b>141</b> |
| <b>8.2</b> | <b>THE FIELDWORK METER</b>                    | <b>142</b> |
| 8.2.1      | METER SPECIFICATIONS (ELCOMPONENT LTD., 1999) | 143        |
| 8.2.2      | METER FEATURES                                | 144        |
| 8.2.3      | USING THE METER                               | 146        |
| 8.2.4      | METER SOFTWARE                                | 147        |
| 8.2.4.1    | Setting the logging parameters                | 147        |
| 8.2.4.2    | Downloading data                              | 147        |
| 8.2.4.3    | Calculating Power                             | 147        |
| 8.2.4.4    | Viewing the data                              | 148        |
| 8.2.4.5    | Costing                                       | 149        |

## **CHAPTER 9. EVALUATING A NATIONAL COGENERATION POLICY** **151**

|            |                                                                   |            |
|------------|-------------------------------------------------------------------|------------|
| <b>9.1</b> | <b>THE BASIS FOR NATIONAL COGENERATION EVALUATION</b>             | <b>151</b> |
| <b>9.2</b> | <b>A COGENERATION FEASIBILITY STUDY</b>                           | <b>152</b> |
| 9.2.1      | TECHNICAL COGENERATION FEASIBILITY                                | 154        |
| 9.2.2      | ECONOMIC COGENERATION FEASIBILITY                                 | 158        |
| 9.2.2.1    | Guiding rules on investment appraisal and the relevant cash flows | 160        |
| 9.2.2.2    | Sensitivity analysis                                              | 160        |
| 9.2.3      | PROJECT APPRAISAL PROCEDURE                                       | 161        |
| <b>9.3</b> | <b>CONSTRUCTING THE PROJECT ANALYSIS MODEL</b>                    | <b>163</b> |
| 9.3.1      | GENERAL DATA SHEET                                                | 163        |
| 9.3.2      | ENERGY BUDGET SHEET                                               | 169        |
| 9.3.3      | O&M SHEET                                                         | 174        |
| 9.3.4      | LOAD-DURATION DATA SHEET                                          | 175        |
| 9.3.5      | CAPITAL SHEET                                                     | 176        |
| 9.3.6      | CASH FLOW SHEET                                                   | 177        |
| 9.3.7      | SENSITIVITY ANALYSIS SHEET                                        | 178        |

## **CHAPTER 10. COGENERATION EVALUATION RESULTS** **181**

|             |                                                 |            |
|-------------|-------------------------------------------------|------------|
| <b>10.1</b> | <b>TARGETING THE ANALYSIS</b>                   | <b>181</b> |
| <b>10.2</b> | <b>THE FEASIBILITY STUDIES</b>                  | <b>184</b> |
| 10.2.1      | THE HOTEL                                       | 184        |
| 10.2.2      | THE SHOPPING MALL                               | 189        |
| 10.2.3      | THE SCHOOL                                      | 191        |
| 10.2.4      | THE HOSPITAL                                    | 194        |
| 10.2.5      | THE MILL                                        | 197        |
| 10.2.6      | THE BANK                                        | 202        |
| 10.2.7      | THE METHANOL PLANT                              | 206        |
| 10.2.8      | THE AMMONIA AND UREA PLANT (NITROGEN PLANT)     | 210        |
| 10.2.9      | THE OIL REFINERY                                | 213        |
| <b>10.3</b> | <b>THE COLLATED RESULTS</b>                     | <b>215</b> |
| <b>10.4</b> | <b>THE TRUE VALUE OF NATURAL GAS</b>            | <b>220</b> |
| <b>10.5</b> | <b>COMPARING LNG AND COGENERATION POLICIES</b>  | <b>220</b> |
| 10.5.1      | ESTIMATING THE RENT FROM LNG                    | 221        |
| 10.5.2      | INCORPORATING USER COSTS                        | 221        |
| 10.5.3      | NATURAL GAS SAVING IN DOLLARS FROM COGENERATION | 223        |

## **CHAPTER 11. DISCUSSING THE FINDINGS AND LOOKING AHEAD** **225**

|             |                                                           |            |
|-------------|-----------------------------------------------------------|------------|
| <b>11.1</b> | <b>JAMAICA'S COGENERATION POLICY</b>                      | <b>227</b> |
| <b>11.2</b> | <b>FORECASTING T&amp;T'S ENERGY PICTURE</b>               | <b>228</b> |
| <b>11.3</b> | <b>T&amp;TEC'S ELECTRICITY FORECAST</b>                   | <b>228</b> |
| 11.3.1      | REVIEWING THE 1997 ELECTRICITY FORECAST                   | 228        |
| 11.3.2      | COMMENTS ON THE 1998 FORECAST                             | 230        |
| <b>11.4</b> | <b>NGC'S NATURAL-GAS FORECAST</b>                         | <b>233</b> |
| <b>11.5</b> | <b>ENERGY EFFICIENCY IMPROVEMENT THROUGH COGENERATION</b> | <b>234</b> |
| 11.5.1      | DSM METHODS                                               | 235        |
| <b>11.6</b> | <b>RENEWABLE ENERGY CONSIDERATIONS FOR THE T&amp;T</b>    | <b>236</b> |
| 11.6.1      | SOLAR ENERGY                                              | 236        |
| 11.6.2      | WIND ENERGY                                               | 237        |
| 11.6.3      | HYDRO-ELECTRIC ENERGY                                     | 238        |
| 11.6.4      | BIOMASS ENERGY                                            | 238        |
| 11.6.5      | OCEAN THERMAL ENERGY CONVERSION (OTEC)                    | 238        |

## **CHAPTER 12. CONCLUSIONS ABOUT A NATIONAL COGENERATION POLICY** **241**

## **REFERENCES** **243**

## **BIBLIOGRAPHY** **249**

## **APPENDIX. THREE-PHASE ELECTRICITY** **253**



|            |                                |            |
|------------|--------------------------------|------------|
| <b>A.1</b> | <b>THREE-PHASE ELECTRICITY</b> | <b>253</b> |
| A.1.1      | GENERATING POLYPHASE POWER     | 253        |
| A.1.2      | ELEMENTS OF 3-PHASE POWER      | 254        |
| A.1.3      | POWER FACTOR CORRECTION        | 256        |

# List of Figures

|                                                                                                                                                                          |    |
|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----|
| Figure 1. Integrated National Energy Planning framework (Munasinghe, 1990).                                                                                              | 4  |
| Figure 2. Basic steps in implementing INEP (Munasinghe, 1990).                                                                                                           | 7  |
| Figure 3. Total primary energy supply 1979 to 1994.                                                                                                                      | 12 |
| Figure 4. Final primary energy consumption 1979 to 1994.                                                                                                                 | 13 |
| Figure 5. Secondary energy produced by power plants (1979 to 1994).                                                                                                      | 15 |
| Figure 6. Public and self-use power plants (1979 to 1994).                                                                                                               | 16 |
| Figure 7. Total final consumption (1979 to 1994).                                                                                                                        | 17 |
| Figure 8. Total final primary energy consumption (1979 to 1994).                                                                                                         | 18 |
| Figure 9. Total final secondary energy consumption (1979 to 1994).                                                                                                       | 19 |
| Figure 10. Global primary energy substitution (Howell, 1993).                                                                                                            | 27 |
| Figure 11. Carbon emissions in kgC/GJ for natural gas, crude oil, and coal (Howell, 1993).                                                                               | 28 |
| Figure 12. Global energy decarbonisation, in tC/kWyr of primary energy consumed, since 1900 AD and scenarios for the future (Howell, 1993).                              | 29 |
| Figure 13. Primary energy intensity, including biomass, of value added in kilowatt year (kWyr) per constant gross domestic product (GDP) in 1980 dollars (Howell, 1993). | 29 |
| Figure 14. Global decarbonisation in tCToe, and global energy de-intensification in toe per US\$ million GDP (oe = oil equivalent) (Howell, 1993).                       | 30 |
| Figure 15. 'Natural' energy de-intensification (Jackson, 1996).                                                                                                          | 31 |
| Figure 16. Primary energy consumption, mtoe (BP Amoco, 2001).                                                                                                            | 32 |
| Figure 17. World energy demand projections. (IEA, 1994)                                                                                                                  | 33 |
| Figure 18. Trends in atmospheric CO <sub>2</sub> concentrations, in parts per million by volume (ppmv) since 1700 AD (Howell, 1993).                                     | 35 |
| Figure 19. Trends in atmospheric methane concentrations, in ppmv since 1000 AD (Howell, 1993).                                                                           | 35 |
| Figure 20. Annual primary energy consumption per capita in toe (BP Amoco, 2001).                                                                                         | 36 |
| Figure 21. Primary energy consumption historically and forecasted for two variants in the methane economy scenario (Howell, 1993).                                       | 38 |
| Figure 22. Global CO <sub>2</sub> emissions in gigatons of carbon per year (GtC/yr) for scenarios in Figure 21 (Howell, 1993).                                           | 39 |
| Figure 23. Atmospheric CO <sub>2</sub> and CH <sub>4</sub> concentrations from the 'methane economy' scenarios, as CO <sub>2</sub> equivalents in ppm (Howell, 1993).    | 39 |
| Figure 24. Annual natural-gas consumption in tcf from 1970 to 2010 (Howell, 1993).                                                                                       | 41 |
| Figure 25. T&T's oil and natural gas reserves and production (OLADE, 1998 & BP Amoco, 2001).                                                                             | 43 |
| Figure 26. T&T's oil and natural gas reserves/production ratio (OLADE, 1998).                                                                                            | 44 |
| Figure 27. Alternate energy prices in T&T (NGC, 1998).                                                                                                                   | 45 |
| Figure 28. Summary T&T CNG data, actual and forecasted (Chung and Joyeau, 1999).                                                                                         | 46 |
| Figure 29. The heat engine (Griffith, 1995).                                                                                                                             | 52 |
| Figure 30. Electricity export options for a local generator (Griffith, 1995).                                                                                            | 54 |
| Figure 31. Cogeneration unit block diagram (ERA Technologies, 1995).                                                                                                     | 55 |

|                                                                                                                                                      |     |
|------------------------------------------------------------------------------------------------------------------------------------------------------|-----|
| Figure 32. Energy-flow comparisons for cogeneration and conventional energy supply (ERA Technologies, 1995).                                         | 56  |
| Figure 33. Typical cogeneration configurations (ERA Technologies, 1995)                                                                              | 57  |
| Figure 34. Internal combustion engine cycles – spark-ignition and compression-ignition (Griffith, 1995)                                              | 58  |
| Figure 35. Gas turbine combustion cycle (Griffith, 1995).                                                                                            | 59  |
| Figure 36. Typical ICE part-load performance (Griffith, 1995).                                                                                       | 62  |
| Figure 37. Typical GT part-load performance (Griffith, 1995).                                                                                        | 64  |
| Figure 38. Cogeneration system performance monitoring instrumentation – ICE-based plants (Griffith, 1995).                                           | 70  |
| Figure 39. Cogeneration system performance monitoring instrumentation – GT-based plants (Griffith, 1995).                                            | 71  |
| Figure 40. Typical small-scale cogeneration unit showing main components (Good Practice Guide 3, 1995).                                              | 76  |
| Figure 41. Typical small-scale cogeneration unit's energy balance (Good Practice Guide 3, 1995).                                                     | 76  |
| Figure 42. Gas turbine cogeneration diagram (Good Practice Guide 43, 1999).                                                                          | 78  |
| Figure 43. Schematic of a typical GT cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).                                  | 79  |
| Figure 44. Schematic of typical spark-ignition engine cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).                 | 80  |
| Figure 45. Schematic of typical dual-fuel compression-ignition engine cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999). | 81  |
| Figure 46. Schematic of back-pressure steam turbine cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).                   | 83  |
| Figure 47. Schematic of combine cycle steam turbine cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).                   | 84  |
| Figure 48. Cogeneration system characteristics for three types of prime mover (Good Practice Guide 143, 1999).                                       | 85  |
| Figure 49. Small-scale GT cogeneration unit – major components and interfaces (Best Practice Programme, 1992).                                       | 87  |
| Figure 50. Small-scale GT cogeneration schematic (Best Practice Programme, 1992).                                                                    | 88  |
| Figure 51. The Atlantic LNG Plant in Point Fortin, Trinidad.                                                                                         | 91  |
| Figure 52. Forecast world energy-demand growth (per year) over the next decade (Brown and Clary, 1997).                                              | 92  |
| Figure 53. Natural-gas proven reserves at end 2000 (BP Amoco, 2001).                                                                                 | 92  |
| Figure 54. World LNG trade growth (True, 1998).                                                                                                      | 94  |
| Figure 55. Typical LNG plant (Bellow Jr. <i>et al.</i> , 1997).                                                                                      | 97  |
| Figure 56. Classical cascade refrigeration cycle (Bellow Jr. <i>et al.</i> , 1997).                                                                  | 98  |
| Figure 57. Mixed refrigerant cycle (Bellow Jr. <i>et al.</i> , 1997).                                                                                | 99  |
| Figure 58. Pre-cooled mixed refrigerant cycle (Bellow Jr. <i>et al.</i> , 1997).                                                                     | 99  |
| Figure 59. The natural gas/LNG business chain (Brown and Clary, 1997).                                                                               | 104 |
| Figure 60. Vapour-compression cycle (Dorgan, Leight and Dorgan, 1995).                                                                               | 117 |
| Figure 61. VC cycle p-h diagram (Dorgan, Leight and Dorgan, 1995).                                                                                   | 118 |
| Figure 62. Absorption-refrigeration cycle (Dorgan, Leight and Dorgan, 1995).                                                                         | 120 |

|                                                                                                                             |     |
|-----------------------------------------------------------------------------------------------------------------------------|-----|
| Figure 63. Absorption-cycle P_H diagram (refrigerant only) (Dorgan, Leight and Dorgan, 1995).                               | 121 |
| Figure 64. Absorption machine input/output (Dorgan, Leight and Dorgan, 1995).                                               | 121 |
| Figure 65. Similarities between absorption and VC systems (ASHRAE, 1998).                                                   | 122 |
| Figure 66. Absorption refrigeration cycle schematic, single effect (Dorgan, Leight and Dorgan, 1995).                       | 127 |
| Figure 67. Absorption system layout, single-effect, one shell (Dorgan, Leight and Dorgan, 1995).                            | 128 |
| Figure 68. Absorption system layout, single-effect, two shells (Dorgan, Leight and Dorgan, 1995).                           | 129 |
| Figure 69. Absorption cycle schematic, double effect, series solution flow (Dorgan, Leight and Dorgan, 1995).               | 130 |
| Figure 70. Absorption cycle schematic, double effect, parallel solution flow (Dorgan, Leight and Dorgan, 1995).             | 131 |
| Figure 71. Absorption system layout, double-effect, two shells, parallel solution flow (Dorgan, Leight and Dorgan, 1995).   | 132 |
| Figure 72. Absorption system layout, double-effect, three shells, parallel solution flow (Dorgan, Leight and Dorgan, 1995). | 133 |
| Figure 73. Part-load capacity chart, single-effect chiller (Dorgan, Leight and Dorgan, 1995).                               | 135 |
| Figure 74. Part-load capacity chart, double-effect chiller (Dorgan, Leight and Dorgan, 1995).                               | 136 |
| Figure 75. Water-tube boiler using exhaust gases (Dorgan, Leight and Dorgan, 1995).                                         | 137 |
| Figure 76. Fire-tube exhaust gas boiler (Dorgan, Leight and Dorgan, 1995).                                                  | 137 |
| Figure 77. SP Max energy data logger (Elcomponent Ltd., 1999).                                                              | 143 |
| Figure 78. The meter – inside front cover (Elcomponent Ltd., 1999).                                                         | 145 |
| Figure 79. The meter connectors (Elcomponent Ltd., 1999).                                                                   | 145 |
| Figure 80. Meter 3-phase connection (Elcomponent Ltd., 1999).                                                               | 146 |
| Figure 81. Viewing logged data as a list (Elcomponent Ltd., 1999).                                                          | 148 |
| Figure 82. Viewing logged data as a graph (Elcomponent Ltd., 1999).                                                         | 148 |
| Figure 83. Turbine engine performance characteristics (ASHRAE, 2000).                                                       | 153 |
| Figure 84. Electricity demand profile (kWe) over a day for a steel-working factory.                                         | 155 |
| Figure 85. School's load-duration curve, kWe with cogeneration.                                                             | 157 |
| Figure 86. Hotel - General data sheet.                                                                                      | 165 |
| Figure 87. Annual chiller maintenance cost, TT\$/kW <sub>r</sub> (NGC, 1998).                                               | 168 |
| Figure 88. Hotel - 'Energy budget' sheet.                                                                                   | 170 |
| Figure 89. Hotel's energy-use profiles, kWe.                                                                                | 173 |
| Figure 90. Hotel - 'O&M' sheet.                                                                                             | 175 |
| Figure 91. Hotel - load-duration data, kW <sub>th</sub> .                                                                   | 176 |
| Figure 92. Hotel – 'Capital cost' sheet.                                                                                    | 177 |
| Figure 93. Hotel – 'Cash flow' sheet.                                                                                       | 177 |
| Figure 94. Hotel – 'Sensitivity analysis' sheet.                                                                            | 179 |
| Figure 95. Hotel – 1999 energy profiles.                                                                                    | 187 |
| Figure 96. Hotel - Energy budget sheet.                                                                                     | 188 |
| Figure 97. Mall – 1999 energy profiles.                                                                                     | 190 |

|                                                                                                                              |     |
|------------------------------------------------------------------------------------------------------------------------------|-----|
| Figure 98. Mall - Energy budget sheet.                                                                                       | 191 |
| Figure 99. School – 1999 energy profiles.                                                                                    | 193 |
| Figure 100. School - Energy budget sheet.                                                                                    | 194 |
| Figure 101. Hospital – 1999 energy profiles.                                                                                 | 196 |
| Figure 102. Hospital - Energy budget sheet.                                                                                  | 197 |
| Figure 103. Mill load-duration curve for metered day                                                                         | 198 |
| Figure 104. Mill – 1999 energy profiles.                                                                                     | 199 |
| Figure 105. Mill - Energy budget sheet.                                                                                      | 201 |
| Figure 106. Bank – 1999 energy profiles.                                                                                     | 203 |
| Figure 107. Bank - Energy budget sheet.                                                                                      | 204 |
| Figure 108. Bank – O&M sheet.                                                                                                | 205 |
| Figure 109. Methanol Plant 1 – daily energy use data for December 1998.                                                      | 208 |
| Figure 110. Methanol Plant 1 – monthly energy use data.                                                                      | 208 |
| Figure 111. Methanol Plant 1 – Energy budget sheet, net cogeneration savings.                                                | 209 |
| Figure 112. Nitrogen Plant 1 – Energy budget sheet: Table 5 - net cogeneration savings.                                      | 213 |
| Figure 113. Refinery – Energy budget sheet: field data and net cogeneration savings.                                         | 214 |
| Figure 114. Daily peak electricity demand distribution (Sitahal and Chong, 1998).                                            | 229 |
| Figure 115. Steel product prices (US\$/tonne), 1987 to 2002 (Energy correspondent, 2001).                                    | 232 |
| Figure 116. Projecting maximum electricity demand and contracted capacity (Sitahal, 1999b).                                  | 232 |
| Figure 117. Generating alternating voltage (Noakes, 1956).                                                                   | 254 |
| Figure 118. A general ac circuit vector diagram – the voltage, E, leads the current, I, by an angle $\alpha$ (Noakes, 1956). | 255 |
| Figure 119. ac circuit current vector diagram (Noakes, 1956).                                                                | 255 |
| Figure 120. Steel-working factory - electricity demand and power factor profile over a day.                                  | 257 |

# List of Tables

|                                                                                                                       |     |
|-----------------------------------------------------------------------------------------------------------------------|-----|
| Table 1. T&T's conventional energy reserves.                                                                          | 13  |
| Table 2. Energy sector's contribution in 1996 to key economic indicators.                                             | 14  |
| Table 3. Carbon content for different energy sources (Howell, 1993).                                                  | 28  |
| Table 4. Summary T&T electricity-use statistics 1983 to 1997 (Sitahal and Chong, 1998).                               | 47  |
| Table 5. Electricity customers in 1998 (T&TEC, 1999).                                                                 | 48  |
| Table 6. Industrial electricity user subgroups (Sitahal, 1999c).                                                      | 49  |
| Table 7. Fundamental economic factors (Griffith, 1995).                                                               | 53  |
| Table 8. Cogeneration plant options and characteristics (The National Gas Company of Trinidad and Tobago Ltd., 1999). | 56  |
| Table 9. Typical ICE performance data (Griffith, 1995).                                                               | 61  |
| Table 10. Typical GT performance data (Griffith, 1995).                                                               | 63  |
| Table 11. Downtime hours per annum – ICE (Griffith, 1995).                                                            | 65  |
| Table 12. Downtime hours per annum – GT (Griffith, 1995).                                                             | 66  |
| Table 13. Indicative maintenance requirements – ICE operating on natural gas (Griffith, 1995).                        | 73  |
| Table 14. Indicative maintenance requirements – GT operating on natural gas (Griffith, 1995).                         | 74  |
| Table 15. Summary of prime movers (Good Practice Guide 43, 1999).                                                     | 86  |
| Table 16. GT performance data (Best Practice Programme, 1992).                                                        | 88  |
| Table 17. Cogeneration reliability (Best Practice Programme, 1992)                                                    | 89  |
| Table 18. LNG importing countries, 1996 (True, 1998).                                                                 | 95  |
| Table 19. LNG exporting countries, 1996 (True, 1998).                                                                 | 95  |
| Table 20. LNG premiums for oil-fired power generation alternatives (in \$/Thousand m <sup>3</sup> ) (Stauffer, 1996). | 103 |
| Table 21. Liquefied natural gas chain costs excluding inlet gas, in \$/GJ (Stauffer, 1996).                           | 105 |
| Table 22 Co-product values: NGLs in \$/thousand m <sup>3</sup> unless otherwise stated (Stauffer, 1996).              | 106 |
| Table 23. Gas resource value (host country maximum gas revenue), in \$/Thousand m <sup>3</sup> (Stauffer, 1996).      | 107 |
| Table 24. Cost of gas delivered to the liquefied natural gas plant (\$/thousand m <sup>3</sup> ) (Stauffer, 1996).    | 108 |
| Table 25. Absorption system requirements (Dorgan, Leight and Dorgan, 1995).                                           | 124 |
| Table 26. LiBr absorption system variations – fixed heat source (Dorgan, Leight and Dorgan, 1995).                    | 125 |
| Table 27. LiBr absorption system variations – fixed cooling capacity (Dorgan, Leight and Dorgan, 1995).               | 126 |
| Table 28. Typical single-effect, indirect-fired, water-LiBr absorption chiller characteristics (ASHRAE, 1998).        | 133 |
| Table 29. Typical double-effect, indirect-fired, water-LiBr absorption chiller characteristics (ASHRAE, 1998).        | 134 |

|                                                                                                                                |     |
|--------------------------------------------------------------------------------------------------------------------------------|-----|
| Table 30. Absorption machine capital costs in US\$ (Dorgan, Leight and Dorgan, 1995).                                          | 138 |
| Table 31. Cooling tower costs for absorption systems in US\$ (Dorgan, Leight and Dorgan, 1995).                                | 139 |
| Table 32. Industrial electricity customer-groups in T&T                                                                        | 152 |
| Table 33. A selection of chiller capital costs from manufacturers.                                                             | 167 |
| Table 34. Cogeneration plant options and characteristics (NGC, 1998).                                                          | 168 |
| Table 35. Typical GT performance data (NGC, 1998).                                                                             | 169 |
| Table 36. Industrial electricity user subgroups (Sitahal, 1999).                                                               | 181 |
| Table 37. 1998 electricity use in subgroups, kWh (T&TEC figures).                                                              | 182 |
| Table 38. Ranking individual facilities by electricity use in 1998 (T&TEC figures).                                            | 183 |
| Table 39. Comparing site and subgroup operating hours (T&TEC figures).                                                         | 184 |
| Table 40. Hotel – summary statistics.                                                                                          | 186 |
| Table 41. Mall – summary statistics.                                                                                           | 189 |
| Table 42. School – summary statistics.                                                                                         | 192 |
| Table 43. Hospital – summary statistics.                                                                                       | 195 |
| Table 44. Mill – summary statistics.                                                                                           | 200 |
| Table 45. Mill – 1998 T&TEC bills.                                                                                             | 201 |
| Table 46. Bank – summary statistics.                                                                                           | 202 |
| Table 47. Bank – 1998 T&TEC bills.                                                                                             | 206 |
| Table 48. Methanol Plant 1 – Energy Budget sheet: Table 1 - daily electricity use for December 1998 (shows only first 6 days). | 207 |
| Table 49. Methanol Plant 1 – Energy Budget sheet: Table 2 - monthly energy use.                                                | 207 |
| Table 50. Methanol Plant 1 – summary statistics                                                                                | 210 |
| Table 51. Nitrogen Plant 1 – summary statistics.                                                                               | 211 |
| Table 52. Nitrogen Plant 1 – Energy budget sheet: Table 1 - electricity use in 1998.                                           | 211 |
| Table 53. Nitrogen Plant 1 – Energy budget sheet: Table 3 – natural-gas use in 1998.                                           | 212 |
| Table 54. Nitrogen Plant 1 – Energy budget sheet: Table 4 – production in 1998.                                                | 212 |
| Table 55. Refinery – summary statistics.                                                                                       | 215 |
| Table 56. Collated energy statistics at the sites studied, with and without cogeneration.                                      | 216 |
| Table 57. Extrapolated energy statistics for studied subgroups.                                                                | 216 |
| Table 58. Cogeneration natural gas saving – relative importance.                                                               | 217 |
| Table 59. Collated cogeneration economic statistics at the studied sites.                                                      | 219 |
| Table 60. Extrapolated cogeneration economic statistics for studied subgroups.                                                 | 218 |
| Table 61. Natural gas user cost (Ram, 2000).                                                                                   | 222 |
| Table 62. Cogeneration natural gas saving in US dollars                                                                        | 223 |
| Table 63. Forecasted and actual 1997 industrial energy sales (Sitahal and Chong, 1998).                                        | 230 |
| Table 64. Energy sales, GWh, and maximum demand, MVA, for large industrial D3 customers, (Sitahal, 1999a).                     | 231 |
| Table 65. T&TEC Base forecast for overall annual electricity sales compared with the corresponding OLADE forecast.             | 233 |
| Table 66. T&T annual natural gas sales, 1993 to 2002 – actual and forecasted.                                                  | 234 |
| Table 67. US energy-resource costs (Moseley and Headley, 1994).                                                                | 235 |

## Notation

|                        |                                                  |
|------------------------|--------------------------------------------------|
| A                      | availability applied to cogeneration engines     |
| A, B, D1, D2, D3, E, S | electricity rate categories                      |
| AAR                    | aqueous ammonia refrigeration                    |
| ac                     | alternating current                              |
| ALNG                   | Atlantic LNG Company Ltd.                        |
| ARI                    | Air conditioning and Refrigeration Institute     |
| Av                     | thermodynamic availability                       |
| av                     | alternating voltage                              |
| bpd                    | barrels of oil per day                           |
| C                      | carbon                                           |
| Caricom                | Caribbean Common Market                          |
| CDCC                   | Caribbean Development and Co-operation Committee |
| CGT                    | combined-cycle gas turbine                       |
| CHW                    | chilled water                                    |
| CNG                    | compressed natural gas                           |
| CO <sub>2</sub>        | carbon dioxide                                   |
| COP                    | coefficient of performance                       |
| COS                    | cost of service                                  |
| CR                     | Cascade refrigeration LNG cycle                  |
| CT                     | cooling tower                                    |
| CW                     | condenser water                                  |
| CX                     | current transformer                              |
| dc                     | direct current                                   |
| DCF                    | discounted cash flow                             |
| DCS                    | distributed control system                       |
| DSM                    | demand-side management                           |
| EMA                    | Environmental Management Authority               |
| EME                    | Emerging Market Economies                        |
| EMP                    | energy master plan                               |
| E                      | 10 <sup>18</sup> , exa- (quintillion)            |
| FDI                    | foreign direct investment                        |
| G                      | 10 <sup>9</sup> , giga- (billion)                |
| GCV                    | gross calorific value                            |
| GDP                    | gross domestic product                           |
| GNP                    | gross national product                           |
| GOTT                   | Government of Trinidad and Tobago                |
| GP                     | Green Paper on Energy Policy                     |
| GT                     | gas turbine                                      |
| ICE                    | internal combustion engine                       |
| IEA                    | International Energy Agency                      |
| IGT                    | Institute of Gas Technology                      |
| INEP                   | integrated national energy planning framework    |



|          |                                                                                                    |
|----------|----------------------------------------------------------------------------------------------------|
| IRR      | internal rate of return                                                                            |
| JPSCO    | Jamaica Public Service Company                                                                     |
| kWe      | electricity power in kilowatt                                                                      |
| kWr      | refrigeration effect in kilowatt                                                                   |
| kWth     | thermal power in kilowatt                                                                          |
| LiBr     | lithium bromide                                                                                    |
| LNG      | liquefied natural gas                                                                              |
| M        | 10 <sup>6</sup> , mega- (million)                                                                  |
| MOE      | Ministry of Energy and Energy Industries                                                           |
| MR       | Mixed refrigerant LNG cycle                                                                        |
| MS Excel | Microsoft Windows spreadsheet application software                                                 |
| mtoe     | million tonnes of oil equivalent                                                                   |
| NGC      | The National Gas Company of Trinidad and Tobago                                                    |
| NGL      | natural gas liquids                                                                                |
| NOx      | nitrogen oxides                                                                                    |
| NPV      | net present value                                                                                  |
| O&M      | operation and maintenance                                                                          |
| OECD     | Organisation for Economic Co-operation and Development                                             |
| OLADE    | Latin American Energy Organisation                                                                 |
| OTEC     | ocean thermal energy conversion                                                                    |
| P        | 10 <sup>15</sup> , peca- (quadrillion)                                                             |
| PMR      | Pre-cooled mixed refrigerant LNG cycle                                                             |
| ppmv     | parts per million by volume                                                                        |
| PV       | photovoltaic                                                                                       |
| r.m.s    | root-mean-square, the square root of the average of the square of a variable over a period of time |
| R/P      | reserves/production ratio                                                                          |
| RPI      | retail price index                                                                                 |
| SCR      | selective catalytic reduction (to GT exhaust)                                                      |
| SCT      | saturated condensing temperature                                                                   |
| SET      | saturated evaporating temperature                                                                  |
| SP Max   | electricity logging meter                                                                          |
| T        | 10 <sup>12</sup> , tera- (trillion)                                                                |
| T&T      | Trinidad and Tobago                                                                                |
| T&TEC    | The Trinidad and Tobago Electricity Commission                                                     |
| tcf      | trillion cubic feet                                                                                |
| toe      | tonnes of oil equivalent                                                                           |
| UK       | United Kingdom                                                                                     |
| UN       | United Nations                                                                                     |
| UNECLAC  | United Nations Economic Commission for Latin America                                               |
| US       | United States of America, World tyrant                                                             |
| VC       | vapour compression refrigeration                                                                   |
| WACC     | weighted average cost of capital                                                                   |
| WASA     | The Water and Sewerage Authority of Trinidad and Tobago                                            |
| WB       | World Bank                                                                                         |

WEC

World Energy Council/Conference

## Chapter 1. Introduction

This thesis looks at energy policy in Trinidad and Tobago (T&T) by focusing on a single policy measure, *natural-gas cogeneration*, to learn about energy policy in general. The energy-policy perspective is concerned with the overall impact of the different natural-gas uses, such as liquefied natural gas (LNG), methanol, ammonia, power generation, plastics, i.e. to what extent each industry benefits the country and at what cost. So this thesis is not too much concerned with details of how each industry actually transforms the natural gas in its process. The thesis investigates natural gas as it is in the ascendancy, both locally and globally, and because oil is on the decline in T&T. Chapters 3 and 4 discuss this in detail.

Natural gas' increasing role in the T&T energy picture suggests the need for a new energy policy, or for revising any existing policy. Chapter 2 explores energy policy in general and in T&T specifically. It demonstrates the energy sector's importance to the T&T economy, confirming the need for proper energy planning. A general energy-policy discussion sets the context for this thesis' focus – natural gas cogeneration. This thesis proposes nationwide natural gas cogeneration as an energy policy measure and further focuses the research on such cogeneration in the *industrial sector*. It then approximately extrapolates results from the industrial sector to the entire country. The aim of the thesis can thus be described as assessing natural-gas cogeneration's potential as a policy measure, using the industrial sector as an example.

The thesis considers natural-gas cogeneration as one energy policy measure because of its many advantages over conventional heat and power supplies. Chapter 5 explores this in detail. Also, nationwide cogeneration has never been considered before in T&T. As already mentioned, the section of an energy policy dealing with natural gas would consider all the likely uses for the resource. This thesis attempts to determine where cogeneration would sit in the hierarchy of natural-gas uses by comparing it with the one that the Government of T&T (GOTT) chooses as its main natural-gas thrust, LNG. Chapter 6 explores LNG in detail, and Chapter 10 compares the two policy measures – proposed cogeneration against existing LNG. LNG provides a reference point for locating natural-gas cogeneration in the overall energy policy framework.

The industry-wide cogeneration evaluation necessarily considers electricity customers. It groups the almost 1,967 customers in 1998 according to similarity in electricity-use characteristics into 15 subgroups, as explained in Chapter 10. This allows a study of one or more representatives from each subgroup to apply to the whole subgroup, and thus covers the whole spectrum of industrial electricity customers. This is a fundamental assumption of the research. The research thus essentially becomes a series of cogeneration feasibility studies at individual sites, needing data gathered from extensive fieldwork, and an analysis model constructed in MS Excel, which applies a standard business project-appraisal procedure. Chapter 8 describes the fieldwork and Chapter 9 the analysis model.

Chapter 10 at first specifically discusses the industrial-cogeneration assessment and results, its assumptions and deficiencies. The discussion then broadens to additional work needed to expand it to a comprehensive energy policy proposal, and a look at energy prospects beyond natural gas, i.e. renewable energy potential in T&T and the Caribbean. Finally, Chapter 11 states the thesis' main conclusions.

## Chapter 2. Energy policy

*Energy policy* is that part of national (or international) policy that is concerned with energy production and supply, its conversion, storage, distribution and use, and with formulating measures aimed at equating anticipated overall demand for energy with the presumed availability nationally and internationally of energy sources. Such a policy would take account of the potential for energy conservation, in particular of finite fuel resources as well as of the environmental impact (Munasinghe, 1990). *Energy planning* is the series of steps or procedures by which the myriad interactions involved in producing all forms of energy may be studied and understood within an explicit analytical framework. It is an essential part of economic planning. *Energy policy analysis* systematically investigates the impact of specific energy policies or policy packages on the economy and society at all levels. *Energy supply- and demand-management* uses a selected set of policies and policy instruments to achieve desirable national objectives.

### 2.1 Reasons for energy policy

The broad rationale underlying all national-level planning and policy-making is the need to ensure the best use of scarce resources in order to further socio-economic development efforts and improve the citizen's quality of life. Policy analysis and formulation is centralised at the national level, but effective policy implementation requires maximum use of decentralised market forces and institutions (Department of Primary Industries and Energy, 1991). Energy planning must be part of, and closely integrated with, overall economic planning and policy analysis to meet many specific, inter-related and frequently conflicting national objectives. The principal emphasis in energy planning and policy analysis is on detailed and comprehensive energy sector analysis, its linkages with the rest of the economy, and the main interactions within the various energy subsectors themselves. It must take into account all the political aspects including economic, social and environmental considerations depending on available energy resources and their acceptance by society. There are further complications in developing countries: substantial market distortions; shortages of foreign exchange, human and financial resources; the need to meet basic needs of a large number of poor households; paucity of energy- and other data; greater emphasis on rural energy problems.

Specific *energy policy goals* include:

- ensuring economic efficiency in supplying and using all energy forms to maximise growth – other efficiency related objectives are energy conservation and eliminating wasteful consumption, and saving scarce foreign exchange,
- raising sufficient revenues from energy sales to finance sector development,
- meeting the poor's basic energy needs and income redistribution,
- diversifying supply, reducing dependence on foreign sources, and meeting national security requirements,



decisions to long-term planning. INEP is a hierarchical framework. Figure 1 clarifies the scope of INEP, policy analysis and supply/demand management.

At the most aggregate level energy is one sector of the whole economy and energy planning at this level analyses the links between the energy sector and the rest of the economy. The range of macroeconomic policy options from long-term structural adjustments to short-term stabilisation programmes will have a significant impact on the energy decisions. More specific links between the energy sector and the rest of the economy include energy-sector inputs such as capital, labour, raw material and environmental resources (clean air, water, space), as well as energy outputs – electricity, petroleum products and the impact on the economy of various energy policies.

INEP's second level views the energy sector as a separate entity composed of sub-sectors such as electricity and petroleum products. This allows detailed analysis, special emphasis on interactions among the different energy sub-sectors, substitution possibilities, and resolving any resulting policy conflicts such as competition between natural gas and oil for electricity production, or diesel and gasoline for transportation.

The third INEP level is the most disaggregate and involves planning within each energy sub-sector. For example, the electricity sub-sector must determine its own demand forecast and long-term investment programmes. Detailed formulating, planning and implementing energy schemes occurs at this level. Most of the research in this thesis looks at cogeneration within the electricity sub-sector in Trinidad and Tobago (T&T) at this INEP level, but this involves using natural gas as a utility, substituting part of the electricity utility at INEP's level 2.

In practice the three INEP levels merge and overlap considerably. For example, energy-environmental interactions cut across all levels, and the analysis must incorporate this as far as possible. The INEP process is a flexible and constantly updated energy strategy, which can meet the often-conflicting national goals described earlier. Such a national energy strategy, of which the optimal investment programme and pricing policy are important elements, may be implemented through a set of energy supply- and demand management policies and programmes that effectively use decentralised policy instruments and market forces.

The *policy instruments* to achieve desired national goals for optimal energy management are:

- physical controls,
- technical methods,
- direct investments or investment-inducing policies,
- education and promotion,
- pricing, taxes, subsidies and other financial incentives, and
- reforms in market organisation, regulatory framework and institutional structure.

Physical controls are most useful in the short-run when there are unforeseen energy shortages, and are thus inapplicable to T&T which is a net energy-exporter. Technical means can be used to manage both energy supply and demand, to determine the most efficient means of producing energy, and to distribute higher efficiency energy conversion devices. Investment policies have a major long-term effect on energy supply and consumption patterns, e.g. extending natural-gas distribution networks. Through education and promotion (propaganda) people can be made aware of the scope for economically beneficial tradeoffs between savings on recurrent energy costs and capital expenditure required to achieve such savings. It is a demand-side management measure. Pricing is a politically sensitive and very effective demand management method. Taxation and subsidies profoundly affect long-term energy consumption patterns where this is desirable from the national perspective. Policy reforms can improve market organisation and promote greater energy sector efficiency.

The chief constraints limiting effective policy formulation and implementation are:

- poor institutional framework,
- insufficient manpower and other resources,
- weak analytical tools,
- inadequate policy instruments,
- lack of political will, and
- other constraints such as low incomes and economic distortions.

Additional constraints can arise from severe market distortions due to taxes, import duties, subsidies and externalities that cause prices to diverge substantially from the true economic opportunity costs. Also severe income disparities in developing countries and other social considerations may lead to subsidised energy prices to meet basic energy needs of poor consumers. Additional considerations affecting policy decisions may be future investment requirements, the energy sector's viability and autonomy, and regional development needs.

### 2.2.1 Planning horizon

INEP must also consider a time-horizon hierarchy, i.e. short-term, medium-term and long-term.

Short-term national energy planning, with about a one-year time scale, is useful for supply/demand management decisions to meet unforeseen problems. If past planning had been successful, short-term energy management would be problem-free as a part of the evolving longer-term energy strategy.

Medium term planning has a 2- to 10-year time horizon and is more flexible as there is sufficient time to make significant policy changes. The most important decisions include planning, evaluating and implementing energy projects, e.g. laying new gas pipelines.



Long-term planning with a 10- to 20-year planning horizon involves the most fundamental strategies of all. It examines a variety of alternative scenarios, as there is more uncertainty in the data used for projections.

Short- and medium-term policies should merge as smoothly and consistently as possible with the long run strategy, there should be no sharp dividing lines among the three.

*Uncertainty* raises great difficulties in energy planning because of the sector's widespread interaction with the rest of the economy and its vulnerability to international events. Specific causes of uncertainty are:

- the long planning horizon for energy investment decisions, long lead times required for energy resource development, and danger of resultant 'lock-in' effects,
- incomplete knowledge of the national energy resource base, and the possibility of finding oil, gas, etc in the future,
- changes in energy-use patterns,
- changes in the technology of energy supply and end-use, and
- variations in energy prices.

So the planning process should be dynamic and continuous, with all data, assumptions and analyses constantly revised using the most recent information.

### 2.2.2 The INEP procedure

Figure 2 shows steps in the INEP procedure. The figure's divisions are conceptual and overlap considerably in practice.

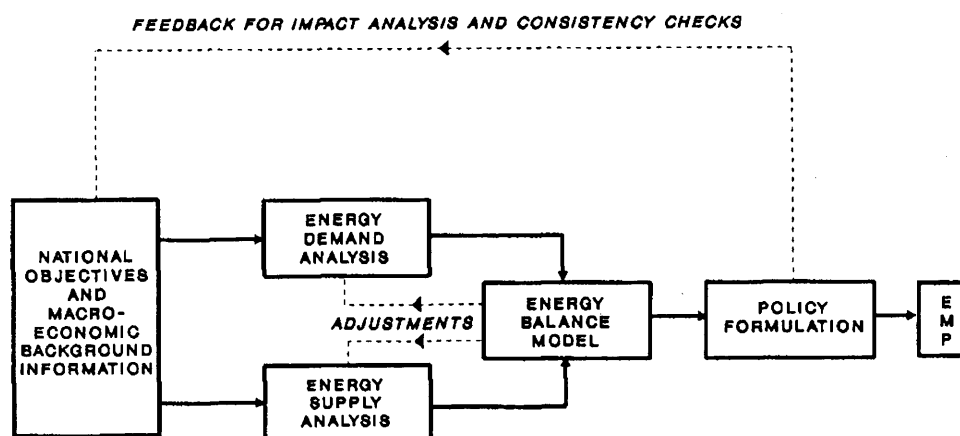


Figure 2. Basic steps in implementing INEP (Munasinghe, 1990).

The first and last steps examine broad relationships between energy and the rest of the economy, corresponding to the highest hierarchical level in INEP. Thus the first step

examines national priorities and objectives, and overall economic background evolution, say over the next 20 years. It addresses questions concerning economic targets like desired GNP growth rate, and energy intensity of future socio-economic development plans such as the industrialisation rate. The first step also needs projections for: future fuel availability and prices on the world market; financial resources available for developing the domestic energy sources; developing relevant new technologies and non-conventional energy sources, e.g. biogas.

The information and assumptions from step-1 strongly influence the subsequent planning stages. These steps, *supply and demand analyses and energy balance*, relate mainly to the lower levels in the INEP hierarchy shown in Figure 1, i.e. energy sector and subsector planning. While these steps deal with forecasts spanning the full long-term INEP horizon, it should develop medium- and short-term projections within the same consistent framework. The principal objective of *energy-demand analysis* is to determine future requirements by type of fuel and by consumer category (or type of usage). Past, present and possible changes in future energy usage patterns form the basis for forecasting the structure of national energy demands. The past and present patterns must be analysed in detail relative to other factors such as prices, incomes, levels of economic activity, supply constraints, and stocks of energy-using equipment.

*Energy-supply analysis* systematically determines all possible future energy supply options, disaggregated by energy subsector. It first examines past and present data on energy resources and production, imports and exports, generation, storage, refining, transportation, distribution and retailing, financial and manpower requirements, costs and output prices. Then it combines this information with projections of fuel resource development projects and programmes, energy subsector output capabilities, capacity to import and export, application of new technologies and non-conventional sources, financial, manpower and organisational resources to provide detailed forecasts of the availability of the different energy forms.

*Energy balance* consists of assigning specific energy sources to corresponding uses to develop supply-demand balances for future years. Projected energy shortages and surpluses can then be reconciled, possibly by returning to earlier steps to re-adjust the supply and demand analyses and forecasts.

This series of four steps will yield a set of energy policies for managing supply and demand to satisfy future national energy needs. *Policy and EMP formulation* produces several alternative packages or sets of policies involving the basic policy tools described earlier, and tests them for their impact on the rest of the economy. Certain consistency checks may show that the consequences of some energy policies may violate other national objectives or assumptions regarding the economy's evolution. Or the strategy may entail unacceptably high balance of payments deficits for energy imports or drain financial resources from sectors like agriculture, or drastically curtail the energy supply to those sectors, infringing on other government priorities. If some of these basic objectives or background data are changed as a result of tradeoffs, then the steps must be repeated using

the new assumptions. Thus the INEP process permits dynamic consistency checks through iterative feedback.

Finally the decision-makers may select the set of energy policies which are consistent with broad national goals and which best satisfy future energy needs. This policy package and the associated set of supply and demand forecasts and balances constitute the EMP.

### 2.2.3 The case against policy

The traditional arguments for policy are (Robinson, 1993): government's responsibility for energy supply; environmental effects associated with energy production, transportation and consumption; externalities which markets fail to take into account (like environmental costs); there is no perfect market. But there is an alternative view to abolish policy and let markets work. This argues that equally there is no perfect government and identifies the following problems with government action:

- Elections are an exchange of policies for votes but voters have little incentive to discover in detail what political parties will do in office, since costs of finding such information is extremely high relative to the influence any individual has on the election outcome. So it is rational for voters to remain ignorant.
- The government in office is the sole policy supplier, which is a monopoly in itself, with attendant familiar problems.
- Governments can use the monopoly power to finance their schemes using other people's money, i.e. citizens', that they have access to.
- Producer pressure groups in a market heavily influence governments to grant them favours paid for by others, but which benefit the groups' members.

On the other hand markets provide for minorities in ways governments by majority voting cannot. Also a market characteristic is the *discovery process* where entrepreneurs seek new ways to do things as consumers seek new products leading to discoveries that would not otherwise have been made. This is impossible to forecast accurately which handicaps policy formulation. The forecasts on which people base decisions are imperfect but competitive forecasting and decision-making, and the resulting discovery process, generate new knowledge. Finally, markets argue for less regulation, as regulators can never know what the outcome of a competitive market would have been.

The experience in International Energy Agency (IEA) member countries demonstrates how these conflicting views are each taken on board to some extent. These countries have markets that are much more developed than those in the third world. Market forces in periods of high energy prices worked towards IEA energy policies achieving their goals (International Energy Agency, 1988). The effect of low prices is yet unknown. Demand and supply interaction in IEA market economies occurs mainly through the price mechanism. Governments acted in the past because of market imperfections, and external policy factors such as long-term energy security and environmental considerations that are not sufficiently internalised in the market. And governments will continue to act though

they are more inclined to reduce market interventions signaling a change to greater competition and flexibility in both the demand and the supply sides. These changes occur in licensing, royalty and taxation schemes, deregulating oil and gas industries, adjusting pricing and taxation policies, and removing some barriers to free energy trade.

## **2.3 Energy policy history in Trinidad and Tobago**

The Government of Trinidad and Tobago (GOTT) released a Draft Policy Document on Energy in 1987 and nothing else until April 1997, when they released a Green Paper on Energy Policy (GP) for public comment, and which is now under review. The Permanent Secretary in T&T's Energy Ministry stresses that 'this is an unpublished draft version, currently under further revision and is to be used for research purposes only, and not to be quoted as a government position.' (Ministry of Energy and Energy Industries, 1997). As it is the only document indicating the GOTT's current thoughts on energy, I will consider it as indicating their intentions. Section 2.4 below paraphrases the GP's content to avoid presenting the entire document here; all relevant facts and figures, and all of the GOTT's policy opinions and philosophy are exactly as presented in it. The last year from which the GP obtained complete data is 1996.

## **2.4 The Energy-policy Green Paper**

The policy document seeks to highlight the main policy thrust for the energy sector, and to identify major policy shifts that may be necessary to efficiently manage the sector.

### **2.4.1 Introduction**

Long-term planning is impossible in the energy sector as it is so unpredictable, so it is important to be flexible and be able to change. The sector is volatile, is characterised by constant research and development, and is also highly sensitive to changes in international politics and economics. Developing the energy industry needs large capital injections, which must be attracted externally in an increasingly competitive environment. This sets the context for the GP.

### **2.4.2 General framework**

The Ministry of Energy and Energy Industries is responsible for energy-sector administration and development in T&T. The sector is crucial to the national economy, and this internal factor along with the country's position in the international energy industry sets the background framework for T&T's energy policy. The Ministry's portfolio is to administer and regulate the energy sector, the mineral sector, and the operational and commercial aspects of the state petroleum and energy-based industries. An Energy Subcommittee reviews critical energy decisions.

T&T's energy policy as a net energy exporter is grounded in realities of the global energy environment and its relative position in the international energy market. So the factors determining the energy policy framework are the country's position as a net energy exporter, its energy demand, its climate, level of industrialisation, and energy sector trends. T&T develops international and regional energy relations through membership in the Latin American Energy Organisation (OLADE), and the World Energy Conference (WEC).

### 2.4.3 Current energy trends and projected futures

This section uses 15 years' historical energy sector data from 1979 to 1994.

*International energy market trends are:*

- Emerging environmental protection policies in all aspects of the industry.
- Globalising commodity and investment markets.
- The need to harmonise energy supply and demand.
- New technologies developing with diverse effects on competitiveness and labour markets.
- Energy importing countries tending to exert downward pressures on market prices by employing sundry strategies and systems.
- Increasing market control through growing commodity markets and forward contracts.
- Increasing competition for capital investment.

World energy demand is expected to grow at ~2% per annum until 2020AD, from a current 8.5 billion tonnes of oil equivalent (btoe) to ~13 btoe. The wild fluctuations that occurred from the mid-seventies to the mid-eighties are not expected again up to 2020AD at least.

International companies are the main local operators so *local trends* largely mirror the international ones. Commercial activities in *primary energy production* started from as early as 1908. Large crude-oil reserves were discovered off the southeast coast in the late sixties and early seventies. Associated natural gas was considered a nuisance at that time and flared. In the late eighties oil discovery peaked, and gas was in the ascendancy. The current reserve mix favours natural gas so that the single most important aspect of energy policy formulation is developing the natural-gas subsector. Natural gas is now used mainly as a feedstock (as opposed to a fuel), and downstream demand stimulates upstream gas production. Alternative energy, both new and renewable, is a major area for future development locally and internationally.

T&T's *transformation sector* consists mainly of: two crude-oil refineries, one now defunct; a natural-gas liquids recovery plant; electricity generation; petrochemical companies using natural gas as both feedstock and fuel (ammonia, urea, and methanol plants); steel and iron carbide plants using natural gas fuel; liquefied natural gas (LNG) plants.



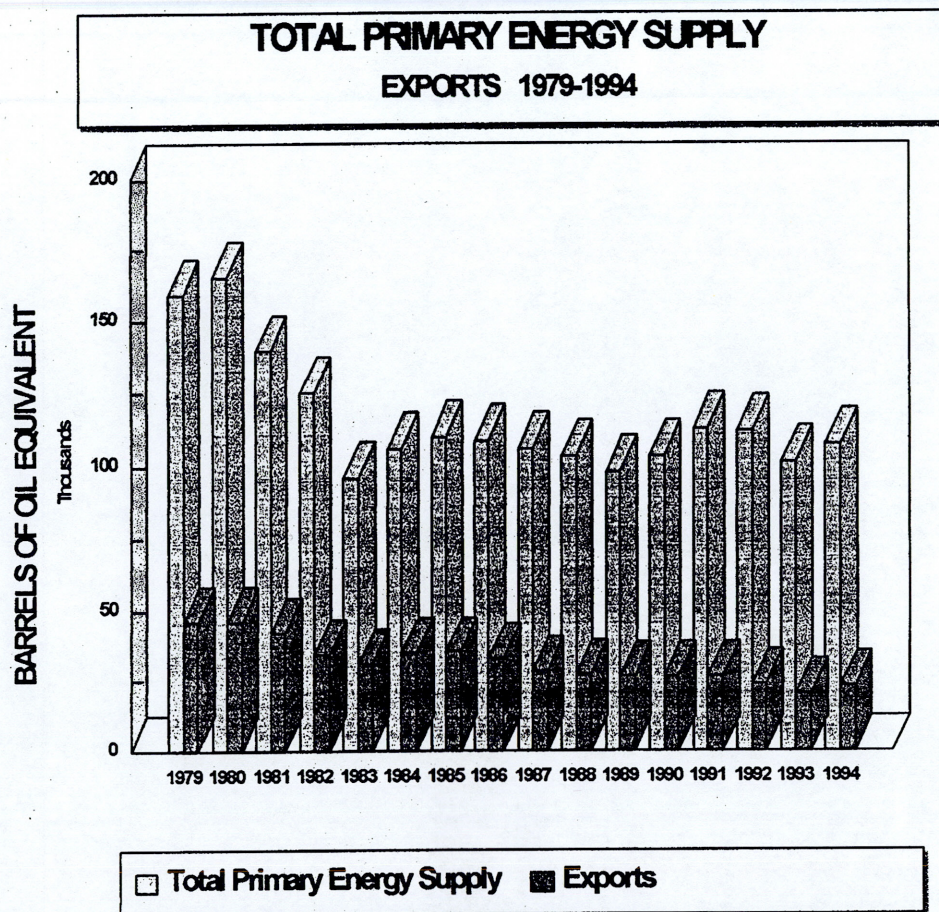


Figure 3. Total primary energy supply 1979 to 1994.

Finally, although domestic energy consumption is small relative to overall energy production as illustrated in Figure 3 and Figure 4, demand-side management is seen as requiring urgent attention.

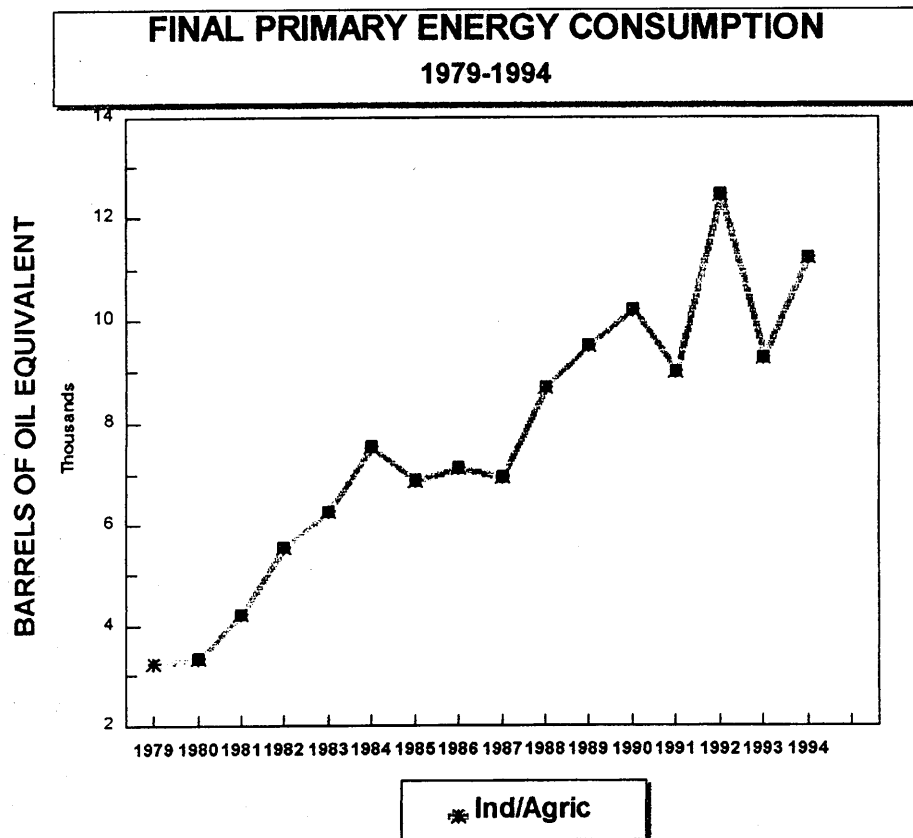


Figure 4. Final primary energy consumption 1979 to 1994.

#### 2.4.3.1 Current reserve structure

Exploration activities and reserve audits give *conventional energy* (crude oil and natural gas) reserve-estimates (see Table 1).

|                                                 | Proven |        | Probable |        | Possible |        |
|-------------------------------------------------|--------|--------|----------|--------|----------|--------|
|                                                 | Land   | Marine | Land     | Marine | Land     | Marine |
| Crude oil (million barrels)                     | 165    | 325    | 163      | 252    | 100      | 2,200  |
| Natural gas ( $10^9 \text{ m}^3$ )              | 1.5    | 287.8  | 0.0      | 170.0  | 0.0      | 76.0   |
| Natural gas (million barrels of oil equivalent) | 8      | 1,673  |          | 988    |          | 442    |

Table 1. T&amp;T's conventional energy reserves.

The GOTT recognises that *non-conventional energy* (meaning renewable energy) *sources*, are ultimately the energy resources of the future but current activities in this area are too small to be represented in national statistics and no recent local audit has been done to



assess its potential. T&T will ensure that it is poised to take advantage of any developments in this regard.

#### 2.4.3.2 The energy-sector's importance

The energy sector is currently the largest single contributing sector to the county's economy, as indicated in its foreign exchange earnings, gross domestic product (GDP), and government revenue (Table 2). This places serious constraints on the development modes for, and ownership structure of, the sector.

| Economic indicator        | Contribution                                                      |
|---------------------------|-------------------------------------------------------------------|
| GDP (at market prices)    | \$8.8 billion or 26.7% of the total GDP of \$32.8 billion         |
| Government revenue        | \$2.5 billion or 32% of total government revenue of \$8.4 billion |
| Foreign exchange earnings | 77 percent                                                        |

Table 2. Energy sector's contribution in 1996 to key economic indicators.

#### 2.4.3.3 Sectoral trends – the primary-energy sector

Primary energy production in T&T comprises crude oil, natural gas, condensate from natural gas, and bagasse – a sugarcane industry by-product. 80% of locally produced crude oil is for export. Local demand, in the form of large petrochemical plants, smelters, and liquefied natural gas (LNG) plants, directly drives natural gas production. On the downstream side, natural-gas distribution, marketing and pricing are being reviewed. In 1995 T&T produced ~0.2% of the world's oil production and ~0.3% of the world's natural-gas production. T&T's energy contribution to the world market is insignificant by any standard but critical to the country's economic welfare, so that future success demands that T&T maximises managerial and operational efficiency in all aspects of the sector's operations. Other concerns are state of reserves and the environment.

#### 2.4.3.4 Sectoral trends – the transformation sector

##### 2.4.3.4.1 Refineries

Current refinery capacity is 160,000 barrels per day (bpd), just recently upgraded from 100,000 bpd. Further capacity upgrades are planned. 72,000 bpd local crude oil is available for refining with a US\$4.50 per barrel profit margin. The margin on imported crude is much less at US\$0.50 to US\$1.50 per barrel. Major refining concerns are:

- Decreasing indigenous crude oil supplies.
- Expanding premium markets in the Caribbean and Latin America.
- Securing appropriate supplies of imported crude.
- Engaging in third-party crude processing arrangements.
- Reducing operating costs.
- Maintaining a good industrial relations climate.



The expanding natural-gas sector needs additional capacity in natural-gas liquids removal plants.

2.4.3.4.2 Electricity

The national electricity generating utility, the PowerGen Company, generates almost all electricity in T&T, with private companies generating only a negligible amount. PowerGen uses natural gas in all its generation, and using imported electricity from the region could affect gas consumption. The increasing degree of industrialisation, electronics, and electrical appliances in the country requires greater quantities and quality of electricity. Figure 5 and Figure 6 illustrate the sector's trends.

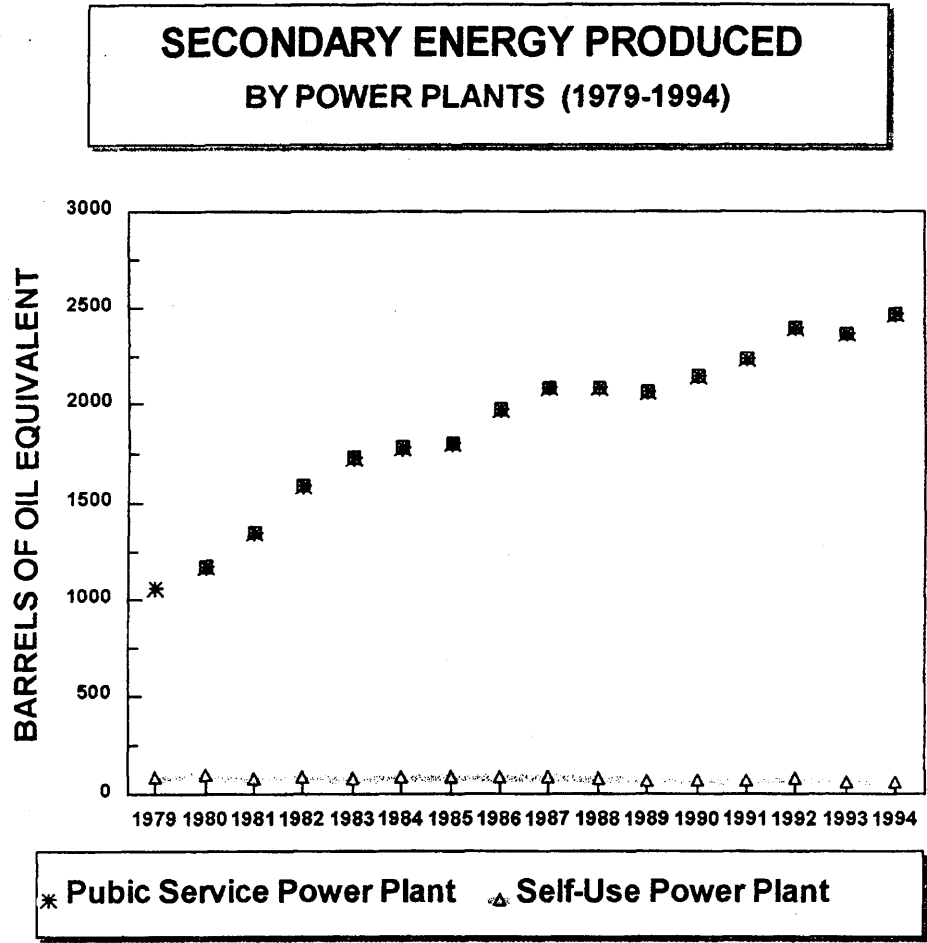


Figure 5. Secondary energy produced by power plants (1979 to 1994).



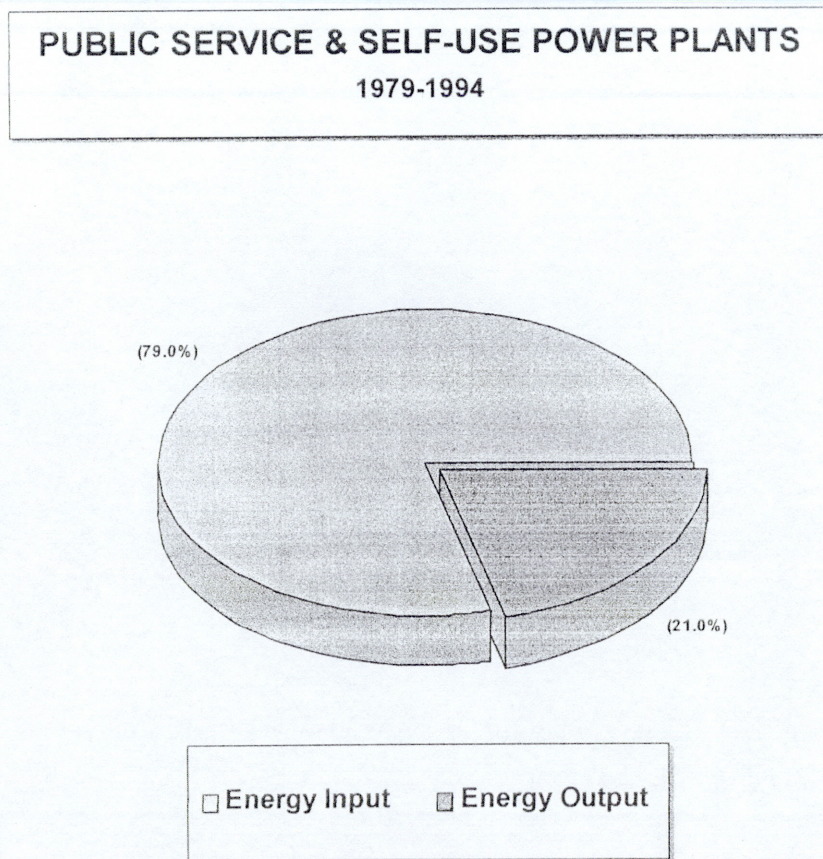


Figure 6. Public and self-use power plants (1979 to 1994).

#### 2.4.3.4.3 LNG plants

LNG is a means for the country to export natural gas so that upstream production is no longer bound by local downstream transformation. Investment negotiations in this area must ensure optimum benefits to the country given natural-gas' central role.

#### 2.4.3.4.4 Natural gas fuel supplies

Natural gas is used as a fuel in electricity generation, metal furnaces, an iron-carbide plant, and some small manufacturing industries. Expansion is projected in: smelting and furnace industries with expanding iron and steel production and a planned aluminium plant; domestic household and commercial use; compressed natural gas (CNG).

#### 2.4.3.4.5 Non-energy products

These come from the petrochemical plants, both first-stage and further downstream, using natural gas as a feedstock. The first-stage plants, such as ammonia, methanol and urea, mainly produce for export. Fiscal incentives for foreign investments limit the financial returns to the country as investors' interests are not always consistent with the country's. T&T must also be careful as a market leader in methanol. The further downstream industry is ethylene-based, removed from the natural gas as a liquid. It is really only in the planning



stage as a new plant to cope with increased natural gas production will provide commercial quantities when built.

#### 2.4.3.5 Sectoral trends – energy consumption

Demand management has not been a major concern in T&T as energy production far surpasses consumption, and energy costs are relatively low and substantially subsidised. The sector needs an effective demand management policy for efficient administration, to be done through a pricing policy. Three major issues in pricing will be standards, efficiency and affordability. Another demand-management measure is education programmes to demonstrate energy efficient technologies, the relative value of wasted energy, and real energy costs that account for environmental damage. Figure 7, Figure 8 and Figure 9 show consumption trends.

The GOTT recognises the intimate link between energy and the environment and plans to promote environmentally cleaner fuels (meaning CNG) and non-conventional energy (meaning non-fossil-fuels). CNG is a recent introduction to T&T. The concerns are not for energy security but for environmental health, although importing the new technologies represents another foreign-exchange drain.

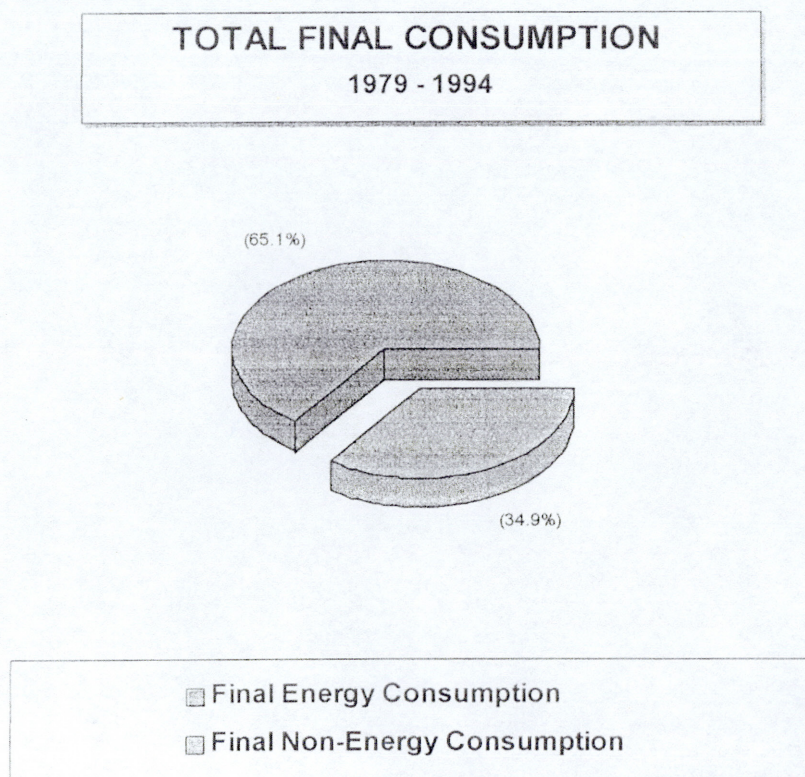


Figure 7. Total final consumption (1979 to 1994).

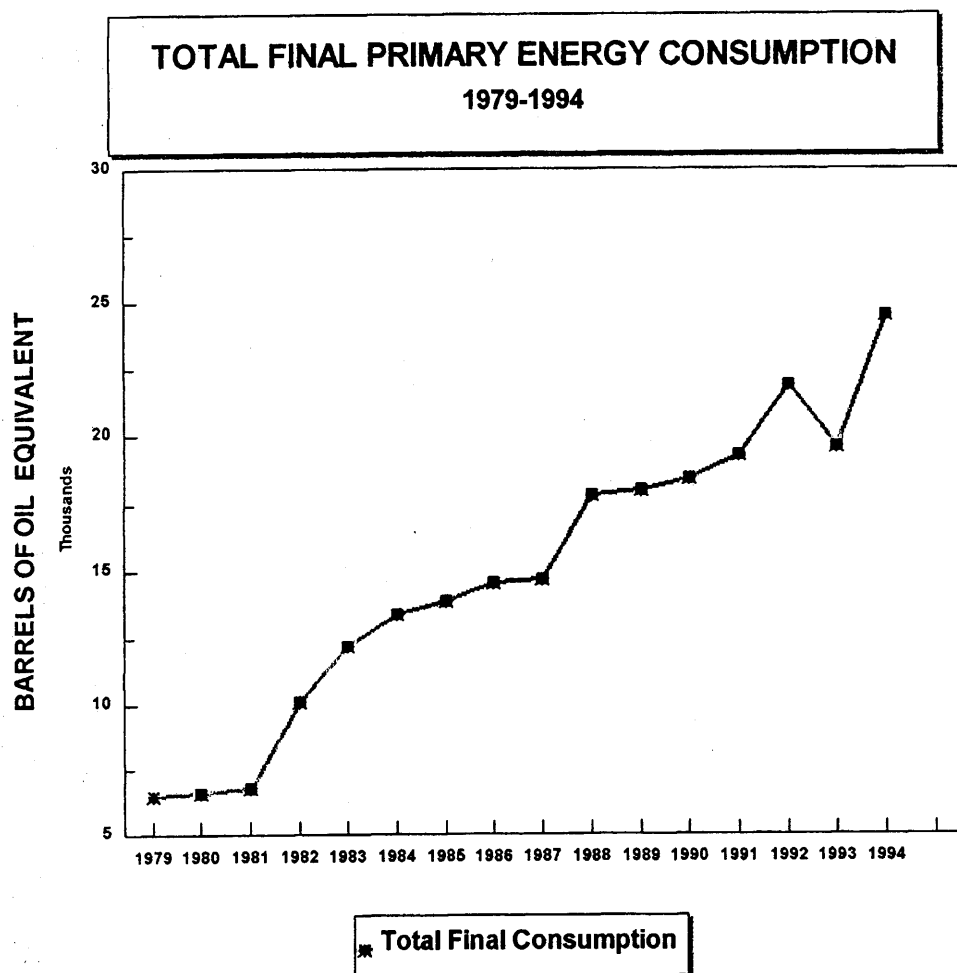


Figure 8. Total final primary energy consumption (1979 to 1994).



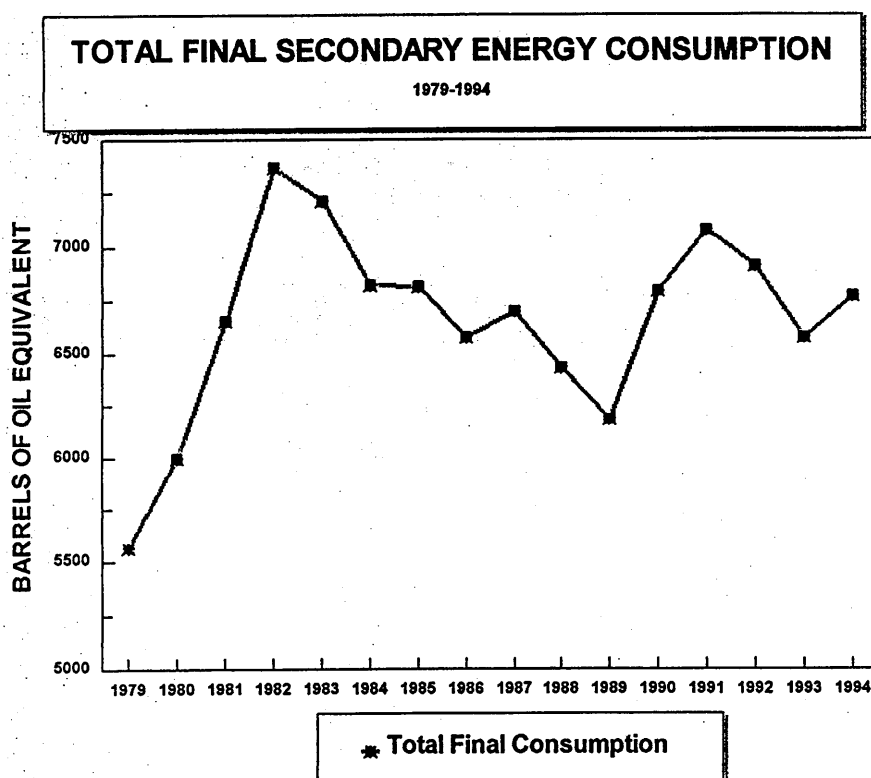


Figure 9. Total final secondary energy consumption (1979 to 1994).

#### 2.4.4 Guidelines for energy policy implementation

The main policy goal for the energy sector is to ensure its efficient administration to achieve optimal returns for exploiting the country's natural resources to benefit all of its citizens. The specific policy objectives are:

- The State's role as facilitator in the sector's development.
- Developing an efficient administrative, regulatory, legal and fiscal framework able to adapt to change and promote sustainable growth and development.
- The security of the country's energy supplies.
- Maximising local crude oil production.
- Effectively using and further developing refining capacity.
- Effectively and optimally monetising the natural gas resources.
- Developing downstream natural-gas-based industries including petrochemicals.
- Demand management.
- Creating an efficient customer-focussed fuel retail marketing sector.
- Actively promoting clean energy/alternative energy options such as compressed natural gas (CNG) as a vehicular fuel, using piped natural gas for domestic purposes and solar energy applications.
- Protecting and preserving the environment.

- Developing nationals and appropriate research and development programmes to ensure that the country remains competitive in the industry.

The GOTT will use several policy instruments to achieve these policy goals, including:

- Legislation and legislative reform.
- Incentives.
- Administrative reform.
- Institutional strengthening and human-resource development and skills upgrading in all aspects of the sector's operations.
- State participation in the sector as a promoter and facilitator.
- Regulation including ensuring compliance with Licensing Terms and Agreements.
- Deregulation.
- Employing efficient communication systems.
- Establishing appropriate information systems.

#### **2.4.4.1 Policy strategies and initiatives**

##### **2.4.4.1.1 Administration in the energy sector**

The state will have a role as a facilitator in energy sector development, with less direct investment and more divestment, managed to ensure optimal returns. It will also promote training of locals, technology transfer, and developing local research capabilities.

Reviewing institutional arrangements in the energy sector will strengthen the administrative machinery. The major state companies engaged in the sector's administration are the National Gas Company and the Trinidad and Tobago National Petroleum Marketing Company. Cabinet recently appointed an energy sub-committee to strengthen administration in the MOE and to make major decisions on energy. The sub-committee members are the Minister of the MOE (the sub-committee head), and Ministers of: Finance; Planning and Development; Trade, Industry and Consumer Affairs; Foreign Affairs; Public Utilities. A Natural Gas Regulatory body and a project promotion and evaluation subsection within the Energy Planning Division of the MOE have also been set up.

##### **2.4.4.1.2 Energy-supply security**

Consider supply security in the context of T&T's energy-export customers, and for local refineries. Security requires very efficient reserve depletion policies and exploration programmes. The country is insignificant in the global market but needs foreign investors to develop local resources, and promote exploration activities to offset reserve depletion. Optimising upstream production is crucial given the energy sector's importance to the economy, and the strategy is:

- Increased exploration and production activities onshore and offshore.
- Establishing downstream gas industries to match current and future production capacities.
- Optimal oil and gas depletion policies.
- Establishing adequate and appropriate gas transmission systems.

- Attracting new investment in exploration and production activities.
- Efficient sub-sector administration.

#### **2.4.4.1.3 Monetising the natural gas resources**

The natural-gas sub-sector is developing at the expense of certain concessions:

- Relatively attractive natural gas prices.
- Fiscal concessions such as tax holidays, duty exemptions, profit-repatriation and generous foreign exchange terms.
- Providing infrastructure such as appropriate sites, harbour facilities, utilities and communications.
- A stable political climate and legal structure.

Some progress has to be made in optimising returns, particularly as it is now the major hydrocarbon sub-sector. Downstream industry developments refer to the petrochemical and other transformation industries described earlier.

#### **2.4.4.1.4 Promoting cleaner energy/alternative energy options**

The GOTT is evaluating a natural-gas pipeline-distribution system for industrial, commercial and domestic users. Concerning renewable-energy technologies, the GOTT regards importing these as an unacceptable foreign-exchange drain and considers the following options:

- Promoting local investment in manufacturing capital equipment for use in producing alternative energy.
- The extent of local value-added input into the producing alternative-energy equipment, e.g. the local labour content, local materials.

#### **2.4.4.1.5 Protecting and preserving the environment**

The GOTT's current investment in alternative energy, despite its position as a net energy exporter, demonstrates its commitment to sustainable development. The GOTT is working closely with the Environmental Management Authority (EMA) to limit environmental degradation from expanding industrial activity. Carbon-dioxide abatement internationally is not mirrored locally but informs T&T's energy policy. The GOTT seeks energy intensity reduction through technological efficiency on the demand side, and efficient electricity generation on the supply side.

#### **2.4.4.1.6 Training, research and development**

The country has a mature hydrocarbon industry whose development paralleled the international industry. Human and capital resources are well developed and the industry, including the oil-service industry, possesses a cadre of petroleum experts. As such, the country can export expertise and technology, and engage in technology transfer.

Budget restricts local research in energy technology, and it happens to a small extent in the University of the West Indies (UWI). Overseas training supplements this (that would mean me then).

## 2.5 Analysing the Green Paper

The Green Paper (GP) describes the GOTT's position on energy policy in very general terms and it is very light on details. This is probably because it is not yet a complete energy policy and its purpose is to invite public comment for reviewing and then formulating the complete energy policy. However, there have been no further developments in this area since the GP's release in April 1997.

Looking at T&T's short history since becoming an independent nation in 1962, there has never been a formal energy policy, although there must have been a *de facto* energy policy in effect, as the energy sector has been by far the largest foreign-exchange earner for over 30 years now. Compare this with the United Kingdom's (UK) recent policy history where policy changes punctuated major changes in the international and local energy industries:

- Gas Act, 1965: to promote and assist gas development and determine the manner for awarding exploration licenses.
- The Fuel Policy, 1967: to set gas price over concerns of the value of the Pound Sterling and the balance-of-payments.
- Gas Act, 1986: to privatise British Gas Corporation and have a policy position on export contracts with employment opportunities, greater exchequer revenues, and benefits to the balance-of-payments.

The energy-policy objectives listed in the GP, and the policy instruments to be used to develop the national energy policy in line with those objectives, are a little more specific than the corresponding ones for energy policy in general, given in Sections 1.1 and 1.2 at the start of this chapter. The State's primary energy-policy strategy is to be a facilitator in developing the energy sector, with more divestment to the private sector, and less direct investment, although the latter will continue in specific cases as needed. This indicates a move towards a freer energy market where an energy pricing policy is an essential tool to regulate the sector's operations (Ministry of Energy and Energy Industries, 1997). But the GOTT admits that energy prices in T&T are comparatively low and in many cases substantially subsidised since energy production is much greater than consumption.

Both the World Bank (WB) and the World Energy Council (WEC) have severely criticised subsidised energy prices (Berkovitch, 1996). The policy in developing countries of supplying energy at prices below production- and distribution-costs is done to help poorer consumers, sometimes venally as a political favour, or more virtuously to promote faster industrialisation. A WB report states that subsidies waste capital and energy resources on a very large scale, such that developing countries use about 20% more energy than if consumers paid the true marginal supply cost. This discourages investment in new, cleaner technologies and more energy-efficient processes. The WEC states that prices that cover production costs and externalities (i.e. environmental impacts) are likely to encourage efficiency, mitigate harmful environmental effects, and create awareness favourable to conservation. Although the GP does not explicitly say it, continuing energy-price subsidies



indicate that energy planning exists alongside, and is sometimes secondary to, other national plans, like political, social, and economic plans.

### 2.5.1 Specific problems with the GP

The policy to establish downstream gas-using industries to match current and future production capacities (Ministry of Energy and Energy Industries, 1997) must be a specious argument. This could mean, for example, an indeterminate number of LNG plants as long as the gas from the well head continues flowing sufficiently. Surely it should be the other way around – planned demand development downstream, with corresponding rigorous cost-benefit analyses, being the fillip for increased gas production upstream. Constructing ‘LNG plants to provide major outlets for upstream natural-gas production’ (Ministry of Energy and Energy Industries, 1997) is seeking to break the link between local natural-gas transformation industries (methanol, urea, etc.) and local natural-gas production. This will perpetuate the country’s current energy situation where most of its foreign earnings come from exporting primary energy products.

T&T exports 80% of its crude-oil production and the energy sector contributes 77% of the nation’s foreign-exchange earnings. Now that LNG gives a means for exporting natural gas, the country exports 40% of its natural-gas production. When the LNG Plant’s planned expansion of two additional trains come online this will rise to 66%. Thus, this represents no shift in energy policy with the discovery of relatively huge natural-gas reserves, just good fortune that gas has come in time to replace dwindling oil production and exports. One can say that the true policy determinant is the need to maintain foreign-exchange earnings, and T&T’s policy towards natural gas is more about economics than energy planning. Chapter 5 considers the LNG experience, but the short energy-industry history in T&T is enough to show the problem of having a single, large foreign-exchange earner, with a volatile market and prices. Hopefully ‘development’ in the GP statement ‘the State recognises the role the sector has played in the country’s development in the past and envisages an even more vital role for the sector in future development’ (Ministry of Energy and Energy Industries, 1997) means ultimately depending less on the energy sector.

There is plenty confusion in the GP about the terms ‘alternative energy’, ‘new energy’, ‘renewable energy’, and ‘cleaner energy’. I take it that alternative- and new energy means natural gas as opposed to oil, and that cleaner energy is compressed natural gas (CNG). The GP is misleading to mention CNG, as the GOTT has no plans to promote this after initially installing 13 CNG filling stations throughout the country in 1995 using the first-generation ‘slow-fill’ technology. Currently there is a programme of refurbishing fuel stations to international standards – car washes, small shops, computerised pumps – but CNG is not included. A single private company to date has plans to import CNG filling stations using a second-generation fast-fill method, which is about four times faster. But in the existing situation only ~1% of the 300,000 vehicles on the road has converted to CNG.

The GP states that sustainable development is an energy-policy goal, which ‘explains current investments in alternative energy in a petroleum exporting country with relatively low domestic petroleum-product prices’ (Ministry of Energy and Energy Industries, 1997). Alternative energy here must mean natural gas as I found no spending in any programme in renewable energy. The policy on renewable energy to do it all locally seems unlikely to succeed. There is one precedent in the Caribbean – solar water heating in Barbados, where conventional-energy prices are high. There are two competing factories producing very simple, reliable water-heating systems using the thermo-siphon effect. The manufacturing inputs are also very basic and the factories are labour-intensive and hardly mechanised. As a result of this and government subsidies that helped to kick-start the industry, almost every building in Barbados, including businesses and hotels, has a solar hot-water system and the factories are profitable going concerns providing employment. There is no hint of a similar initiative in T&T.

It is also unusual to refuse to import any of the renewable-energy technologies without first doing a cost-benefit analysis, especially as T&T is deficient in research and development in this area, and most of these technologies are now highly sophisticated and well beyond local manufacturing capabilities. In any case, T&T’s current energy industry, both production and transformation, is almost completely run by foreign companies. The policy on renewable energy seems certain to prevent any progress in this area unless the GOTT has more detailed plans not mentioned in the GP.

The GP mentions demand-side management (DSM) on three separate occasions and stresses its important role in reducing the energy sector’s impact on the environment. The GP states that ‘the first major step in this direction [i.e. DSM] is setting up an efficient and timely database, supported by an effective energy pricing policy’ (Ministry of Energy and Energy Industries, 1997). This is too little information to reveal the plan for DSM, for example – what is the content of the database? The MOE is also to work closely with the EMA over environmental concerns but the EMA, formed in 1994, was only given the power to devise legislation towards the end of 2000. The GP also pays lip service to sustainable development.

Finally, for meaningful comments on ‘the efficient reserve-depletion policies and exploration programmes’, on ‘using imported electricity from the region’, and on ‘natural-gas pipeline distribution programmes to reach industrial, commercial, and domestic users’ much more detail is needed. These are very important areas of any energy policy emerging from the GP.

So in summary, T&T does not have a formal energy policy as yet. The energy sector has undergone a fundamental shift from oil to natural gas as the major fossil fuel, and this appears to be the reason for devising the GP. T&T’s basic approach to the energy sector has not changed however, constrained as it is by its critical role as a foreign-exchange earner. In the absence of a formal policy it is difficult to discern any comprehensive government plan, or even to get enough details for more than speculations. The GOTT must certainly have estimates of how long the country’s fossil-fuel reserves will last, and

although this may be beyond the GP's planning horizon, have they tackled the question of what they will do when these are depleted?

This thesis explores a single energy policy proposal – natural-gas cogeneration. It focuses on the industrial sector but cogeneration should be as widespread as possible. The research began in 1997 so this is taken as the base year, but uses relevant updated data whenever available.



## Chapter 3. World energy

### 3.1 Global energy supply and demand trends

There has been a worldwide historical trend towards more efficient energy use to meet human needs. The ultimate goal is to derive all energy from renewable, non-polluting sources. Successively cleaner, more efficient, primary energy sources replace existing ones (Figure 10), ultimately moving from solid- and liquid-based to gas-based fuel systems, i.e. wood→coal→oil→gas. This suggests that gaseous fuels will be the most popular energy source this century. New energy sources emerge, coinciding with the dominant, competing source saturating and declining. Figure 10 shows that new energy sources replace the dominant ones almost every 100 years on a global scale.

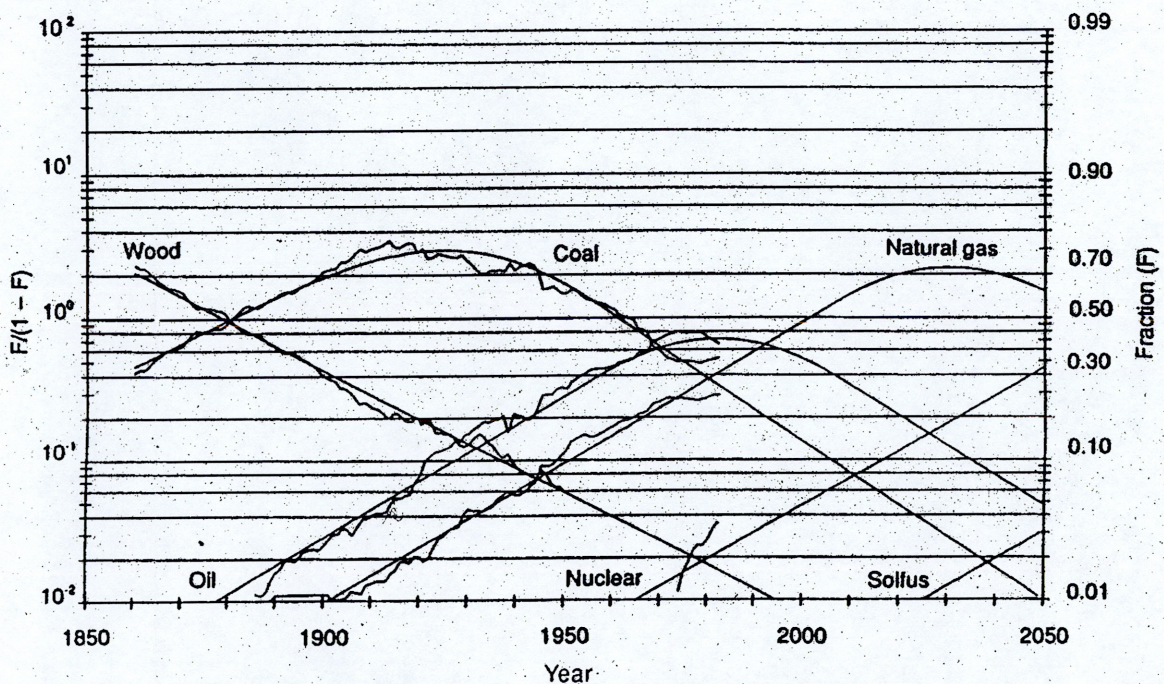


Figure 10. Global primary energy substitution (Howell, 1993).

Part of the trend towards gaseous energy sources is energy decarbonisation, i.e. using energy sources with higher hydrogen to carbon ratios (Figure 11), resulting in carbon dioxide-emission ( $\text{CO}_2$ ) reduction per unit primary energy and per unit economic activity. A natural gas (methane) primary energy scenario achieves high decarbonisation rates. Table 3 compares the carbon content of different energy sources, in tonnes of carbon per unit of energy derived from each source, where that unit of energy is kilowatt-year ( $\text{tC/kWyr}$ ). A methane economy achieves gradual, continued global energy decarbonisation as a transition to an ultimately carbon-free future.



| Energy source | Tonnes of carbon per kilowatt year of energy, tC/kWyr |
|---------------|-------------------------------------------------------|
| Wood          | 0.844                                                 |
| Coal          | 0.735                                                 |
| Oil           | 0.849                                                 |
| Natural gas   | 0.442                                                 |

Table 3. Carbon content for different energy sources (Howell, 1993).

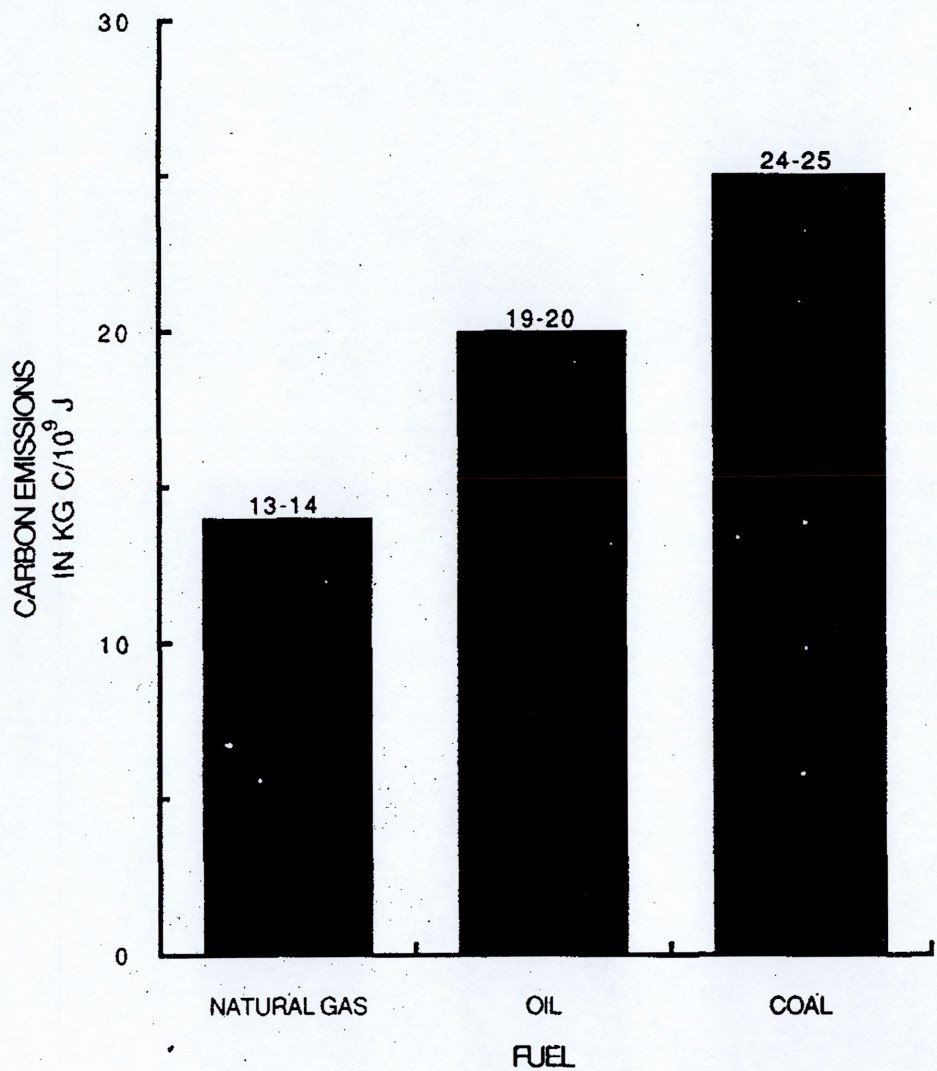


Figure 11. Carbon emissions in kgC/GJ for natural gas, crude oil, and coal (Howell, 1993).

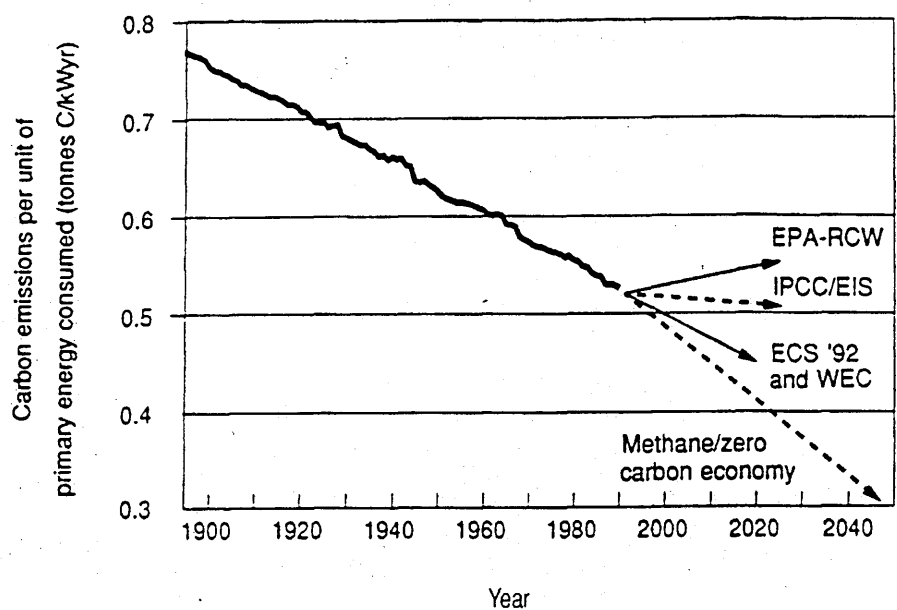


Figure 12. Global energy decarbonisation, in tC/kWyr of primary energy consumed, since 1900 AD and scenarios for the future (Howell, 1993).

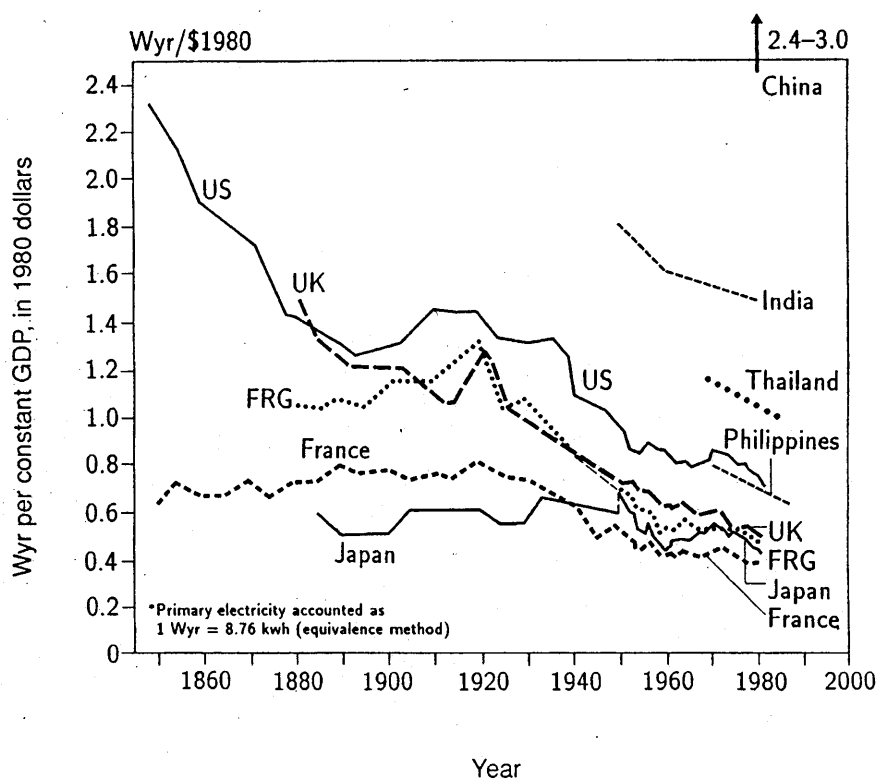


Figure 13. Primary energy intensity, including biomass, of value added in kilowatt year (kWyr) per constant gross domestic product (GDP) in 1980 dollars (Howell, 1993).

Besides energy decarbonisation, energy intensity in economic activity is steadily decreasing, even for developing countries who benefit from the experience of the developed countries, by following a similar development path (Figure 13, Figure 14, and Figure 15). In Figure 15 each country follows a bell-shaped curve of energy intensity in economic activity with time, roughly the case in Figure 13. The curves become progressively flatter as countries that start developing later learn from the mistakes of those that started earlier.

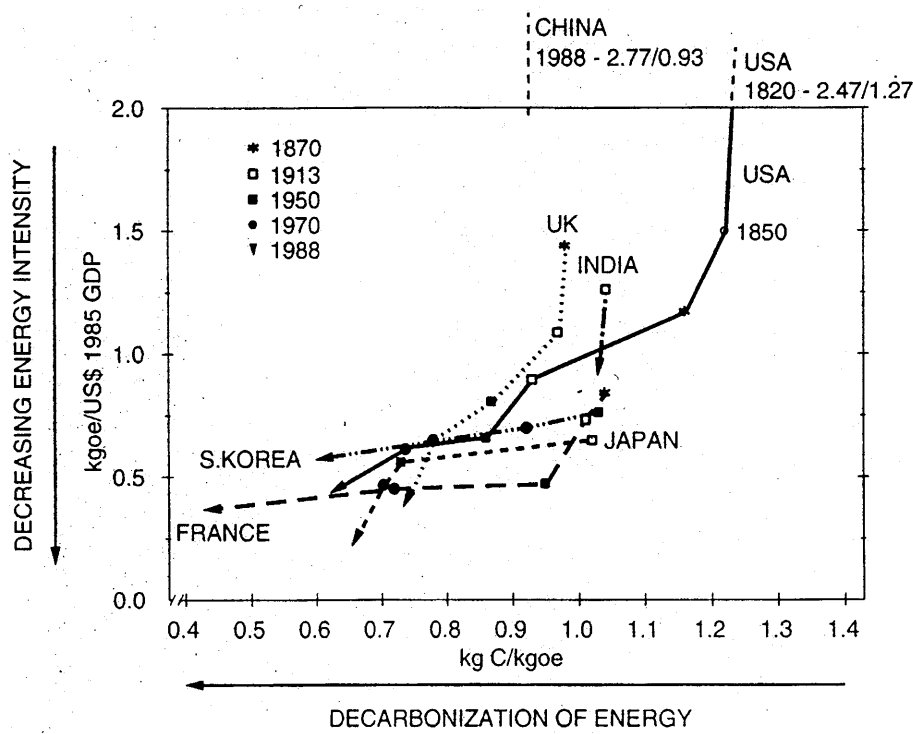
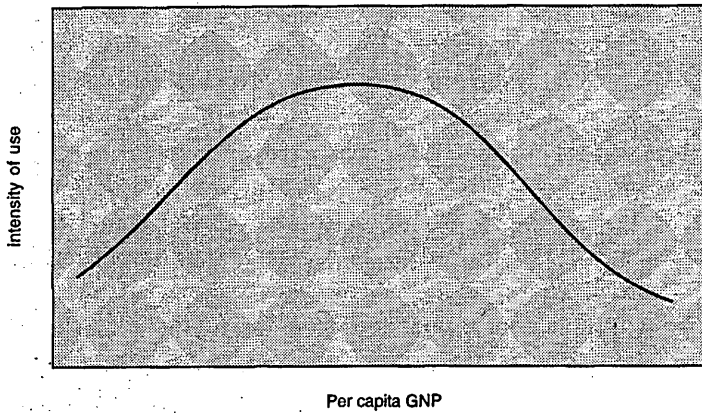
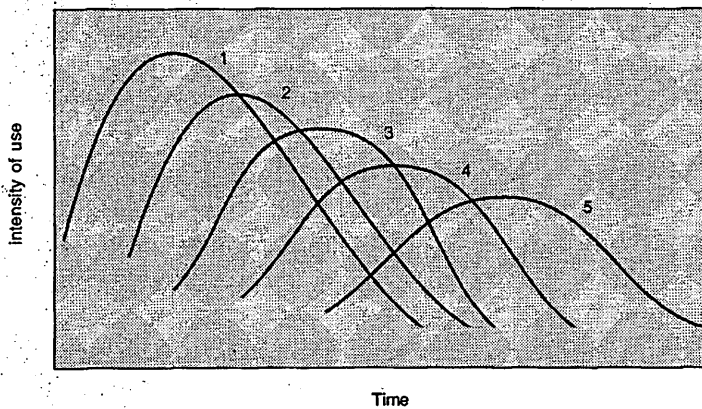


Figure 14. Global decarbonisation in tCToe, and global energy de-intensification in toe per US\$ million GDP (oe = oil equivalent) (Howell, 1993).



(a) bell-shaped curve showing intensity of use against GNP



(b) développement of intensities of use in different countries (1-5) over time

Figure 15. 'Natural' energy de-intensification (Jackson, 1996).

### 3.2 Energy outlook

Figure 16 compares energy-demand trends in countries of the Organisation for Economic Co-operation and Development (OECD), and countries with emerging marketing economies (EMEs) or developing countries. These exclude Central Europe and the Former Soviet Union, as defined by BP Amoco (2001). In 2000 the OECD accounted for 59.1% of the World's primary energy consumption, and EMEs 29.2%. The International Energy Agency (IEA, 1994) predicted that developing countries would be responsible for ~40% of World primary energy use by 2010.



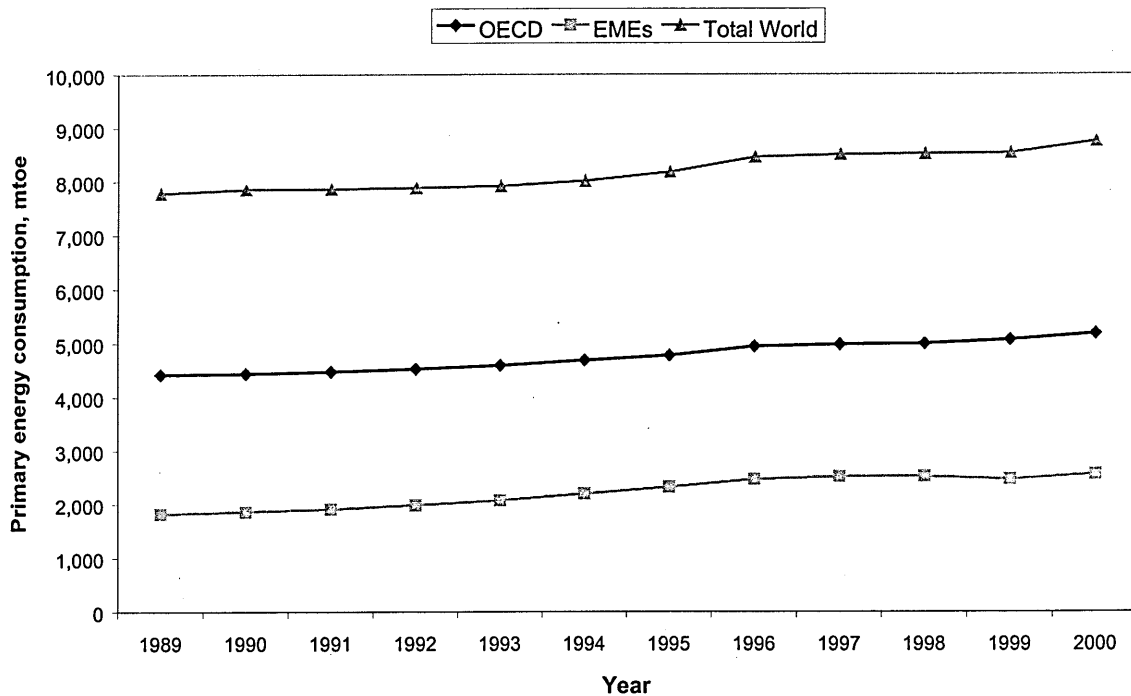


Figure 16. Primary energy consumption, mtoe (BP Amoco, 2001).

Figure 17 shows that world energy-demand projections over the next fifty years vary by more than a factor of two. This is primarily due to assumptions about energy efficiency trends and demonstrates the uncertainty in forecasting energy industries. Energy demand in all developing countries is forecasted to increase on average by about 4.2% per annum up to 2010 AD (IEA, 1994). By then it would have more than doubled the 1990 figure, and at 4,500 million tonnes of oil equivalent (mtoe) would account for two thirds of the world increase in energy-demand. Economic expansion in Latin America over the next 15 years is expected to be around 4% per annum. The figure for T&T, considered as part of Latin America, was actually over 5% in 1999 (Ministry of Finance, 2000).

In countries with their own natural gas resources, and the industries to exploit them, the natural-gas share of energy demand rapidly increases (Howell, 1993). Natural gas substitutes oil, partly to increase oil exports, and expands petrochemical production capacity. So the industrial sector accounts for a major share in the final energy demand, and the forces driving this are critical to understanding the total energy situation and its likely evolution, with or without an energy policy.



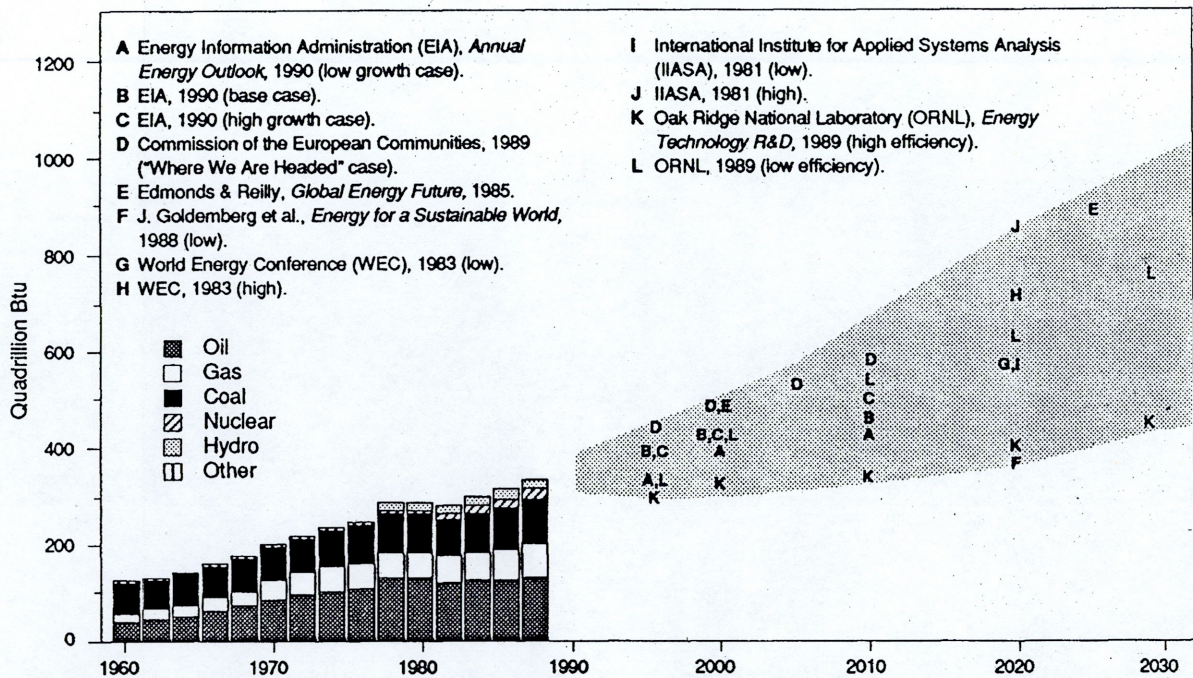


Figure 17. World energy demand projections. (IEA, 1994)

### 3.3 Global natural gas resources

Methane exists in variable concentrations throughout the Earth's atmosphere, water and rock. It is less dense than air at standard conditions. Throughout the Earth's crust it can be found at temperatures up to 800°C and can exist as deep as 18 kilometres. Natural gas is primarily methane, with small amounts of ethane, propane and butane. Methane is the simplest hydrocarbon. About half of the energy from burning comes from carbon, the other half from hydrogen. Until the early 1970's natural gas was mainly considered at best a marginally economic oil industry by-product.

In 1990 fossil fuels supplied 80% of the world's energy demand (Howell, 1993). They remain more convenient than competing primary energy sources such as renewable energy sources. These have shortcomings like intermittent availability, they are not storable or transportable by themselves, and cannot be used as a fuel for the transportation sector. New natural gas discoveries have outpaced oil discoveries globally. To date conventional natural gas resources worldwide are recoverable in about the same quantities as crude oil but natural gas consumption in energy terms are about half of oil consumption. Compared to the year-2000 2.3 trillion m<sup>3</sup> per year world consumption rate, the identified 146.43 trillion m<sup>3</sup> *conventional* natural-gas reserves (BP Amoco, 2001) are huge. And with about the same amount to be discovered there is nearly a 125-year conventional natural gas supply. Absolute finiteness is not a problem for the next 100 years. At any stage a lesser cost fuel may replace gas in the energy mix, but the large natural gas resource potential is



sufficient to warrant substantial reliance on the physical source for many decades to perhaps as long as a century in the future (Howell, 1993).

### 3.4 Global energy and the environment

Small changes in the atmosphere's chemistry have a profound impact on living organisms (Howell, 1993). The current dry atmosphere comprises 78% nitrogen, 21% oxygen, and 1% trace gases (0.93% argon, 0.035% carbon dioxide, 0.0001% methane, 0.00005% hydrogen). The greenhouse effect is the warming that occurs when certain atmospheric gases – primarily water vapour, CO<sub>2</sub>, methane, nitrous oxides, carbon monoxide, and ozone – trap infrared radiation near the Earth's surface. As a result the average surface temperature is 14°C to 15°C whereas it would have been -18°C without this effect. Thus the greenhouse effect is a natural phenomenon and made the Earth habitable in the first place.

Humans burning fossil fuels release CO<sub>2</sub> and contribute to the greenhouse effect, called an *anthropogenic* contribution. CO<sub>2</sub> emissions represent the largest waste mass flow into the environment compared to all other anthropogenic waste. Energy-related CO<sub>2</sub> emissions currently stand at 6 gigatons (GtC) per annum (Howell, 1993). Compare this to the global steel production at ~700 megatons (Mt) for an idea of scale. Fossil fuel CO<sub>2</sub> emissions are the largest human source. The global CO<sub>2</sub> contributions from the different fossil fuels are: 45% from coal, 40% from oil, and 15% from natural gas. The CO<sub>2</sub> concentration in the atmosphere increased by 25% since the industrial revolution, and methane increased exponentially (Figure 18 and Figure 19). Atmospheric methane concentration doubled over the past 200 years and currently increases at 1% per annum, about three times the rate of increase for CO<sub>2</sub>. Both are greenhouse gases, methane the more potent by far – it has 21 times CO<sub>2</sub>'s greenhouse effect. Methane may also contribute to stratospheric ozone depletion. It is also harmful to the atmosphere's oxidising capability, which normally serves as a tropospheric vacuum cleaner and controls pollutant build-up. Methane has a 10-year residence time in the atmosphere; CO<sub>2</sub>'s residence time is 200 to 500 years.

Still there is some doubt about the human contribution to climate change. Over the past 100 years the mean global surface temperature rose by 0.5°C (Howell, 1993). It is not clear if this is related to the greenhouse effect or part of a natural warming trend that began about 500 years ago. Nevertheless, persistent surface temperature rise causes changes in regional precipitation patterns, temperature, and cloud cover. The sea level rises from thermal expansion and from polar ice caps melting.

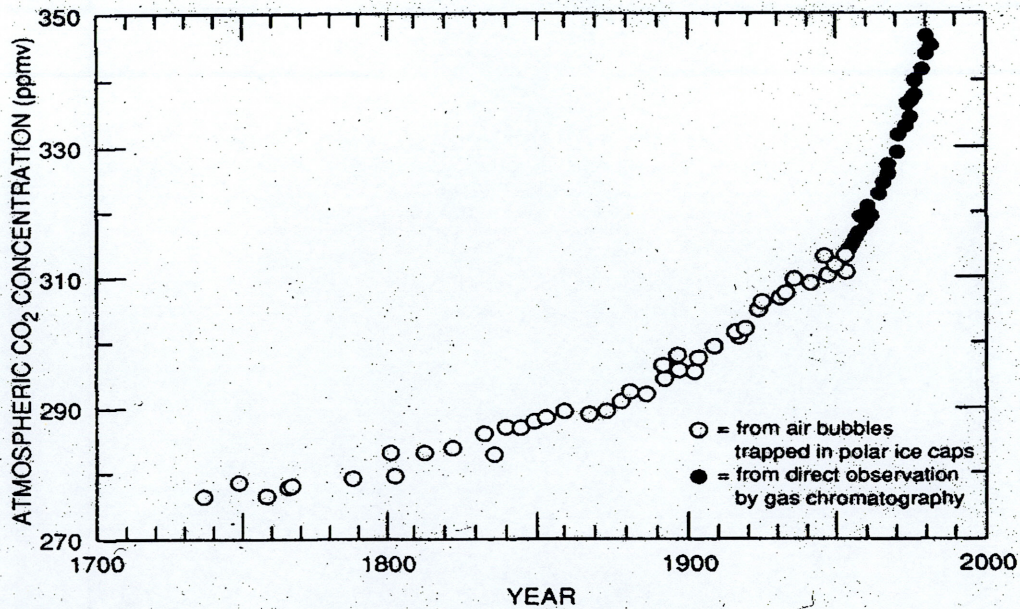


Figure 18. Trends in atmospheric CO<sub>2</sub> concentrations, in parts per million by volume (ppmv) since 1700 AD (Howell, 1993).

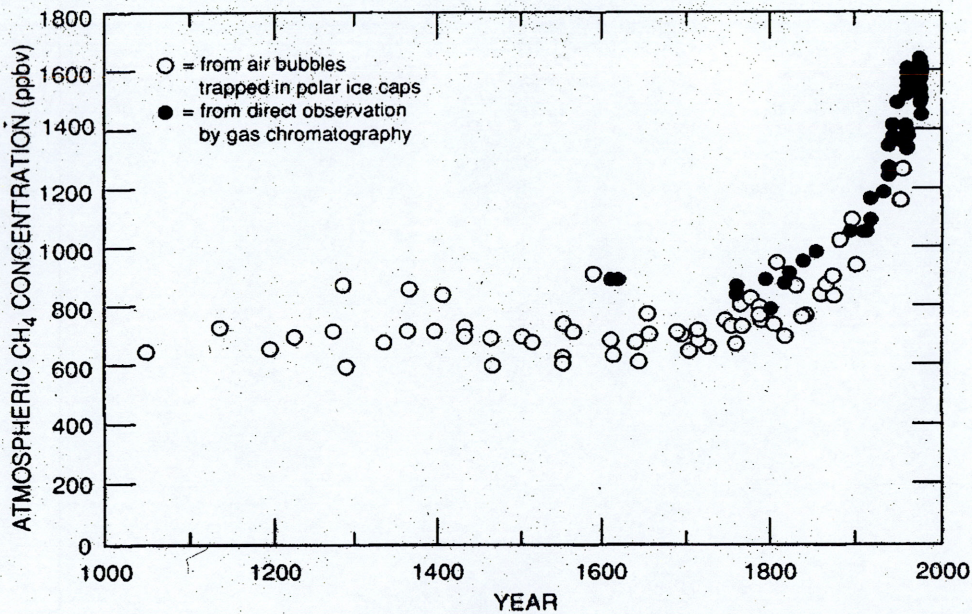


Figure 19. Trends in atmospheric methane concentrations, in ppmv since 1000 AD (Howell, 1993).

Currently 80% of humanity shares less than 20% of global wealth. Equally, 80% of the world's population accounts for just 20% of carbon and methane emissions (Howell, 1993). Figure 20 shows the year-2000 per capita primary energy consumption in tonnes of oil



equivalent for different regions. World population is now growing at ~2% per annum, and the long-term figure since 1800 AD is ~1% per annum. Population is expected to double this century according to World Bank and United Nations projections. The implications to global environmental health are serious considering development expectations of third world countries. Although these countries have per capita GNP and energy consumption that are far lower than those of typical industrial countries, their energy efficiency is also generally lower and the growth rate in demand for energy services is far higher. Between the years 1983 and 1998 annual growth in energy consumption averaged 5.4% in developing countries and 2.3% in Eastern Europe, compared to an average of 0.9% in OECD countries. There is a need to reconcile the opening gap between energy needs for development and reducing emissions. Economic- and social-development are strong determinants of future greenhouse gas emissions and current trends are unsustainable.

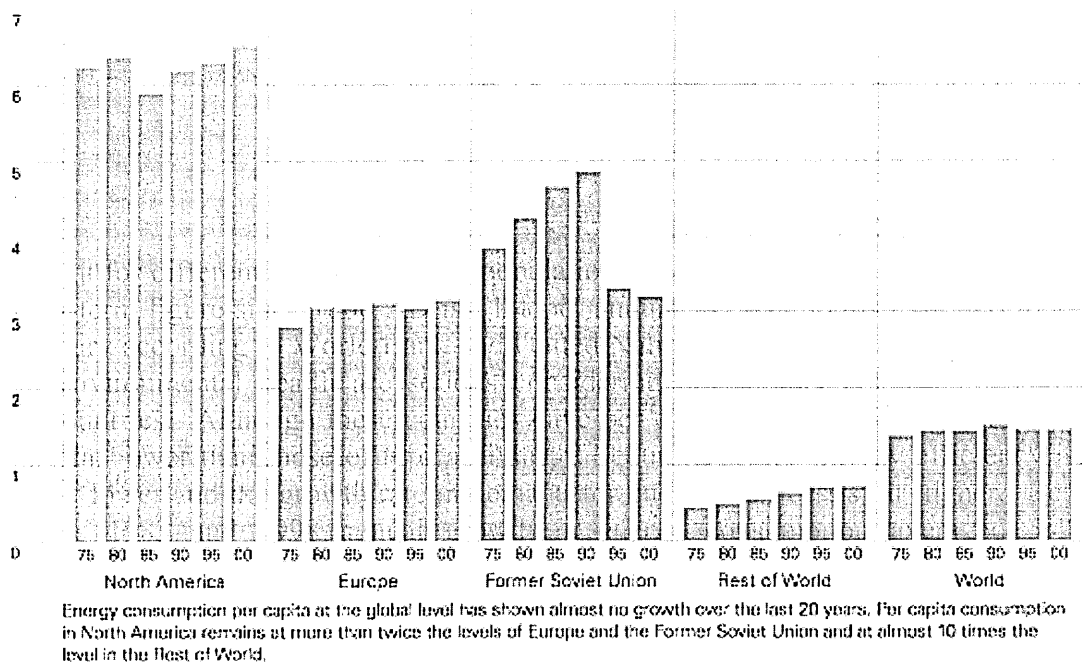


Figure 20. Annual primary energy consumption per capita in toe (BP Amoco, 2001).

Recognising this, 153 countries signed a Framework Convention on Climate Change following a summit in Rio de Janeiro in 1992. They agreed *inter alia* to reduce greenhouse gas emissions as a precautionary principle towards arresting climate change, regardless of doubts about the extent of the human effect. Agenda 21 determined that global environmental quality and economic health are tightly linked and that development should be sustainable, i.e. meets present needs without compromising the ability of future generations to meet theirs.

### 3.5 The case for natural gas

There is increasing evidence of multiple economic and geopolitical benefits from a worldwide shift to natural gas (Howell, 1993). This assumes no new nuclear installations

so natural gas has the lion's share of primary energy for the next 50 years. Three strong indications of an early natural gas future are:

1. New natural gas markets are developing through increasing environmental concerns.
2. Natural gas resource discoveries are far outpacing consumption.
3. Gas hydrates and ultra-deep natural gas discoveries have revealed that there are vast methane occurrences throughout the Earth's crust.

Since the bulk of anthropogenic greenhouse gases come from burning fossil fuels, substituting other fossil fuels with natural gas could reduce our contribution to climate change (Figure 11), i.e. natural-gas use as global warming mitigation. Burning natural gas produces 25% less CO<sub>2</sub> than burning oil (Howell, 1993). A natural gas vehicle compared with one run on gasoline produces 24% less CO<sub>2</sub>, and 90% less reactive hydrocarbons and carbon monoxide, which are main contributors to photochemical smog. Natural-gas vehicles are already feasible and the fuel is cheaper. The economics are particularly favourable for public transport and private fleets. Also natural-gas vehicles produce 20% to 50% less nitrous oxides and no sulphur dioxide, resulting in less acid precipitation. Natural-gas-fuelled, combined-cycle electricity generating plants emit 50% less CO<sub>2</sub> than conventional oil-fuelled plants. Natural-gas combustion produces practically no particulates which, along with lower acid precipitation, helps reduce pollution (a more local adverse ecological effect as opposed to global climate change).

Recent global estimates reveal annual rates of decarbonising energy at ~0.3%, and reducing energy intensity of value added GNP at ~1%. But with annual global economic growth at ~3% this cannot offset global CO<sub>2</sub> emissions, which are increasing at ~1.7% per annum, so doubling by 2030 AD. The lower dashed line in Figure 12 suggests that even higher decarbonisation rates are needed to offset future global population and economic growth. This rate should be 0.8% to 1.4% per annum, 2 to 4 times the rates achieved in the past. Increased substitution with natural gas, a 'methane economy', is a step towards this. Figure 21 shows scenarios of primary energy consumption in the methane economy, Figure 22 shows the resulting decarbonisation rates, and Figure 23 shows the resulting global effect on the atmosphere.

But natural-gas production releases methane, with worldwide leakage from production and distribution systems accounting for 7% to 8% of global emissions from all sources, and 11% to 12% of all anthropogenic methane emissions (rice paddies, landfills, animal stomachs). Other sources are natural surface seeps, ocean vents, and wetlands. Natural-gas exploration and production uses the same oil infrastructure and so disrupts ecosystems, has leakage problems, is inflammable and potentially explosive under compression, and is a fire hazard in the home and on the rig. Conversely, it is impossible to pollute ground- and surface-water, as natural gas is lighter than air.



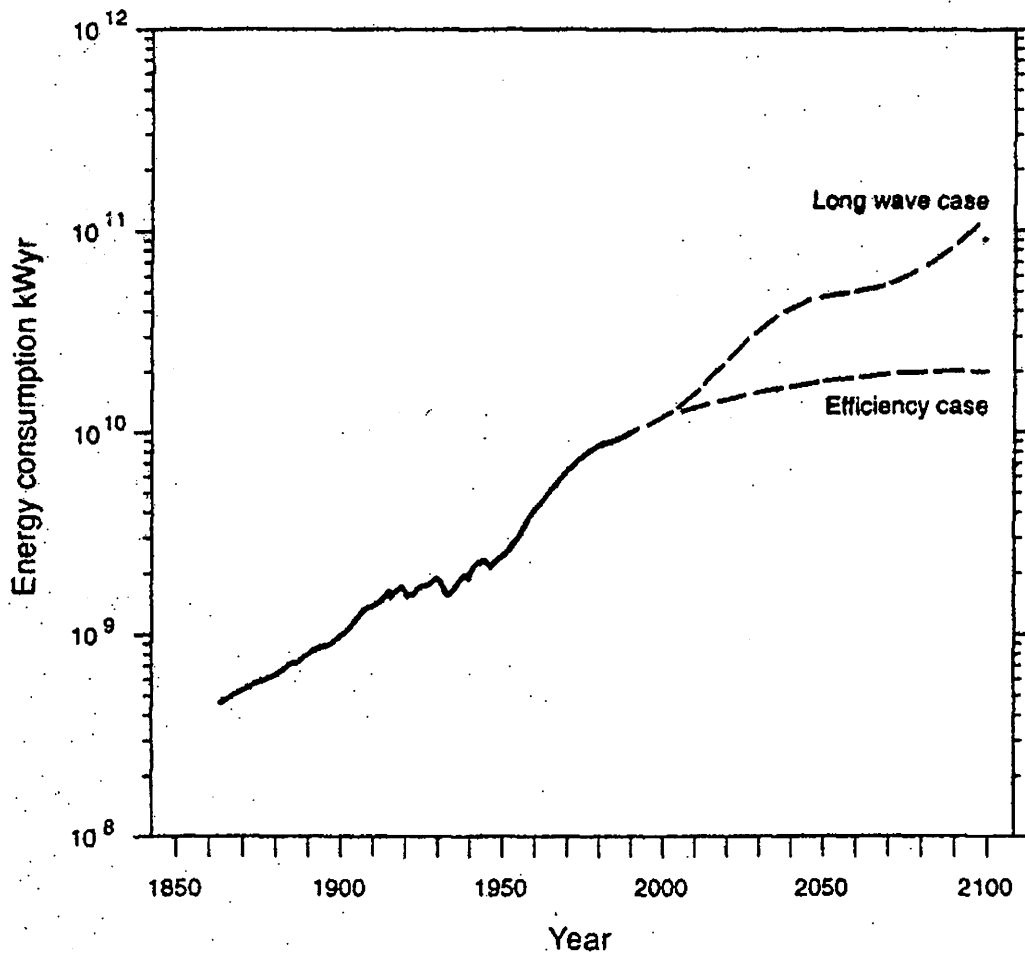


Figure 21. Primary energy consumption historically and forecasted for two variants in the methane economy scenario (Howell, 1993).

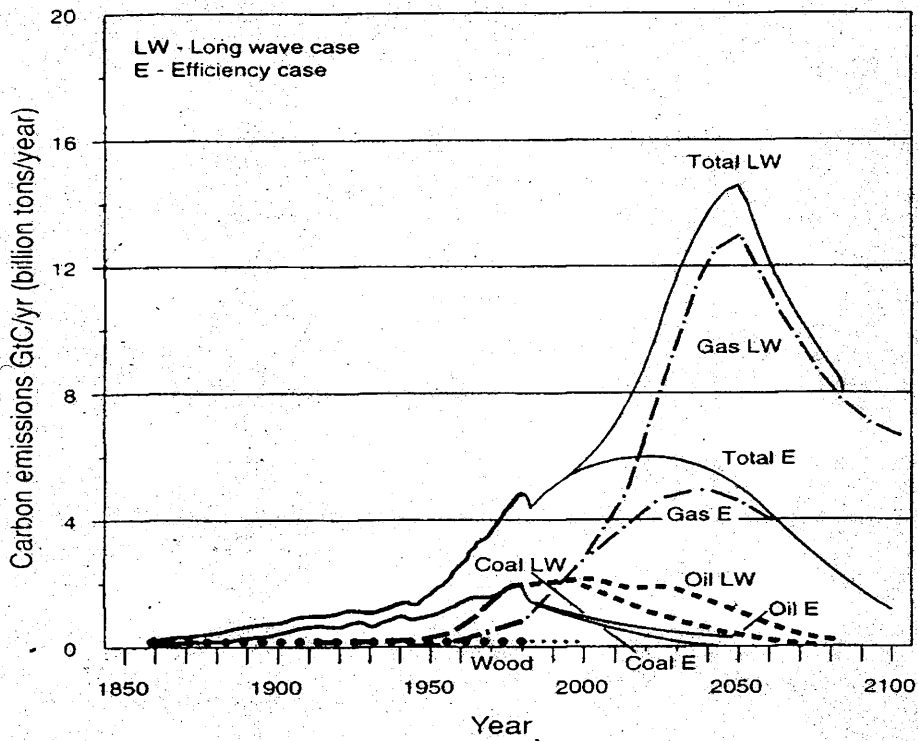


Figure 22. Global CO<sub>2</sub> emissions in gigatons of carbon per year (GtC/yr) for scenarios in Figure 21 (Howell, 1993).

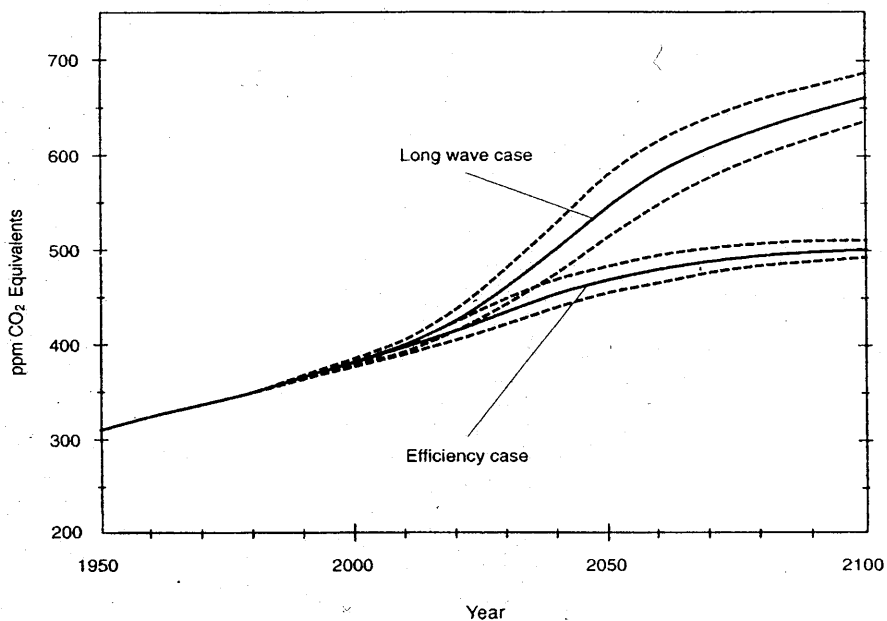


Figure 23. Atmospheric CO<sub>2</sub> and CH<sub>4</sub> concentrations from the 'methane economy' scenarios, as CO<sub>2</sub> equivalents in ppm (Howell, 1993).

As the intrinsic value of natural gas to the economy increases infrastructure will improve and leakage become insignificant, especially relative to methane loss from oil production and handling. Historically, during the initial years in an energy source's development, associated technology grows exponentially, economic efficiency is enhanced, productivity increases, and a new, long wave of economic growth starts. The late 1920's were the oil technological innovation period (rotary drill bit, advances in exploration and refining, improvements in the internal combustion engine), leading to today's developed economy. Natural gas is now beginning its technological innovation at all stages – exploration to end-use - as seen in non-conventional natural-gas production, natural-gas vehicles and natural-gas fuel cells. Methane emissions from natural gas production do not pose a major problem in the future provided leakage rates remain below 4% of gas consumption (Howell, 1993).

The ultimate energy-gas future is a hydrogen one, i.e. hydrogen as an energy carrier regardless of the primary energy source. The ultimate goal is hydrogen derived from renewable energy sources. Hydrogen is the most efficiently burning fuel in all applications, and is the cleanest environmentally when it comes from water. Energy transport over great distances by pipeline is more efficient than by electricity (Howell, 1993). So natural gas is a bridge to future energy systems. Increasing natural-gas use now puts down infrastructure for the present and the future: storage capability, pipelines and distribution facilities, the technologies to use natural gas in homes, industries, electricity utilities, aeroplanes, cars. Natural gas and its supply and distribution infrastructure generally:

- Reduce greenhouse gas emissions
- Generate minimal solid and liquid waste during production, transportation and consumption
- Serve as a transition fuel to a renewable energy future
- Provides an industrial base for developing more environmentally conscious technologies

T&T's current natural-gas infrastructure is completely dedicated to industry. Though this thesis focuses on the industrial sector, it proposes a policy that will extend natural gas to all energy-use sectors. Figure 24 shows historical and forecasted worldwide natural-gas consumption in tcf. These forecasts were made in the year 1985 and the large variation in the different forecasts, and between forecasted and actual consumption since then, demonstrate the uncertainty in short- and medium-term forecasting in the natural-gas industry. The implication for policy-making is the need for flexibility, the ability to shift emphasis and focus as needed, over a range of options for using natural gas. T&T's posture must be reactive (as opposed to proactive) given our insignificant reserves on a global scale.

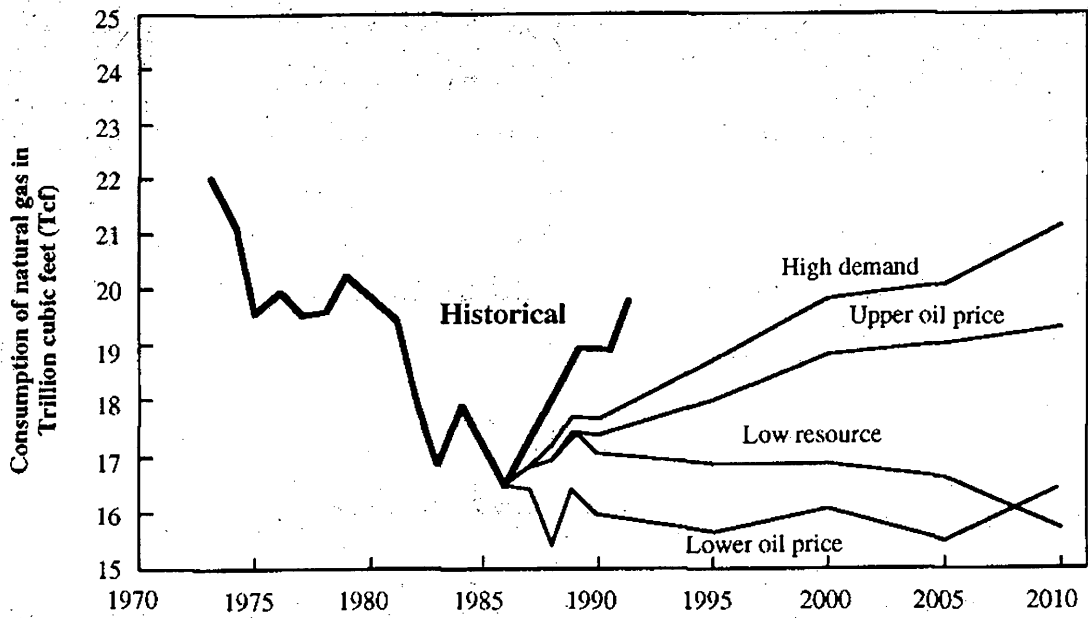


Figure 24. Annual natural-gas consumption in tcf from 1970 to 2010 (Howell, 1993).



# Chapter 4. Trinidad and Tobago energy

Trinidad and Tobago’s (T&T) fossil-fuel resources are oil and natural gas. Figure 25 shows the country’s proven reserves and production between 1970 and 1996 in equivalent energy terms (barrels of oil equivalent, boe). It shows that while oil is declining, gas is in the ascendancy. T&T’s economy still depends heavily on the oil export-price, as oil exports still earn significant foreign exchange revenues, also natural gas is priced relative to oil. The natural-gas statistics are relevant to this thesis as it focuses on natural gas cogeneration. Most of the oil produced is exported, and the country actually imports crude oil for refining. Before the Atlantic LNG plant began operating in 1999, providing a means for exporting natural gas, local natural-gas consumption drove production.

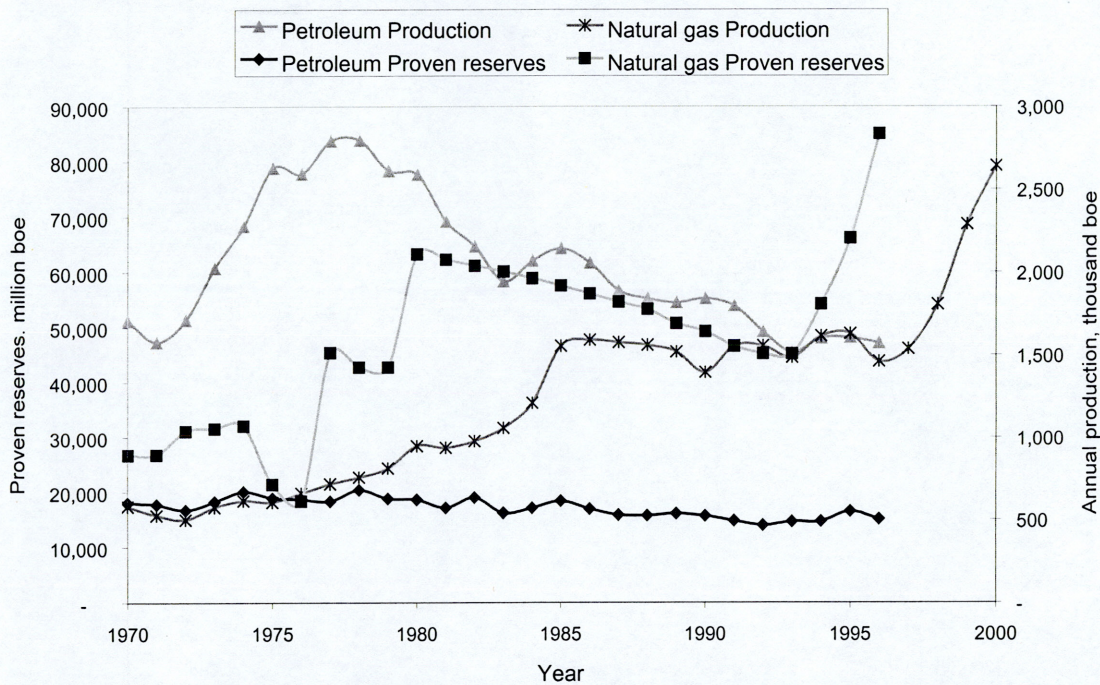


Figure 25. T&T’s oil and natural gas reserves and production (OLADE, 1998 & BP Amoco, 2001).

Notice that the reserves/production (R/P) ratio updates every year from production changes and from finding new reserves. For example, according to the R/P ratio, oil should have been depleted within 10 years for the past 30 years from Figure 26.



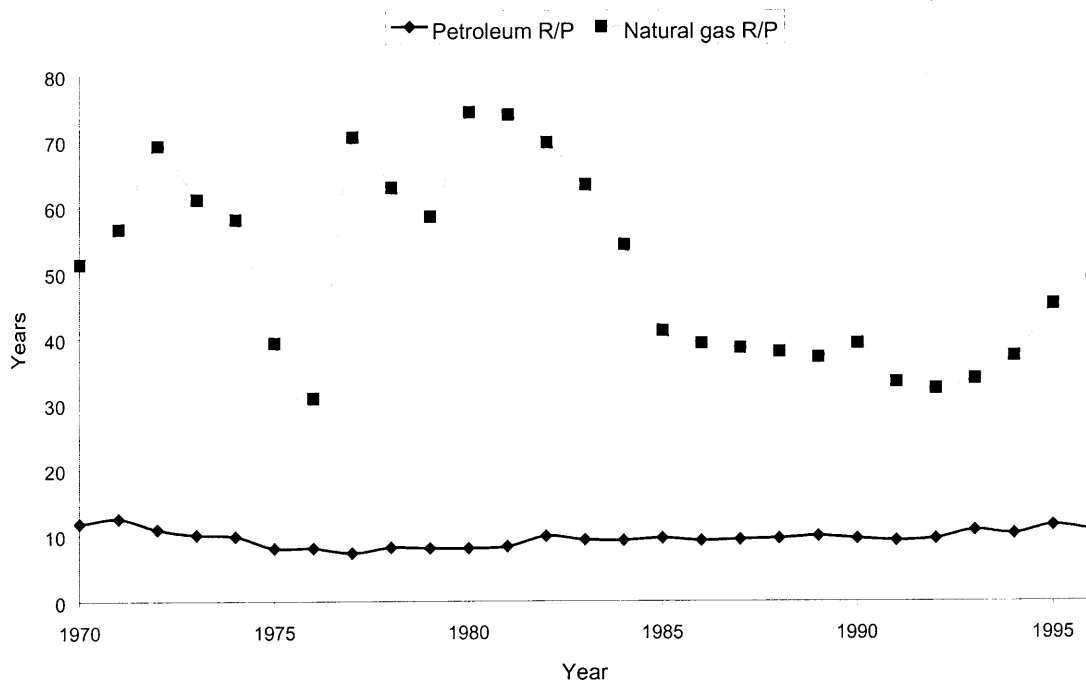


Figure 26. T&T's oil and natural gas reserves/production ratio (OLADE, 1998).

## 4.1 Natural gas

The Government of Trinidad and Tobago (GOTT) established the National Gas Company of Trinidad and Tobago Limited (NGC) in 1975, a fully State-owned company. The Company's core business is compressing, purchasing, transporting and selling natural gas. Figure 25 shows annual natural-gas production between 1970 and 1996. Practically all electricity in T&T is generated using natural gas; this started in the early 1970s. A State-owned ammonia plant, the first large petrochemical plant using natural gas for the process (and also as fuel), started operating in the 1977.

In 1997 NGC sold daily on average 20.1 million m<sup>3</sup> of natural gas. This is 5% up on 1996's daily average of 19.1 million m<sup>3</sup>. 87.2% of this went into petrochemical production, power generation, and reducing metal ore. The rest went into natural-gas processing, refining, cement production, and the light industrial/commercial sector. T&TEC took an extra 7.7% over their 1996 off-take due to expansion in the country's only iron and steel plant. Of the natural gas sold to industry in 1997, 57.1% went into petrochemical manufacturing, 23.4% into power generation, 6.7% into reducing metal ore, 6.7% into refining, 2.4% into gas processing, and the remaining 3.6% into other activities. In 1997 NGC had 100 customers, 83 of them in the light industrial/commercial sector.

BP Amoco (2001) figures, displayed from 1997 onwards in Figure 25, reveal accelerated natural-gas use in the years after 1997. Average daily natural-gas production was 23.6

million m<sup>3</sup> in 1998, 29.9 million m<sup>3</sup> in 1999, and 34.5 million m<sup>3</sup> in 2000. This represents corresponding increases on the previous year of 17.4%, 25.7% and 15.3%. The largest increase in 1999 over 1998 is due to the Atlantic LNG plant commissioning in 1999. It uses on average 12.6 million m<sup>3</sup> per day but only began operating in September of that year.

Natural-gas sales from 1975 to 1995 increased at an 8% average annual rate. Between 1997 and 2001 NGC projected sales to increase by 12% to 14% compounded rate, reaching 32.2 million m<sup>3</sup> per day by 2001 (The National Gas Company of Trinidad and Tobago Limited, 1998). BP's figures show that these projections have already been exceeded.

According to BP Amoco (2001) T&T's proven natural-gas reserves stood at 600 billion m<sup>3</sup> at the end of 2000, or 0.4% of global proven reserves. T&T's population at the end of 1996 was ~1,269,000, and with an average annual population growth-rate of 0.83% since 1971 (OLADE, 1998), the population in 2000 cannot be more than ~1,311,658. This represents ~0.02% of an estimated 6 billion world population. So in per capita terms T&T is very rich in natural-gas resources. Sill, T&T's 48.2-year R/P ratio for proven natural-gas reserves at the end of 2000 is less than the global 61-year ratio. Ram (2000) estimates that this can fall by half with the planned expansion in LNG.

#### 4.1.1 Compressed natural gas

One area where natural gas still has largely untapped potential for substituting oil as a fuel is transportation. The main incentive for using *compressed natural gas* (CNG) instead of gasoline and diesel in internal combustion engines is its vastly improved environmental performance. CNG is also cheaper; Figure 27 shows alternate energy prices in T&T effective January 1, 1997.

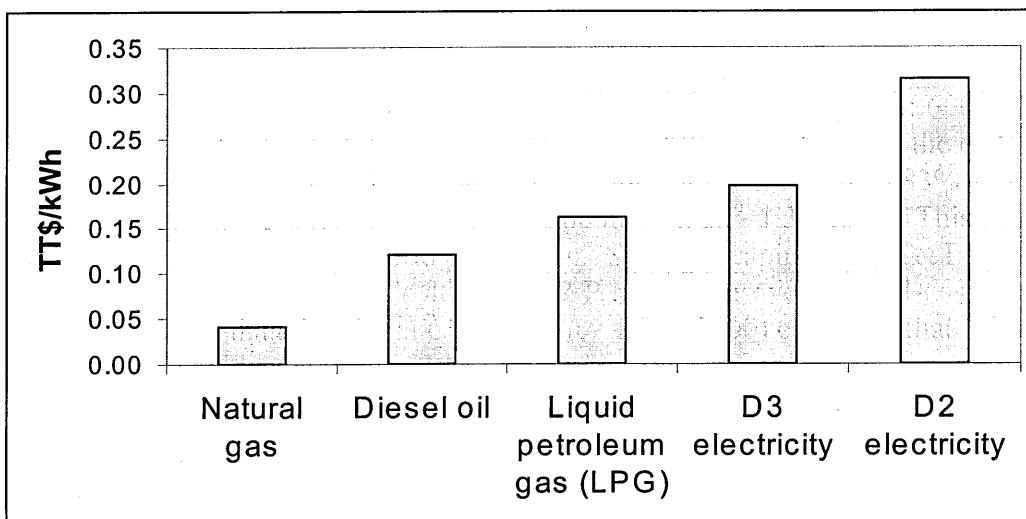


Figure 27. Alternate energy prices in T&T (NGC, 1998).

The GOTT began a CNG pilot programme in 1994 but abandoned it in 1999. Figure 28 shows the programme’s results up to 1998. By 1998 the programme had installed 11 ‘slow-fill’ stations and 2 ‘fast-fill’ stations throughout the country, and about 3,500 cars had converted to CNG. The slow-fill station fills a car in nine minutes, whereas a fast-fill station fills two cars in about four minutes. With about 300,000 vehicles on T&T’s roads in 1999, the potential for converting cars to use CNG is large with just about 1.2% already converted.

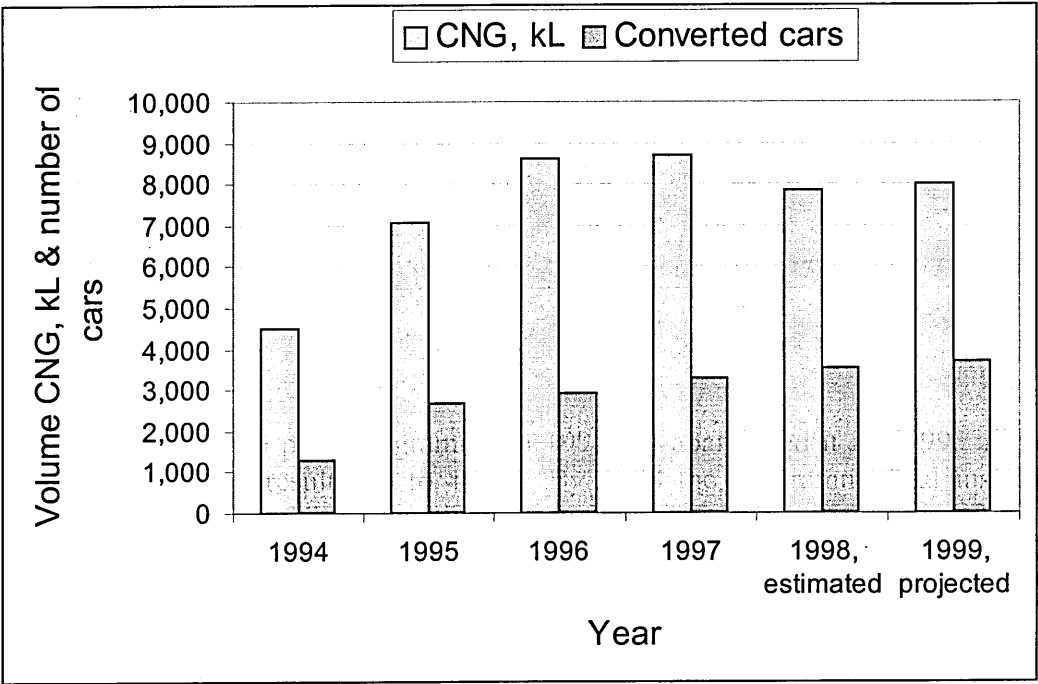


Figure 28. Summary T&T CNG data, actual and forecasted (Chung and Joyeau, 1999).

4.2 Electricity

The State-owned national electricity utility, the Trinidad and Tobago Electricity Commission (T&TEC), was responsible for generating, transmitting and distributing all of the nation’s electricity until 1995. In 1995, T&TEC divested power generation to a single private company, PowerGen. Natural-gas turbines generate practically all electricity at three separate sites (Port of Spain, Point Lisas, and Penal) at an overall 26.1% average efficiency (Table 4). All of the turbines except those at Penal, are simple-cycle turbines. The Penal installation comprises combined-cycle turbines and contributes 236 MW out of the total 1189 MW installed capacity, at 34% to 37% power-generating efficiency. There is currently no significant independent power production or cogeneration in T&T.

| Year | Total customers | Sales, GWh | Maximum demand, MW | Total installed capacity, MW | Overall generating efficiency, % |
|------|-----------------|------------|--------------------|------------------------------|----------------------------------|
| 1983 | 250,500         | 2,521      | 470.9              | 987.0                        |                                  |
| 1984 | 259,000         | 2,520      | 460.1              | 1,124.0                      | 24.1                             |
| 1985 | 272,700         | 2,497      | 470.1              | 1,188.7                      | 25.8                             |
| 1986 | 280,400         | 2,751      | 563.0              | 1,188.7                      | 28.2                             |
| 1987 | 285,800         | 2,929      | 555.0              | 1,188.7                      | 28.4                             |
| 1988 | 291,600         | 2,932      | 549.0              | 1,188.7                      | 26.6                             |
| 1989 | 292,000         | 2,920      | 541.0              | 1,188.7                      | 27.3                             |
| 1990 | 293,100         | 3,117      | 557.0              | 1,188.7                      | 25.2                             |
| 1991 | 296,200         | 3,156      | 569.0              | 1,188.7                      | 24.9                             |
| 1992 | 298,000         | 3,367      | 593.0              | 1,188.7                      | 25.6                             |
| 1993 | 299,200         | 3,345      | 609.0              | 1,188.7                      | 25.2                             |
| 1994 | 299,600         | 3,491      | 607.0              | 1,188.7                      | 26.2                             |
| 1995 | 299,400         | 3,723      | 665.0              | 1,188.7                      | 25.7                             |
| 1996 | 302,200         | 3,944      | 710.0              | 1,188.7                      | 26.1                             |
| 1997 | 307,100         | 4,343      | 746.0              | 1,188.7                      | 26.1                             |

Table 4. Summary T&amp;T electricity-use statistics 1983 to 1997 (Sitahal and Chong, 1998).

#### 4.2.1 Electricity rate structure

T&TEC charges customers different rates for electricity based on type of supply (single- or three-phase), and on their maximum demand in kVA. The rate categories are A, B, Industrial-D1, -D2 and -D3, E, and S (T&TEC Registry, 1999). Rate A (domestic residential) and Rate B (general commercial) customers are single-phase electricity customers and pay only for energy in kWh, and not for maximum demand in kVA. Rate D1 (light industrial) is a low-voltage supply that is metered at one point. The supply is three-phase, 60 Hz alternating current (ac) at 230 V up to a 199 kVA load, and at 400 V up to a maximum 350 kVA load. Rate D2 (medium industrial) is a high-voltage supply that is metered at one point. The supply is three-phase, 60 Hz ac at 6.6 kV, 12 kV, 33 kV, or 66 kV, for loads from 200 kVA to 3,999 kVA. Rate D3 (heavy industrial) is a high-voltage supply that is metered at one point. The supply is three-phase, 60 Hz ac at 33 kV, 66 kV, or 132 kV for loads from 4,000 kVA to 25,000 kVA. Rate E (very large load) is a high-voltage supply that is metered at one point. The supply is three-phase, 60 Hz ac at 66 kV, or 132 kV for loads from above 25,000 kVA.

The electricity cost to industrial customers comprises separate charges. The *maximum demand* charge is levied monthly, and is applied to the maximum demand in the month. This is the average load during the fifteen-minute period of greatest use as indicated by T&TEC's meter. In cases where demand is intermittent or subject to violent fluctuations, T&TEC may use a shorter interval, or the kVA of the transformer capacity required to serve the customer's load, or assess maximum demand on the basis of installed capacity.

The *energy charge* applies per kWh, used uniformly for all kWh. In T&T there are no peak rates. *Fuel charge* allows T&TEC to partially recover the cost of fuel used in producing and delivering electricity. T&TEC reserves for each customer a declared transmission and distribution capacity, the *reserve capacity*. The *reserve-capacity charge* is the minimum demand charge for the month based on 75 % of the declared reserve capacity, and is the minimum bill. Another charge is the *exchange-rate adjustment* for changes in the cost of foreign inputs from movements in T&T's dollar value relative to the US dollar.

This thesis incorporates all of the charges to produce an overall electricity cost per kWh for each rate (Table 5). This cost is the average over all customers in each rate category for all of 1998.

| Rate category          | Customers      | % overall energy use | Overall electricity cost, TT\$/kWh |
|------------------------|----------------|----------------------|------------------------------------|
| Domestic residential A | 279,608        | 23.0                 | 0.2211                             |
| General commercial B   | 27,822         | 9.0                  | 0.2399                             |
| Industrial D1          | 1,370          | 7.0                  | 0.3219                             |
| Industrial D2          | 576            | 20.0                 | 0.2829                             |
| Industrial D3          | 20             | 18.0                 | 0.1712                             |
| Industrial E           | 1              | 22.0                 | 0.1625                             |
| Street light S         | 424            | 0.4                  | 0.8179                             |
| <b>Total</b>           | <b>309,821</b> | <b>99.4</b>          |                                    |

Table 5. Electricity customers in 1998 (T&TEC, 1999).

#### 4.2.2 Industrial – D electricity customers

T&TEC groups customers in each D-rate category into subgroups according to the type of facility. Different industries have different electricity-use characteristics, so T&TEC groups industrial customers that are broadly similar in this respect into the fifteen subgroups described in Table 6. Thus each subgroup can have customers of one or more D-rate categories, or equally each D-rate category can comprise customers from one or more of the fifteen sub-groups. There were only twenty D3 customers in 1998 (Table 5) and these are mostly from the MF subgroup. D1 and D2 customers are much more numerous and comprise members of all the subgroups.



| Code | Description                                                               |
|------|---------------------------------------------------------------------------|
| BIC  | Banks, insurance companies and credit unions, and financial institutions. |
| BUS  | Businesses, e.g. stores and groceries.                                    |
| CIN  | Cinemas and recreation centers.                                           |
| ES   | Essential and social services.                                            |
| FI   | Food/drink manufacturing industry and agro-based industries.              |
| FOR  | Food outlets and restaurants.                                             |
| GA   | Clothes-making industries.                                                |
| HL   | Hotels and holiday resorts.                                               |
| MF   | Manufacturing industry.                                                   |
| MIA  | Media.                                                                    |
| MIG  | Government ministries (including Health) and offices.                     |
| NUN  | General.                                                                  |
| OIL  | Oil industry.                                                             |
| ORG  | Private organisations.                                                    |
| SCH  | Schools and educational institutions.                                     |

Table 6. Industrial electricity user subgroups (Sitahal, 1999c).

### 4.3 Forecasting T&T energy

See Chapter 10.

## Chapter 5. Cogeneration

### 5.1 Power- and heat-generation fundamentals

*Heat* is energy transfer due to a temperature difference. *Work* is energy transfer from applying a force to move an object over a distance, and so involves physical displacement. *Power* is work done per unit time. Some observations about heat and work are:

- Work transforms into heat with 100% conversion-efficiency.
- Heat cannot be transformed into work with 100% efficiency.
- Potential heat sources have a qualitative aspect, which affect their usefulness in transferring energy, as well as a quantitative aspect.

Some conclusions from these observations that are pivotal to cogeneration economics are:

- Work is a more valuable form of energy than heat.
- An energy source that can produce work is more valuable than one that can produce heat alone.

A *heat engine* is a device that operates in a thermodynamic cycle to convert heat into work. The First Law of Thermodynamics applied to heat engines means that to produce work, a quantity of heat must be supplied to an engine. The Second Law of Thermodynamics dictates that to produce work, an engine must reject a portion of the supplied heat to a lower-temperature thermal energy reservoir. Figure 29 illustrates this process and defines the *Carnot efficiency*. This is the theoretical maximum efficiency with which a heat engine converts heat into work. Current material technology limits the maximum heat-supply temperature in practical engines, and the minimum temperature to which the heat is rejected is usually ambient, so the best engine efficiency in practice is ~53% (typically ~35%).

*Availability* ( $A_v$ ) refers to the potential for a heat source to produce work. The higher heat-source temperature, the higher the availability and the greater the amount of work it can produce.

$$A_v = Q (T_1 - T_2) / T_1$$

where:

$A_v$  = availability

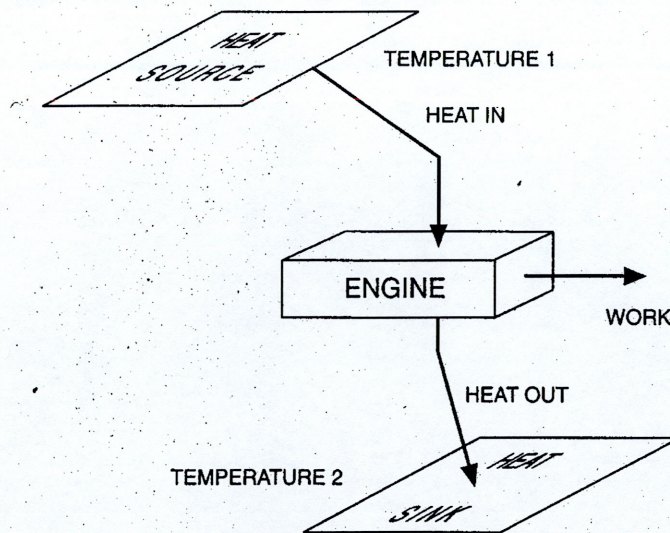
$Q$  = heat source's energy content

$T_1$  = temperature the heat source produces in Kelvin

$T_2$  = ambient temperature in Kelvin

So availability derives from the Carnot efficiency.



**Notes**

1.  $\text{Carnot Efficiency} = \frac{\text{Temperature 1} - \text{Temperature 2}}{\text{Temperature 1}}$

where

temperature is absolute temperature in Kelvin (Celsius + 273.15)

Figure 29. The heat engine (Griffith, 1995).

### 5.1.1 Combining power- and heat-generation

Fossil fuels largely dominate today's economies, and are often used for generating power and heat separately. Generating power produces heat as described earlier, so combining the two should help use finite fossil fuel resources more efficiently. There are two major considerations in doing this:

- Heat is difficult and expensive to transport (via pipes) relative to the value of the energy transported, so the heat demand should be as near as possible to its generation.
- Heat must be at a high enough temperature to be useful but this reduces the power-generating efficiency. As work is more valuable than heat, a relatively high proportion of the heat rejected by an engine must be recovered to economically justify the associated power-generation efficiency lost.

Fuels can produce high temperatures and thus have high availability. When fuels are burnt there is no more capacity to do work and this has implications for finite fossil fuel resources – they should be used as efficiently as possible. This means using fuels for generating work rather than heating, and using the rejected heat as much as possible. When a heat engine generates electricity, typically ~65% of the primary energy input is rejected as heat.



Cogeneration recovers the majority of this to give an overall efficiency of ~80% (Good Practice Guide 3, 1995).

5.2 Conditions for cogeneration

It is possible to quickly evaluate cogeneration’s suitability at a site before any feasibility study, which itself has a cost, and subsequent capital investment decision. Chapter 8 describes in detail cogeneration appraisal and economic analysis.

5.2.1 Economic factors

A cogeneration scheme is only a financial success if it cuts electricity and heating costs such that the financial savings provide an acceptable return on the capital investment. It must outperform conventional power purchasing and heat production at the site. Table 7 lists the fundamental economic factors to consider. Cogeneration sets convert gas to electricity at about 25% to 32% efficiency depending on the heat-engine type. Historically, electricity costs about 3 to 4 times as much as gas in Trinidad and Tobago (T&T), so the value of the electricity produced is roughly equal to the value of the fuel. This means that the value of the heat recovered, minus any maintenance costs, is the financial saving.

| <i>Factors working to the advantage of local heat generation and the purchase of centrally generated electricity.</i> | <i>Factors working to the advantage of local heat and electricity generation.</i>     |
|-----------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------|
| <input type="checkbox"/> The use of low cost fuels at large power stations.                                           | <input type="checkbox"/> The more effective use of input fuels achieved by CHP plant. |
| <input type="checkbox"/> Economies of scale achieved in the operation and maintenance of large power stations.        | <input type="checkbox"/> The elimination of electricity transmission losses.          |
| <input type="checkbox"/> Access to low cost capital finance.                                                          |                                                                                       |
| <input type="checkbox"/> Government subsidies in the finance and operation of large power stations.                   |                                                                                       |

Table 7. Fundamental economic factors (Griffith, 1995).

5.2.2 Local demand patterns

Heat and electricity are difficult to store, so investment in cogeneration is only cost-effective where significant and simultaneous heat and electricity demands exist for a high number of hours per year. The ratio of heat demand to power demand at the site is important too, considering that different types of heat engines have characteristic *heat-to-power ratios*. But the degree to which demand profiles converge is the fundamental factor determining cogeneration’s suitability on a site, and not the heat-to-power ratio (Griffith, 1995). Profiles-convergence refers to the extent to which heat- and electricity-demands coincide over a given period. Also the temperature at which the heat is needed is a more crucial consideration in engine-technology choice than the heat-to-power ratio. Electricity and heat demands vary from season to season (almost entirely absent in T&T), day to day,

and hour to hour, and so does the heat-to-power ratio. The actual size of the electricity demand will determine engine technology too, different technologies being appropriate to different size ranges. Section 5.3.1.2 on engines describes this in more detail. The heat-to-power ratio can also be managed by converting some electricity demand to heat demand, e.g. by replacing electrical vapour-compression cooling-equipment with absorption chillers.

### 5.2.3 Export

Exporting heat and/or electricity can be a revenue source for the cogeneration scheme and improve its economics. To export heat the importer's site must be close, as distribution systems are expensive. Contractual commitments for supply-security to the heat importer must be considered. Also the supply price must compete with the candidate's on-site heat generating costs. Figure 30 shows the electricity-export options available. The regulatory framework for exporting will determine each option's cost effectiveness. Heat and electricity export are best done at large cogeneration schemes that have access to low-cost capital, and where supply-security commitments are not a significant additional burden to cogeneration plant operation. If the exported-electricity price is low, exporting will only be worthwhile at times when virtually 100% of the heat generated can be used profitably.

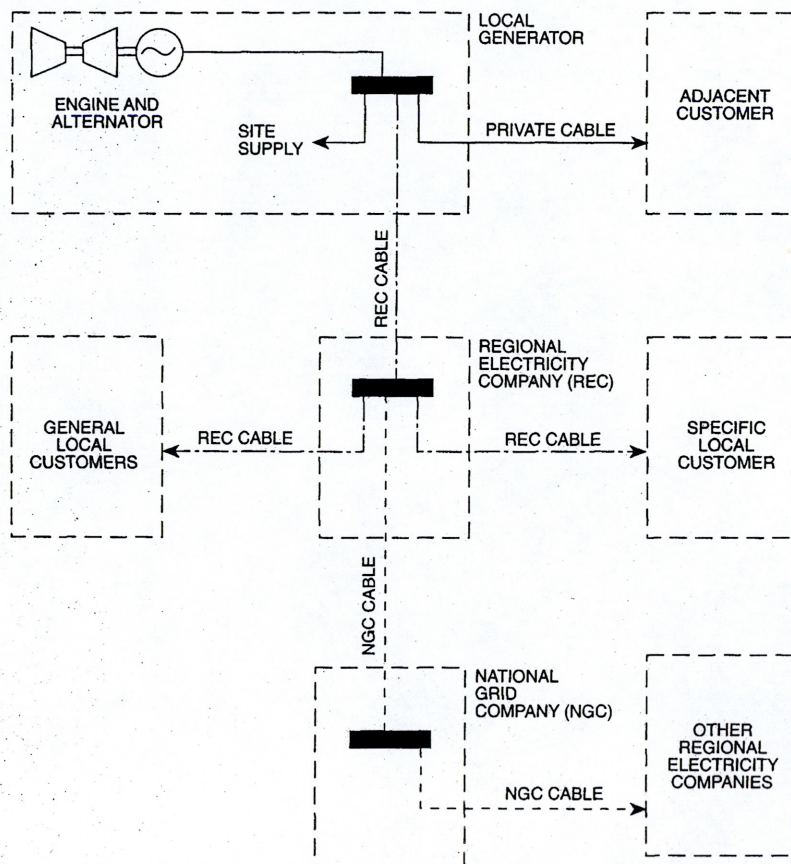


Figure 30. Electricity export options for a local generator (Griffith, 1995).



### 5.2.4 Operation and maintenance

Cogeneration evaluation must take fully into account operation and maintenance costs. This is discussed in detail in Section 5.4.

## 5.3 Cogeneration hardware

A typical cogeneration plant comprises 6 key elements:

- A heat engine (prime mover)
- A generator or alternator coupled to the engine that converts the engine's mechanical energy to electrical energy.
- A heat recovery system that collects heat from the engine cooling and exhaust systems.
- A control system controlling the whole unit during starting, synchronising, and continuous operation. It will often include data-logging and diagnostic features, with telemetry capability.
- A noise-reduction package, including the engine exhaust system and noise-reduction for the generator as well.
- Electrical cabling and pipe work to deliver electricity and heat outputs to the site's distribution infrastructure.

Figure 31 shows a block diagram of a cogeneration unit and Figure 32 compares the energy flows in cogeneration and conventional energy supply. Energy losses from a cogeneration plant occur mainly through residual energy in exhaust gases, plus generator and gearbox losses and radiation. Overall, cogeneration reduces energy consumption by ~30% or more. Table 8 describes different plant categories and their characteristics. Figure 33 illustrates the different cogeneration configurations.

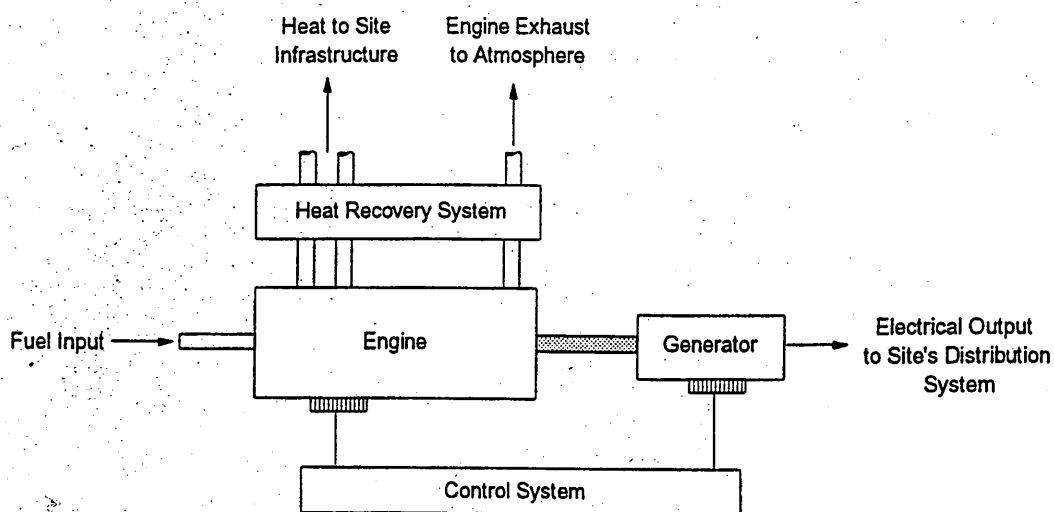


Figure 31. Cogeneration unit block diagram (ERA Technologies, 1995).

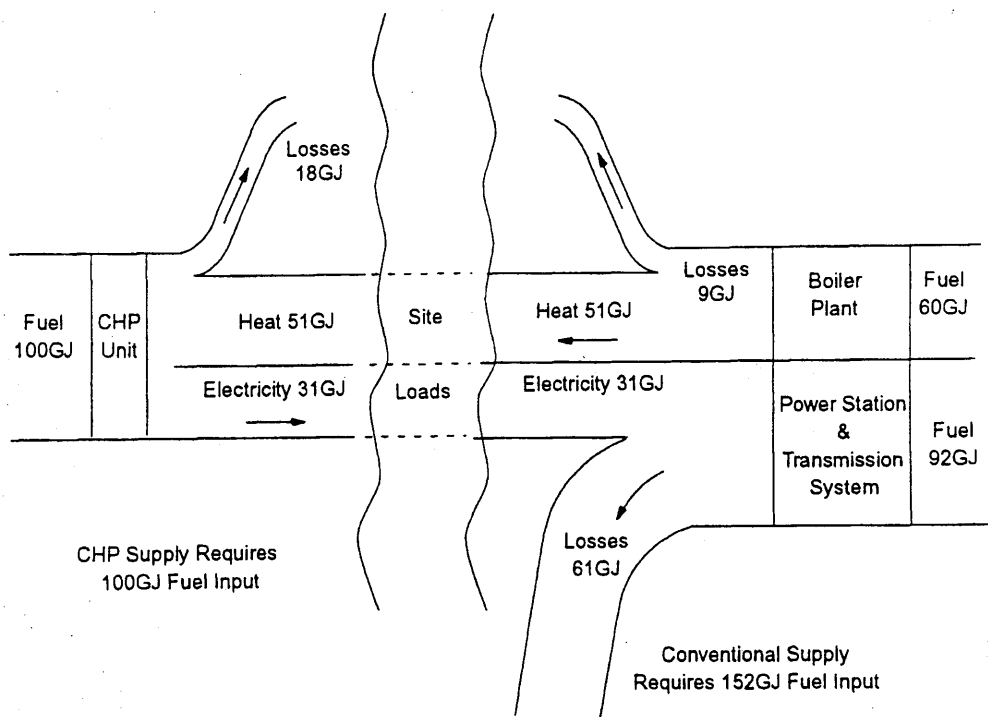


Figure 32. Energy-flow comparisons for cogeneration and conventional energy supply (ERA Technologies, 1995).

|                           | Spark<br>ignition ICE | Compression<br>ignition ICE | Simple-cycle<br>GT | Combined-<br>cycle GT |
|---------------------------|-----------------------|-----------------------------|--------------------|-----------------------|
| Typical elec. rating, Mwe | 0.01 - 5              | 0.1 - 30                    | 1 - 100+           | 4 - 100+              |
| Heat:power ratio          | 1:1 - 2:1             | 0.7:1 - 1.5:1               | 1.5:1 - 3:1        | 0.5:1 - 2:1           |
| Elec. efficiency, %       | 25 - 40               | 30 - 45                     | 25 - 40            | 35 - 50               |
| Overall efficiency,%      | 65 - 80               | 65 - 80                     | 65 - 85            | 70 - 80               |
| Capital cost, TT\$/kWe    | 5000 - 9000           | 5000 - 8000                 | 4000 - 10000       | 3500 - 10000          |
| O&M cost, TTc/kWhe        | 7 - 15                | 5 - 10                      | 3 - 9              | 3 - 10                |

Table 8. Cogeneration plant options and characteristics (The National Gas Company of Trinidad and Tobago Ltd., 1999).

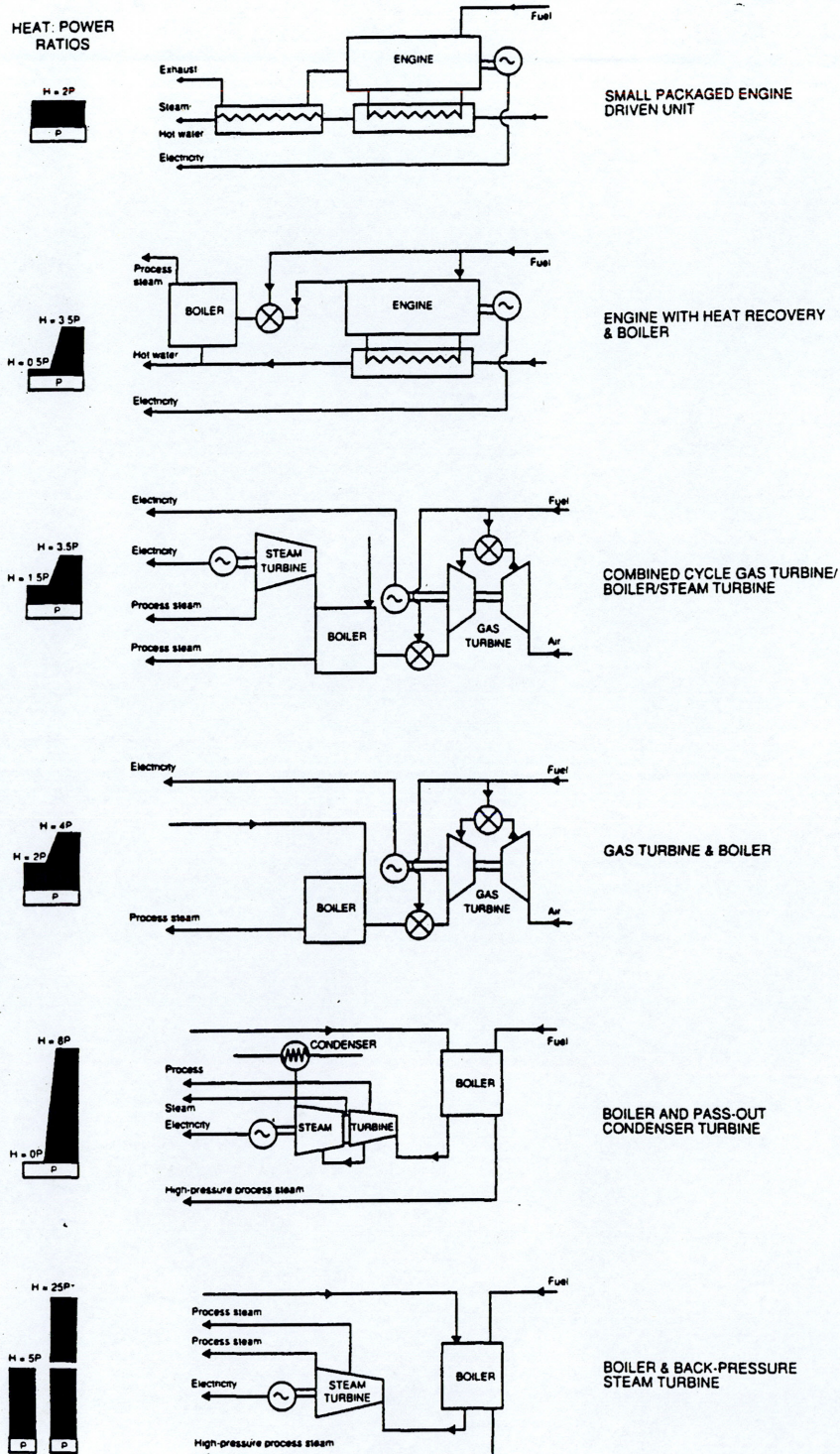


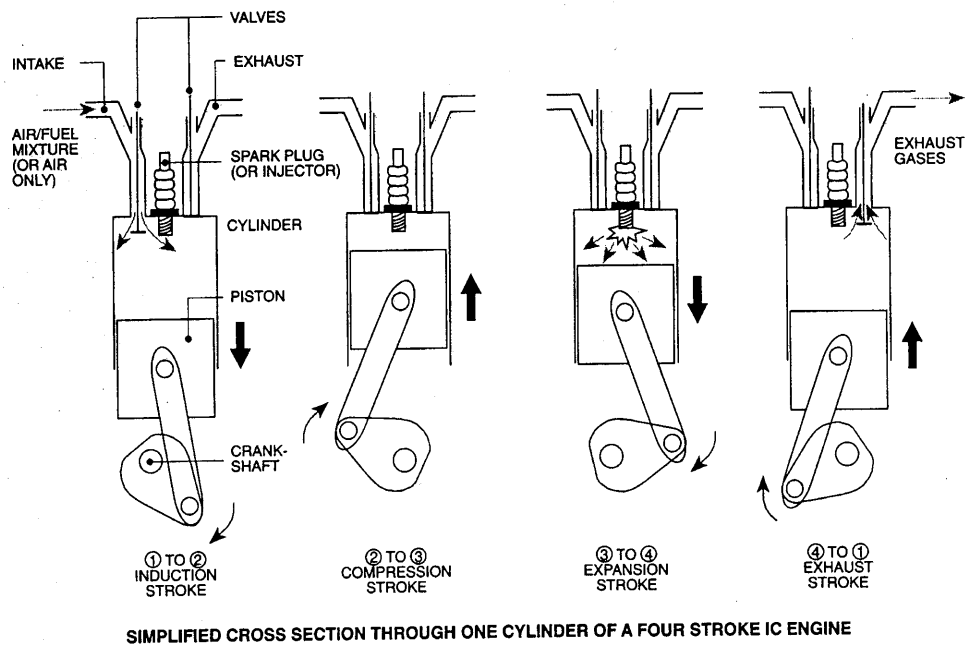
Figure 33. Typical cogeneration configurations (ERA Technologies, 1995)



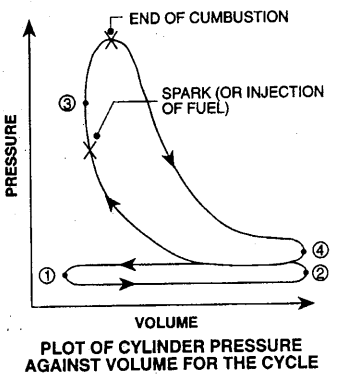
5.3.1 The engines

5.3.1.1 Combustion process

In the *reciprocating internal combustion engine (ICE)* fuel combustion occurs within the engine’s cylinders, and results in combustion products at high temperature and pressure. This is the high-temperature reservoir. The engine rejects heat to a low-temperature sink (the atmosphere). Figure 34 illustrates the combustion process.



Notes  
1. Text in (brackets) applies to compression ignition engines.

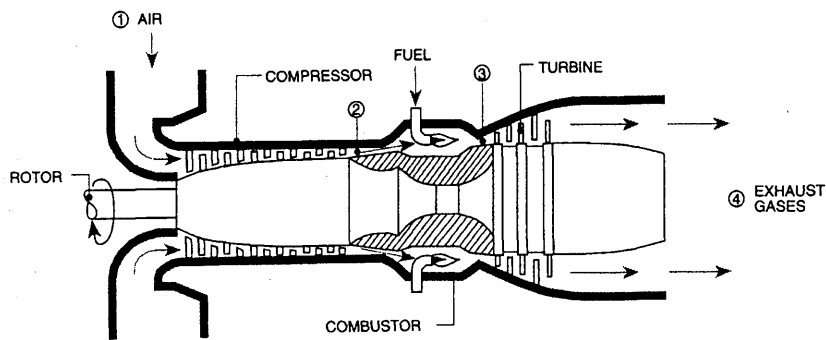


| Points<br>In Cycle | Stroke      | Operation                                                               |                                                                                                                                                                         |
|--------------------|-------------|-------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
|                    |             | Spark Ignition                                                          | Compression Ignition                                                                                                                                                    |
| ① to ②             | Induction   | Intake port open, air/fuel mixture drawn into cylinder.                 | Intake port open, air drawn into cylinder.                                                                                                                              |
| ② to ③             | Compression | Air/fuel mixture compressed.                                            | Air compressed.                                                                                                                                                         |
| ③ to ④             | Expansion   | Spark initiated ignition and controlled combustion of air/fuel mixture. | Direct injection of fuel into cylinder (or into a small chamber opening onto the cylinder), then spontaneous ignition followed by rapid combustion of air/fuel mixture. |
| ④ to ①             | Exhaust     | Exhaust port open, products of combustion evacuated from cylinder.      | Exhaust port open, products of combustion evacuated from cylinder.                                                                                                      |

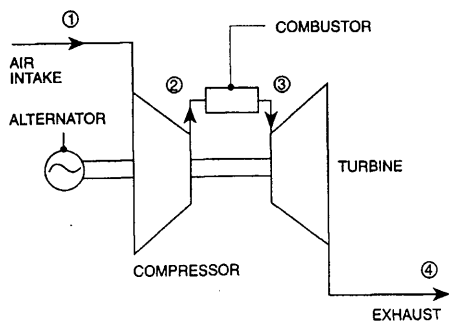
Figure 34. Internal combustion engine cycles – spark-ignition and compression-ignition (Griffith, 1995)

The engine rejects heat:

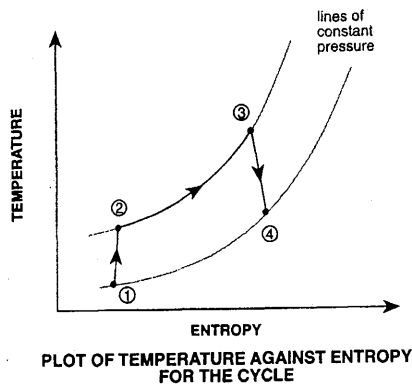
- directly in the exhaust,
- through heat transfer from the engine-jacket water, lubricating oil, and charge-air cooling systems (for turbo-charging with after-cooling), and
- through heat transfer from the engine's outer surfaces.



SIMPLIFIED CROSS SECTION THROUGH A TYPICAL SINGLE SHAFT GAS TURBINE



DIAGRAMATIC REPRESENTATION OF SINGLE SHAFT GAS TURBINE CYCLE



| Points in Cycle | Process                                                                                                                                     |
|-----------------|---------------------------------------------------------------------------------------------------------------------------------------------|
| ① to ②          | Air compressed in axial compressor to typically 14 bar; 400°C.                                                                              |
| ② to ③          | Fuel combusted in compressed air stream at approximately constant pressure to further raise the temperature of the air to typically 1100°C. |
| ③ to ④          | Air and combustion products expanded through turbine down to atmospheric pressure and typically 500°C.                                      |

Figure 35. Gas turbine combustion cycle (Griffith, 1995).



In the *gas turbine (GT)* fuel combustion again occurs within the engine (i.e. in the combustion chambers). However, in comparison with ICEs, GTs have much less mechanical components and bearing surfaces and are inherently more reliable and have far longer service intervals. Figure 35 illustrates the GT combustion cycle.

The engine rejects heat:

- directly in the exhaust gases,
- by heat transfer from the lubricating-oil cooling system, and
- heat transfer from the engine's outer surfaces.

A GT is fairly simple, versatile and robust. It can operate on a wide variety of gaseous and liquid fuels and its continuous combustion simplifies emissions-control compared to an ICE's pulsed combustion. Auxiliary GT equipment are air filters, acoustic systems, fuel compressors, and starting equipment (electric motor, ICE, or pneumatic starter, to run the compressor up to threshold speed).

### **5.3.1.2 Engine characteristics in relation to cogeneration**

#### **5.3.1.2.1 Power output**

ICEs are typically used in applications requiring shaft power between 20 kW and 15 MW. Engines with outputs between 20kW and 100kW are vehicle-derived. Above 100kW, engines are designed for base-load electricity generation (Griffith, 1995).

GTs typically have shaft power outputs ranging from 200kW to over 200MW. They are hardly used for cogeneration plants below 1MW electrical (MWe) capacity due to poor efficiency and high capital cost per kW power output. Both aero-derivative and industrial engines are available in a range of 500kW to 50MW (Griffith, 1995).

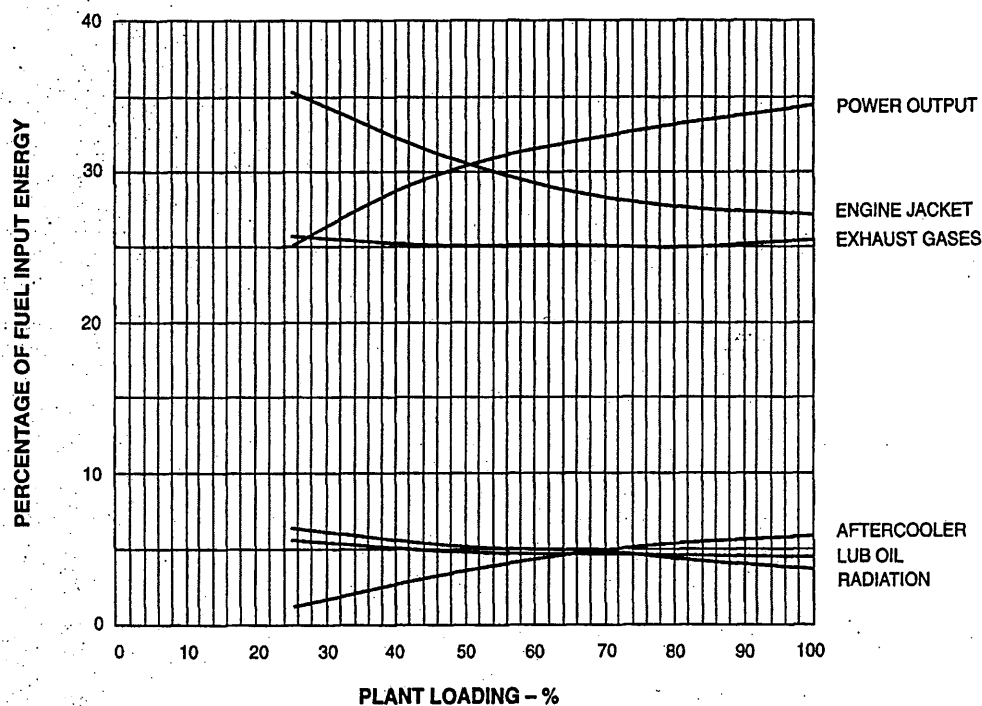
#### **5.3.1.2.2 Power generation efficiency and heat output**

| Item                                                   | Percentage of Fuel Input Energy <sup>1</sup> |               |                            |               |               | Temperature – °C |        |
|--------------------------------------------------------|----------------------------------------------|---------------|----------------------------|---------------|---------------|------------------|--------|
|                                                        | Engine Size Range <sup>2</sup> – kW          |               |                            |               |               | Flow             | Return |
|                                                        | 80–120                                       | 400–600       | 400–600<br>HT <sup>6</sup> | 800–1,200     | 4,000–6,000   |                  |        |
| Power Output<br>(variation within each size range)     | 33<br>(30–35)                                | 35<br>(30–38) | 35<br>–                    | 36<br>(31–41) | 41<br>(35–42) | –                | –      |
| Exhaust Gases                                          | 22                                           | 26            | 26                         | 26            | 35            | 450              | –      |
| Engine Jacket Cooling System                           | 33                                           | 25            | 22                         | 24            | 9             | 95               | 85     |
| Lubricating Oil Cooling System                         | 4                                            | 4             | 6                          | 4             | 4             | 85               | 75     |
| Charge Air Cooling System                              | 6                                            | 6             | 6                          | 6             | 7             | 35               | 30     |
| Outer Surfaces of Engine                               | 2                                            | 4             | 5                          | 4             | 4             | –                | –      |
|                                                        | 100                                          | 100           | 100                        | 100           | 100           |                  |        |
| Heat Recoverable at High<br>Temperature <sup>3</sup>   | 10                                           | 11            | 12                         | 11            | 16            | 200              | 190    |
| Heat Recoverable at Medium<br>Temperature <sup>4</sup> | 15                                           | 16            | 39                         | 16            | 22            | 120              | 110    |
| Heat Recoverable at Low<br>Temperature <sup>5</sup>    | 54                                           | 47            | 47                         | 46            | 38            | 80               | 70     |

- Notes
- <sup>1</sup> The figures given in each size range are for a typical spark ignition turbo-charged IC engine operating at full load on natural gas, with input energy taken at the lower heat value.
  - <sup>2</sup> Refers to shaft power output.
  - <sup>3</sup> Heat recovered to generate hot water/steam at 200°C, exhaust gas temperature reduced to 230°C.
  - <sup>4</sup> Heat recovered to generate hot water/steam at 120°C, exhaust gas temperature reduced to 150°C.
  - <sup>5</sup> Heat recovered to generate hot water at 80°C, exhaust gas temperature reduced to 120°C.
  - <sup>6</sup> Engine modified to run at high jacket cooling water temperatures of typically 125°C flow and 115°C return.

Table 9. Typical ICE performance data (Griffith, 1995).

Table 9 and Figure 36 contain typical performance data for ICEs. The amount of heat available from the engine jacket is roughly equal to that from the exhaust (Evans, 1991). The maximum temperature available off the engine jacket is 125°C (to preserve oil quality). Oil cooling is separate to maintain it at 80°C to 95°C so that about 5% to 10% of the heat recovered comes from the oil cooler. Part-load performance is a significant part of the operating strategy.



**Notes**

1. The performance data are for a typical 500 kW shaft power output, spark ignition turbo-charged IC engine operating on natural gas.

Figure 36. Typical ICE part-load performance (Griffith, 1995).

Table 10 and Figure 37 contain typical performance data for GTs. The exhaust gases contain almost all of the heat rejected from a GT. Also, up to 3 to 4 times the fuel input can be burnt in exhaust gas after-burners to increase the recoverable heat. A GT has significantly less operating flexibility than an ICE regarding its part-load operation, which places a more stringent constraint on plant sizing.

| Item                                                | Percentage of Fuel Input Energy <sup>1</sup> |               |               |               | Temperature – °C |        |
|-----------------------------------------------------|----------------------------------------------|---------------|---------------|---------------|------------------|--------|
|                                                     | Engine Size Range <sup>2</sup> – kW          |               |               |               | Flow             | Return |
|                                                     | 400–600                                      | 800–1,200     | 4,000–6,000   | 14,000–24,000 |                  |        |
| Power Output<br>(variation within each size range)  | 22<br>(16–22)                                | 27<br>(20–28) | 32<br>(24–36) | 37<br>(32–39) | –                | –      |
| Exhaust Gases                                       | 77                                           | 72            | 67            | 62            | 500              | –      |
| Lubricating Oil Cooling System                      | <1                                           | <1            | <1            | <1            | 70               | 50     |
| Outer Surfaces of Engine                            | <1                                           | <1            | <1            | <1            | –                | –      |
|                                                     | 100                                          | 100           | 100           | 100           |                  |        |
| Heat Recoverable at High Temperature <sup>3</sup>   | 43                                           | 40            | 38            | 36            | 200              | 190    |
| Heat Recoverable at Medium Temperature <sup>4</sup> | 55                                           | 52            | 49            | 46            | 120              | 110    |
| Heat Recoverable at Low Temperature <sup>5</sup>    | 60                                           | 57            | 53            | 49            | 80               | 70     |

Notes

<sup>1</sup> The figures given for each size range are for a typical gas turbine operating at full load on natural gas, with input energy based on the lower heat value of the fuel.

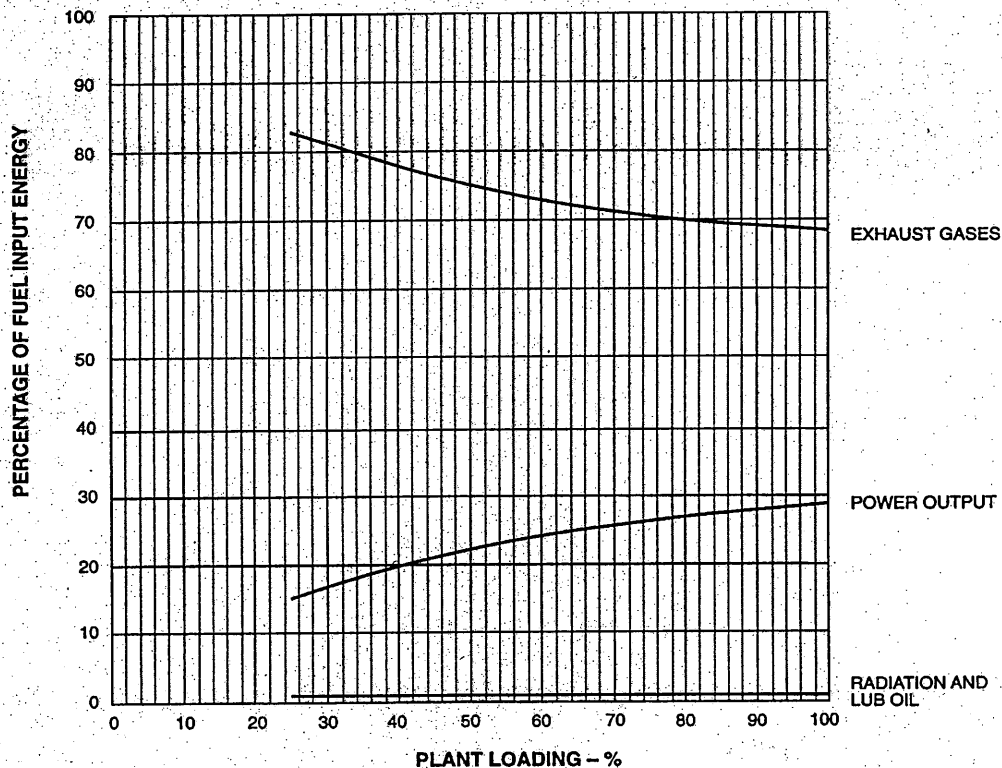
<sup>2</sup> Refers to shaft power output.

<sup>3</sup> Heat recovered to generate hot water/steam at 200°C, exhaust gas temperature reduced to 230°C.

<sup>4</sup> Heat recovered to generate hot water/steam at 120°C, exhaust gas temperature reduced to 150°C.

<sup>5</sup> Heat recovered to generate hot water at 80°C, exhaust gas temperature reduced to 120°C.

Table 10. Typical GT performance data (Griffith, 1995).



**Notes**

1. The performance data are for a typical 5 MW shaft power output, gas turbine operating on natural gas.

Figure 37. Typical GT part-load performance (Griffith, 1995).

### 5.3.1.2.3 Fuels and their supply

ICEs run on natural gas suffer only very low engine deposits and lubricating-oil degradation, and thus a lower maintenance burden than oil-run engines. All but the largest engines need only relatively low fuel-supply pressure and natural gas at normal pipeline supply pressure is adequate.

In GTs, blade cleanliness is important to maintaining design efficiency in the turbine expansion stage. This means that natural gas engines operate many months between turbine washes with little performance loss. GTs require fuel supply under high pressure to the combustion chamber, which typically operates between 13 and 21 bar. Compressing the gaseous fuel takes up to 5% of the engine's power output. An auxiliary reciprocating or screw compressor supplies the fuel at 11 to 21 bar.

A high operating maximum temperature in the GT results in high overall engine efficiency. But achieving high temperatures in practice requires high combustion chamber pressure and high fuel supply pressure, which reduces the engine's net power output. So there is a trade-off between engine efficiency and the air and gaseous fuel compression requirements.



### 5.3.1.2.4 Maintenance and service-loss

This concerns *reliability* and *availability*. *Reliability* refers to individual incidents of failure and can be expressed as the expected number of failures over a specified time period, or the reciprocal, i.e. the mean time between failures. Reliability figures do not provide information on the likely hours lost per annum through engine downtime and so are useless for evaluating return on investing in cogeneration.

*Availability*, *A* – not to be confused with thermodynamic availability described earlier – is the amount of time the generating set is available to operate. Operating time is lost because of:

- generating set failure, and
- the generating set is off line for planned engine maintenance.

So availability depends both on reliability and maintenance needs.

$$A = \frac{Hr - (Hm + Ho)}{Hr} \times 100$$

where:

*A* is availability,  
*Hr* is the number of hours needed to be in service per annum,  
*Hm* is the number of hours planned maintenance per annum (assuming continuous operation), and  
*Ho* is the number of hours predicted unplanned outages per annum (assuming continuous operation).

Manufacturers calculate availability using

$$A = \frac{Hr - (Hm + Ho)}{Hr - Hm} \times 100$$

To avoid the above confusion, a better measure is *availability hours*, *Ha*, which is the number of hours the set is available to run per annum

$$Ha = 8760 - (Hm + Ho)$$

|                                |       |       |       |       |
|--------------------------------|-------|-------|-------|-------|
| Generating set size, kWe       | 100   | 500   | 1,000 | 5,000 |
| Total downtime hours per annum | 1,500 | 1,000 | 1,000 | 750   |

Table 11. Downtime hours per annum – ICE (Griffith, 1995).

Table 11 and Table 12 give typical downtime hours per annum (i.e. *Hm* + *Ho*) for ICEs and GTs respectively. They show that GTs have higher reliability and, along with lower maintenance demands, the result is significantly more running hours per annum than ICEs.

|                                |     |       |       |        |
|--------------------------------|-----|-------|-------|--------|
| Generating set size, kWe       | 500 | 1,000 | 5,000 | 20,000 |
| Total downtime hours per annum | 500 | 500   | 250   | 250    |

Table 12. Downtime hours per annum – GT (Griffith, 1995).

Some *disadvantages* of GTs over ICEs are (ERA Technologies, 1995):

- Parasitic compression losses.
- Sensitivity to environmental conditions - the output falls by ~1% for each 1°C rise in ambient temperature.
- Low efficiency compared to similar-sized ICE, especially at smaller sizes. GT electricity-generating efficiency is 20% to 25% at 1MW, ~30% at 5MW to 10 MW, ~35% at 20MW to 30MW, and ~40% for larger outputs. ICE efficiency is 35% to 40% at all sizes.
- Higher specific capital costs, ICEs cost 25% to 50% less at low power ratings.

Some *advantages* of GTs over ICEs are (ERA Technologies, 1995):

- Small size and light weight.
- They can operate in combined-cycle mode.
- Overall cogeneration efficiency is ~80%, and heat is recovered at higher temperatures.

### 5.3.1.3 Adapting the engines to cogeneration

ICEs are designed for stationary use, or are vehicle-derived. The important performance criteria for a vehicle engine are:

- high power/weight ratio,
- high power/cost ratio,
- reasonable fuel efficiency, and
- good reliability.

The criteria for a stationary ICE for base-load electricity generation are:

- reasonable power/cost ratio,
- high fuel efficiency,
- high reliability,
- long service intervals, and
- low maintenance down time.

So the high power-to-weight ratio of vehicle engines conflict with the more robust and physically large engines designed for long service intervals and low maintenance down time. Vehicle engines are thus fundamentally not well suited to cogeneration. The choice must be considered on a life-cycle-costing basis. Regarding practical service life in continuous operation, vehicle-derived engines need a complete engine-block change after 20,000 hours or 2.5 years, whereas industrial engines designed for base-load generation

usually do not need this for over 100,000 hours or 12 years. There are many examples of large ICEs in service after 200,000 hours running (Griffith, 1995).

GTs are designed for industrial use and for aircraft. Important performance criteria for a land-based, industrial GT are:

- high reliability,
- good fuel efficiency,
- low maintenance down-time, and
- long service interval.

The criteria for an aero-engine are:

- high power-to-weight ratio,
- extremely high reliability,
- good fuel efficiency,
- low maintenance down time, and
- small cross-sectional area to minimise drag.

Industrial and aero GTs are similar in size. Unlike in the case of vehicular ICEs, aero-derived GTs are essentially already well suited to cogeneration and the differences with static GTs are not a fundamental consideration when evaluating alternative engines for cogeneration.

GTs are designed specifically for rotary power and so deliver high performance in driving rotary machinery, such as pumps and alternators. The compressor, combustion chamber and turbine-configuration have been optimised for this purpose. Bearing surfaces, casing construction, and inspection facilities are all configured to achieve long service intervals and low down time. As a result, GTs typically operate for over 8,000 hours before shut down for detailed inspection and possible maintenance (Griffith, 1995). GTs have been operated continuously for over 10,000 hours in the field.

#### 5.3.1.3.1 Heat recovery

Heat recovery is the essence of successful cogeneration. Heat in the exhaust gases from an ICE is recovered using a waste-heat boiler or heat exchanger. A simple water-to-water, or oil-to-water heat exchanger recovers heat from the water or oil cooling system. Heat is recovered at a relatively low temperature from the outer engine casing by enclosing the engine and drawing air through to an air-to-water heat exchanger.

Heat sources from a GT are the exhaust gases, the oil cooling system, and the outer engine casing, in common with an ICE. A GT has no water cooling system. For cogeneration, heat is recovered only from the exhaust gases of a GT. Heat from the other two sources is too low in quantity and temperature.

#### 5.3.1.3.2 Capital and operating costs

For a given ICE-size, the vehicle-derived unit is cheaper than the industrial unit. Comparing between sizes, the bigger engines are cheaper per kW output. The capital cost of different GTs with similar output varies between manufacturers. A 1MWe GT set could cost ~30% more than an equivalent ICE set (Griffith, 1995).

Operating costs for an ICE and a GT comprise fuel, planned maintenance and repairs, and engine supervision and management. The GTs significantly lower fuel-to-power efficiency means higher fuel costs but planned maintenance and repair costs are lower.

### 5.3.2 Alternators (ac generators)

These are either *synchronous* or *asynchronous*. Asynchronous (or induction) generators are used on sets that are typically 100kWe capacity or lower. The set starts using an external electrical supply so the generator output is inherently synchronised with the external supply and needs no special synchronising control and protection equipment. Also, the set's engine needs no motor to get it up to starting speed. The advantage of this is that it needs no batteries or separate starting motor. A disadvantage of asynchronous generators is that the induced excitation current cannot be controlled to regulate the alternator's output voltage or power factor to compensate for variations on the site as a whole. The generator may need power-factor correction itself as it takes a high starting current. Also, the asynchronous generator cannot be used as a stand-by power source.

*Synchronous* generators are typically used on generator sets over 100kWe in capacity (Griffith, 1995). Auxiliary direct-current (dc) generators (on the same shaft as the alternator) produce a rotor excitation current for the alternator so synchronous generators can operate in the absence of an external electricity supply. The set alternator must be run up to speed disconnected from any external supply and then its output must be synchronised with it before connection to the supply system. As rotor excitation is externally provided (as opposed to induced), excitation can be closely controlled to vary voltage, hence power output and power factor. Thus both of these can be corrected at the site.

Advantages of a synchronous generator are:

- it can be used as a stand-by generator, and
- it produces electricity at unity or leading power factor.

A disadvantage is that it has to be battery started.

Synchronous generators are usually preferred over asynchronous generators for capacities over 100kWe as they cost less overall and have better generation efficiency at these sizes (Griffith, 1995).

## 5.4 Operation and maintenance (O&M)

O&M for grid-supplied electricity is virtually zero. Boiler O&M is relatively simple and cheap. Cogeneration O&M is relatively complex and is necessary to avoid poor performance, frequent unplanned shut downs, excessive running hours lost, and shortening the predicted operating life by complete removal from service. All of these affect the plant economics. Technical staff is needed for regular inspection, and depending on the type of site, this can have a large cost. Maintenance is more specialised and is usually not provided in-house but requires a maintenance contract. Reciprocating engines need routine servicing every 1,000 hours (Griffith, 1995) and major overhauls every 18 months. GTs have longer service intervals but service costs are high when they do occur. In the case of small-scale packaged cogeneration, the vendor usually provides an all-inclusive supply and maintenance contract so that investing in cogeneration does not increase existing low O&M commitments.

A cogeneration plant is a complex mechanical installation. The operating strategy and maintenance levels will significantly affect the financial returns on the investment.

### 5.4.1 Operating strategy options

The simplest strategy is to run the engine at its *maximum rated power output* whenever it is available, selling excess electricity and dumping excess heat.

An *electrical-led* strategy controls the engine's electrical power output according to the site's electrical demand, up to the engine's maximum rating, running it whenever it is available and dumping excess heat.

A *heat-led* strategy is similar to the electrical-led one, this time the site's heat demand controls the engine's output. Excess electricity is sold.

Whatever the operating strategy, it must avoid rapid and frequent cogeneration plant cycling to save component life. For each case above, exhaust-gas boost burners and/or conventional boilers can be used as needed for thermal demand in excess of the engine's output.

#### 5.4.1.1 Choosing the control strategy

As a rule, maximum-output or heat-led strategies are appropriate if exporting electricity is allowed and the export price is good. Individual site economics will determine the best strategy, while energy cost-savings/revenues and maintenance costs will help to optimise the operating mode.



### 5.4.2 Operation

Modern cogeneration plants are typically fully automated and do not need operator intervention for start up, synchronisation, output control and shut down. Temperatures, pressures, fluid levels, etc are automatically monitored and logged. With automated condition monitoring the control system is programmed to detect unusual values for monitored parameters. An operator is needed to respond to faults in manual restarts following a plant shut down through system faults, but technical staff is not needed in permanent attendance. Figure 38 and Figure 39 show the instrumentation typically required for an ICE and a GT respectively. Plant operation can be contracted out where appropriate.

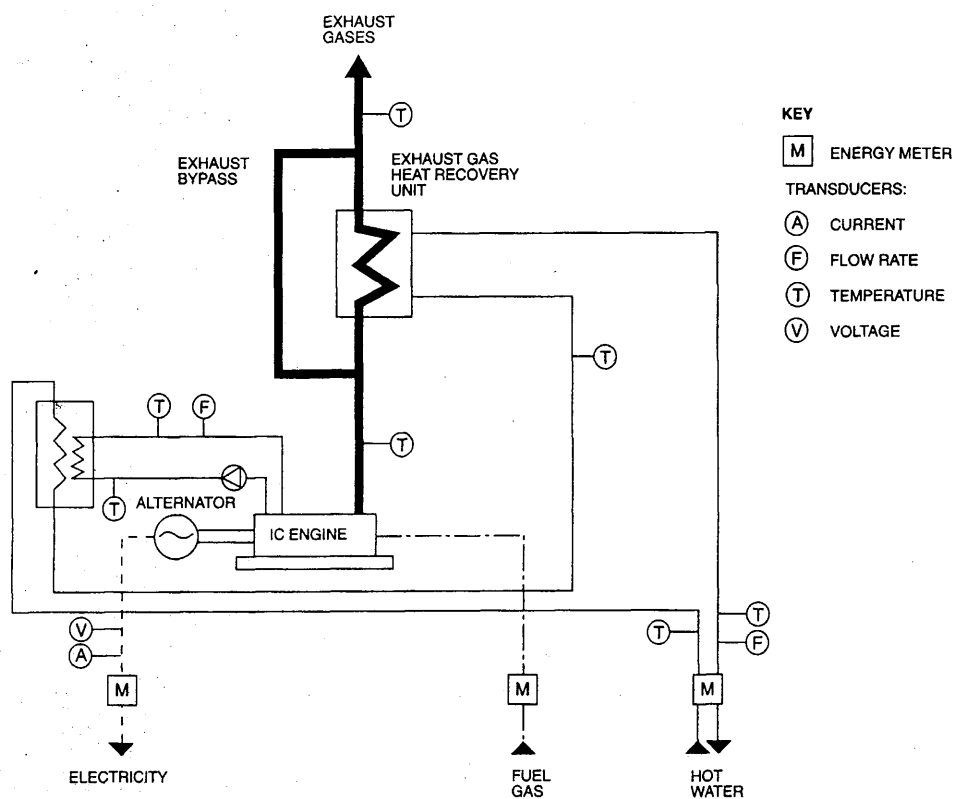


Figure 38. Cogeneration system performance monitoring instrumentation – ICE-based plants (Griffith, 1995).

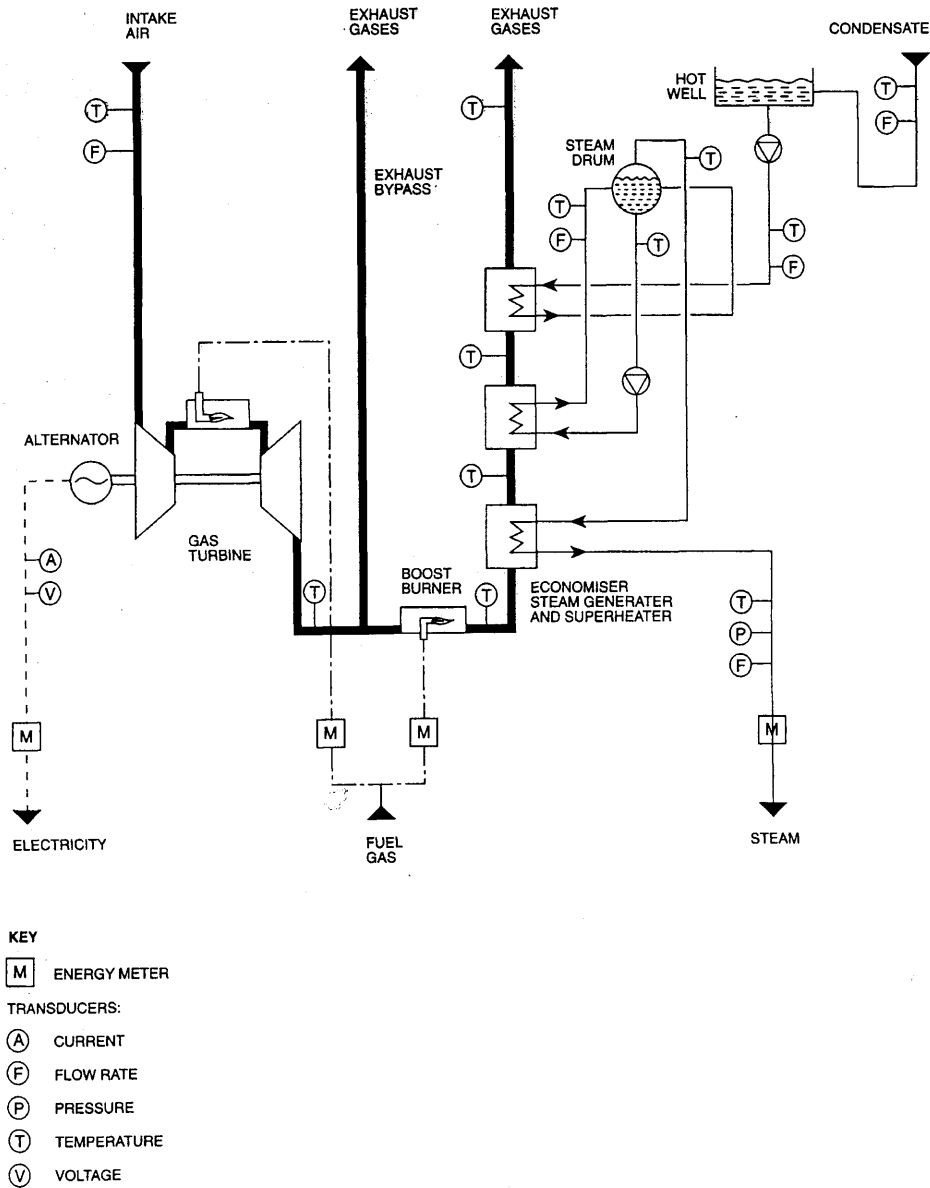


Figure 39. Cogeneration system performance monitoring instrumentation – GT-based plants (Griffith, 1995).

Some in-house maintenance tasks for an ICE are:

- Replacing lubricating oil filters and air filters.
- Topping up lubricating oil and coolant water supply systems.
- Lubricating oil and coolant water changes.
- Dispatching lubricating oil samples to maintenance contractor for analysis.
- Battery level and acidity checks plus top-ups as necessary.
- Visually inspecting pipes and hoses for leaks.

- Visually inspecting drive belt condition plus checking the tensions and adjustments as necessary.
- Attendance on the maintenance contractor's personnel during major maintenance work.

For GTs:

- Cleaning gas turbine compressor blades on-line weekly.
- Quarterly soak cleaning gas turbine compressor blades at cranking speeds.
- Replacing (or cleaning) intake air filters.
- Topping up lubricating oil plus replacing oil filters and oil changes.
- Attendance on the maintenance contractor's personnel during major maintenance work.
- Visually inspecting pipes for leaks.

For boilers and heat recovery equipment:

- Normal boiler attendance duties.
- Heat exchanger strainer checks plus cleaning as necessary.

For intakes and exhausts:

- Exhaust system water trap checks plus refilling as necessary.
- Visually inspecting exhaust system for leaks.

For gas compression plant:

- Topping up lubricating oil plus replacing oil filters and oil changes.
- Visually inspecting pipes and hoses for leaks.
- Fuel gas filter checks plus replacement as necessary

### 5.4.3 Maintenance

Maintenance is a specialised activity. Table 13 and Table 14 list typical maintenance requirements for an ICE and a GT. The other main components requiring maintenance as detailed above are boilers and heat recovery equipment, intakes and exhausts, gas compression plant, alternators, and fire safety systems.

| <i>Elapsed Operating Time – hours</i>                 | <i>Engine Components</i>                   | <i>Maintenance Work</i>                                                                                                                                                                                                                                                                        |
|-------------------------------------------------------|--------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1,000–2,000<br>and every<br>1,000–2,000<br>thereafter | Lubricating oil systems                    | Send oil samples for analysis<br>Check oil pressures and levels<br>Replace main engine oil depending upon findings from oil analysis<br>Replace turbo-charger oil depending upon findings from oil analysis<br>Visually inspect sealing rings                                                  |
|                                                       | Fuel supply and carburation systems        | Measure exhaust oxygen<br>Check and clean air filters<br>Check and clean fuel gas filters<br>Check tightness of throttle valve<br>Visually inspect control rods                                                                                                                                |
|                                                       | Engine block, cylinders and cylinder heads | Measure compression<br>Check and reset valve clearances                                                                                                                                                                                                                                        |
|                                                       | Cooling systems                            | Check levels<br>Visually inspect hoses<br>Check operation of pressure relief valve                                                                                                                                                                                                             |
|                                                       | Ignition                                   | Clean and adjust spark plugs<br>Check distributor<br>Check and adjust timing                                                                                                                                                                                                                   |
|                                                       | Drive and timing belts                     | Visually inspect belts for condition<br>Check and adjust belt tensions                                                                                                                                                                                                                         |
| 4,000–6,000<br>and every<br>4,000–6,000<br>thereafter | Lubricating oil systems                    | Replace oil filters                                                                                                                                                                                                                                                                            |
|                                                       | Fuel supply and carburation systems        | Replace air filters<br>Clean fuel gas filters and replace as necessary<br>Overhaul turbo-charger and replace bearings<br>Clean and inspect charge air cooler                                                                                                                                   |
|                                                       | Engine block, cylinders and cylinder heads | Remove cylinder heads, clean out water spaces, examine valves, springs, rocker gear etc<br>Clean camshaft bracket, camshaft bearings, tappet and oil pipe assemblies and check wear<br>Examine large end bearings and main bearings, securing nuts and split pins.<br>Check bearing clearances |
|                                                       | Cooling systems                            | Reverse flush water spaces in cylinder casings                                                                                                                                                                                                                                                 |
|                                                       | Ignition                                   | Replace distributor cover<br>Replace spark plug covers                                                                                                                                                                                                                                         |
|                                                       | Controls                                   | Check correct operation of all control and safety systems                                                                                                                                                                                                                                      |
|                                                       |                                            |                                                                                                                                                                                                                                                                                                |

Table 13. Indicative maintenance requirements – ICE operating on natural gas (Griffith, 1995).

| <i>Elapsed Operating Time – hours</i> | <i>Engine Components</i>                                         | <i>Maintenance Work</i>                                                                       |
|---------------------------------------|------------------------------------------------------------------|-----------------------------------------------------------------------------------------------|
| –                                     | Compressor blading                                               | Wash on-line and soak wash at cranking speeds at intervals determined by condition monitoring |
| 1,000                                 | Combustion chambers plus compressor and turbine blading          | Visually inspect using boroscope                                                              |
| 2,000 and every 2,000 thereafter      | Lubricating oil system                                           | Send oil sample for analysis and check level                                                  |
|                                       | Intake air systems                                               | Check intake air filters                                                                      |
| 7,000                                 | Combustion chambers plus compressor and turbine blades           | Visually inspect using borescope                                                              |
| 8,000                                 | Combustion chamber                                               | Dismantle and inspect                                                                         |
|                                       | Controls                                                         | Check correct operation of all control and safety systems                                     |
|                                       | Starter, auxiliary gearbox, turbine, main gearbox and alternator | Check alignments                                                                              |
|                                       | All ancillary equipment                                          | Visually inspect                                                                              |
|                                       | Lubricating oil system                                           | Change oil and oil filters as necessary                                                       |
|                                       | Intake air system                                                | Change intake air filters as necessary                                                        |
| 15,000                                | As 7,000 hours                                                   |                                                                                               |
| 16,000                                | As 8,000 hours                                                   |                                                                                               |
| 23,000                                | As 7,000 hours                                                   |                                                                                               |
| 24,000                                | As 8,000 hours plus                                              |                                                                                               |
|                                       | Compressor section                                               | Dismantle and inspect all components and check clearances                                     |
|                                       | Turbine blades                                                   | Remove sample blades for off-site condition assessment                                        |
|                                       | Auxiliary gearbox                                                | Dismantle and inspect all components and check clearances                                     |
| 31,000                                | As 7,000 hours                                                   |                                                                                               |
| 32,000                                | As 8,000 hours                                                   |                                                                                               |
| 39,000                                | As 7,000 hours                                                   |                                                                                               |
| 40,000                                | As 24,000 hours plus                                             |                                                                                               |
|                                       | Turbine section                                                  | Dismantle and inspect all components and check clearances                                     |
|                                       | Reduction gearbox                                                | Dismantle and inspect all components and check clearances                                     |
|                                       | General                                                          | Replace ancillary equipment as necessary                                                      |

Table 14. Indicative maintenance requirements – GT operating on natural gas (Griffith, 1995).



#### **5.4.3.1 Condition monitoring**

Three basic maintenance modes are:

1. Changing a component well within expected operating life to minimise failure-risk.
2. Changing a component only in event of failure.
3. Condition monitoring.

Mode 2 is satisfactory for small, simple items but a component's complete failure is too expensive for a complex plant, so option 1 has traditionally been adopted. It has become possible to gauge the further life of a component through condition monitoring techniques, so that a part can be replaced before failure but only when it shows signs of deterioration. Condition monitoring comprises visual inspection, oil analysis, and temperature and vibration detection.

### **5.5 Scale of cogeneration**

It is useful to consider cogeneration applications as either small-scale or large-scale as they are significantly different in each of the areas discussed so far.

#### **5.5.1 Small-scale cogeneration**

This refers to a cogeneration plant with a capacity of 1MWe or less, so the ICE is the appropriate prime mover (Good Practice Guide 3, 1995). Nearly all are available as pre-tested, packaged units. Typically 30% of the primary energy input is converted to electricity and 50% is recovered as heat (a heat-to-power ratio of 1.7 to 1). Measures encouraging the uptake of small-scale cogeneration are:

- standard packaged units are available,
- rising energy costs,
- environmental benefits,
- a variety of 'no capital cost' financing options are available from suppliers, and
- Government encouragement – removing institutional, legislative and market barriers.

##### **5.5.1.1 Small-scale cogeneration technology**

Figure 40 shows the main components and Figure 41 shows the energy balance. The cogeneration unit operates in parallel with the national grid which supplements it, or to which it exports excess electricity. Heat exchangers do all the heat recovery, a non-condensing heat exchanger recovers 80% to 85% of the available heat. Most units use synchronous generators, and the engines can operate at part-load. For example, a 75kWe unit can operate over a 37kWe to 75kWe range, with similar and proportional variation in heat production (Good Practice Guide 3, 1995). Electricity is usually not exported in small-

scale cogeneration. An acoustic enclosure surrounds the packaged unit to reduce noise to a range of 65 dB to 75 dB at around 1 metre distance.

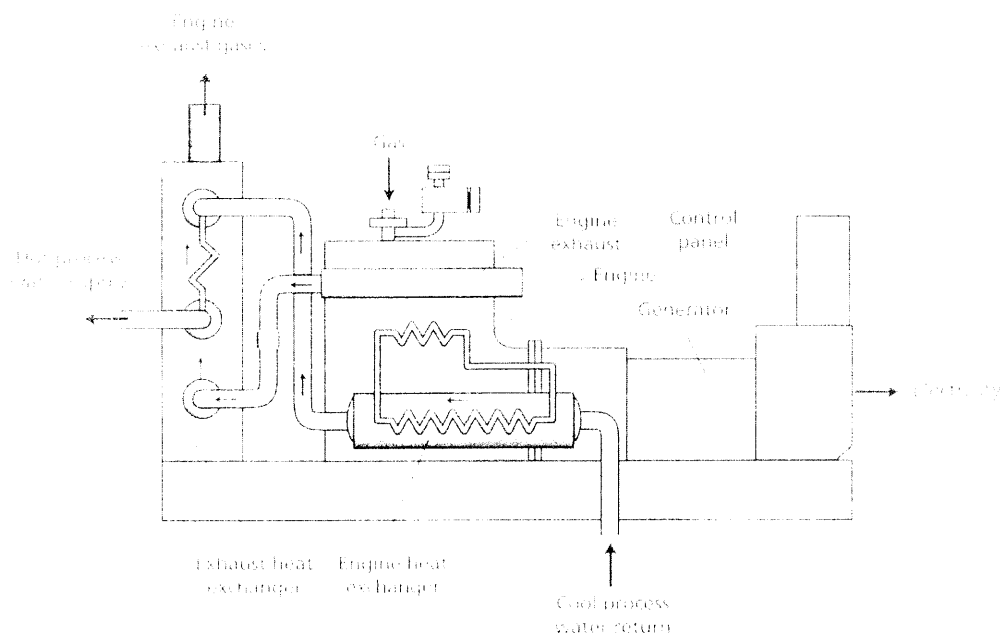


Figure 40. Typical small-scale cogeneration unit showing main components (Good Practice Guide 3, 1995).

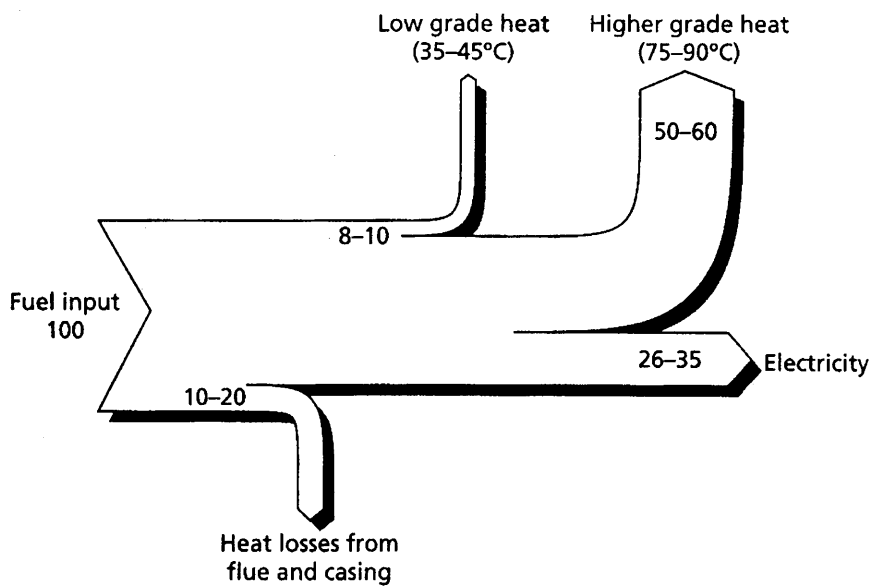


Figure 41. Typical small-scale cogeneration unit's energy balance (Good Practice Guide 3, 1995).

#### 5.5.1.1.1 Operating and control strategy

The unit achieves savings from running as long as possible so it cannot be sized for peak demand, as it would be under-used most of the time. The control system has the following priorities: safety, reliability, ease of plant operation, efficiency. From the user's point of view, the cogeneration unit may respond to heat demand with or without regard to electricity requirements, or respond to electricity requirements with due regard to site heat requirements. No single strategy is best for every situation. Choosing a good strategy could quadruple the savings from a given size and make of cogeneration installation (ERA Technologies, 1995). If the plant is too small to export much electricity, then the choice of strategy is not important. Otherwise the chosen control strategy must allow such exports. The least attractive strategy is usually one that follows electrical load and dumps surplus heat but this is not always the case. If difference in capital cost is ignored, modulation is generally as good as, or better than, on/off control. Finally, sophisticated energy management concepts with thermal storage for example, rarely give better payback than conventional systems.

#### 5.5.1.2 Small-scale cogeneration maintenance

Over the life cycle, maintenance would include routine service and lubrication as well as complete overhaul. Typical routine maintenance means changing oil, filters, spark plugs, and drive-belts at 600- to 2,000-hours intervals (Good Practice Guide 3, 1995), commonly performed in-house or contracted out. Cogeneration units come with microprocessor technology to control and continuously monitor performance and condition, generating logged data, which helps locate faults and schedule maintenance. The resulting regular reports and savings-calculations optimise maintenance costs and deliver high cogeneration system-availability. Maintenance costs per kW<sub>e</sub> decrease with increasing unit size.

#### 5.5.1.3 Conclusions about small-scale cogeneration

T&T has practically no cogeneration history but some relevant conclusions can be drawn from the experience with small-scale cogeneration in the UK (ERA Technologies, 1995):

- A cogeneration plant meeting only the base load does not necessarily provide the best payback.
- Where capital costs for essential ancillaries (components other than the prime mover) are high, there is likely to be an optimal cogeneration plant size.
- Near the optimal size, the performance is not very sensitive to the operating strategy (electrical- or heat-load following, with numerous variants), but away from the optimal it can be highly sensitive.
- Cogeneration-scheme viability is sensitive to electricity cost and engine maintenance cost, and less sensitive to fuel cost.
- With suitable demand patterns, optimised cogeneration installations give acceptable paybacks.



### 5.5.2 Large-scale cogeneration

The prime movers in large-scale cogeneration considered here are GTs and ICEs. Figure 42 shows a typical GT cogeneration unit. The heat-to-power ratio from a GT ranges from 1.5:1 to 3:1, and with after-burning it increases to between 5:1 and 10:1. Electricity-generation efficiency ranges from 20% to 35%, and is typically 30%. Smaller machines' efficiency falls off markedly if operated below 70% rated output. Larger machines have better part-load performance. 95% availability can be expected.

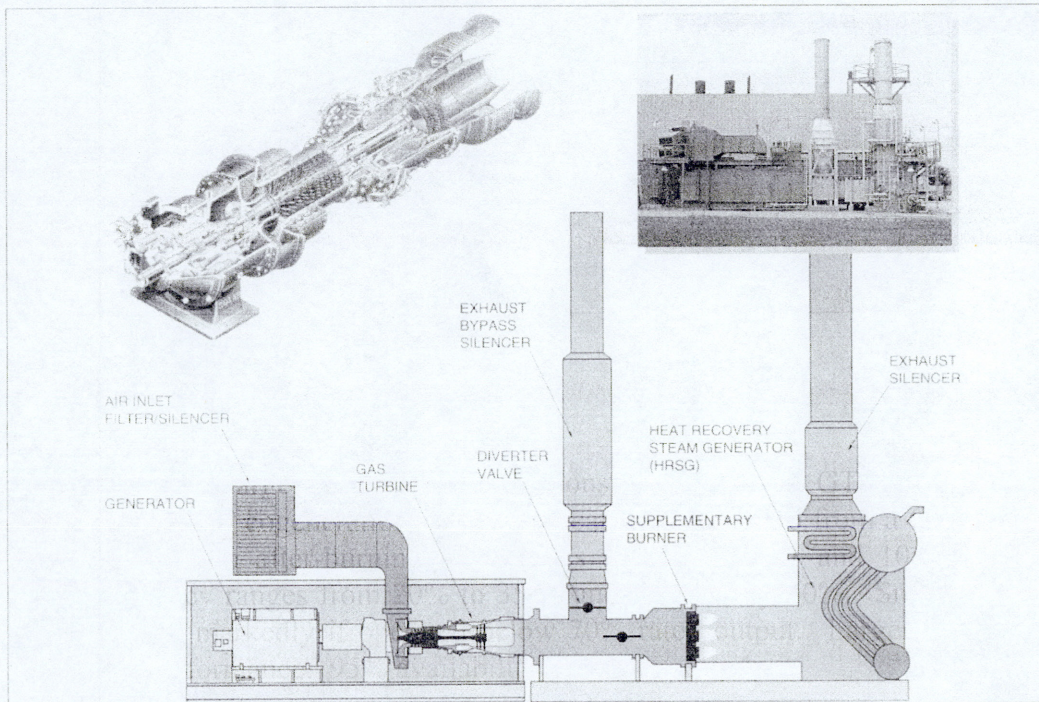


Figure 42. Gas turbine cogeneration diagram (Good Practice Guide 43, 1999).

GT advantages are:

- Potential operational flexibility in heat/power ratio.
- High reliability permitting long-term unattended operation.
- High-grade heat provided.
- Constant, high speed allows close frequency control of the electricity output.
- High power/weight ratio.
- Low cooling water requirements.
- Low foundation loads.

GT disadvantages are:

- Limited number of unit sizes within the output range.
- Needs high-pressure gas supply or in-house booster.
- High noise levels.



- Poor efficiency at low loading.

Figure 43 shows a schematic of a typical GT cogeneration unit and its energy balance.

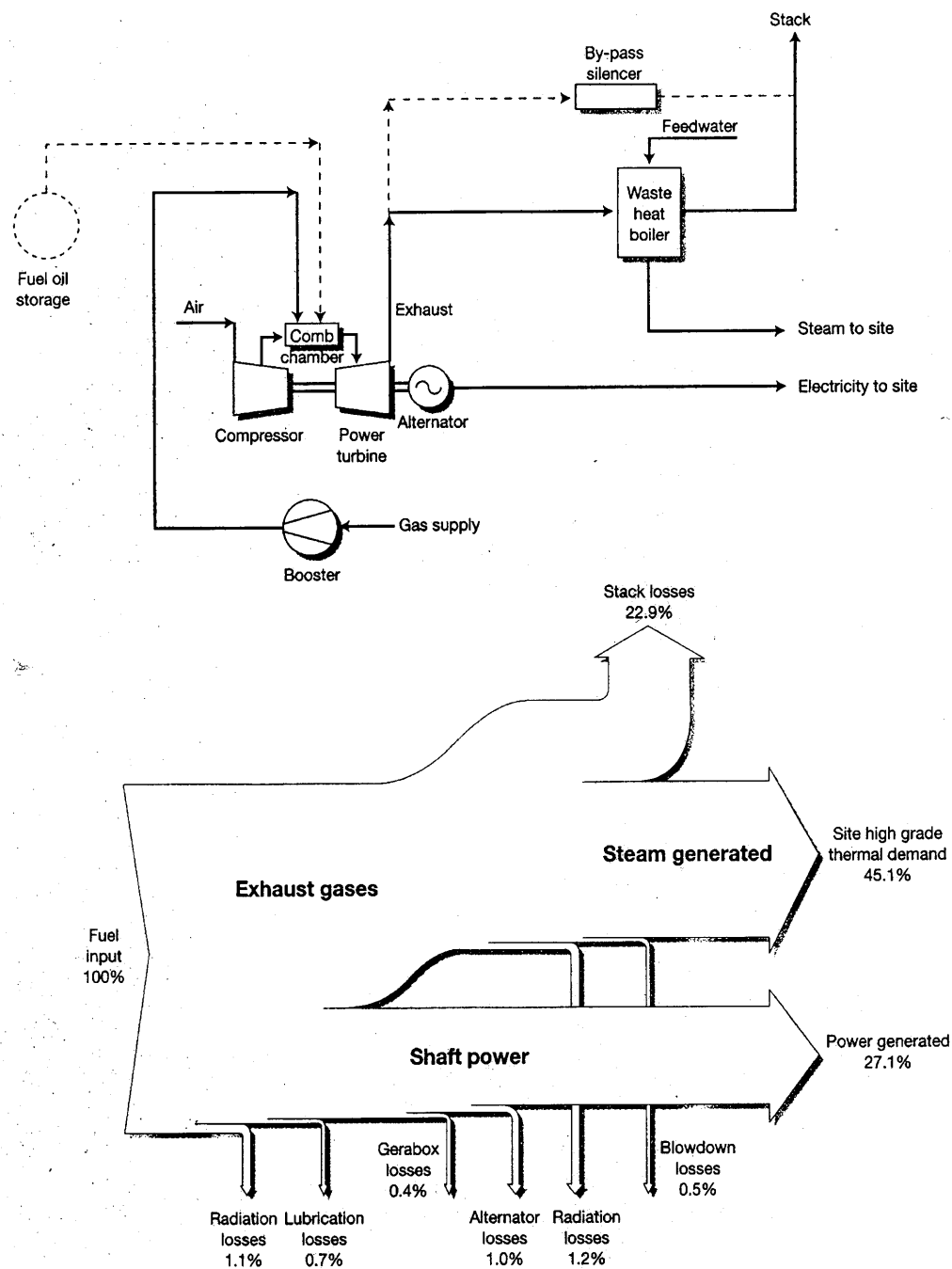


Figure 43. Schematic of a typical GT cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).

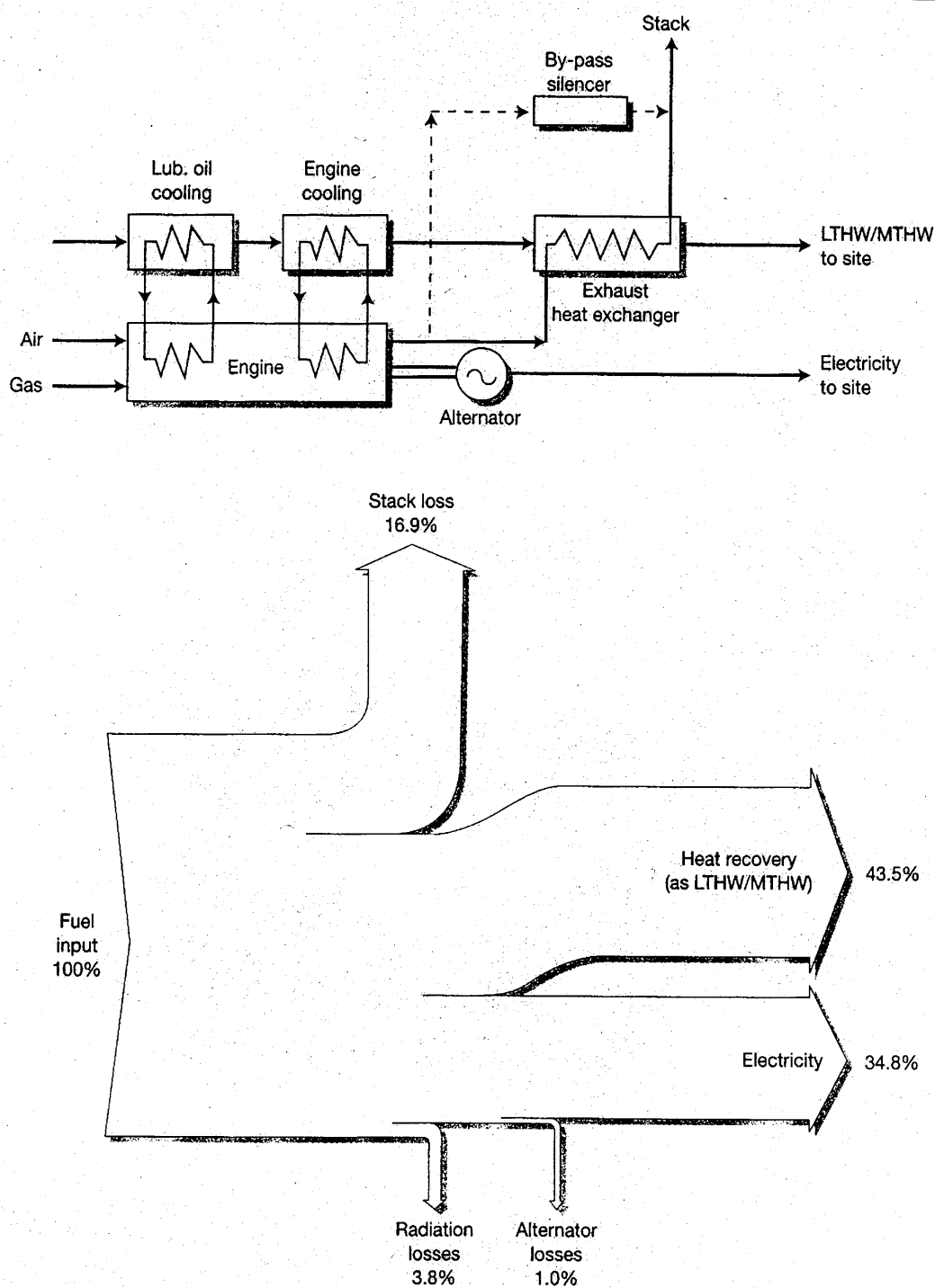


Figure 44. Schematic of typical spark-ignition engine cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).



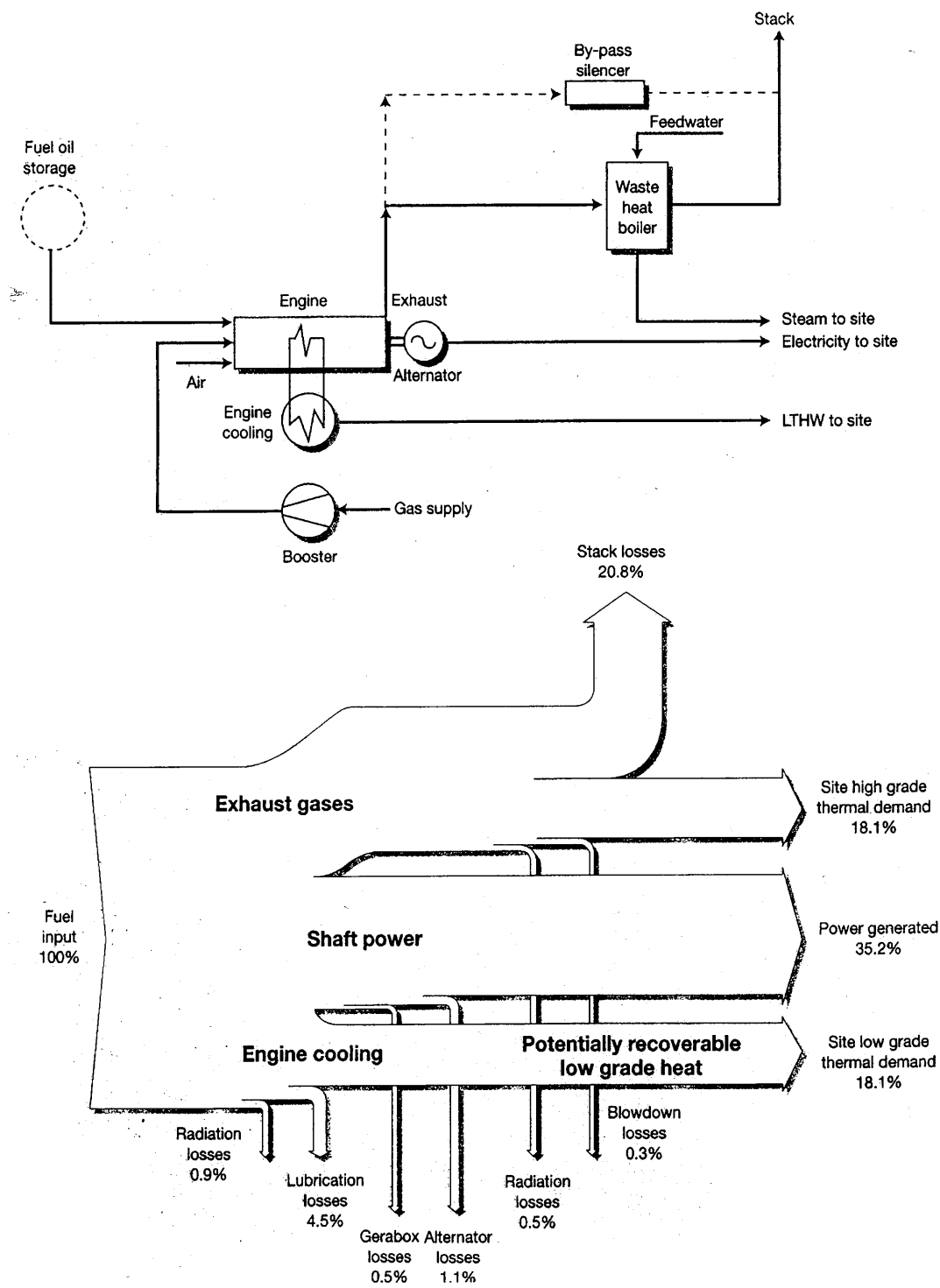


Figure 45. Schematic of typical dual-fuel compression-ignition engine cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).

ICEs have heat:power ratios of 1:1 to 2:1. The lubricating oil in these engines *must* be cooled so there is a compulsory heat supply of hot water, typically 70°C to 80°C, up to 120°C. Exhaust heat is available at up to 400°C. Engine availability is 85% to 92%. Figure 44 and Figure 45 show typical ICE cogeneration units and their energy balances.

ICE advantages are:

- High power efficiency achievable over a wide load range.
- Wide range of unit sizes.

ICE disadvantages are:

- It must be cooled even if the recovered heat is useless.
- A large portion of the recovered heat is low- and medium-grade from the jacket and lubricating oil cooling.
- Low power/weight ratio and out-of-balance forces requiring substantial foundations.

Figure 46 and Figure 47 show some other configurations for GT cogeneration, and Figure 48 displays the system characteristics for simple-cycle GTs, diesel ICEs, and gas ICEs in large-scale cogeneration. Table 15 summarises the different prime-mover characteristics.

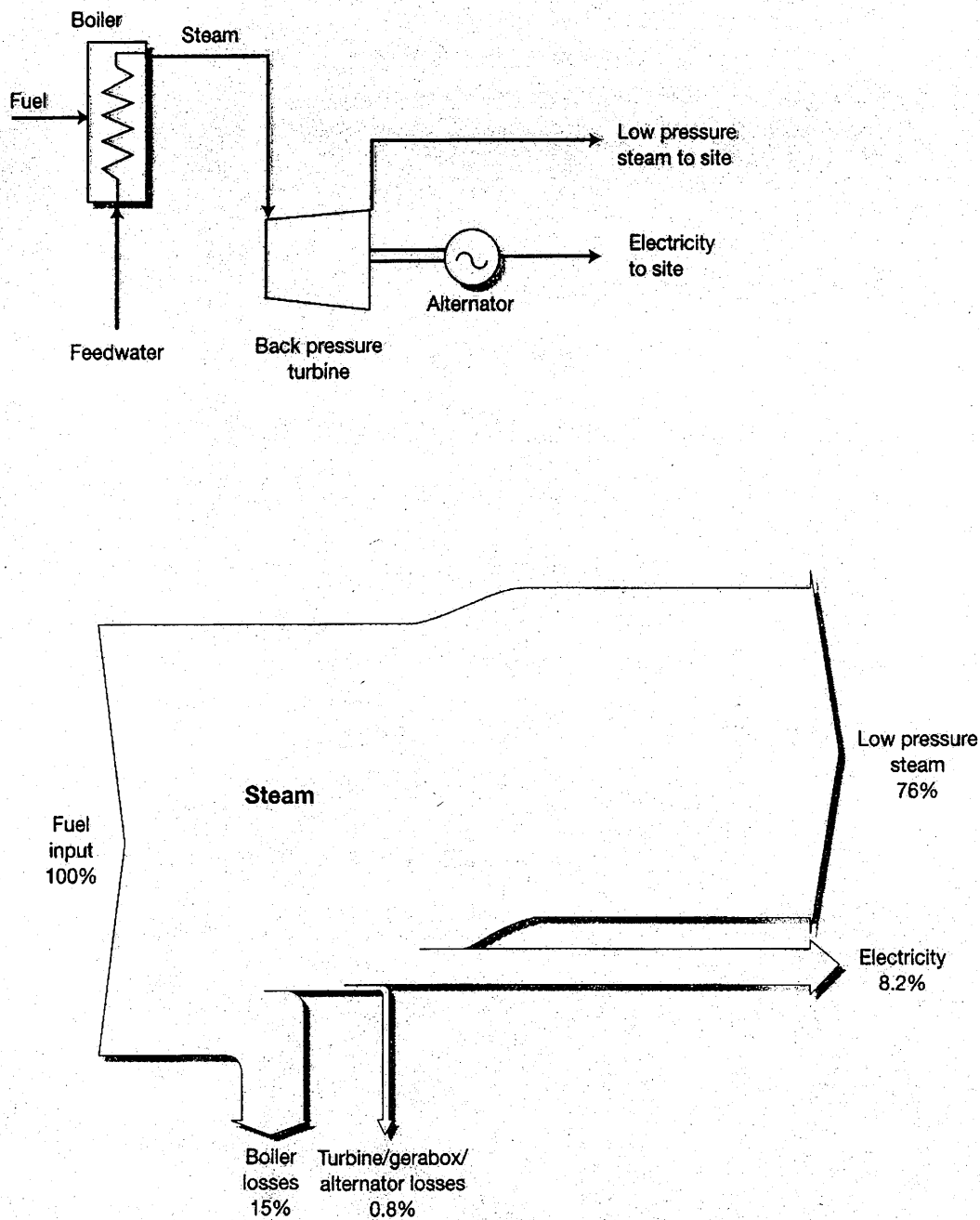


Figure 46. Schematic of back-pressure steam turbine cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).

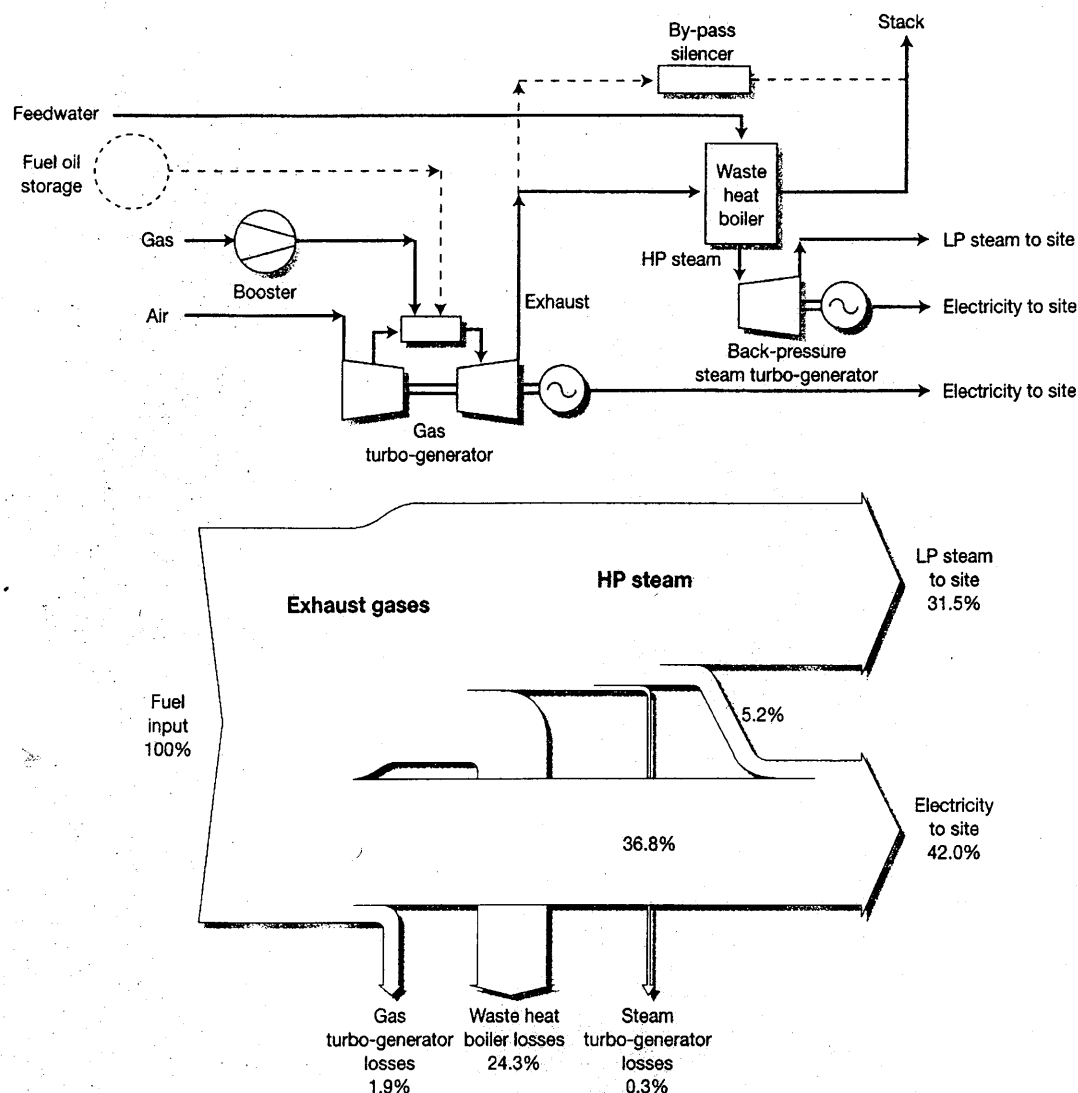


Figure 47. Schematic of combine cycle steam turbine cogeneration unit and its energy balance (GCV) (Good Practice Guide 43, 1999).

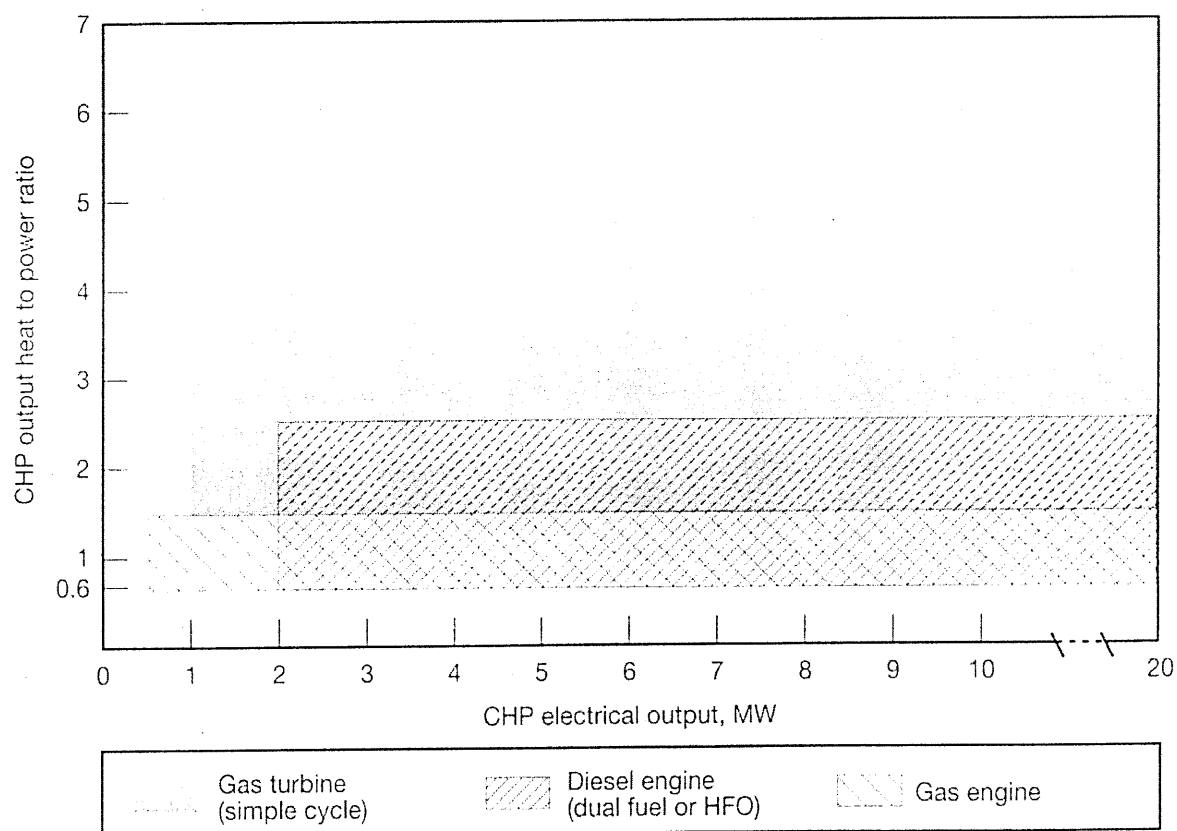


Figure 48. Cogeneration system characteristics for three types of prime mover (Good Practice Guide 143, 1999).

| Type of plant      | Typical output range        | Typical fuels                                        | Typical heat:power ratio                              | Grade of heat output |
|--------------------|-----------------------------|------------------------------------------------------|-------------------------------------------------------|----------------------|
| Gas turbine        | 0.5 MW <sub>e</sub> upwards | Natural gas<br>Gas oil<br>Landfill, bio and mine gas | 1.6:1<br>Up to 5:1 with supplementary firing          | High                 |
| Compression engine | 2 MW <sub>e</sub> upwards   | Natural gas +5%<br>Gas oil<br>Heavy fuel oil         | 1:1 to 1.5:1<br>Up to 2.5:1 with supplementary firing | Low and high         |
| Spark engine       | Up to 4 MW <sub>e</sub>     | Natural gas<br>Landfill, bio and mine gas            | 1:1 to 1.7:1                                          | Low and high         |
| Steam turbine      | 0.5 MW <sub>e</sub> upwards | Any, but converted to steam                          | 3:1 to 10:1                                           | Medium               |
| Combined cycle     | 3.5 MW <sub>e</sub>         | As gas turbine                                       | Down to 1:1                                           | Medium               |

Table 15. Summary of prime movers (Good Practice Guide 43, 1999).

### 5.5.2.1 Performance monitoring for large-scale cogeneration

Performance monitoring is a key function of modern control systems. Monitoring data is needed to:

- detect faults, malfunctions and under-performance, at the earliest possible stage,
- enable fine-tuning, optimisation,
- facilitate modifications to respond to alterations in site energy loads, new or amended electricity supply tariffs, fuel price and availability fluctuations, and
- audit the return on investment.

*Optimisation* is one step further in control and monitoring (Good Practice Guide 43, 1999). The objective is to maximise the installation's economic benefits. It may be done on-line using continuously updated, real-time data, or off-line using snapshot (current or historical) data or manual data input. On-line optimisation is either open loop, advisory mode only, or closed loop where the optimiser adjusts the cogeneration system's operating parameters.

### 5.5.2.2 Maintenance

Prime-mover maintenance is the second biggest operating cogeneration cost behind fuel costs (Good Practice Guide 43, 1999). Scheduled maintenance downtime for GTs is



typically 2 weeks per year, and 5 weeks per year for ICEs. Maintenance contracts range from routine scheduled maintenance to guaranteed availability and engine replacement.

## 5.6 Gas turbine small-scale cogeneration

Traditionally the majority of existing GTs below 1MWe capacity have been designed for stand-by operation and not continuous power generation due to their high cost and low efficiency. This makes them unsuitable for cogeneration. Commercial, packaged small-scale cogeneration is mostly based around reciprocating engines primarily because of their lower cost. But plenty of the recoverable heat is low-grade (below 85°C) whereas a GT has about 2.5 times the capacity to generate steam (Best Practice Programme, 1992). Small-scale GT cogeneration is an emerging technology. Figure 49 shows the major components and interfaces.

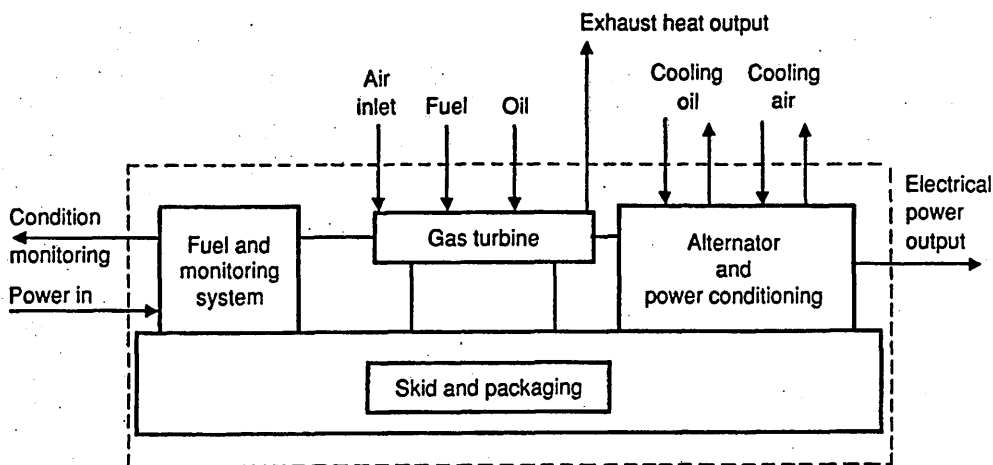


Figure 49. Small-scale GT cogeneration unit – major components and interfaces (Best Practice Programme, 1992).

### 5.6.1 The hardware

For a typical, small, 250kWe GT, the power output at the shaft is delivered at 20,000 to 40,000 rpm. This would need a gearbox to reduce rotation to 1,500 rpm for the generator to produce 50Hz electricity. Alternatively, a high-speed alternator can be coupled directly to the output shaft and the power frequency reduced using electrical or electronic circuits. The two generator options have little difference in production costs but the high-speed alternator is smaller, has a lower weight, and fewer mechanical parts resulting in higher reliability.

Figure 50 shows a schematic of the unit. The major components are a recuperated GT, alternator and power conditioning, fuel and monitoring systems, and skid and package. Table 16 summarises performance data for a recuperated 250kWe GT.

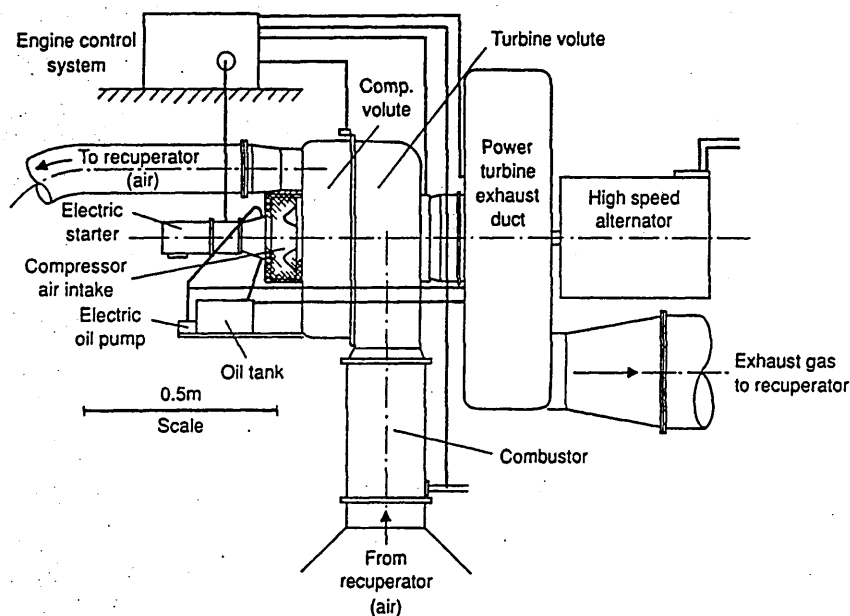


Figure 50. Small-scale GT cogeneration schematic (Best Practice Programme, 1992).

|                                      |      | Base load rating |
|--------------------------------------|------|------------------|
| Mass flow (air)                      | kg/s | 1.6              |
| Cycle pressure ratio                 |      | 5.0              |
| Recuperator effectiveness            | %    | 85               |
| Fuel flow                            | MJ/s | 0.7              |
| Output shaft speed                   | rpm  | 38,000           |
| Shaft power output                   | kW   | 250              |
| Shaft thermal efficiency (net basis) | %    | 34               |
| Potential exhaust heat               | kW   | 450              |

Table 16. GT performance data (Best Practice Programme, 1992).

### 5.6.1.1 Recuperator

In a recuperated GT heat is extracted from the exhaust stream to pre-heat the combustion air. For small GTs to generate electricity at 34% efficiency, comparable to ICEs, the engine must be recuperated. This reduces the exhaust temperature but it is still suitable for generating steam. Simple cycle GTs typically have an electricity generating efficiency of 20% (heat/power ratio of 4:1). Characteristics of the recuperator heat exchanger are: high pressure difference between streams; high volume flow ratio; and high temperature gas streams.

5.6.1.2 Alternator and power conditioning

Alternator technology choices are:

- 1. conventional (1,500 rpm) alternator, which needs a 25:1 gearbox,
- 2. induction motor/generator, and
- 3. high-speed alternator operating at 38,000 rpm with an air-cooled rotor and oil-cooled stator.

Electrical conditioning is needed with a high-speed alternator to condition the power output frequency and voltage to be compatible with the grid.

Fuel and monitoring systems comprise screw compressors for the gas supply and a gas metering system. The skid and packaging contribute significantly to the installation cost.

Table 17 compares the reliability of GT- and ICE cogenerators.

|                     | Gas turbine | Reciprocating |
|---------------------|-------------|---------------|
| Reliability %       | 99          | 96            |
| Availability %      | 97          | 90            |
| Start reliability % | 99          | 95            |

Table 17. Cogeneration reliability (Best Practice Programme, 1992)

5.7 Cogeneration and energy policy

Elements of the UK’s energy policy and strategy can be selected as a starting point to set and agenda for cogeneration development in T&T. Some relevant policy initiatives are:

- Create new market for electricity sales from cogeneration system – small-scale cogeneration schemes should get good prices for their power, also rewarding cogeneration’s environmental benefits.
- Secure economic and environmental benefits to the nation’s power supply which local cogeneration schemes can bring – local generation recognised and rewarded rather than regarded as an economic threat.
- Enable future power stations to be co-located with major thermal loads – for example industrial cogeneration meeting local power and thermal requirements as an alternative to higher cost and more environmentally disruptive developments.
- Ensure investment is targeted on energy efficient measures like cogeneration – for example, using tax write-offs.
- Support international initiatives promoting cogeneration – such as carbon- and energy taxes.



## Chapter 6. Liquefied natural gas

Natural gas, and especially liquefied natural gas (LNG), is in a position to participate strongly in the energy growth now being triggered by strong worldwide economic growth, increasingly open markets, and expanding international trade. The comparative remoteness of much of the resource base from established and emerging markets can make LNG a very attractive option for transporting natural gas. LNG is practically used only as a means for transporting natural gas, as it is re-gasified at the user's end and used in all conventional natural gas applications.

In 2000 the Atlantic LNG single-train plant converted ~40% of T&T's natural gas production into LNG (see Chapter 4, Section 4.1). With two additional trains planned, this percentage will increase in the future. Thus LNG must be considered the Government's main energy-policy thrust regarding natural gas.

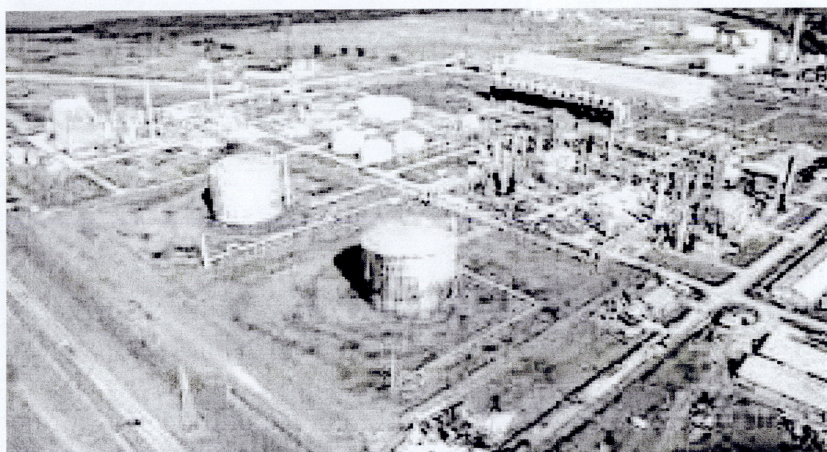


Figure 51. The Atlantic LNG Plant in Point Fortin, Trinidad.

### 6.1 Worldwide LNG potential

World energy demand is predicted to grow on average about 2% annually over the next decade. Worldwide gas production now supplies 20% of the world's energy requirements. Over the next 10 years, worldwide natural-gas demand is forecast to grow 3.5% per year (Figure 52). This compares to about 2.2% for oil and exceeds anticipated general economic growth trends. Using gas as LNG is a relatively recent contributor to this gas growth. Anticipated growth of 7% per year over the next 10 years will increase LNG's share of worldwide energy use to about 2% (Brown and Clary, 1997).



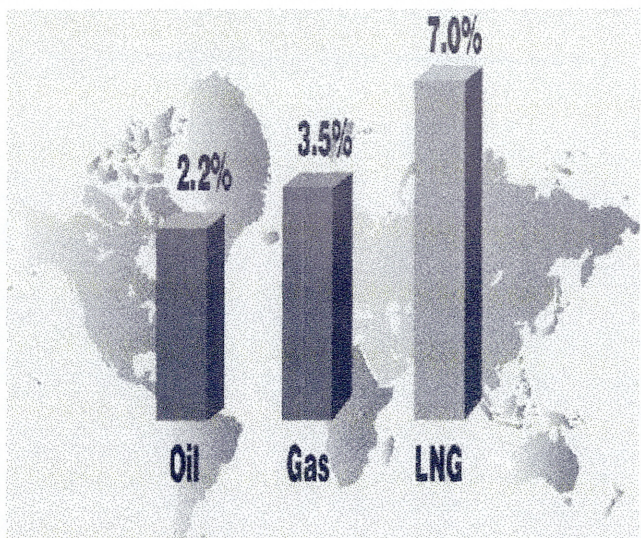


Figure 52. Forecast world energy-demand growth (per year) over the next decade (Brown and Clary, 1997).

Figure 53 displays the distribution of gas reserves around the world, thus indicating which regions are most have the most potential for LNG development. More than half the world’s gas reserves and future potential occurs in seven countries that are remote from established markets: Russia, Iran, Kazakhstan, Saudi Arabia, Qatar, Turkmenistan, and Australia. Despite this remoteness, these resources will play a dominant role via long-haul pipeline and LNG. Russia is already a large producer with significant exports via long-haul pipeline. Australia is also expanding its LNG trade.

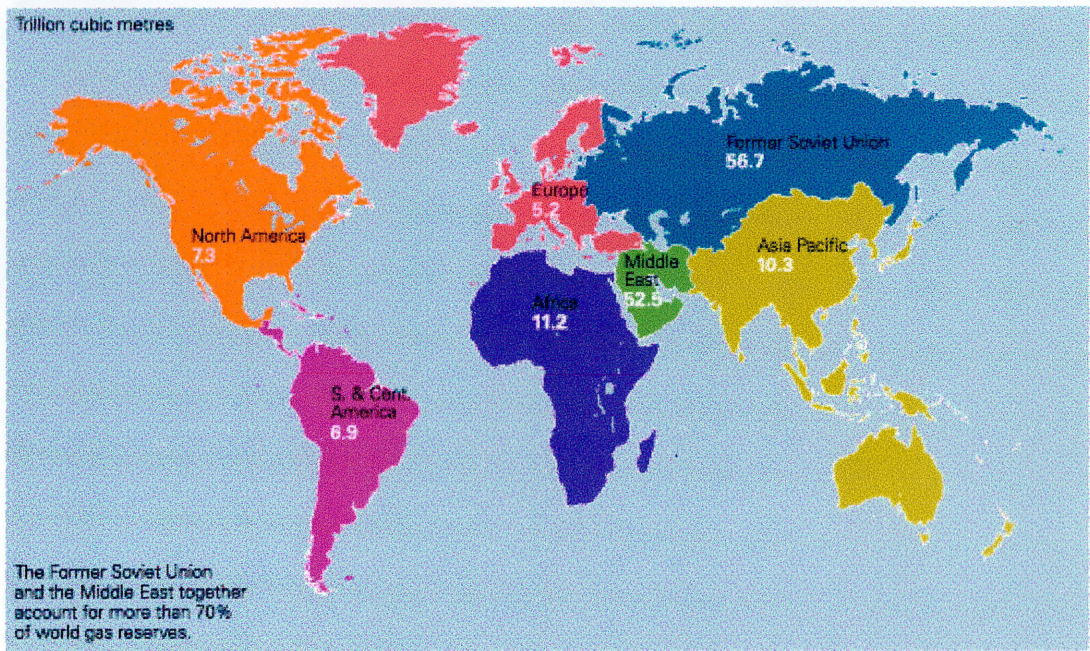


Figure 53. Natural-gas proven reserves at end 2000 (BP Amoco, 2001).



Focus on significant reserve development through LNG is on countries such as Qatar, with giant gas fields that have not been significantly depleted. The Former Soviet Union and the Middle East clearly dominate the world potential for gas resources (BP Amoco, 2001). The Former Soviet Union has 37.8% (56.7 Tm<sup>3</sup>) of the world's total gas reserves and an estimated 40% (66 Tm<sup>3</sup>) of the world's gas future potential. The majority of this is in remote Arctic areas such as Western Siberia. The Middle East has approximately 35% (52.5 Tm<sup>3</sup>) of the world's gas reserves and 11% (17 Tm<sup>3</sup>) of its undiscovered potential. Qatar's North field is the world's largest natural-gas field, with reserves of more than 8.5 Tm<sup>3</sup>. With contractual sales to Japan and Korea, it will soon be one of the world's largest LNG suppliers.

The Asia-Pacific Rim countries hold 6.8% (10.3 Tm<sup>3</sup>) of the world's gas reserves and 12% (18 Tm<sup>3</sup>) of the world's undiscovered gas potential. With 60% of the world's population, this region is destined to have the largest demand for oil and gas resources. LNG could help to balance supply and demand between the Middle East and Asia-Pacific Rim, linking these two major resource regions. Europe's estimated gas resources are currently 3.5% (5.2 Tm<sup>3</sup>) of the world's reserves and 8% (12 Tm<sup>3</sup>) of the undiscovered potential. Gas fields in the UK, the Netherlands, Norway, Germany, and Italy supply substantial quantities but almost 40% is imported from Russia, Algeria, and elsewhere. LNG supplied from other Middle East countries could eventually be significant.

North America's gas market is the most mature with a consumption of 0.6 Tm<sup>3</sup>/year and is estimated to increase to 0.70-0.73 Tm<sup>3</sup>/year by 2010. Gas reserves along the Canadian east coast and the Scotian Shelf may also become significant. LNG is not expected to be a major contributor given the substantial future potential of 25 Tm<sup>3</sup>, remaining in North America.

African natural-gas sources represent 7.4% (11.2 Tm<sup>3</sup>) of the world's gas reserves and 5% (7 Tm<sup>3</sup>) of the undiscovered gas potential. Potential gas contributions are concentrated in mainly in Algeria and West African countries.

South and Central America has 4.6% (6.9 Tm<sup>3</sup>) of the world's gas reserves and approximately 6% (8.5 Tm<sup>3</sup>) of the undiscovered gas potential. Most of the known gas resources are in Venezuela and Colombia. However, South America's southern regions are still generally considered immature. A considerable proportion of the future potential is estimated to be in these regions.

## 6.2 Worldwide LNG trade

The 1990s have witnessed a turnaround in the growth of LNG demand (Figure 54) that has tracked equally strong natural-gas demand growth. A study by the US-based Institute of Gas Technology (IGT) reveals that LNG imports worldwide have climbed nearly 8% per year since 1980 and account for 25% of all natural gas traded internationally. In the mid-



1970s, the share was only 5% (True, 1998). In 1996, world LNG trade rose 7.7% to a record 92 billion m<sup>3</sup>, outpacing the overall rate for natural gas, which increased 4.7% in 1996. By 2015, the IGT study forecasts that natural-gas use would surpass coal as the world's second most widely used fuel, after petroleum. Much of this growth will occur in the developing countries of Asia where gas use was projected to grow 8%/year through 2015.

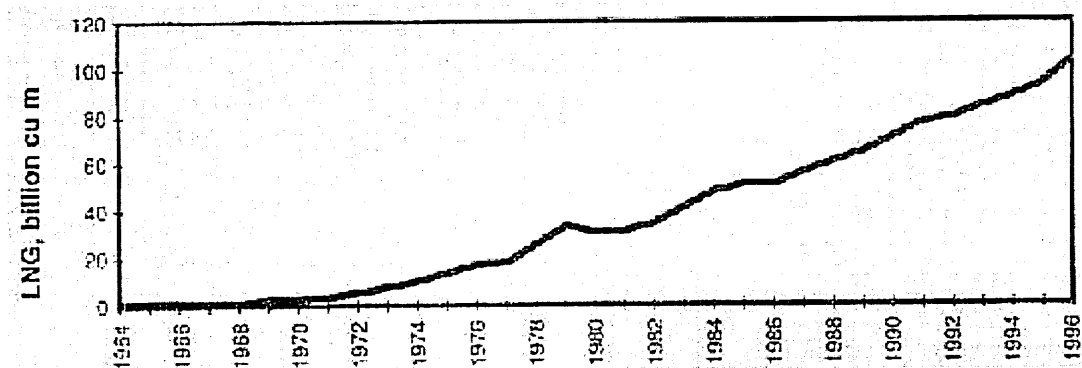


Figure 54. World LNG trade growth (True, 1998).

Another LNG-trade study, from Ocean Shipping Consultants Ltd., UK (True, 1998) reflects similar trends. Global LNG demand will grow significantly through to 2010 and result in eventual growth in sea-borne shipping capacity. World trade in LNG expanded from 92.5 billion m<sup>3</sup> in 1995 to 137.0 billion cubic metres (billion m<sup>3</sup>) in the year 2000 (BP Amoco, 2001), and will expand to 155.8 billion m<sup>3</sup> by 2005. By 2010 LNG trade levels will reach more than 183 billion m<sup>3</sup>, equivalent to an expansion of more than 4.5% per year during the 15-year period. The study concluded that LNG trade expansion will be most dynamic near-term, bolstered by expansion projects in Indonesia and Malaysia, along with new ones in Qatar, Oman, Nigeria, and Australia.

### 6.2.1 Worldwide LNG imports and exports

IGT figures for 1996 (Table 18) show that almost 77% of the world's LNG were delivered to the three Asian countries, Japan, Korea, and Taiwan. Demand in the region rose nearly 9% that year. Japan retained the title of world's largest LNG importer, with 61% of the total, but its market grew by only 5%. Since Korea began importing LNG more than 10 years ago its demand has grown by 20% per year; in 1996, Korean imports grew 40% to 13 billion m<sup>3</sup>. Almost all the remainder of world LNG production went to Europe in 1996, where markets have remained static. That changed for 1997: Italy completed refurbishing its only terminal at Panigaglia and resumed imports from Algeria. Turkey nearly doubled its imports in 1996 and has an enormous appetite currently being fed by spot market purchases.

| Country         | Million metric tons | Billion cu m of gas | % of total | % change over 1995 |
|-----------------|---------------------|---------------------|------------|--------------------|
| Japan           | 44.237              | 56.034              | 60.93      | 4.53               |
| Korea           | 9.470               | 11.995              | 13.05      | 35.99              |
| Spain           | 5.568               | 7.053               | 7.67       | 0.19               |
| France          | 5.104               | 6.455               | 7.03       | 0.13               |
| France/Belgium* | 0.165               | 0.209               | 0.23       | -75.97             |
| Belgium†        | 2.662               | 3.025               | 3.94       | -5.95              |
| Taiwan          | 2.575               | 3.262               | 3.55       | 5.55               |
| Turkey          | 1.767               | 2.238               | 2.43       | 97.63              |
| U.S.            | 0.850               | 1.077               | 1.17       | 124.35             |
| <b>Total</b>    | <b>72.598</b>       | <b>91.959</b>       | <b>100</b> | <b>7.68</b>        |

\*Joint purchases from Abu Dhabi. †To this should be added 0.485 million cu m received by GdF for Distrigaz.

Table 18. LNG importing countries, 1996 (True, 1998).

For exports (Table 19), Asia-Oceania accounted for 70% of the World's LNG production in 1996, the world's largest exporter being Indonesia with 35% of total sales. Algeria regained its second-place standing after revamping its plants. Exports from Malaysia rose 29% in 1996 with the Dua plant completion. Qatar moved into ninth position as exporter at the start of 1997 and exported more than 12 million tonnes per year in 2000. Oman, Trinidad, and Nigeria were set to join the list of exporting countries.

| Country      | Million metric tons | Billion cu m of gas | % of total | % change over 1995 |
|--------------|---------------------|---------------------|------------|--------------------|
| Indonesia    | 25.372              | 32.133              | 34.95      | 3.85               |
| Algeria      | 14.412              | 18.258              | 19.85      | 8.94               |
| Malaysia     | 12.112              | 15.342              | 16.68      | 29.11              |
| Australia    | 7.151               | 9.058               | 9.85       | 2.19               |
| Brunei       | 6.038               | 7.649               | 8.32       | -0.64              |
| Abu Dhabi    | 5.315               | 6.732               | 7.32       | 9.03               |
| U.S.         | 1.312               | 1.662               | 1.81       | -1.79              |
| India        | 0.885               | 1.121               | 1.22       | -18.99             |
| <b>Total</b> | <b>72.598</b>       | <b>91.959</b>       | <b>100</b> | <b>7.68</b>        |

Table 19. LNG exporting countries, 1996 (True, 1998).

The Ocean Shipping Consultants Ltd. study forecasted that Japan will import nearly 80 billion m<sup>3</sup> per year by 2010, 36% more than in 1995. South Korea's commitment to gas use and LNG imports is reflected in a growth of about 314% in trade levels to 29.5 billion m<sup>3</sup> per year by 2010. Taiwan's imports will also see more than a threefold increase during 1995-2010, increasing to 14 billion m<sup>3</sup> per year. Japan, South Korea, and Taiwan combined will account for 70% of world LNG trade in 2010. New markets in Thailand, India, China, and Philippines should boost LNG trade medium- to long-term, although their combined trade share by 2010 will only reach 10% equivalent to 17.5 billion m<sup>3</sup> per year.

### 6.3 LNG technology

Origins of LNG manufacturing technology can be traced to the low-temperature cryogenics used in air liquefaction developed in the 1920s. The first application of LNG was in the early 1930s in helium recovery from natural gas for strategic purposes (use in military balloons). The process was based on liquefying the hydrocarbon components of natural gas, leaving behind helium for recovery as a gas. The LNG was re-vaporised after helium extraction and sold as pipeline gas. In 1939, Hope Natural Gas Co. of the US, built the first plant that actually liquefied natural gas and stored LNG for later use (Bellow Jr. *et al.*, 1997). In the early 1960s, major investments started occurring in LNG 'base-load' plants. These are commercial-scale plants liquefying natural gas for export to consuming markets. The Camel plant in Arzew, Algeria, was the vanguard of such plants with a three-train total capacity of 7 million m<sup>3</sup> per day. It exported LNG product to the UK with the first cargo shipped on 7 October 1964. This plant is still operating today. LNG plants are typically designed for 20 years life, although extension to 40 years is possible with little extra cost.

Plants were later built in Skikda in Algeria, Marsa El Brega in Libya, and Kenai in Alaska. The product from the Algerian and Libyan plants went to supply the French and Italian natural-gas markets, while the Alaskan plant product went to Japan. Throughout the 1970s, LNG manufacturing experienced a rapid growth through base-load plants, most of which were installed in South-east Asia. Japan initially fuelled this growth, then Korea and Taiwan, whose rapidly growing appetites for LNG were driven by strategic priorities to diversify their energy-supply sources and to alleviate air pollution in their densely populated cities. Plants with capacities ranging from 24 to 34 million m<sup>3</sup> per day each were built in Lumut (Brunei), Arun and Badak (Indonesia), Das Island (Abu Dhabi), and Bintulu (Sarawak). At the same time, the Algerian plants in Arzew and Skikda added additional LNG trains and Marsa El Brega (Libya) built a four-train plant to meet burgeoning demand from France, Italy, and Spain.

The economic downturn in the 1980s brought on by the rapid increases in crude prices slowed LNG growth somewhat. Economies began to strengthen, however, and a sharp upturn in industrial development in much of Asia, coupled with increasing global environmental concerns, have catapulted LNG to the forefront of energy growth worldwide. As a result, the 1990s have brought many new LNG projects to fruition with major installations in Trinidad, Qatar, Nigeria, and Oman as well as several existing plant expansions. This growth forecast puts LNG as the leading energy source in supplying an increasing share of new energy worldwide well into the 21st Century (Bellow Jr. *et al.*, 1997).

#### 6.3.1 LNG-process developments

Natural gas at the wellhead is unsuitable to be liquefied because it contains impurities that would hamper or damage the liquefaction equipment. Thus, raw natural gas must undergo several operations to remove the contaminants that would freeze, plug, or corrode the liquefying cryogenic facilities. Figure 55 is a schematic of the essential steps: entrained







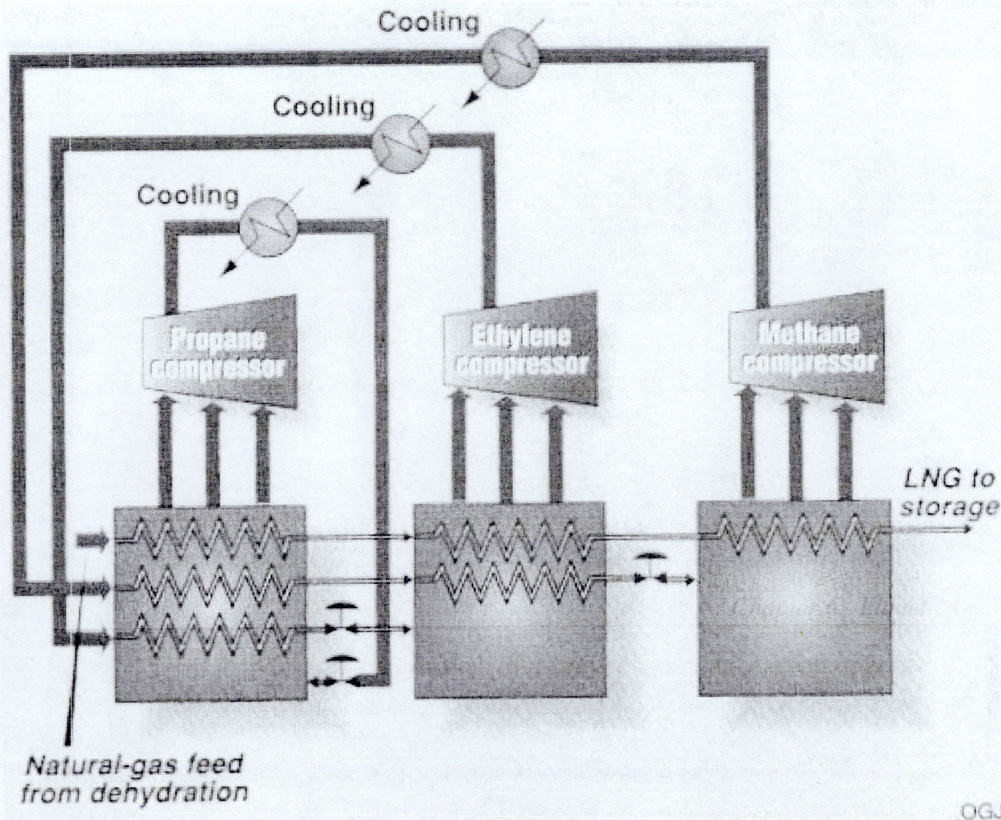


Figure 56. Classical cascade refrigeration cycle (Bellow Jr. *et al.*, 1997).

The Mixed Refrigerant (MR) cycle was developed to reduce the number of compressor and heat-exchanger trains, and first used in Libya's Marsa El Brega plant. In this cycle, a single refrigerant made up of nitrogen, methane, ethane, propane, butane, and pentane, is compressed, cooled, then flashed, either at a single or double pressure level, before cooling the treated natural-gas feed in a multi-stream exchanger (Figure 57). MR make-up and compression levels were tailored to match the needs associated with the feed-gas composition and plant-inlet conditions.



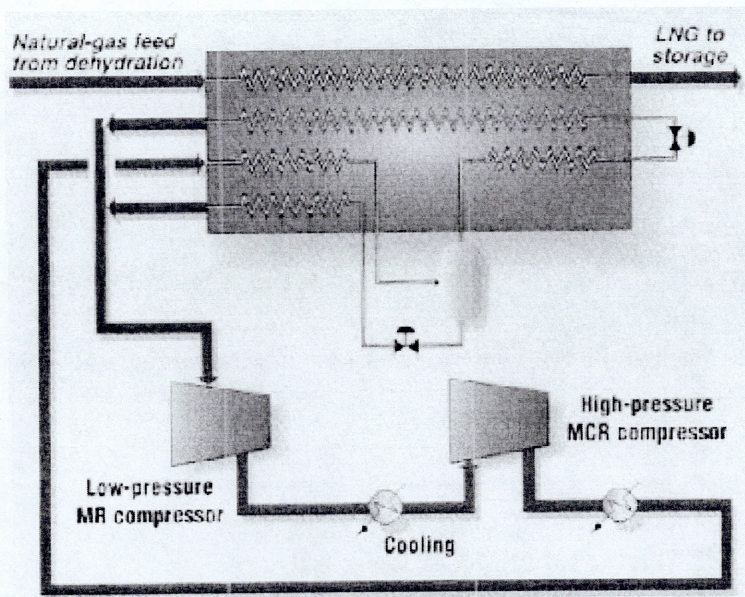


Figure 57. Mixed refrigerant cycle (Bellow Jr. et al., 1997).

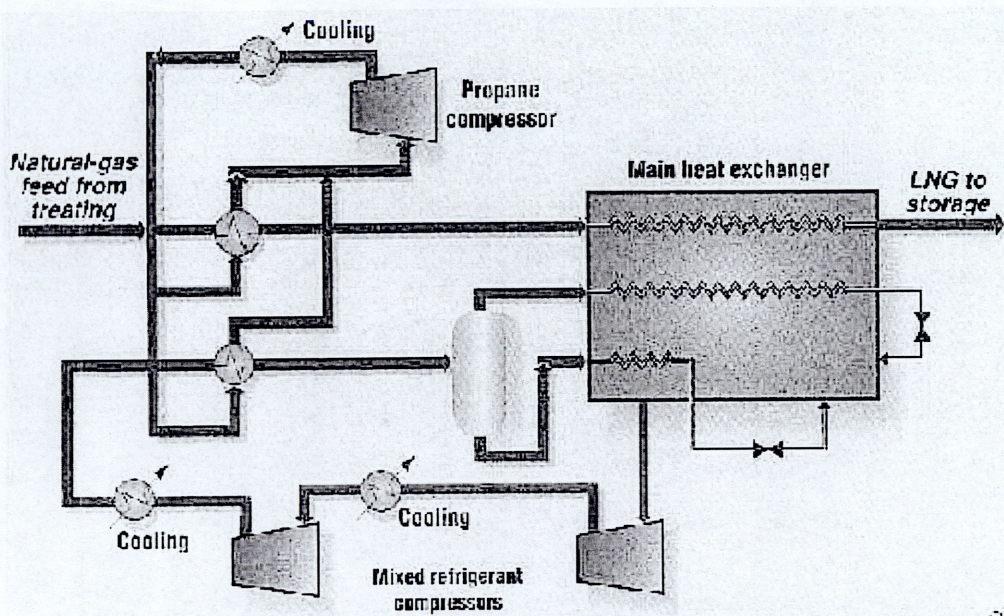


Figure 58. Pre-cooled mixed refrigerant cycle (Bellow Jr. et al., 1997).

The Pre-cooled Mixed Refrigerant (PMR) cycle is the latest liquefaction-cycle development. This combines the simpler MR-cycle refrigerant-train configuration with the CR-cycle efficiency. In the PMR cycle (Figure 58), either a single component or a multi-component refrigerant is used to pre-cool the mixed refrigerant before the latter is flashed and exchanged against the treated natural-gas feed. This cycle uses a single-component pre-cool refrigerant (propane) and has been used in the majority of the latest LNG-plant



designs. Nigeria's first LNG plant currently under construction at Bonny Island will be the first to use a dual-component pre-cooling refrigerant in a PMR.

### 6.3.2 LNG technology developments

The major technical developments in the LNG industry have been in maximising the capacity of the major equipment in the process plant to improve individual-train capacity for economies of scale. The major plant units are the acid-gas absorber in the treating unit, the main heat exchanger in the liquefaction unit, and the centrifugal compressors on the pre-cooling refrigerant and the mixed refrigerant. Economy of scale translates into reduced total plant cost per unit LNG produced. Considering that liquefaction technology is mature, future technological advancements in LNG manufacturing would have the same focus, i.e. achieving equipment-capacity improvement while maintaining and improving safety, efficiency, reliability, and maintainability. Further developments of proprietary solvents/adsorbents will continue the progress in improving efficiency and contaminants-removal selectivity with the benefits of reduced capital and operating costs.

The industry is also looking at smaller units; a major new frontier for the LNG industry will probably be commercialising floating LNG technology (as opposed to conventional onshore LNG construction). This concept has been studied for many years. Recently the industry has developed a renewed interest in such an approach in an effort to reduce the costs and schedule of LNG projects. Floating LNG technology would place liquefaction close to the offshore natural gas platform and avoid significant natural-gas transportation costs. Industry consortia such as the Gas Utilisation Research Forum and several contractors continue to investigate alternative configurations and sizes of floating LNG plants.

## 6.4 LNG economics

LNG provides a way to move natural gas to markets geographically restricted from pipeline connections, and in effect completes the global chain of the natural gas business, which came first with regional, then with international pipelines.

The following basic principles make a LNG project feasible (Acord, 1995):

- Joint venture partners and the host country need a mutual understanding and commitment to every component of the LNG business chain. The goal is to maximise the value of the gas extracted at the wellhead. This key point yields the greatest economic benefits to all parties, and means that the LNG plant and shipping are generally operated on a cost pass-through basis, (see Section 6.4.1).
- A long-term sales contract with a floor price, in which the LNG buyers share some of the project risk and facilitate some of the financing, is required in order to both justify and protect the partners' and the hosts' investments.
- Getting LNG to the burner-tip (i.e. end user) requires a complex set of business arrangements, which extend from the gas reservoir to the power plant or industrial facility that burns the gas. The distance can cover thousands of miles. LNG is a

business chain between seller and buyer that involves many activities and specialised single purpose facilities. The gas field must be drilled and production equipment installed, onshore or offshore. A LNG plant and harbour facilities need to be constructed. Ships must be ordered. The receiving country will need a port and re-gasification facilities and pipelines to the end-users. If the LNG is required for increased power generation, a new power plant will be needed.

A project has some natural economic advantages if the resource base is large enough to support expansions beyond 2 trains, liquid yield is high, and shipping distances to prospective markets are as short as possible (Acord, 1995). From the supplier's standpoint the project's large capital requirements and long lead times require:

- Long term contracts (20-30 years).
- Stringent take-or-pay obligations.
- Some protection against fluctuating economic conditions by a floor price for example.

At the same time, the supplier takes on the obligation to ensure sufficient gas/LNG supplies are available over the life of the contract to meet annual LNG demand requirements. Because of the sheer magnitude of these projects, there is usually heavy government-involvement of on both sides. The buyers are for the most part public utilities, and the sellers usually include state oil companies. Equity partners play an important role as facilitator, technical advisor, and project co-ordinator.

An efficient-scale, grassroots LNG facility of about 6 million tonnes/year capacity requires a pre-start-up outlay of about \$5 billion or more for the supply facilities - production, feed-gas pipeline, liquefaction, and shipping. The LNG-chain's demand side requires a similar outlay, counting the import-regasification terminal and a combination of 5 gigawatts (GW) or more of electric power generation or the equivalent in city and industrial gas-using facilities (Nissen *et al.*, 1995).

LNG projects differ from those related to crude oil and oil products in the project's scale and front-loading; the relatively large cost of transportation and terminalling; and the relatively small magnitude of trade. As a consequence, there exist no well-developed commodity markets for free-on-board or delivered LNG. A new LNG supply project is dedicated to its buyers. Indeed, the buyers' revenue commitment is the project's only bankable asset, the facilities being essentially worthless without an assured market. At the same time, a LNG buyer must dedicate import and end-user facilities and service commitments to the specific LNG supply project.

Thus a LNG project can be considered as two complementary chains: a physical chain of jointly designed and optimised facilities delivering the resource to the end-user, and a chain of business ventures with interlocking operating commitments, jointly determined revenue allocation or transfer pricing, and jointly contingent financing.

LNG trade is inherently international, moving remote gas to a high-value market and almost inevitably crossing borders. No single sovereign or regulatory authority can enforce cost recovery through the chain. As a consequence, each business segment in the chain, with its financing and its operating and revenue entitlements and commitments, must be a viable business entity.

A system for strategic LNG-project evaluation includes:

- Assessing project costs based on explicit design and empirical engineering cost data.
- Assessing project economics based on a cost-of service (COS) evaluation incorporating detailed specification of the time structure of outlays, revenues, and sovereign payments as represented in standard, corporate capital-budgeting project-evaluation methods.

A project's COS is the real levelised price per unit of LNG or gas output (commonly expressed in \$/MJ). It covers forward capital and operating costs; sovereign take (i.e. taxes and royalties); and recovery of capital employed at start-up (including a required after-tax rate of return or "hurdle rate") net of credits from selling any co-produced condensate and LPG from the liquefaction.

A thorough study would calculate the COS within each segment of the LNG chain (production, pipeline, liquefaction, and shipping), for each outlay. The following sections present the results of one such study (Stauffer, 1996).

### 6.4.1 LNG's delivered value

LNG's value to the end-user depends entirely upon the type of use, the alternatives available to the consumer, and any environmental restrictions that would confer a premium value upon natural gas. Base-load electric power generation is currently the most common LNG use and its market's economics effectively dictate the value of large-scale LNG trade. So evaluating LNG's delivered value can be simplified by considering this single end-use and comparing LNG's value against the next cheapest electricity generating modes, looking at each cost/benefit element.

Stauffer's (1996) study compares combined-cycle gas turbines (CGTs) using natural gas versus residual or crude oil, common for generating electricity in the US, T&T's main LNG customer. The study compares like vs. like, i.e. LNG versus liquid fuel burned in combined-cycle plants. So the oil-fired CGT is the benchmark for LNG valuation. Natural gas supplied to a power station is worth more than residual or crude oil, as it avoids the latter's extra investment costs and operating and maintenance (O&M) costs. The capital cost for a liquid-fuelled CGT is slightly higher because:

- It requires different combustors.
- Systems for washing and dosing the fuel with inhibitors must be installed.
- The units are slightly downrated when run on oil instead of gas.
- Increased downtime and capacity degradation reduces unit availability.

- NO<sub>x</sub> reduction may be necessary, involving a selective catalytic reduction (SCR) unit on the GT exhaust stream.

Additional O&M costs include additives necessary to neutralise the vanadium concentrated in heavier liquid fuels. The turbines must be taken off line more often for washing ash from the turbine blades, and the overhaul cycle is shorter.

The resulting gas-value premium is the total extra cost of using oil in gas turbines divided by the total amount of gas (Table 20). 'Heat-rate' in the Table refers to the ratio of fuel input in J to the power output in kWh. So the heat-rate effect is the excess fuel that oil-burning uses over natural-gas for generating the same power. The actual LNG premium is modest because of recent improvements in modern gas turbine technology: worth 0.17 cents per kWh more than low-sulphur crude oil, and 0.08 cents per kWh if nitrogen oxide (NO<sub>x</sub>) reduction is not mandated.

| Cost item             | CGT without SCR | CGT with SCR |
|-----------------------|-----------------|--------------|
| Capital cost          | 2.84            | 7.09         |
| Heat rate effect      | 2.13            | 2.13         |
| O&M-cost difference   | 3.55            | 8.51         |
| <b>Total premiums</b> | <b>8.52</b>     | <b>17.73</b> |

Table 20. LNG premiums for oil-fired power generation alternatives (in \$/thousand m<sup>3</sup>) (Stauffer, 1996).

Several caveats must be noted:

- The precision in these calculations is misleading; cost parameters reflect typical recent reports for green-field plants.
- Add-on LNG trains, such as planned in Trinidad, enjoy infrastructure savings, so their yields are greater.
- Associated gas entails no field costs, so the net wellhead value is commensurately higher.
- All of the studies money figures are expressed in US dollars unless otherwise indicated.

#### 6.4.2 The cost of supplying LNG

LNG's supply cost is the sum of production, transportation and delivery costs. It is a particularly capital-intensive energy-supply mode with high, fixed costs at each step: liquefaction plant, specialised cryogenic tankers, purpose-built regasification facility at the receiving harbour (Figure 59).

*Liquefaction plant:* This is the most expensive link in the supply chain. Capital requirements for a 14.1 million m<sup>3</sup> per day plant are \$1.6 to \$2 billion (Stauffer, 1996). The liquefaction process is capital-intensive; the initial investment works out to some \$20,000 to \$25,000 per barrel of oil equivalent per day of plant capacity. That is comparable to the upper end of investment levels in the North Sea for example. This translates into a



liquefaction capital cost of \$35 to \$46 per thousand  $\text{m}^3$ . Fuel costs or operating and maintenance charges could add as much as another \$18/thousand  $\text{m}^3$  of gas. There is also the input-gas cost itself to consider. The capital cost enjoys only modest economies of scale at an existing site because capacity is increased by replicating liquefaction trains rather than by constructing larger units.

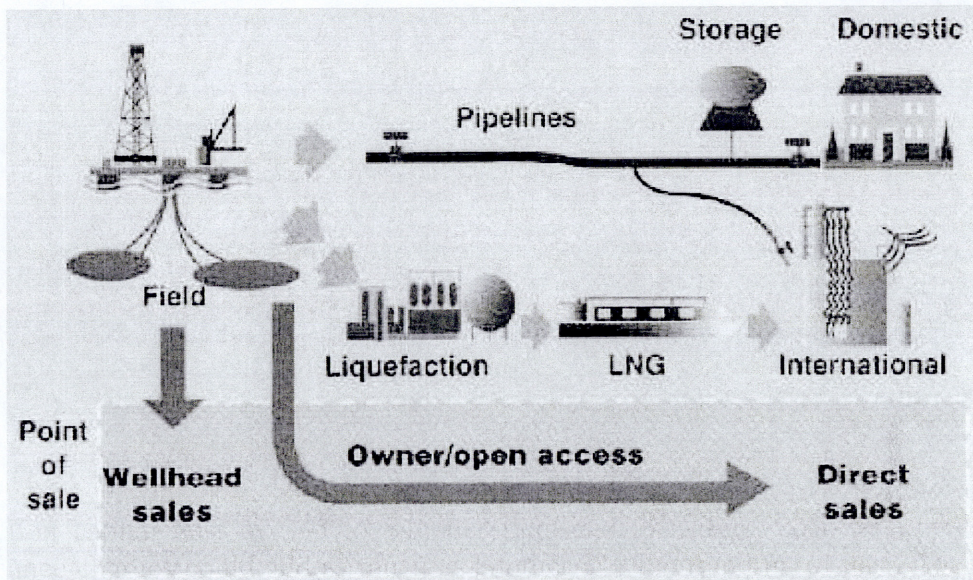


Figure 59. The natural gas/LNG business chain (Brown and Clary, 1997).

*Tanker fleet:* There is no merchant market for cryogenic tankships, so the fleet must be purpose-built and dedicated to the project. The number and size of the vessels depend upon the route and port-size limitations or canal depths. Studies show a transport cost that is proportional to distance – \$0.19 per GJ per 1,000 km (Stauffer, 1996). Since port turnaround times are fixed and not dependent upon distance, the overall per-km average cost for longer routes is less.

*Regasification plant:* The LNG must be regasified for ultimate delivery to end users. At the receiving terminal a special plant heats the tanker's LNG and transforms it into pipeline gas for distribution into the gas grid. This entails hundreds of millions of dollars in fixed single-purpose investment, and the equivalent unit cost is \$12 to \$18/thousand  $\text{m}^3$  delivered to the end users.

*Plant fuel and tankship boil-off:* The LNG plant consumes 12% to 15% of inlet gas as plant fuel. Some LNG is additionally lost en route as tanker boil-off, which is captured as supplementary tanker fuel.

*Co-product values:* The liquefaction plant co-produces large volumes of natural gas liquids (NGLs), for example ethane for petrochemical feedstock. Their economic impact is dramatic and should be explicitly accounted for (see Section 6.4.3).



Table 21 summarises the LNG chain costs, where capital is charged at 10% to 12%. The LNG-link's full cost (excluding inlet gas cost) is ~\$1.90/GJ for short-haul trades, rising significantly to ~\$3.23/GJ for the longer trades, such as from the Gulf to Japan or the US East Coast (Stauffer, 1996). The displayed costs exclude wellhead costs and pipelining to the LNG plant. They also exclude taxes or royalties since the objective is to determine the maximum value of the supply gas and hence the maximum government take.

|                | Short haul (2000 km) | Long haul (9000 km) |
|----------------|----------------------|---------------------|
| Liquefaction   | 1.09                 | 1.09                |
| Transport      | 0.38                 | 1.71                |
| Regasification | 0.43                 | 0.43                |
| <b>Total</b>   | <b>1.90</b>          | <b>3.23</b>         |

Table 21. Liquefied natural gas chain costs excluding inlet gas, in \$/GJ (Stauffer, 1996).

#### 6.4.3 NGL credits

Co-product credits are vital. The wetness of the feed gas stream to the LNG plant dominates the LNG economics. The extractable liquids are ethane, propane, butane and a host of heavier hydrocarbons that exist as vapour or as entrained liquids. The value of the NGLs that can be extracted at the liquefaction plant determine the venture's ultimate profitability.

The quantity and mix of NGLs vary considerably from field to field. Condensate fields can yield more than 5.4 barrels of NGL/thousand m<sup>3</sup> of gas. Associated gas is generally richer in NGL than is non-associated gas and yields 1.4 to 2.1 barrels of NGL/thousand m<sup>3</sup>. Some non-associated gas can be almost dry, yielding as little as 0.4 to 0.7 barrels of NGL/thousand m<sup>3</sup>. Associated gas is gas accompanying petroleum deposits, and is therefore usually *rich* in NGLs. Some non-associated gas can also be rich in NGLs, otherwise it is lean.

The gas stream's wellhead value depends intimately upon the richness of the gas. North American associated gas with a content of 1.8 barrels of NGL/thousand m<sup>3</sup> is equivalent to \$23 to \$34/thousand m<sup>3</sup> depending upon the NGLs mix. That figure is at least half or more of the wellhead methane-value itself, indicating NGL-recovery's importance to overall gas-production economics. In Saudi Arabia, the co-product LNG value is more than the wellhead gas price (Stauffer, 1996).

The NGLs can be extracted in dedicated gas plants or partially in gas-oil separation plants. However, a LNG plant usually routinely extracts all of the liquids as the process temperatures are low enough to liquefy methane and so drop out all of the heavier hydrocarbons. Total LNG plant cost includes that extraction cost. Where the gas is processed separately but not liquefied, the extraction costs vary considerably, but can be

approximated as being equal to 30% of the gross value of the liquids over a range of conditions often encountered in practice, i.e. an 'average' case (Stauffer, 1996).

NGLs' relative importance is even greater when tested in the context of a LNG project. The feed gas differs considerably from country to country; in Algeria it is largely non-associated gas, but some is atypically rich, so that the yield is high (Table 22). In Qatar or Oman the gas is non-associated but much leaner. In Abu Dhabi most of the feed gas has been associated and yields average.

|   |                                                               | Lean gas        | Rich gas      |
|---|---------------------------------------------------------------|-----------------|---------------|
|   | Natural gas liquids (in barrels per thousand m <sup>3</sup> ) | 0 – 0.89        | >3.55         |
| 1 | Gross NGLs credit                                             | 0 – 13.47       | >53.19        |
| 2 | (Field yield)                                                 | (0 – 8.08)      | (31.91+)      |
|   | <b>Net national credit (= 1 – 2)</b>                          | <b>0 – 5.39</b> | <b>21.28+</b> |

Average export value of NGLs ~\$15 per barrel; field yield = the recovery value from conventional field processing rather than at a liquefied natural gas plant, taken at 60% of gross value; net national credit = the gross NGLs yield, minus what could have been recovered through conventional processing; zero cost assigned to reinjecting the stripped, lean gas

Table 22 Co-product values: NGLs in \$/thousand m<sup>3</sup> unless otherwise stated (Stauffer, 1996).

The NGL credit or value thus depends upon the feed gas and how it is processed. Two cases are important: *project economics* as opposed to *national cost/benefit*. The first case looks at the project itself and the full NGL value is a net gain to the project because the extra facilities for treating the NGLs are minimal. Liquefying the methane knocks out all heavier hydrocarbons so incurring negligible incremental costs. Thus a yield of 1.8 barrels/thousand m<sup>3</sup> results in ~\$27/thousand m<sup>3</sup> in co-product credits.

The second case looks to the national economic impact, and the NGL credit is less because of the opportunity cost of alternative extraction. The NGLs might have been extracted by a dedicated gas plant, as at Phoenix Park Gas Processors Ltd in Trinidad, at a cost of 30% to 40% of the gross yield. Most liquids, including the ethane where a market exists, can be extracted and commercialised without recourse to a LNG plant. Thus the net co-product credit attributable to a LNG plant, compared with commercialising the same NGLs via conventional processing, is the difference between the two net recovery values. Thus, the 'average' gas stream yields a co-product credit of between \$11 and \$30/thousand m<sup>3</sup> depending upon whether one uses a 'national' or 'project' economic yardstick. The net credit is based upon 1.8 barrels/thousand m<sup>3</sup>, a 'saved' processing cost of 40% of gross revenues and a weighted average value of condensates and liquefied petroleum gases of 75% of the oil price (i.e. \$18/barrel in this case).

A further consideration adds to NGLs' attractiveness and to foreign investors' interest in an integrated LNG project. NGL extraction is taxed at a very much lower rate than oil production, as it is deemed to be an industrial process. Hence the percentage profit yield on

a barrel of NGL is 4 to 6 times greater than that for oil (Stauffer, 1996). This is an important attraction to foreign partners in LNG projects as the NGL operations are distinctly more profitable given the low taxation rate and simultaneously much less risky than producing and marketing LNG. Host governments are frequently responsible for the LNG train while the foreign partners share more significantly in the NGL operations.

Thus NGL credits are doubly important. The low taxation rate is a subtle, but critical, incentive to foreign investors or lucky local partners, and the credit itself is a major part of any positive wellhead value that can be attributed ultimately to the hydrocarbon resources themselves. Governments can hive off the eminently profitable NGL extraction segment to private investors, in order to promote a project, but the net real gains to the host country are minimal except for the most proximate markets. This is compellingly the case where the NGLs might be extracted conventionally and the stripped gas re-injected, which would reduce the added NGL credit from the LNG plant by half or more.

#### 6.4.4 Net cost/benefit balance

*Plant-gate (inlet) value:* The net feed-gas value to the LNG plant is the *netback* from the value of the gas delivered to the power plant, i.e. it equals the burner-tip value to the end user less the costs of re-gasification, transport, and liquefaction (the LNG chain) plus the co-product credits from the extraction of the associated NGLs. So a netback valuation procedure starts with the resource value at the final point of use and works back through all the costs involved in getting it to that point from the resource's origin, to value the resource at the origin.

The two principal variables are shipping cost, which is almost proportional to distance, and the NGL credits, which depend entirely upon the feed-gas properties. NGLs are credited to the plant rather than being offset against wellhead production costs because they are extracted at the plant as part of the liquefaction process. The other costs (i.e. liquefaction and regasification) are essentially common to all new projects.

Three cases illustrate: short-haul trade as between Trinidad and the US Gulf Coast, an intermediate case as Australia to Korea, and a long-haul case as from the Arabian Gulf to Japan (Table 23). With the long-haul trade carrying a transport cost of \$50/thousand m<sup>3</sup> the plant inlet gas value is only \$19.64/thousand m<sup>3</sup>. Short haul yields a \$69.64/thousand m<sup>3</sup> plant inlet value.

|   |                                     | Short haul | Medium haul | Long haul |
|---|-------------------------------------|------------|-------------|-----------|
| 1 | Plant inlet value                   | 69.64      | 41.07       | 19.64     |
| 2 | Gas supply cost                     | 28.21      | 28.21       | 28.21     |
|   | <b>Gas resource value (= 1 – 2)</b> | 41.43      | 12.86       | -8.57     |
|   | NGLs credit                         | 30.00      | 30.00       | 30.00     |

Table 23. Gas resource value (host country maximum gas revenue), in \$/thousand m<sup>3</sup> (Stauffer, 1996).

**Wellhead value (netback residual):** The net gas wellhead value is still lower than the plant gate value because of three effects. First, the LNG plant consumes about 10% to 12% of its throughput as compressor and process fuel. For example 1.11 m<sup>3</sup> to 1.14 m<sup>3</sup> m<sup>3</sup> of dry gas equivalent must be delivered to the plant per m<sup>3</sup> of LNG equivalent at the outlet. Second, gathering and pipelining costs further reduce the wellhead value and these vary widely. Third, production costs can be substantial and also vary considerably. In the case of associated gas the production costs attributable to the gas are effectively zero as the gas is unavoidably co-produced with the oil and must be separated from it before the stabilised oil can be exported. Associated gas enjoys a clear cost advantage, but is rarely available in an adequate quantity to support a 2-train LNG plant. Costs for non-associated gas (exclusive of royalties or taxes) depend entirely upon the gas field's productivity. In this case the integrated project would need to bear the full costs of gas-field exploration, development, and production. The probable production-cost range is \$7 to \$27 /thousand m<sup>3</sup>. A lower cost is improbable and a higher cost could not be supported, as will become evident later.

Table 24 shows the build-up of the cost of gas delivered to the LNG plant where all-in production cost is \$18/ thousand m<sup>3</sup> and the gathering and pipeline charges are another \$7/ thousand m<sup>3</sup> of final output. 1.125 thousand m<sup>3</sup> of dry gas equivalent supply yields 1 thousand m<sup>3</sup> of liquefied gas at the plant outlet as discussed earlier.

|                   | Non-associated gas | Associated gas |
|-------------------|--------------------|----------------|
| Wellhead cost     | 18                 | Nil            |
| Pipeline cost     | 7                  | 7              |
| <b>Subtotal</b>   | 25                 | 7              |
| Fuel loss factor  | 1.125              | 1.125          |
| <b>Total cost</b> | 28.13              | 7.88           |

Table 24. Cost of gas delivered to the liquefied natural gas plant (\$/thousand m<sup>3</sup>) (Stauffer, 1996).

Note two points. First, associated gas's cost advantage is clear: \$20.25/thousand m<sup>3</sup> in this example. Second, the wellhead value of gas itself is the plant inlet value minus the total cost of producing and delivering the gas to the plant. Hence, in this example non-associated gas would require a plant inlet value of at least \$28/thousand m<sup>3</sup> just to break even, i.e. covering returns to capital but leaving a zero value to the gas itself.

**Net economic balance:** Weighing all elements, the real economic balance is precarious. The net gas value – the *netback resource rent* – equals the plant inlet value, as derived from the end user market, minus the gas supply cost. Short-haul LNG is potentially profitable, even without NGL credits, in the sense that the residual value at the wellhead to the gas itself is some \$41/ thousand m<sup>3</sup> (Table 23). This is the amount that the resource owner, the host government, could capture in the form of taxes or royalty or through a rent-skimming mechanism. However, even in this most favourable case NGL credits contribute a full



three-quarters of the net wellhead value for the project. Leaner gas – with a yield of less than 1.8 barrels/ thousand  $\text{m}^3$  – would be much less profitable.

The long-haul case is clearly unattractive – the wellhead value is actually negative at - \$8.57/thousand  $\text{m}^3$  (Table 23). The distant market cannot afford to pay enough of a premium to offset the \$50/thousand  $\text{m}^3$  shipping tariff, and a very high NGL credit would be needed only to break even at the wellhead.

In the intermediate case the lower shipping cost result in a small wellhead value for the gas: \$12.86/thousand  $\text{m}^3$ , or ~\$2.20 per barrel of oil equivalent. Even for this profitable trade the netback value for the natural gas resource itself is but a fraction of the energy value of oil. Thus the co-product credit is vitally important to tip the balance in the project's favour. If the gas is lean as some Nigerian supply then the wellhead gas value would drop to zero.

Government fiscal yields are thus low; gross revenues can be large, but are overwhelmingly returns to capital, not any rent for the gas resource. Unlike in the case of Middle East oil, where net fiscalisable revenues (rents) per barrel are \$12 to \$16/barrel, net wellhead values for gas into LNG plants are low or negative. Projects for the intra-Asian LNG trade would yield government revenues of no more than about \$2.50/barrel of oil equivalent, while long-distance trades would yield nothing, unless oil prices were to rise appreciably.

More generally, the host country realises even less real gas values if the NGLs could be extracted by field processing and re-injecting the gas. That option's costs are field-specific, but rough estimates suggest that the preceding calculation, based on *project* economics, overstates the *national* benefits by about \$11/ thousand  $\text{m}^3$  (Stauffer, 1996). Viewed using the more sensitive lens of the national cost/benefit approach, even the intermediate-distance project only breaks even and in substance yields no real net revenue to the host government.

Thus LNG profits are squeezed in two directions – from above by oil prices and from below by costs. The delivered price of low-sulphur crude oil or residual oil caps the LNG value to market-sensitive power stations, the major users. Modern gas turbines can burn those heavier fuels at modest extra cost. That penalty sets the market-based premium for LNG at less than US\$18/ thousand  $\text{m}^3$ .

#### 6.4.5 Summarising LNG economics

So from the exporting country's perspective the profitability of long-haul LNG exports is problematic. Even with full co-product (NGL) credits, host governments can reap no tax revenues. Short-haul trades, such as Trinidad to the US Gulf Coast, can be economically attractive even with low oil prices: the netback value of gas at the wellhead can be as much as \$41/thousand  $\text{m}^3$ . Delivered LNG costs increase steadily with distance and projected cost savings are small, even with larger tankers and upgraded liquefaction trains. The

netback methane value thus falls steadily as the market is more remote and is effectively zero for the long-distance trades.

There is another factor that can distort LNG project evaluation: for the producer or host government, conventional books of account could be constructed to show profits and even taxable income. However, such accounting would disguise the real costs by not displaying the opportunity costs of capital or by consolidating upstream and downstream operations so that downstream returns to investment capital could appear, in part, as upstream wellhead profits.

LNG-project financing involves governments of the producer and the buyer, the project sponsor, and lenders. Early LNG projects were financed on a government-to-government basis or with heavy consuming country government support. Alternatively, oil companies and other foreign shareholders raised a large part of the financing with general corporate debt. More recently, commercial banks and government export credit agencies have been willing to lend funds to these projects on a limited or non-recourse basis (i.e. lenders may only look to project cash flows or assets for repayment) as for Qatargas and Rasgas in Qatar. Generally the debt would be recourse to the sponsors through completing construction.

While all of these points are important, the LNG purchaser's credit rating has been especially critical in the lenders' analysis. This is because the payment by the purchaser generates the cash flow required to service the debt. If the purchaser has a strong credit rating, the lenders will be more comfortable that payments can and will be made.

Another technique that sponsors use in expansion cases is to provide lenders for expansion trains with additional security by giving them subordinated rights to revenues from existing LNG projects. This type of sponsor support allows lenders to be comfortable with the structure during periods of low prices. Sponsors should be able to preserve a higher level of debt if they can demonstrate to the lenders a stable and predictable stream of revenue, taking into consideration the historical volatility of oil prices.

The government of the exporting LNG country (which is often a project sponsor) can also play a role in determining both the economic viability and financeability of a LNG project. Royalty payments on gas and condensate, and taxes are one of the largest cost elements of a LNG venture. In a competitive buyers' market, the host government can improve the marketability of LNG and make the project much more attractive to lenders by subordinating royalties to the lenders, and by offering extended tax holidays to the LNG project. These actions greatly enhance the cash flow of the project, which also improves coverage ratios that lenders use as an indicator for sizing permissible debt. The tax, legal, and regulatory frameworks of both the exporting and consuming countries must be conducive to foreign investment and there must be assurances that these governments will not promulgate changes that could have an adverse impact on the project cash flows or the abilities of the parties to perform.

Thus projects emerge where the host government bears virtually all of the risk and accepts below-market rates of return as a *quid pro quo* for the technical and marketing expertise of private partners. Concessions make the project attractive to the lender at the exporting government's expense. The separate interests are in conflict.

## 6.5 The Trinidad and Tobago LNG experience

At the start of 1999 T&T became the world's biggest ammonia *exporter*, a major gas-based product, and by the end of the 1999, became the world's leading methanol exporter, another gas-based product. One of the Western Hemisphere's largest gas-processing plants was recently inaugurated in Trinidad, when the Phoenix Park Gas Processors company completed expanding its liquids processing and fractionation facility (Anon., August 1999).

Overall, in 1999 T&T's energy sector contributed about 18% of total government revenues. That represented 22% of the country's Gross Domestic Product (GDP) and 67% of its exports. Since 1995, foreign investment in the country's energy sector has amounted to US \$6 billion.

Gas consumption expanded by 8.7% a year during the 1977-1997 period and grew by 12-14% between 1997 and 2001, one of the fastest growth rates of any gas-producing country. That major gas market has been created since 1977, when industrial use was first made of gas reserves that the then Amoco Trinidad Oil Company had discovered nine years earlier off Trinidad's east coast (Anon., August 1999). It was only from the mid-1990s onwards that the companies began specifically drilling exploratory gas wells and Amoco was again the most successful. Natural gas used locally was all associated gas until the 1970s, when the first dry gas fields were discovered off the north shore of Trinidad. Since that time, and especially since Amoco brought the first gas field on stream in 1983, the country increasingly used this production to replace oil used in petrochemical plants and for power generation (Stauffer, and Croft, 1996).

British Petroleum (BP) acquired Amoco and now holds Trinidad's largest block of gas reserves. BP and British Gas (BG) were both anxious to find outlets for their local gas production and were soon brought into the picture. A feasibility study found that a single-train LNG plant in Trinidad could be a profitable investment (Anon., June 1999).

### 6.5.1 Atlantic LNG

There are currently twelve LNG producing countries. Soon, there will be two more - Angola and Egypt. T&T became only the tenth country in the world producing LNG, and the first in the Latin America and Caribbean region with Atlantic LNG's (ALNG) commissioning in 1999. ALNG converts 12.6 thousand m<sup>3</sup> per day of natural gas into LNG for transport to markets in the US and Spain over the next 20 years.

ALNG is the largest single-train LNG plant that has been built to date, with 4.6 billion m<sup>3</sup> of gas a year input and 3 million tonnes of LNG output per year. It is also the cheapest,

with a ~US\$950m capital cost, including financing costs, and US\$50m less than originally budgeted. It is the fastest-build LNG plant to date: six and a half years from conception to completion, 34 months for construction and hand-over (Anon., August 1999).

Now the partners comprising the ALNG project have moved quickly on to the next stage. They convinced the Government of T&T (GOTT) to sanction another 197 billion m<sup>3</sup> of local gas for LNG, and that pricing arrangements will be sound enough to justify tying up so much gas on one project for over 23 years. As far as gas reserves are concerned, the partners point out that even the Energy Ministry's own estimates put T&T's proven gas reserves at 600 billion m<sup>3</sup>. The companies themselves believe this figure could be trebled through further exploration that they are prepared to undertake.

#### **6.5.1.1 ALNG Trains 2 & 3 expansion**

In March 2000 the government approved proposals to expand the Atlantic LNG plant by two additional trains. BP Amoco, the main upstream supplier to the plant and a major ALNG shareholder, agreed to lower the domestic gas price by about 12% in exchange for a lump sum payment from the National Gas Company (NGC) to compensate in part for revenue loss, and a deal was struck. However, the deal was made in the midst of an acrimonious dispute between the Ministry of Energy and the NGC on how best to exploit the island's vast natural gas reserves – whether to export them as LNG or to use them as feedstock for domestic gas-based industries. As a result, assurances that gas will be supplied to the domestic market were written into the agreement. The second and third trains were expected at that time to be commissioned in 2002 and 2003 respectively.

The dispute was politically damaging for the Government and the protagonists – the Energy Minister lost ministerial responsibility for the NGC, which has now been assumed by the Prime Minister. The dispute highlighted the lack of a coherent policy for gas, and the need for building consensus; the Energy Minister recently announced that a Gas Master Plan for the industry would be drafted (Anon., 2000) although he made no mention at all of the Green Paper on Energy Policy. The importance of any Natural Gas Master Plan lies in the fact that the commodity is about to overtake oil in its contribution to the country's economy (Editorial, 2001). T&T is a leading exporter of methanol, ammonia and will be the World's fifth largest exporter of LNG after completing the planned ALNG expansion in 2003. For NGC, the conflict drew attention to the significant financial losses the company sustained in the past two years resulting from sharp falls in its market-sensitive gas price on the back of a soft commodity market, particularly for ammonia and methanol.

#### **6.5.2 The country's concerns**

Section 10.5 in Chapter 10 describes the ALNG project's economics in some detail. This Section explores some of the broad concerns over the LNG projects, and a LNG industry as a whole in T&T.

Some analysts are concerned about T&T devoting so much of its current gas reserves of 0.6 trillion cubic m<sup>3</sup> to one product - ~0.3 trillion m<sup>3</sup> will be required over 20 years, including the planned 2-train extension, almost half of the existing reserves base. T&T's current gas R/P is just over 48 years, including ALNG's Train One consumption (about 12 thousand m<sup>3</sup> per day). Trains two and three (~27 thousand m<sup>3</sup> per day) drops the ratio by almost half, to 23 years (Renwick, 2001). BP Amoco is confident about discovering ~113 billion m<sup>3</sup> a year in incremental gas reserves, thus adding another 564 billion m<sup>3</sup> to the currently accepted proven reserve figure of 600 billion m<sup>3</sup> by 2005. BP Trinidad has about 40 drilling prospects for natural gas identified in its east-coast offshore acreage.

Under the ALNG-expansion agreement, the company has no obligation towards establishing a proposed ethylene complex, except to guarantee supply of one-third of the ethane requirement to keep such a project running. The Government's Green Paper on Energy Policy recognised that although State-owned NGC had a ten percent shareholding in the ALNG first train, there were no benefits to be derived from any additional LNG trains unless a viable ethylene project could be derived. Such a project would capture the co-product credit benefits (see Section 6.4.3). The proposed ethylene project's viability was one of the concerns NGC raised in pointing out areas in the Agreement that needed further consideration. ALNG gave no commitments towards facilitating the ethylene complex in T&T (Persad, 2000).

The expansion-project's details have not been made publicly available, similarly for the original ALNG contract. The agreement's terms are unknown beyond press-releases: the tax revenue that will accrue from the deal (~\$30 billion over 20 years); the number of jobs it will provide at the construction stage (~3000); the proportion of locally-acquired inputs (~25%); and that the tax revenue could be twice the estimated figure with high natural gas prices. The real terms on which the proposed expansion proceeds, consuming ~27 thousand m<sup>3</sup> per day of a non-renewable component of the national patrimony, should be:

- The trade-offs between short, medium and long-term benefits and disadvantages.
- The balance decided between tax revenues over the next decade, which will depend on the raw natural gas World-price, and the potential value-added of downstream industries such as methanol, urea and ammonia.
- NGC's concerns about the imbalance between the gradually increasing price at which it purchases gas, and its fluctuating sales price to large petrochemical industries in T&T.
- Assurance from BP Amoco and the other investors to prove up the natural gas reserves to the level to be used in Trains 2 and 3, to be sure that the increased three-train production does not deplete known reserves over the agreement's life. Otherwise, T&T opens itself to blackmail later as the government begins to panic over proven reserves diminution.
- An agreement for capturing ethylene for use in manufacturing plastics and other downstream products.

With no such detail, to announce that T&T will get a bonanza of \$20 - \$30 billion over two decades is no more than public relations. The estimated TT\$2 billion average earning per



year over the project's life is not corrected for any terms-of-trade effect (Best, March 2000), given the real decline in all commodity prices, not least gas. When export prices (affected by the terms of trade) declined nearly 10% in 1998-99, T&T increased production of some outputs by over 15%. The data call for careful interpretation. Physical output (GDP) registered 4.0% and 5.1% growth rates for the country in 1998 and 1999 respectively, according to T&T's Central Bank estimates. But owing to depressed export prices in the context of stable or rising import prices, national income actually fell, at least in the first year, by between 2% and 4%. IMF figures confirm those of the Central Bank – the country was actually worse off (Best, April 2000). The 1998-99 world economic downturn not only led to a drop in export earnings, and to overseas borrowing, it also retarded a whole slate of mega-projects (see Chapter 11, Section 11.3), including delaying LNG Trains 2 and 3. Until the oil market recovered in the second half of 1999 and petrochemical prices stabilised at between 40% and 50% below 1994-95 levels, T&T simply used up more and more reserves for a smaller income.

## 6.6 LNG in T&T from a Policy perspective

Andrews (October 2000) describes Professor David Pearce's studies on why some developing countries with large fossil fuel reserves do not do as well economically as countries without. In Pearce's *resource curse hypothesis*, quite often massive resource endowments are illusory in terms of the return that they provide to the economy. T&T's large oil and natural gas stock may be more of a curse than a blessing because it may encourage the Government to spend money wastefully. Governments are more careful about spending money when resources are scarce. T&T has been running down its oil and gas assets without building up other assets, i.e. consuming the resource without reinvesting the proceeds. Revenues from the depletable resource go back into consuming goods and services, not just by private individuals but by governments. The profits should go back into the economy in the form of other assets such as new technology, schools, universities, health, and the natural environment, the value of which may not be immediate and obvious but which may have disastrous results if neglected. Sustainability requires that every year income be put to one side to cover depreciation of the country's assets.

Pearce concludes that according to World Bank figures the Caribbean countries Antigua, Barbados and the Dominican Republic have positive genuine savings, i.e. they are saving more than their assets depreciate. But Haiti, Jamaica, Venezuela and T&T have negative genuine savings, i.e. they are spending excessively to replace their assets and are not really saving. The common feature of three of those states – Jamaica, Trinidad and Tobago, and Venezuela – is that they are endowed with rich natural resources.

A United Nations Economic Commission for Latin America and the Caribbean/ Caribbean Development and Co-operation Committee (UNECLAC/CDCC) report, summarising economic developments in the Caribbean during the decade of the 1990s reinforces this resource curse hypothesis (Editorial, 2000). It concludes that the decades-old goal of

modernising Caribbean economies remains unachieved. The challenges to diversifying in the first decade of the 21st century are formidable.

First, the Caribbean's political economies' characteristics (i.e. the 15 members of the Caribbean Common Market (Caricom), the Dominican Republic, Cuba and the Netherlands Antilles) in the 1990s continued to be centered on exporting hydrocarbons, bauxite, tourism services and agricultural products - sugar, bananas and cocoa. The CDCC report states that overall, manufacturing amounts to no more than 10% of GDP in the Caribbean.

Alongside the narrow export-range and the manufacturing sector's shallowness, is the reality that Europe and the United States remain almost exclusively the markets for the Caribbean's products. This means that manufacturing continues to be almost completely dependent on import substituting schemes and preferential markets in the US and the European Community.

The CDCC report states that regional economies remain hugely dependent on North American and European savings for investment. Foreign direct investment (FDI) grew from US\$689 million in 1990 to US\$2 billion in 1997, 48% of this figure going to Trinidad and Tobago's energy sector. 1997 to 1999 figures can be expected to reflect the same pattern, perhaps an even greater percentage flowing to the gas-based industries in Trinidad. The resulting picture is that of economies dependent and vulnerable to notoriously fickle international commodity prices and an export base structured on producing a narrow range of commodities with little value-adding activity. The hard reality of the Caribbean's situation remains an economy producing raw material exports for the manufacturing factories of the North, like the 19th century plantation. T&T's policy of recent reckless expansion into LNG only confirms this. It actually represents a backward step, as although methanol and ammonia are basic commodities, they do represent some value-added at the petrochemical plants. LNG is simply exporting the raw material primary-energy, and on a scale that far exceeds the existing petrochemical manufacturing.

The CDCC report considers the 1990s' economic gains to be fragile and capable of disappearing with the next hurricane or a decline in foreign exchange earnings from the main export commodities, and includes the T&T economic growth of the past five to six years. In fact this economy, highly successful in attracting FDI to the energy-based extraction sector with its dependence on international raw material prices and the trans-national corporations' production structures, is perhaps the greatest victim of the 1990s pattern of investment and export (Editorial, 2000). The resource curse hypothesis emphasises the need for a careful Policy for exploiting resources, energy in T&T's case, and how easily large industrial activity can have little effect.

The capital intensive nature of the investments in the energy sector means that it is quite possible that the vast sums of money spent here may not translate (or trickle down) into improved infrastructure, better living conditions and higher standards of education, health and security. As much of the capital flowing into T&T is foreign, most of the profits and dividends from operations in Trinidad end up flowing overseas (Andrews, 2000). Also

most of the projects, especially in the petrochemical sector, receive long-term tax holidays, which limit the immediate revenue inflows from such investment. As in the case of the Iron Carbide plant, some investors also receive natural gas at prices implying a virtual subsidy by local taxpayers to the foreign investor, who is free to pack up and leave if the project does not work out.

One last example demonstrates the perversity of T&T's current energy policy posture. ALNG is supplying LNG for Puerto Rico's first gas-fired power-generating plant. It is a cogeneration project with a 460 MWe capacity, together with a 15-million-litre-per-day water desalinisation plant, to be developed on a 30-acre site in Panuelas. It is bad enough that T&T's natural gas is promoting cogeneration in another country, while T&T is completely without such a policy. Yet at the same time, the GOTT approved plans in August 2000 for a US\$120 million desalination project in T&T's largest industrial estate (Singh, 2000). The estate has the largest electricity-generating gas-turbine installation in the country (634 MW out of a total 1189 MW, or 53% (Sitahal and Chong, 1998)) but not once was the cogeneration idea mentioned, whether in connection with desalination or with the significant industrial thermal requirements all around the estate. To make matters even worse, the Water and Sewerage Authority (WASA) considers the desalination plant to be unnecessary as T&T receives more than enough rain, being more akin to South America than the rest of the West Indian islands.

## Chapter 7. Absorption cooling

Refrigeration systems use an energy input to produce a cooling effect. Absorption systems and vapour-compression (VC) systems are two types of central cooling/refrigeration equipment. VC systems use mechanical work, usually from an electric motor. The absorption cycle is primarily heat-operated, i.e. it pumps heat with minimum work input. In many facilities in Trinidad and Tobago (T&T), classified as industrial electricity users, the main or only thermal load is air conditioning. In almost all cases VC systems provide the cooling. For cogeneration to work in such cases, a heat input must satisfy this cooling load, i.e. by substituting the VC machines with absorption chillers.

Absorption equipment is classified according to the method of heat-input to the primary generator (i.e. firing method), and whether the absorption cycle is single- or multiple-effect. There are four configurations depending on the heat source:

- Direct fired.
- Indirect-fired, employing low-pressure steam or hot water.
- Indirect-fired, employing high-pressure steam or hot water.
- Indirect-fired, employing hot exhaust gases.

Larger machines use mechanically driven pumps to circulate the internal fluid. This is a small electrical work input of about 1% of the heat input (ASHRAE, 1997) and is normally ignored in describing the machine's thermal performance.

### 7.1 The vapour-compression cycle

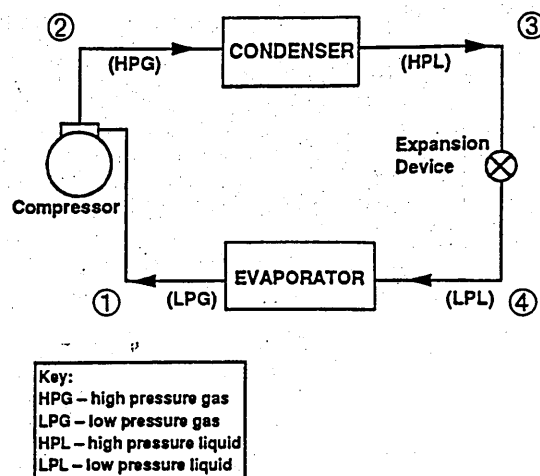


Figure 60. Vapour-compression cycle (Dorgan, Leight and Dorgan, 1995).

By far the most common system applied for air conditioning and refrigeration applications in T&T is the VC cycle. The basic cycle is essentially the same regardless of the compressor type (reciprocating, screw, scroll, or centrifugal) or refrigerant (CFC or non-CFC) used. Figure 60 shows a simplified schematic of the equipment layout for a typical VC cycle. Piping separates each cycle component –the compressor, condenser, evaporator, and expansion valve.

A pressure-enthalpy (p-h) diagram can represent the VC cycle, displaying the refrigerant's complete state through the cycle. Figure 61 is a p-h diagram for the VC cycle in Figure 60.

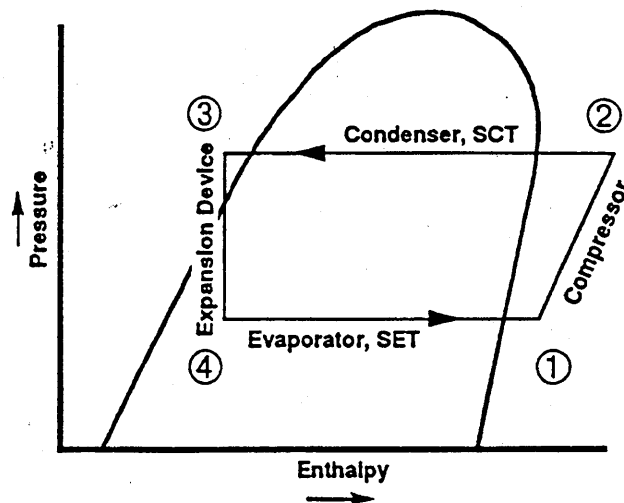


Figure 61. VC cycle p-h diagram (Dorgan, Leight and Dorgan, 1995).

- Process 1→2: At point 1 the refrigerant is a low-pressure vapour. The compressor increases the vapour's pressure to the point 2 with a related temperature increase.
- Process 2→3: At point 2 the refrigerant is a high-pressure, high-temperature vapour. At this point the refrigerant's pressure must have a corresponding saturated condensing temperature (SCT) higher than the condensing media. From point 2 to point 3 the vapour passes through a condenser that removes heat, condensing the vapour to a sub-cooled liquid.
- Process 3→4: From point 3 to point 4 the liquid refrigerant is throttled through an expansion valve or other similar device, where some of the liquid flashes to vapour, forming a low-pressure, low-temperature two-phase mixture. The expansion device serves as the metering control to match the refrigeration load.
- Process 4→1: From point 4 to point 1 the two-phase mixture passes through an evaporator. The refrigerant liquid-vapour mixture flashes to vapour by transferring heat from the chilled-water loop. The water passing through the evaporator is cooled and is circulated to the load. The refrigerant exiting the evaporator is a low-pressure vapour. At this point the refrigerant's pressure must have a corresponding saturated evaporating temperature (SET) lower than the cooled media.



## 7.2 The absorption cycle

The key processes in the absorption cycle are *refrigerant absorption* and *desorption*. Absorption is the process in which concentrated (strong) solution absorbs refrigerant vapour. The absorption process releases heat of condensation and heat of mixing into the fluid. Usually a cooling tower cools the fluid to allow the solution to continuously absorb sufficient refrigerant while maintaining a low-pressure condition. Desorption (generation) is adding heat to a dilute (weak) solution to drive refrigerant vapour from it, thus concentrating the solution and permitting refrigerant recycling and reuse at the evaporator. The main machine components are the generator (desorber), condenser, evaporator, absorber, and solution heat exchanger. The expansion valve is a refrigerant-flow restrictor.

*Effect* refers to the number of times the absorption machine uses the input heat, either directly or indirectly whereas *stage* refers to the number of evaporator/absorber pairs at different temperatures in an absorption machine. A single-stage system has a single evaporator/absorber operating at a constant or primary temperature. A two-stage system has two pairs each operating at a different temperature. In the basic, single-effect cycle for cooling, a volatile liquid *refrigerant* evaporates in the evaporator vessel at a low pressure to produce cooling at a low temperature. The mechanical refrigeration cycle draws refrigerant vapour into the compressor at low pressure and physically compresses it. The refrigerant is a volatile substance that:

- a) leaves the solution at the generator,
- b) performs the refrigeration process at an evaporator, and
- c) is reabsorbed at the absorber to complete the thermodynamic cycle.

In the absorption cycle a separate adjacent absorber absorbs refrigerant vapour into cooled *solution*, thus reducing the vapour pressure. The solution is a liquid of at least two components, one soluble in the other. The combination is called an absorption system's *working fluid* or *fluid pair*. The *absorbent* is a material that extracts one or more substances from a fluid medium it is in contact with due to an affinity. The material changes physically and/or chemically during the process. The absorbent's high chemical affinity for the refrigerant releases heat of condensation and mixing. *Condensation* refers to refrigerant-vapour liquefaction when it gives up any superheat present and its latent heat to an available heat sink.

A second fluid (water or ambient air) removes and rejects this heat to a heat sink, usually through an evaporative condenser, to prevent the evaporator and absorber pressure from rising. The *sorbent* is the portion of the solution that transports the absorbed refrigerant through the processes that make up the thermochemical compressor. The *diluted sorbent solution* is pumped to the higher temperature and pressure generator (*desorber*) side of the system, which re-concentrates the solution to complete the cycle. The dilute (weak) solution has a relatively low sorbent mass fraction, and thus a relatively high refrigerant mass fraction. A *concentrated (strong) solution* has a relatively high sorbent mass fraction,

and thus a low refrigerant mass fraction. *Recuperative energy exchange* occurs between the hot concentrated solution leaving the generator and the cooler dilute solution pumped from the absorber back to the generator and improves the overall thermal efficiency.

Figure 62 shows an absorption cycle schematic. The refrigerant cycle (path 2-3-4-1) is identical in both the VC and absorption cycles. Each technology handles the compressor function differently. In vapour compression a mechanical compressor completes the compressor function. Absorption technology replaces the compressor function with a solution circuit and a pump.

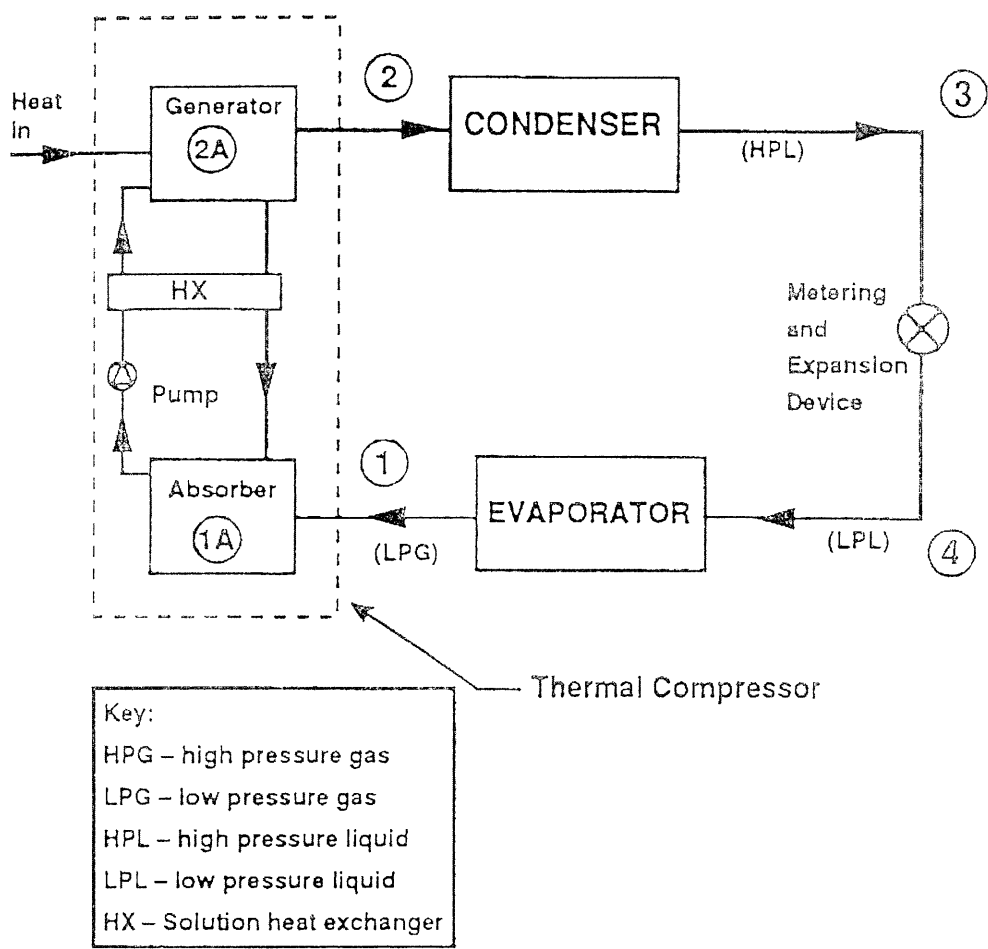


Figure 62. Absorption-refrigeration cycle (Dorgan, Leight and Dorgan, 1995).

Figure 63 shows the p-h diagram for the refrigerant portion of the absorption cycle. Process 1→2: At point 1 the low-pressure, low-temperature refrigerant vapour enters the thermal compressor and is absorbed into a solution at point 1A. The absorbent-refrigerant mixture's state changes from 1A to 2A through a combination of pumping and adding heat.



At point 2A heating the absorbent solution (boiling) separates the refrigerant vapour from it, and generates a high-temperature, higher pressure refrigerant gas condition at point 2.  
Process 2→3→4→1: The refrigerant gas completes the refrigeration cycle, which is identical to the VC cycle.

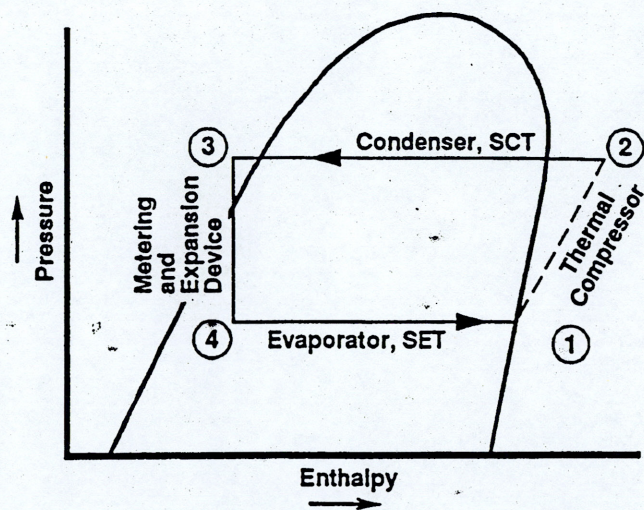


Figure 63. Absorption-cycle P\_H diagram (refrigerant only) (Dorgan, Leight and Dorgan, 1995).

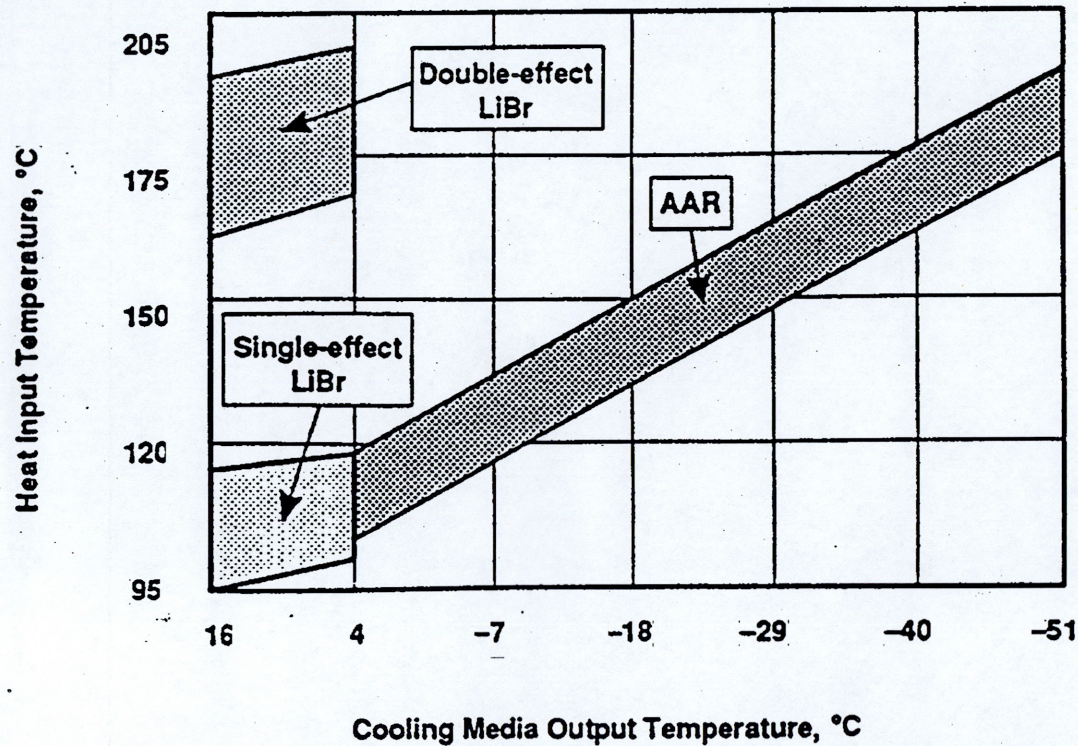


Figure 64. Absorption machine input/output (Dorgan, Leight and Dorgan, 1995).



Absorbent-refrigerant solutions are mixtures used in the absorption cycle. Two types are commonly available:

- Lithium-bromide (LiBr)/water mixture: LiBr is a salt and is the absorbent; water is the refrigerant. This solution is especially common for commercial cooling.
- Water/ammonia mixture (aqueous ammonia refrigeration - AAR): water is the absorbent and ammonia the refrigerant. Typically used for low-temperature cooling or freezing (see Figure 64).

The key difference between an absorption cycle and a VC cycle is the process that transforms the low-pressure refrigerant to a high-pressure vapour, process 1→2 in Figure 61. A VC cycle mechanically compresses the low-pressure vapour. An absorption cycle absorbs the low-pressure vapour into a solution at low pressure, pumps it to a high pressure, and then heats it to produce a high-pressure vapour. An absorption cycle's compressor function is commonly referred to as a *thermal compressor*, *thermochemical compressor*, or a *chemical compressor*. Figure 65 shows the absorption cycle in two portions - refrigeration portion and thermochemical compression portion - thus establishing a parallel with VC refrigeration.

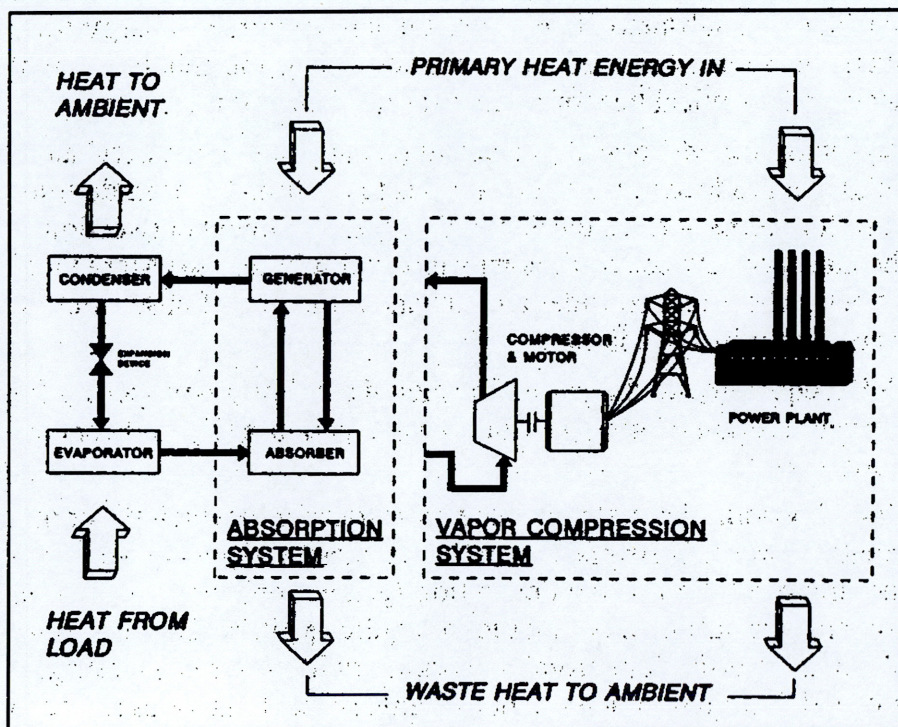


Figure 65. Similarities between absorption and VC systems (ASHRAE, 1998).



### 7.3 Coefficient of performance (COP)

COP is a ratio to rate a machine's energy-transfer effectiveness, i.e. energy transferred to energy input.

$$COP = \frac{\text{cooling delivered}}{\text{energy input required}}$$

This COP does not include power for the cooling tower's fans and pumps. However, a full system economic analysis must include these energy costs.

The COP for a single-effect system is typically two-thirds that of a double-effect system, which makes more efficient use of the input energy (Dorgan, Leight and Dorgan, 1995). VC systems have COPs ranging from 2 to 6.75 but typically require a higher grade of energy to power them (electricity versus gas or recovered heat). Any comparison must account for the cost of the energy required by each. The amount of mechanical work required to compress the vapour determines a VC system's COP. The amount of heat required to operate the cycle determines an absorption cycle's COP.

In a simple comparison between a VC chiller with a 5.5 COP and a double-effect absorption unit with a 1.0 COP, if the electricity cost is more than 5.5 times the recovered heat's value on a \$/kWh basis, the absorption chiller should have an operating cost advantage. Including the auxiliary energy use (for cooling water pumps, and cooling-tower fans), the electricity cost would have to increase to ~8.3 times the heat's value for the absorption chiller to have an advantage. If the recovered heat has no value, then the COP has no impact for determining a simple economic decision.

The conditions under which COP is obtained is important for comparing COPs. The Air-conditioning and Refrigeration Institute (ARI) rates COP at standard conditions:

|                                                          |                           |
|----------------------------------------------------------|---------------------------|
| Supply cooling water temperature from the cooling tower: | 29°C                      |
| Chilled-water supply temperature:                        | 7°C                       |
| Chilled-water flow rate:                                 | 0.043 L/s·kW <sub>r</sub> |
| Cooling water flow rate, single-effect:                  | 0.065 L/s·kW <sub>r</sub> |
| Cooling water flow rate, double-effect:                  | 0.072 L/s·kW <sub>r</sub> |
| Cooling water flow rate, vapour compression:             | 0.054 L/s·kW <sub>r</sub> |

An absorption machine's COP varies depending on the temperature of the recovered heat, the leaving chilled fluid temperature, and the type of absorption machine used. The tradeoff between the double-effect machine's higher COP compared to a single-effect machine is an increase in the machine cost and a higher temperature heat input requirement. So COP has an impact on an absorption machine's first cost and size. Double-effect absorption systems reject less heat due to the higher COP.



## 7.4 Absorption system characteristics

All systems have three primary elements:

- heat source,
- cooling load, and
- heat sink.

### 7.4.1 Heat source

Common heat sources are hot water, process steam, hot air, and hot combustion products (exhaust gases). Important characteristics for evaluating a heat source are:

- source heat stream temperature,
- recovered heat stream flow rate,
- source heat stream chemical composition, and
- recovered heat stream temperature- and flow-intermittence.

The source heat stream typically heats the recovered heat stream using a heat exchanger to protect the absorption machine from contaminants and corrosive elements in the source heat stream. A clean stream is best used directly.

#### 7.4.1.1 Source heat stream temperature

As the input temperature to an absorption machine decreases, the cooling output also decreases. Three grades of heat sources are high, medium and low. High-grade heat is above 650°C. Medium-grade heat ranges from 230°C to 650°C. The exhaust from ICEs and GTs lie in this range, and can generate steam pressure over 1,480 kPa. Higher-end medium-grade heat, over 425°C, drives double-effect machines or AARs for low-temperature applications. Below 425°C the heat drives single-effect chillers. Low-grade heat, under 230°C, is suitable for single-effect machines only, or absorption heat pumps (see Table 25).

|                                      | Single-effect LiBr machine | Double-effect LiBr machine | Low-temperature ammonia machine |
|--------------------------------------|----------------------------|----------------------------|---------------------------------|
| Steam input, kPa                     | 135 – 205                  | 110 – 120                  | 100 – 1480                      |
| Steam input, °C                      | 110 – 120                  | 175 – 185                  | 100 – 195                       |
| Hot water or process fluid input, °C | 115 – 150                  | 155 – 205                  | 100 – 195                       |
| Cooling output, °C                   | 4 – 38                     | 4 – 27                     | -51 – 4                         |
| COP                                  | 0.6 – 0.7                  | 0.9 – 1.2                  | 0.1 – 0.8                       |

Table 25. Absorption system requirements (Dorgan, Leight and Dorgan, 1995).

### 7.4.2 Cooling load

Absorption and VC machines are used in the same cooling applications: process cooling, space cooling, dehumidification, low-temperature cooling.

### 7.4.3 Heat sink

Heat is rejected typically through a cooling tower (CT). The absorption process generates heat that requires 1.5 to 2 times more system heat rejection than similar VC systems (Dorgan, Leight and Dorgan, 1995). This also affects the amount of water treatment and auxiliary loads (pumps and fans).

Table 26 and Table 27 illustrate the basic differences between single- and double-effect absorption machines and how varying the input conditions affects the output conditions.

| Description                   | Units  | Double-effect   |                          |           |                                    |                     | Single-effect |                     |
|-------------------------------|--------|-----------------|--------------------------|-----------|------------------------------------|---------------------|---------------|---------------------|
|                               |        | Base steam case | Increased steam pressure | Hot water | Increased cooling water $\Delta T$ | Decreased CHW temp. | Steam         | Decreased CHW temp. |
| Leaving CHW temperature       | °C     | 6               | 6                        | 6         | 6                                  | 4                   | 6             | 4                   |
| Recovered heat quality        | kPa    | 894             | 998                      | 653       | 894                                | 894                 | 184           | 184                 |
| Amount recovered heat         | kW     | 2,563           | 2,528                    | 2,660     | 2,563                              | 2,563               | 2,967         | 2,967               |
| Flow recovered heat           | Kg/s   | 1.03            | 1.02                     | 1.04      | 1.03                               | 1.03                | 1.36          | 1.36                |
| Design cooling output         | kWr    | 2,810           | 2,640                    | 3,236     | 2,810                              | 2,810               | 2,095         | 2,095               |
| Nominal machine size          | kWr    | 2,670           | 2,350                    | 3,889     | 3,557                              | 2,867               | 1,934         | 2,005               |
| Heat rejection                | kWt    | 5,230           | 4,890                    | 5,997     | 5,210                              | 5,230               | 5,246         | 5,246               |
| Cooling water $\Delta T$      | °C     | 6               | 6                        | 6         | 11                                 | 6                   | 6             | 6                   |
| Total energy usage            | kWh/yr | 1,371,000       | 1,272,000                | 1,583,000 | 902,000                            | 1,358,000           | 1,180,000     | 1,180,000           |
| Total energy demand           | kW     | 261             | 242                      | 300       | 103                                | 259                 | 225           | 225                 |
| Absorption machine first cost | US\$   | 352,000         | 315,000                  | 465,000   | 425,000                            | 360,000             | 193,000       | 199,000             |

Note: The source heat stream is the exhaust gas from a GT. The exhaust gas flow-rate is 7.7kg/s at 516°C. The amount of recovered heat is based on a gas-to-steam heat recovery system (or a gas-to-water in the case of the hot water unit) recovering steam at the listed quality. Compare the design cooling output for relative machine performance.

Table 26. LiBr absorption system variations – fixed heat source (Dorgan, Leight and Dorgan, 1995).

| Description                   | Units  | Double-effect   |                          |           |                                    |                      | Single-effect |                     |
|-------------------------------|--------|-----------------|--------------------------|-----------|------------------------------------|----------------------|---------------|---------------------|
|                               |        | Base steam case | Increased steam pressure | Hot water | Increased cooling water $\Delta T$ | Decrease d CHW temp. | Steam         | Decreased CHW temp. |
| Leaving CHW temperature       | °C     | 6               | 6                        | 6         | 6                                  | 4                    | 6             | 4                   |
| Recovered heat quality        | kPa    | 894             | 998                      | 653       | 894                                | 894                  | 184           | 184                 |
| Amount recovered heat         | kW     | 2,563           | 2,667                    | 2,370     | 2,563                              | 2,563                | 4,120         | 4,120               |
| Design cooling output         | kWr    | 2,810           | 2,810                    | 2,810     | 2,810                              | 2,810                | 2,810         | 2,810               |
| Nominal machine size          | kWr    | 2,670           | 2,502                    | 3,377     | 3,557                              | 2,867                | 2,603         | 2,705               |
| Heat rejection                | kW     | 5,230           | 5,230                    | 5,230     | 5,230                              | 5,230                | 7,175         | 7,175               |
| Cooling water $\Delta T$      | °C     | 6               | 6                        | 6         | 11                                 | 6                    | 6             | 6                   |
| Total energy usage            | kWh/yr | 1,371,000       | 1,362,000                | 1,377,000 | 902,000                            | 1,379,000            | 1,584,000     | 1,581,000           |
| Total energy demand           | kW     | 261             | 260                      | 261       | 103                                | 261                  | 179           | 179                 |
| Absorption machine first cost | US\$   | 320,000         | 356,000                  | 404,000   | 425,000                            | 342,000              | 261,000       | 271,000             |

Note: The design cooling output is constant at 2,810kWr. The amount of recovered heat and the absorption machine size are allowed to vary.

Table 27. LiBr absorption system variations – fixed cooling capacity (Dorgan, Leight and Dorgan, 1995).

7.5 The Lithium Bromide-water absorption cycle

As explained before, the compressor function is the only difference with the VC cycle. The condenser, expansion device, and evaporator components perform the same functions as in VC systems.

7.5.1 Single-effect absorption process

Figure 66 shows a single-effect absorption machine schematic. For the refrigeration cycle to work the refrigerant vapour must change pressure between points 1 and 2. In an absorption machine the thermal compressor achieves this. Within the compressor the LiBr-water solution in the absorber section first absorbs the refrigerant vapour. Then the solution pump pressurises the now-weak absorbent (dilute solution) to overcome the generator pressure. Evaporation (heating) in the generator separates the refrigerant from the LiBr-water solution and produces a pure refrigerant vapour and a strong absorbent (concentrated solution).



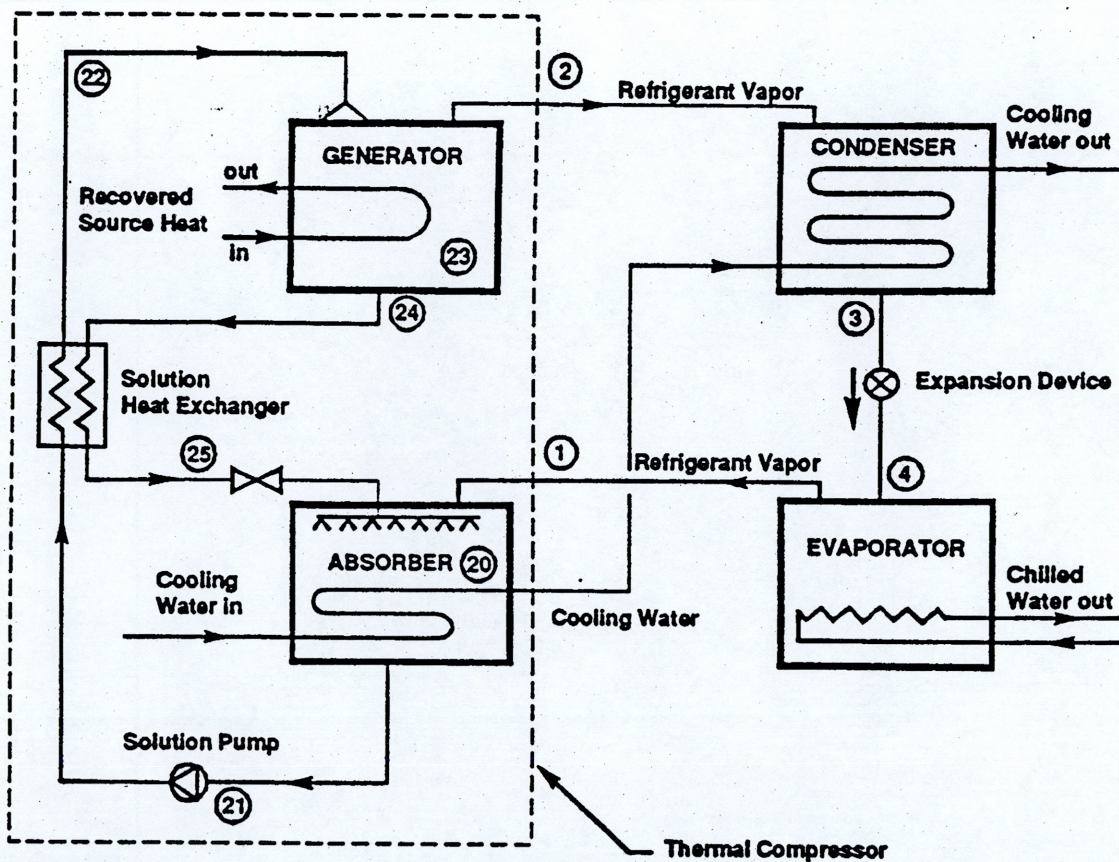


Figure 66. Absorption refrigeration cycle schematic, single effect (Dorgan, Leight and Dorgan, 1995).

- Process 1→20: At point 1 low-pressure, low-temperature refrigerant vapour from the evaporator enters the thermal compressor into the absorber section.
- Process 20→21: From point 20 to 21 the strong absorbent (concentrated solution) from the generator section absorbs the refrigerant vapour. This increases the amount of refrigerant in the solution, thus diluting the solution at point 21 to a weak absorbent (dilute solution). As the refrigerant vapour is absorbed it condenses, releasing heat related to the phase change. In addition, the absorption process generates heat (heat of reaction). Cooling water circulating through the absorber section removes the heat that these two processes generate.
- Process 21→22: From point 21 the weak absorbent is pumped from the absorber section to the generator. In addition to transporting the solution, pumping also overcomes the pressure differences between the absorber and generator sections. The weak absorbent passes through the solution heat exchanger, preheating it to point 22. This heat exchange is a key element in reducing heat energy required for the generator, and in increasing cycle efficiency.



- Process 22→23: At conditions from point 22 the weak absorbent enters the generator. Heat from the recovered heat stream is added to the generator to heat the solution to the required temperature.
- Process 23→24: Adding more heat to the solution boils it, releasing refrigerant until the absorbent-refrigerant solution matches the saturated temperature-pressure-concentration related to point 24. At the higher pressure, high-temperature refrigerant leaves the thermal compressor for the condenser at point 2. The solution becomes concentrated with the reduced amount of refrigerant in it at point 24.
- Process 24→25: From the generator the strong absorbent passes through a solution heat exchanger where it is pre-cooled to point 25.
- Process 25→20: From point 25 the strong absorbent passes through a throttling or expansion device to reduce the pressure of the strong absorbent. Some of the refrigerant within the solution flashes to vapour.

An absorption machine can economically use water as a refrigerant as the machine operates at pressures well below atmospheric conditions. In the evaporator's low-pressure environment in an absorption machine (82.7 Pa) water boils at 4°C as compared to 100°C at atmospheric conditions – 101.3kPa.

### 7.5.2 Single-effect absorption machine configuration

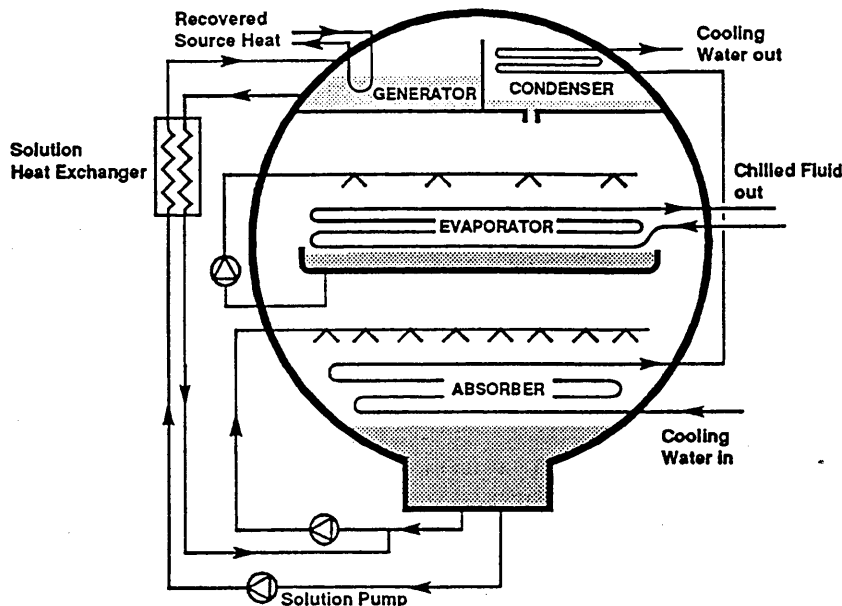


Figure 67. Absorption system layout, single-effect, one shell (Dorgan, Leight and Dorgan, 1995).

A LiBr single-effect absorption machine's actual physical configuration varies with each manufacturer. Currently there are two popular configurations for a single-effect absorption



machine. The first configuration shown in Figure 67 houses the entire process within one shell. The second shown in Figure 68 has a separate shell for the absorption machine's condenser and generator sections. Separate sections in an absorption machine are insulated from each other to reduce heat losses and gains between them.

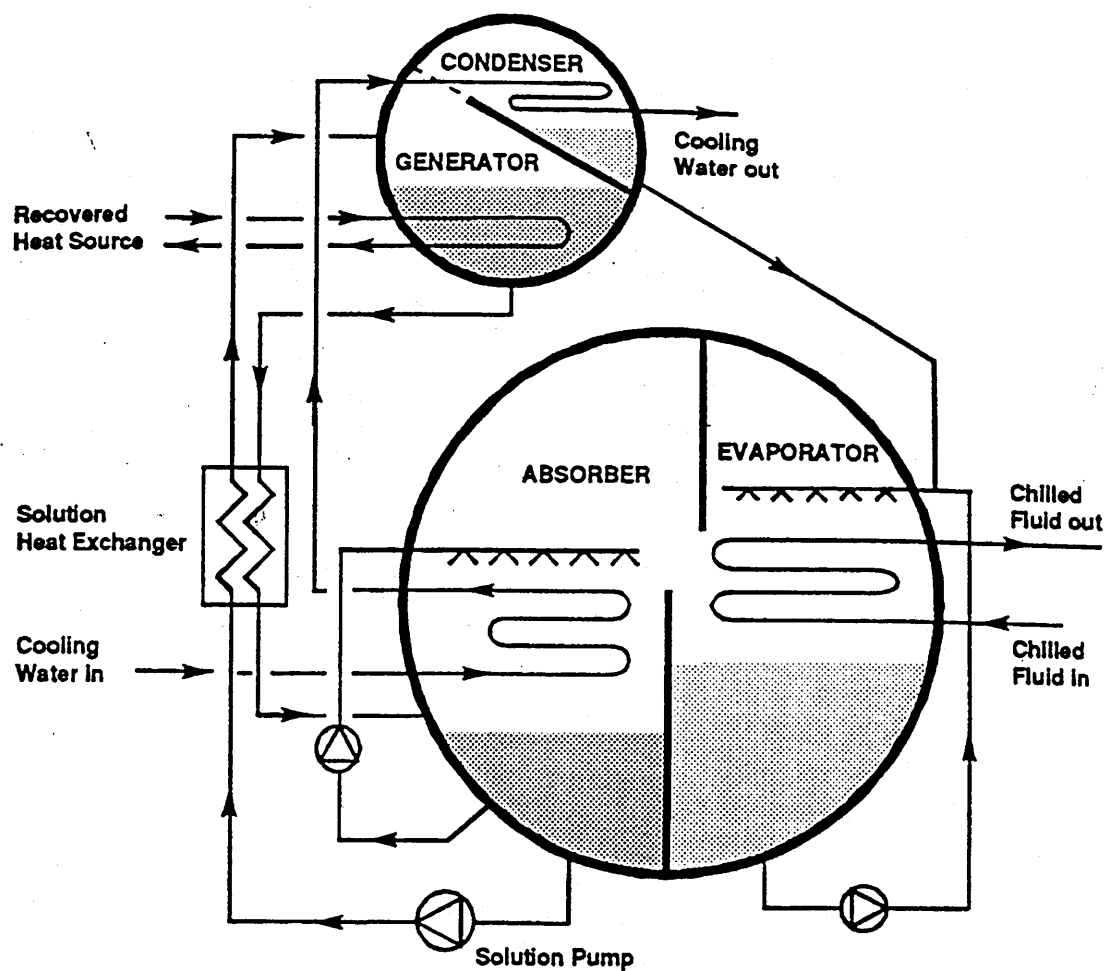


Figure 68. Absorption system layout, single-effect, two shells (Dorgan, Leight and Dorgan, 1995).

### 7.5.3 Double-effect absorption process

A double-effect absorption machine has an additional generator and condenser to the single effect cycle, giving two generation stages to separate the refrigerant from the absorbent. The heat-source temperature required to drive the high-stage generator must be higher than that used for a single-effect machine.

Indirectly using input heat a second time increases the absorption system's overall efficiency. The high-stage generator uses heat supplied by an outside process to drive off

refrigerant. On condensing, the heat from this refrigerant vapour evaporates the refrigerant out of solution in the low-stage generator to yield yet more refrigerant. Passing the high-stage refrigerant vapour through a tube bundle in the low-stage generator accomplishes this heat transfer which causes the high-stage vapour refrigerant to condense (see Figure 69).

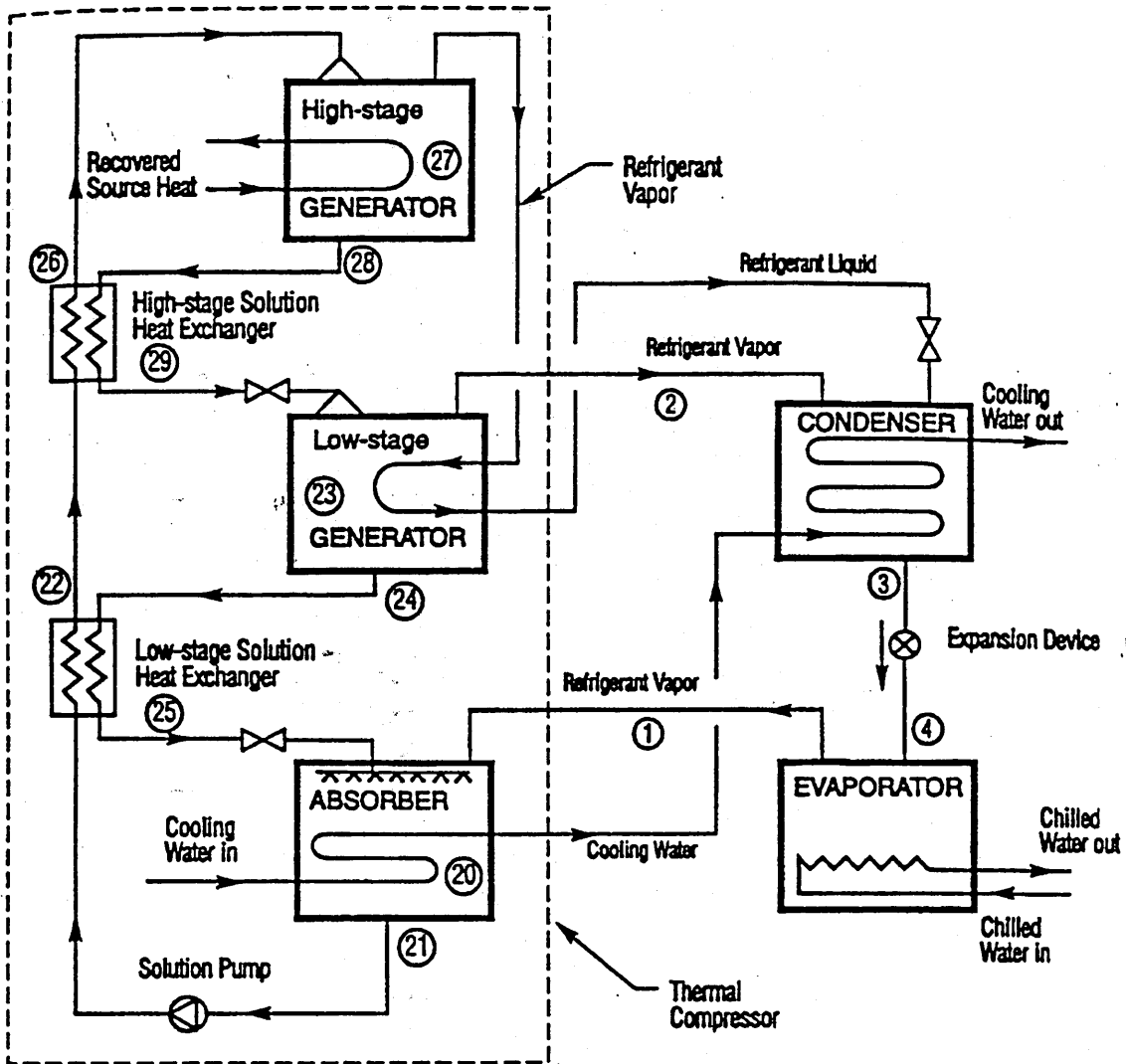


Figure 69. Absorption cycle schematic, double effect, series solution flow (Dorgan, Leight and Dorgan, 1995).

Double-effect machines need less cooling water than single-effect ones since the refrigerant vapour's heat of condensation from the high-stage generator is used to desorb the refrigerant from solution in the low-stage generator. Therefore double-effect machines reject less heat per unit cooling output.

One way of circulating the weak absorbent to the high- and low-stage generators is to first pump the weak absorbent to the high-stage generator and concentrate it to an intermediate solution concentration. This is then supplied to the low-stage generator and is further concentrated to a strong absorbent, process 28 to 24. Figure 69 shows this series flow system-type. Another way is to directly supply the weak absorbent to both the high-stage and low-stage generators. Each concentrates the weak absorbent and returns it to the absorber section. Figure 70 shows this parallel-flow system schematically. Point 29 approaches point 23 in a series flow configuration, and point 29 mixes with point 24 in a parallel-flow configuration.

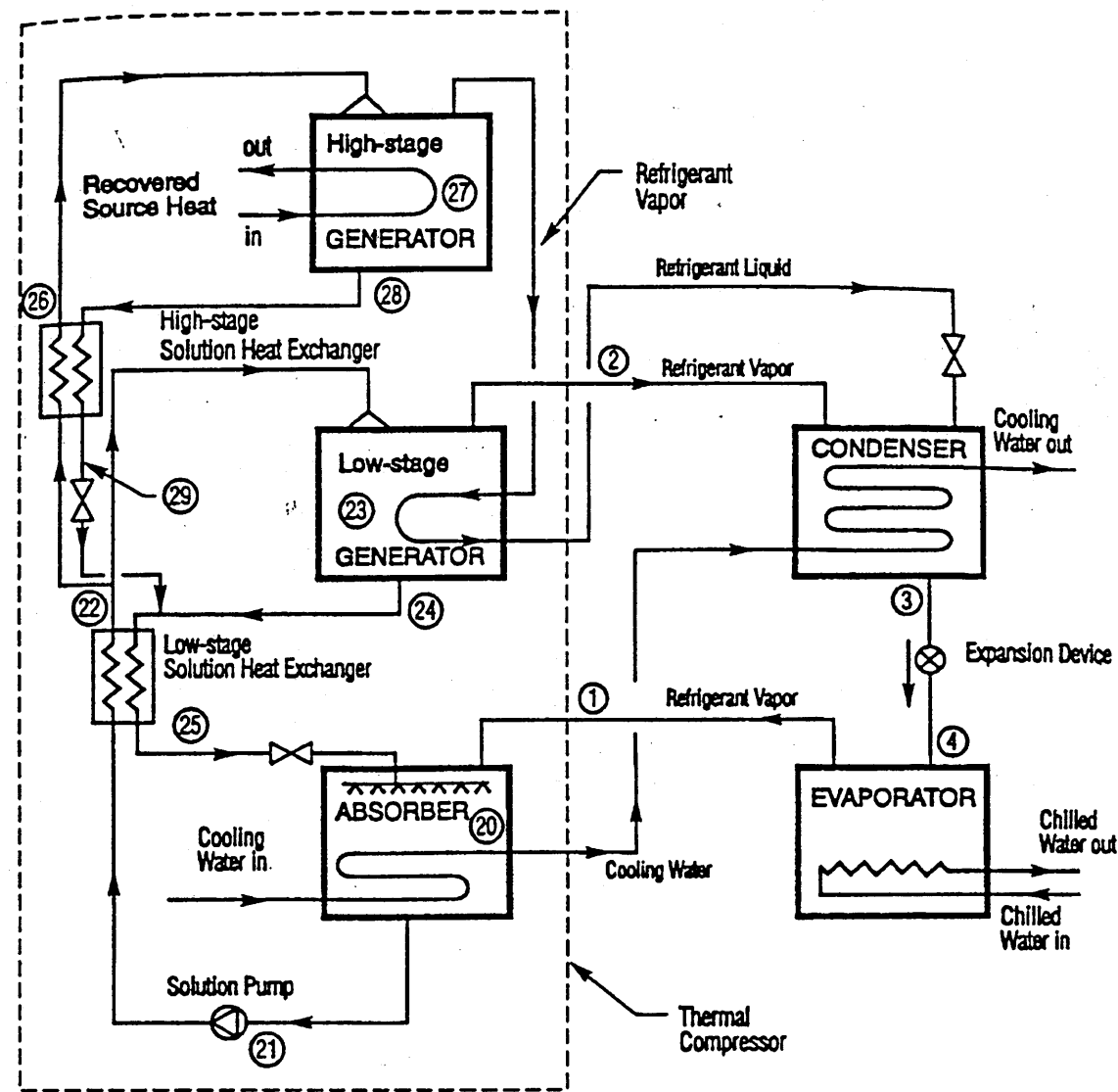


Figure 70. Absorption cycle schematic, double effect, parallel solution flow (Dorgan, Leight and Dorgan, 1995).

7.5.4 Double-effect absorption machine configuration

As with a single-effect system, the actual physical double-effect system configuration varies with each manufacturer. Double shell and triple shell are two popular forms. The double shell variety (Figure 71) has one shell for the absorber, condenser, evaporator, and low-stage generator and another shell for the high-stage generator. The triple-shell variety (Figure 72) has a separate shell for the condenser and low-stage generator. Figure 71 and Figure 72 show the parallel-flow configuration.

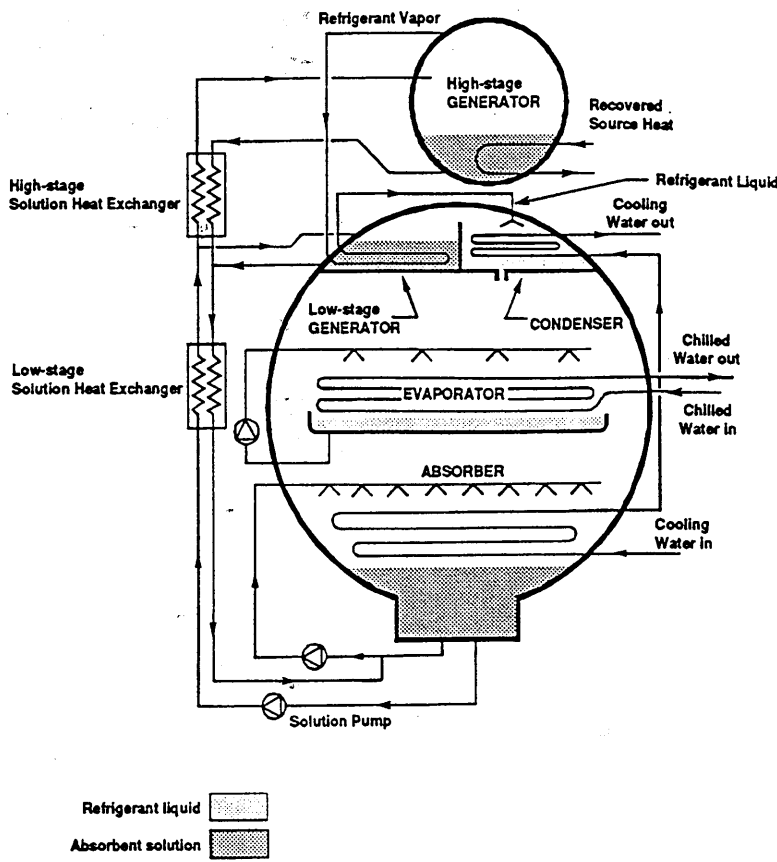


Figure 71. Absorption system layout, double-effect, two shells, parallel solution flow (Dorgan, Leight and Dorgan, 1995).

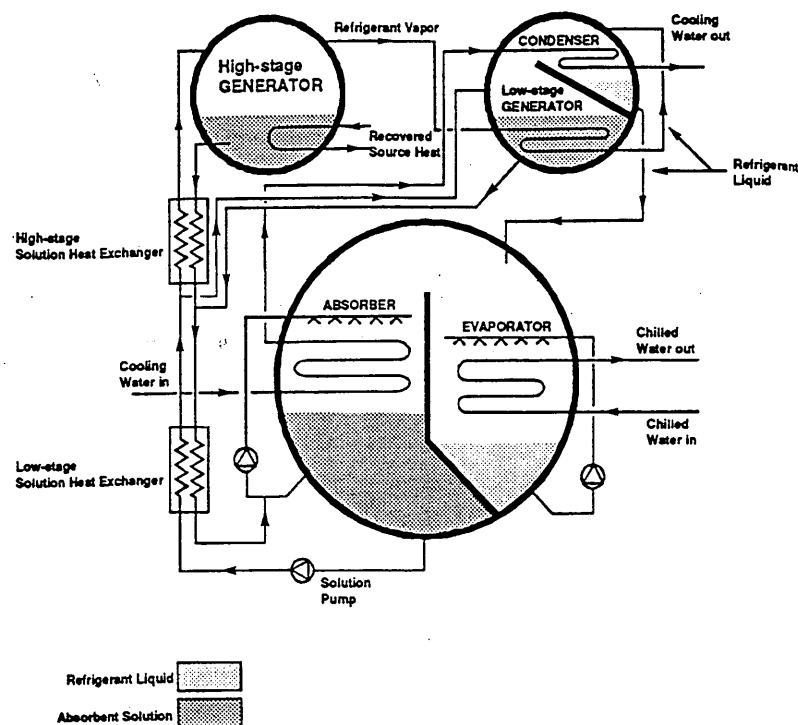


Figure 72. Absorption system layout, double-effect, three shells, parallel solution flow (Dorgan, Leight and Dorgan, 1995).

7.5.5 Comparing single- and double-effect systems

|                                               |                                                                                        |
|-----------------------------------------------|----------------------------------------------------------------------------------------|
| Steam input pressure, kPa gauge               | 60 to 80                                                                               |
| Steam consumption per kW <sub>r</sub> , kW    | 1.48 to 1.51                                                                           |
| Hot fluid input temperature, °C               | 115 to 132, with as low as 88°C for some smaller machines for waste heat applications. |
| Heat input rate per kW <sub>r</sub> , kW      | 1.51 to 1.54 with as low as 1.43 kW for some smaller machines.                         |
| Cooling water temperature in, °C              | 30                                                                                     |
| Cooling water flow per kW <sub>r</sub> , mL/s | 65, with up to 115mL/s for some smaller machines                                       |
| Chilled water temperature off, °C             | 6.7                                                                                    |
| Chilled water flow per kW <sub>r</sub> , mL/s | 43, with 47mL/s for some smaller machines                                              |
| Electrical power per kW <sub>r</sub> , W      | 3 to 11, with a minimum of 1W for some smaller machines                                |
| Nominal capacity, kW <sub>r</sub>             | 180 to 5,800, with 18 to 35kW <sub>r</sub> for some smaller machines                   |
| COP                                           | 0.5 to 0.7                                                                             |

Table 28. Typical single-effect, indirect-fired, water-LiBr absorption chiller characteristics (ASHRAE, 1998).



Generally a double-effect system is chosen over a single-effect system whenever there is a heat source with the temperatures sufficient to power a double-effect machine. Even though a double-effect machine's first cost is the greater it typically maximises the COP and cooling output when using recovered heat (Dorgan, Leight and Dorgan, 1995). Table 28 summarises a single-effect machine's requirements and parameters, and Table 29 summarises for a double-effect machine.

|                                                                                  |              |
|----------------------------------------------------------------------------------|--------------|
| Steam input pressure, kPa gauge                                                  | 790          |
| Steam consumption (with condensate saturated conditions) per kW <sub>r</sub> , W | 780 to 810   |
| Hot fluid input temperature, °C                                                  | 188          |
| Heat input rate per kW <sub>r</sub> , kW                                         | 0.83         |
| Cooling water temperature in, °C                                                 | 30           |
| Cooling water flow per kW <sub>r</sub> , mL/s                                    | 65 to 80     |
| Chilled water temperature off, °C                                                | 7            |
| Chilled water flow per kW <sub>r</sub> , mL/s                                    | 43           |
| Electrical power per kW <sub>r</sub> , W                                         | 3 to 11      |
| Nominal capacity, kW <sub>r</sub>                                                | 350 to 6,000 |
| COP                                                                              | 1.0 to 1.2   |

Table 29. Typical double-effect, indirect-fired, water-LiBr absorption chiller characteristics (ASHRAE, 1998).

## 7.6 Part-load operation

As the cooling load on an absorption machine decreases, the amount of heat supplied to the generator decreases and reduces the solution temperature, so the solution becomes more dilute. The chilled fluid outlet temperature is maintained, while the entering and leaving cooling (condenser) water temperature is allowed to float. As heat input decreases, condenser heat also decreases resulting in lower leaving cooling water temperatures.

The part-load COP can be greater than at full-load (Dorgan, Leight and Dorgan, 1995). Figure 73 shows the relationship between the percent design load, percent energy input, and the corresponding cooling water temperature for a single-effect system. The correlation is such that as the entering cooling water temperature decreases so does the generator's required heat input. Therefore, if cooler cooling-water is available, the heat input to the absorption machine can be decreased. Figure 74 shows the relationship between the percent of design load, percent of energy input, and entering cooling water temperature for a double-effect machine. As in a single-effect machine, the energy input decreases as the load decreases.

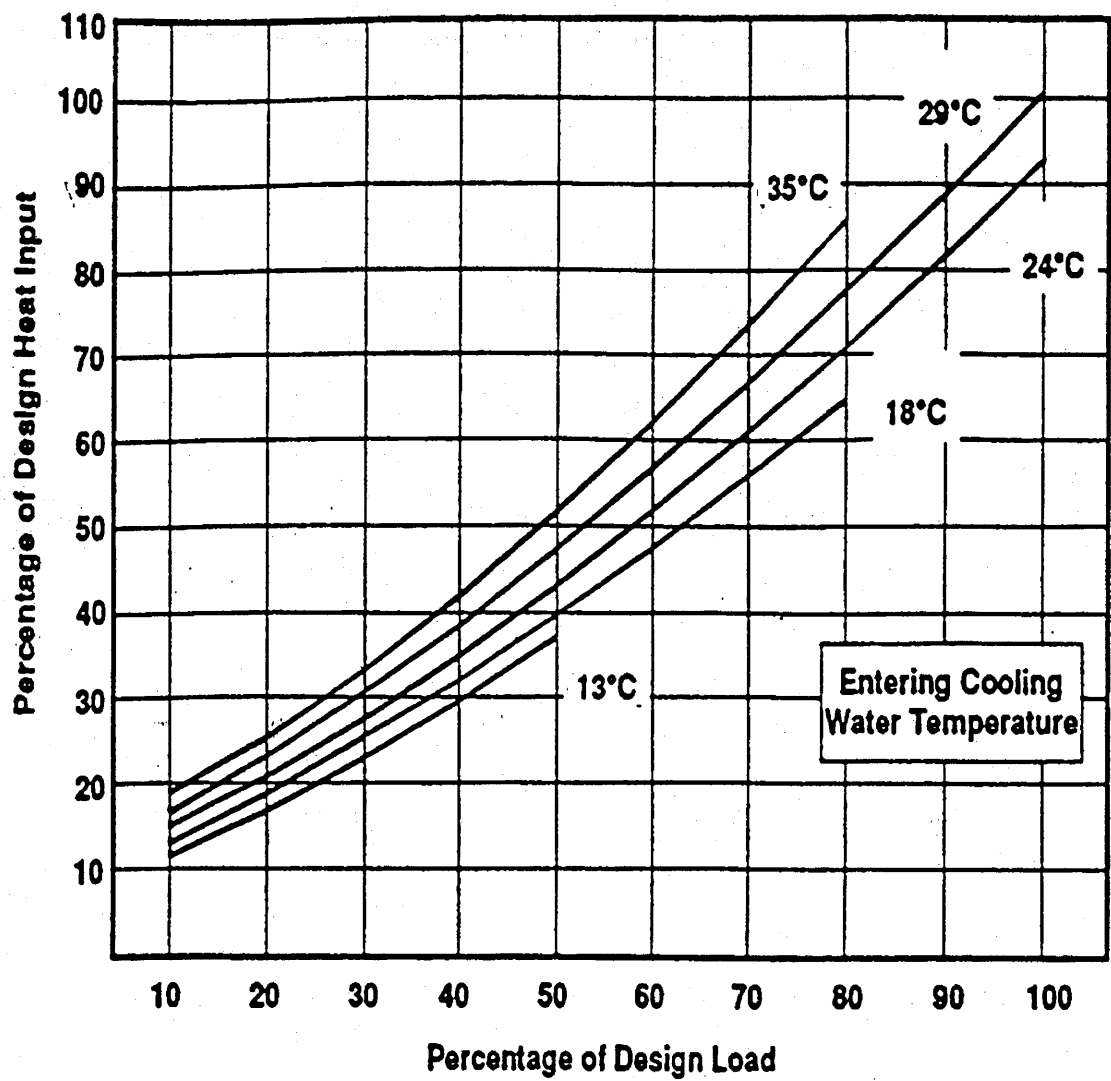


Figure 73. Part-load capacity chart, single-effect chiller (Dorgan, Leight and Dorgan, 1995).

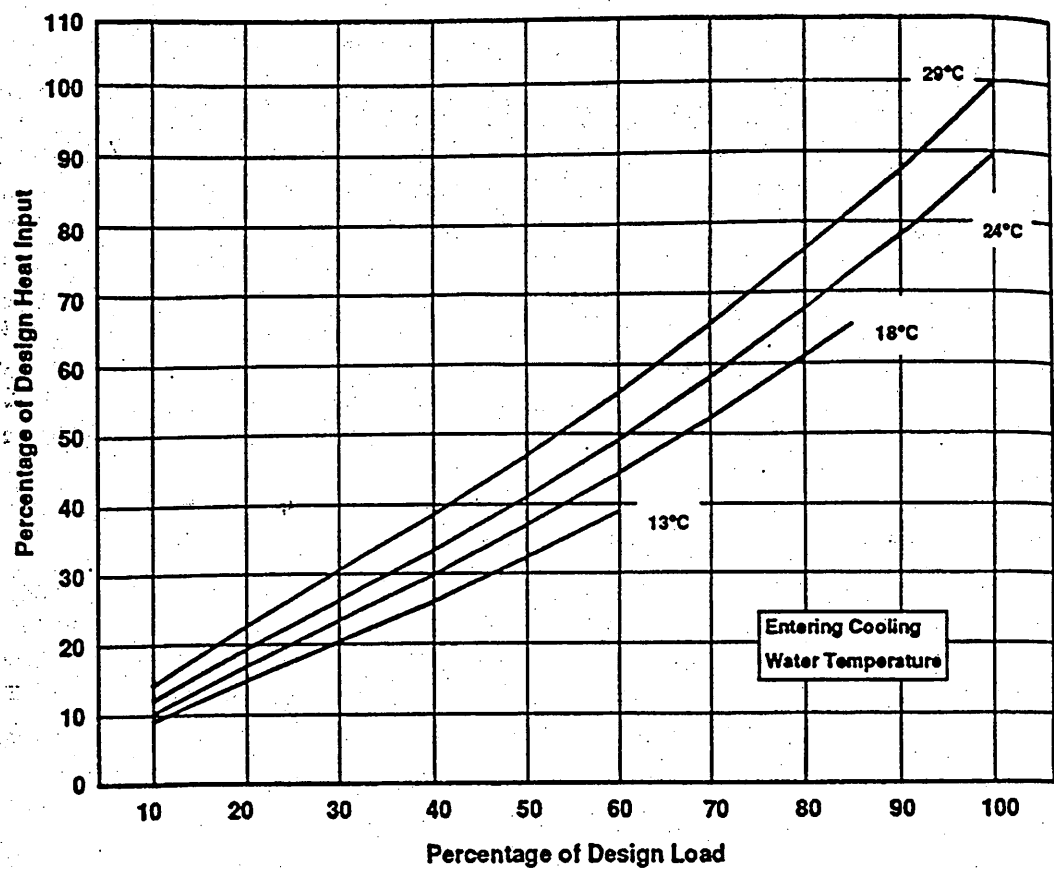


Figure 74. Part-load capacity chart, double-effect chiller (Dorgan, Leight and Dorgan, 1995).

## 7.7 Heat recovery

Using the source heat stream directly saves on initial capital investment as it avoids heat recovery equipment. Also there is no heat-exchanger efficiency losses, though there are possible efficiency losses in the absorption machine if fouling builds up. A heat exchanger brings possible increased maintenance cost and some energy loss, and also lowers the available peak temperature depending on the heat exchanger's effectiveness.

Cogeneration GTs have high heat recovery capability, require no cooling water, and have clean exhaust when using natural gas. The exhaust gas temperature ranges from 430°C to 530°C, has between 2.93 to 4.98 kJ/kWs generating capacity, and 15% to 18% oxygen content for supplemental firing. Cogeneration ICEs typically provide low-pressure steam or water at 82°C to 121°C, suitable for single-effect absorption cooling (Dorgan, Leight and Dorgan, 1995). Using cogeneration heat to power an absorption machine also reduces peak electricity demand.



Exhaust gas boilers using GT-exhaust are constructed as either water-tube or fire-tube (see Figure 75 and Figure 76). Water tube boilers provide better exhaust gas silencing, faster start-up times, and high-energy recovery at low cost. Fire-tube boilers are long lasting and have simple piping arrangements.

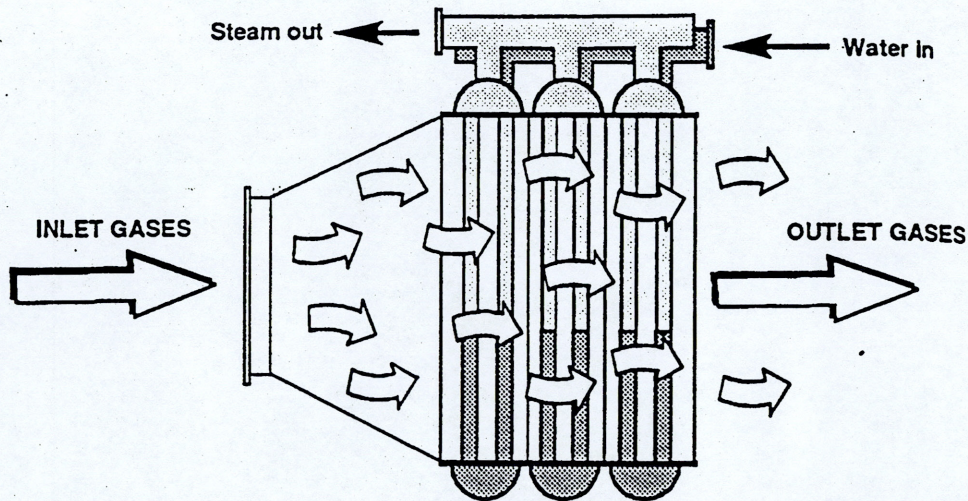


Figure 75. Water-tube boiler using exhaust gases (Dorgan, Leight and Dorgan, 1995).

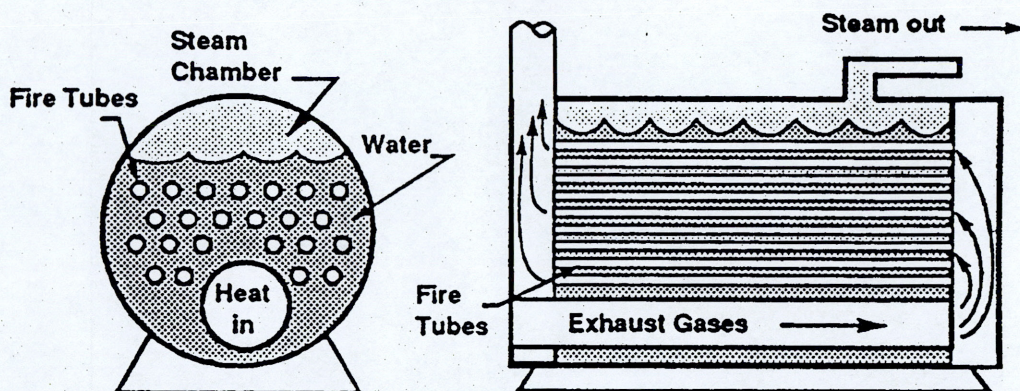


Figure 76. Fire-tube exhaust gas boiler (Dorgan, Leight and Dorgan, 1995).

## 7.8 Absorption system benefits

- Absorption systems have lower electrical needs compared to VC systems.
- Absorption units are quiet and vibration free.
- Recovered heat can be used to power the absorption refrigeration cycle.



- Absorption machines reduce chlorofluorocarbon (CFC) use and eliminate concerns about lubricants in the refrigerant.
- Absorption units are economically attractive when fuel costs are substantially less than electricity costs (typically if fuel cost is 12% to 20% of electricity cost (Dorgan, Leight and Dorgan, 1995)).

7.9 Absorption system economics

An absorption-system initial feasibility analysis would use nationwide averages, pricing books, and industry rules of thumb. The important costs for consideration are equipment, installation, operating, and maintenance costs.

7.9.1 First costs

First-cost items are the absorption machine, heat rejection-, heat recovery-, and auxiliary-equipment. Absorption systems are physically larger than equivalent VC machines and cannot be dismantled to fit, as this would compromise the machine’s hermetic integrity. Table 30 gives absorption machine capital costs; an initial estimation would use the average in a range (Dorgan, Leight and Dorgan, 1995). Table 31 shows CT costs, including cooling water pump and piping costs, about US\$31/kWr. The costs also include installation. Heat-recovery equipment costs are very variable. For example, heat recovery steam generator costs range from US\$33 to US\$88/(kg/h); US\$55 is recommended (Dorgan, Leight and Dorgan, 1995).

|                                                 | LiBr-water                        |                                   | Aqueous ammonia    |
|-------------------------------------------------|-----------------------------------|-----------------------------------|--------------------|
| Nominal size at ARI conditions, kW <sub>r</sub> | Single-effect, \$/kW <sub>r</sub> | Double-effect, \$/kW <sub>r</sub> | \$/kW <sub>r</sub> |
| 900                                             | 95 – 190                          | 130 – 260                         | 340                |
| 1,750                                           | 65 – 140                          | 90 – 195                          | 340                |
| 3,500                                           | 60 – 110                          | 80 – 155                          | Custom             |
| 5,300                                           | 55 – 110                          | 80 – 150                          | Custom             |

Table 30. Absorption machine capital costs in US\$ (Dorgan, Leight and Dorgan, 1995).



| Cooling water temperature difference, °C | Single-effect machine, \$/kW <sub>r</sub> | Double-effect machine, \$/kW <sub>r</sub> |
|------------------------------------------|-------------------------------------------|-------------------------------------------|
| 6                                        | 68                                        | 60                                        |
| 8                                        | 61                                        | 55                                        |
| 11                                       | 58                                        | 53                                        |

Note: This table is based on per-kW design cooling (evaporator) output. It is important to realise that the numbers are averages only. The increase in CT cost for an absorption system over a similarly sized VC system does not increase linearly. The incremental cost for a CT (cost to the contractor) is typically US\$7 to US\$9 per condenser kW<sub>r</sub> (Dorgan, Leight and Dorgan, 1995).

Table 31. Cooling tower costs for absorption systems in US\$ (Dorgan, Leight and Dorgan, 1995).

### 7.9.2 Operating costs

The absorption machine’s electrical energy-use cost and the penalty from heat recovery equipment can be ignored (Dorgan, Leight and Dorgan, 1995). The condenser water (CW) pump and the CT fan are major electricity users for the absorption cooling system. At ARI conditions and a 6°C condenser-water temperature difference, typical CW pump performance is:

- 0.1L/s·kW<sub>r</sub> water circulation, and 0.025kW/kW<sub>r</sub> energy use for a single-effect machine, and
- 0.08L/s·kW<sub>r</sub> water circulation, and 0.021kW/kW<sub>r</sub> energy use for a double-effect machine.

The corresponding CT fan power is 0.028 kW/kW<sub>r</sub> and 0.023 kW/kW<sub>r</sub> respectively. A part-use factor applies to the fans since they do not operate continuously, but intermittently, to maintain leaving cooling water temperature. Initial energy-use calculations use a factor of 0.4 (Dorgan, Leight and Dorgan, 1995).

### 7.9.3 Maintenance costs

There is no consensus in comparing VC and absorption machine maintenance costs so they are taken as the same (Dorgan, Leight and Dorgan, 1995). In terms of operation and maintenance, modern water-LiBr absorption chillers are typically trouble-free and easy to operate with a design life exceeding twenty years (ASHRAE, 1998).

## Chapter 8. Fieldwork

This thesis evaluates natural gas cogeneration as an Energy-policy measure for Trinidad and Tobago (T&T), specifically among industrial electricity-customers. It does this by evaluating representative facilities, then extrapolating to the whole spectrum of industrial customers, as it cannot be the exhaustive study that a proper policy proposal would need. So the evaluation is essentially a series of cogeneration-project feasibility studies at individual sites.

A cogeneration feasibility study requires specific data:

- Electricity- and heat-demand profiles over a day for each type of day: weekday, weekend, and public holiday.
- *Average* electricity- and heat-demand profiles over a year to determine how demand varies with seasonal changes in site-operations and weather.
- The number of operating hours per annum.
- Forecasted changes in operations, including any planned energy-conservation measures, e.g. energy-efficient lighting, DDC air conditioning controls.

Cogeneration, both at individual sites and at a national level, should only be contemplated *after* evaluating the potential for energy conservation and management (and demand-side management on the national level). This would constitute a separate energy-policy measure and is outside this thesis' scope, which thus evaluates cogeneration in the energy-situation as is.

The detailed data needed for cogeneration feasibility studies in T&T is unavailable in publications and must be obtained through fieldwork. A cogeneration study on a national basis also needs less site-specific information, such as energy-use statistics for the country as a whole, including forecasts and projections. Some of this data is published but the fieldwork yields more comprehensive data through interviews with key persons in this area. Energy-use data from the Trinidad and Tobago Electricity Commission (T&TEC) for every industrial customer in 1998 corroborates less detailed published data from the Latin American Energy Organisation (OLADE). Even at individual sites, interviews with persons responsible for energy management improves the understanding of the facility's operations. So the fieldwork was not confined to metering although a significant part of it is metering 3-phase electricity. The Appendix describes the relevant features of 3-phase electricity.

### 8.1 Fieldwork method

The basic fieldwork procedure:

1. Determine the individual facilities to investigate, and contact them about the fieldwork. Information that helped in selecting sites came from:

- OLADE.
  - Lists of T&T's industrial estates, the companies therein, and their T&TEC rate categories.
  - Prior knowledge from work experience.
2. Set up a meeting with personnel responsible for energy monitoring at the sites that responded positively to the initial request for an energy audit. Ask in advance for:
    - Energy bills for the most recent 12 consecutive months to help determine the yearly energy profile.
    - Information from the facility's independent metering if available (relevant mainly to D3 customers).
    - Supervised access to main electrical switchgear and main air conditioning panels if appropriate. The site energy manager would normally have a line-diagram schematic of the facility's electrical system, which helps to easily locate these panels.
  3. Conduct actual interviews with site personnel and meter the site if possible. For sites with significant air conditioning loads the metering takes at least two full days, as the cooling-load profile must be monitored separately from the overall facility's profile. Some sites only allow metering at sub-panels that must then be totalled, introducing some error as each sub-panel is metered on a different day. It also increases the length of the survey at that site.

An accurate picture of T&T's current overall energy situation as a starting point would theoretically allow the fieldwork to be meticulously planned and focussed for maximum efficiency in use of time and effort. The practical fieldwork is very different. Much of the data that would allow targeting the fieldwork, of the kind described at the start of Chapter 9, could only be obtained *during* the fieldwork, and the information only becomes available gradually. Thus, the fieldwork approach is constantly updated and fine-tuned with growing experience. As a result some early-metered sites turn out to be completely inappropriate for a cogeneration study, such as the steel-working factory described in the previous section. Some appropriate sites may refuse to participate in the fieldwork, so the main consideration during the fieldwork was to visit any site that co-operated. The overall result is some duplication of effort so that not all of the information gathered during the fieldwork is relevant or included in this thesis.

The actual metering for a cogeneration study should be done over an entire week to distinguish between weekday and weekend, except for the large petrochemical facilities that operate continuously and mainly uniformly. This would have been possible with a focussed fieldwork exercise using the time efficiently, but it was not done in this study.

## 8.2 The fieldwork meter

Chapter 3 describes rate categories for industrial electricity customers. D3 customers are mainly large petrochemical plants with their own energy monitoring systems. Wherever possible, these provided the data needed for evaluating cogeneration. All other D-rate customers had to be metered independently in order to obtain daily electricity demand



profiles. They all have 3-phase power supplies, to be monitored using a 3-phase wattmeter. This study uses the SP Max energy profile logger (Figure 77). It logs electricity load profiles, consumption data, and power factor profiles for single- and 3-phase power, and uses SP PowerPack software.



Figure 77. SP Max energy data logger (Elcomponent Ltd., 1999).

8.2.1 Meter specifications (Elcomponent Ltd., 1999)

| Feature          | Specification                                                                                     | Comments                            |
|------------------|---------------------------------------------------------------------------------------------------|-------------------------------------|
| Maximum channels | 6                                                                                                 | Selectable storage for each channel |
| Range            | Ch1 0-275 V ac r.m.s for 50/60 Hz operation<br>Ch2 0-1 V ac – CX input<br>Ch3 0-1 V ac – CX input |                                     |



|                              |                                                                                                                                             |                                                                 |
|------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------|
|                              | Ch4 0-1 V ac – CX input<br>Ch5 0°-360° Ch1 to Ch2 – power factor calculated via software<br>Ch6 Pulse input – for dry or free contacts only |                                                                 |
| <b>External connections</b>  | 1 voltage/auxiliary power, 1 download, 3 current, 1 pulse                                                                                   |                                                                 |
| <b>Sensor type</b>           | External CXs, internal impedance network for voltage                                                                                        |                                                                 |
| <b>Sampling rate</b>         | 0.25 second                                                                                                                                 |                                                                 |
| <b>Data storage rate</b>     | 1 second to 15 minutes                                                                                                                      | Set via software                                                |
| <b>Parameters stored</b>     | Minimum/maximum, or Average, or both                                                                                                        | Set via software                                                |
| <b>Samples per average</b>   | 4-3600, depending on storage rate                                                                                                           | Set automatically                                               |
| <b>Memory</b>                | 512K, non-volatile RAM                                                                                                                      |                                                                 |
| <b>Memory treatment</b>      | Stop when full, or wrap                                                                                                                     | Set via software                                                |
| <b>Storage capacity</b>      | 15 days for 6 channels, min/max/avg, 1 min. storage interval                                                                                | Capacity depends on number of channels used and storage mode    |
| <b>Status indicator</b>      | Line power, over/under voltage, phase error/over current/no current, recording, battery charged (inside cover)                              |                                                                 |
| <b>Power</b>                 | Line power, internal battery                                                                                                                | Battery recharged via line power                                |
| <b>Battery life</b>          | 14 days                                                                                                                                     |                                                                 |
| <b>Communications</b>        | Opto-isolated RS232                                                                                                                         | Support for remote set-up                                       |
| <b>Software</b>              | SP PowerPack                                                                                                                                | Requires PC running Windows 3.1 or later and 1 free serial port |
| <b>Accuracy</b>              | $\pm 0.25\%$ Range + CX error                                                                                                               |                                                                 |
| <b>Safety</b>                | Optically isolated download                                                                                                                 |                                                                 |
| <b>Operating temperature</b> | -20°C to 50°C                                                                                                                               |                                                                 |

CX = current transformer

### 8.2.2 Meter features

Figure 78 shows meter features found inside the front cover:



- **Status indicators** – on, off, or flashing, indicate different operating conditions: battery charge, line power, under/over voltage, phase error, over current, recording.
- **Two-button operation** – sleep and reset.
- **Purge valve knob** – if the meter is hermetically sealed.
- **Serial port connection** – 9-pin RS232 connector for communicating with a PC via cable.

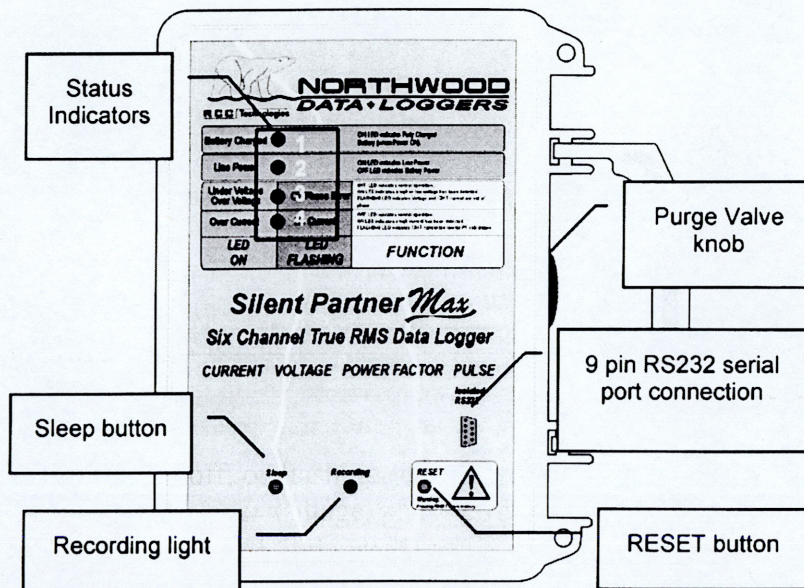


Figure 78. The meter – inside front cover (Elcomponent Ltd., 1999).

Figure 79 shows the meter's connectors:

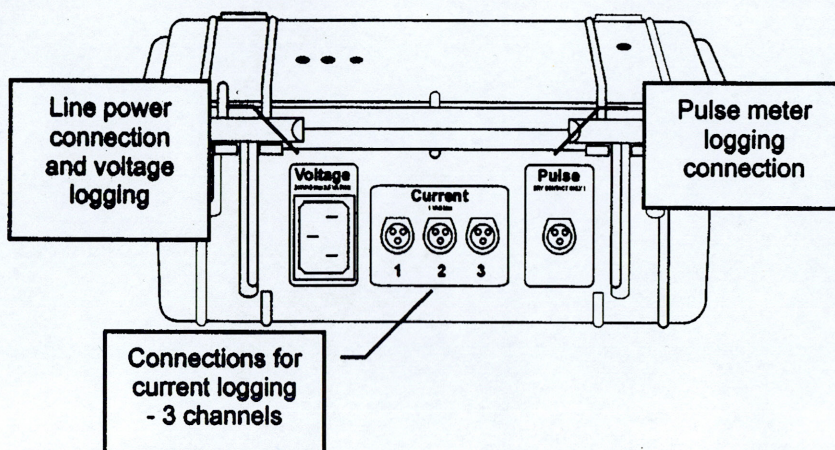


Figure 79. The meter connectors (Elcomponent Ltd., 1999).

- **Voltage** – a single voltage connection to the same phase that Current-1 connects.



- **Current** – three current input connectors for current transformers (CXs).
- **Pulse** – to log data from almost any kind of pulse meter. It differs from other kinds of logging in that the SP Max counts and stores all pulses it receives. Min/max and average data storage modes do not apply.

### 8.2.3 Using the meter

At all facilities logged during the fieldwork the meter was connected for 3-phase monitoring. Figure 80 displays 3-phase meter connection; it follows the convention for naming the phases Red (R), Yellow (Y), and Blue (B). N is the neutral line in a 4-wire 3-phase system. The facility's main electricity supply panel is usually located just after the high-voltage transformer bringing grid electricity onto the site. All fieldwork metering occurs on the low-voltage side because:

- The high voltage is dangerous, and only specially qualified persons have access to it.
- The limit to the meter's voltage input would require a potential transformer (PT), which was not available during the fieldwork.

D3 facilities in the petrochemical industry normally have their own distributed control system (DCS), which can be set up to monitor any plant operating parameter. This provides adequate data for a cogeneration study. High security at these plants also makes fieldwork metering impossible.

As far as possible the metering at any point should cover at least 24 hours but this really depends on the facility's personnel being available at the appropriate time of day. In some cases the meter had to be removed before 24 hours.

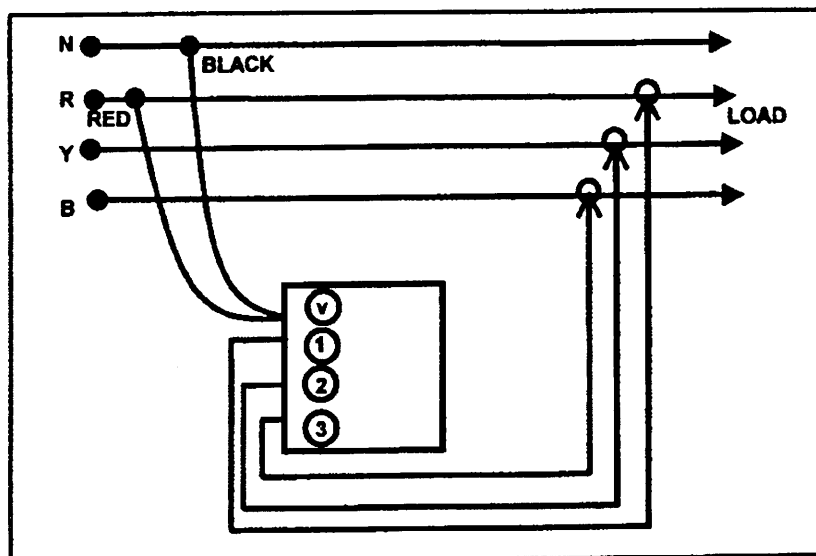


Figure 80. Meter 3-phase connection (Elcomponent Ltd., 1999).

## 8.2.4 Meter software

The SP PowerPack software is used to:

- Set up the meter.
- Set the logging parameters.
- Interrogate the meter (status report).
- Download collected data.
- Display, manage and print downloaded data.
- Calculate energy consumption and power data from primary measured values.

### 8.2.4.1 Setting the logging parameters

- **Data storage interval and survey length:** the shorter the interval the more quickly the logger's memory fills. The fieldwork used a one-minute interval giving 1,440 logs of each monitored parameter over 24 hours. Using this mode for all 6 channels, the meter has fifteen days' storage capacity.
- **Wraparound mode:** instructs the meter to respond when memory is full - either stop recording and enter sleep mode to conserve energy, or continue recording and wrap around to replace the oldest data with new data. The fieldwork used the latter mode.
- **Channel configuration:** 6 data input channels, can all log simultaneously or some can be disabled and their allocated memory reassigned to active channels, allowing longer survey recordings. Configured features are:
  - Storing min/max and/or average values. The meter samples data multiple times during each storage interval (four times per second). So for a minute sample-interval the meter samples 240 times to determine minimum, maximum and average of all the monitored parameters.
  - Specifying CX type, to instruct the meter on the transformer ratio.
  - Setting current and voltage limits for event detection, to detect any readings outside a specified range.

### 8.2.4.2 Downloading data

This does not clear the meter's memory, allowing the same data to be downloaded more than once if required.

### 8.2.4.3 Calculating Power

When power factor, voltage and current channels are enabled the meter logs the phase angle between voltage and current and uses this to develop power factor. It can then calculate power demand (kW) and energy use over the interval (kWh). The meter records voltage in volts (V) and current in amps (A), and logs power factor as a fraction.

8.2.4.4 Viewing the data

The software can select any combination of channels to display as either a list or graph (Figure 81 and Figure 82 respectively). It also displays summary survey information. The displays can be printed or exported to a spreadsheet. This thesis uses the data in MS Excel worksheets, which is much more versatile than SP PowerPack at manipulating the data. The meter's data display were only used during the fieldwork to confirm correct information download, and to get a quick appreciation of the daily profile before leaving the site. All of the subsequent analysis uses MS Excel.

| I1: Current (A), V: Voltage (V), PF: PF (PF), Pulse 1: Pulse 1 (Lit) |          |             |         |       |       |  |
|----------------------------------------------------------------------|----------|-------------|---------|-------|-------|--|
| Item                                                                 | Date     | Time        | V Volts |       |       |  |
|                                                                      |          |             | Min     | Max   | Avg   |  |
| 1                                                                    | 03/17/99 | 11:13:05 AM | 256.3   | 256.3 | 256.3 |  |
| 2                                                                    | 03/17/99 | 11:13:06 AM | 256.0   | 256.4 | 256.3 |  |
| 3                                                                    | 03/17/99 | 11:13:07 AM | 255.6   | 256.4 | 255.9 |  |
| 4                                                                    | 03/17/99 | 11:13:08 AM | 256.3   | 256.4 | 256.3 |  |
| 5                                                                    | 03/17/99 | 11:13:09 AM | 256.3   | 256.4 | 256.3 |  |
| 6                                                                    | 03/17/99 | 11:13:10 AM | 256.3   | 256.5 | 256.4 |  |

Figure 81. Viewing logged data as a list (Elcomponent Ltd., 1999).

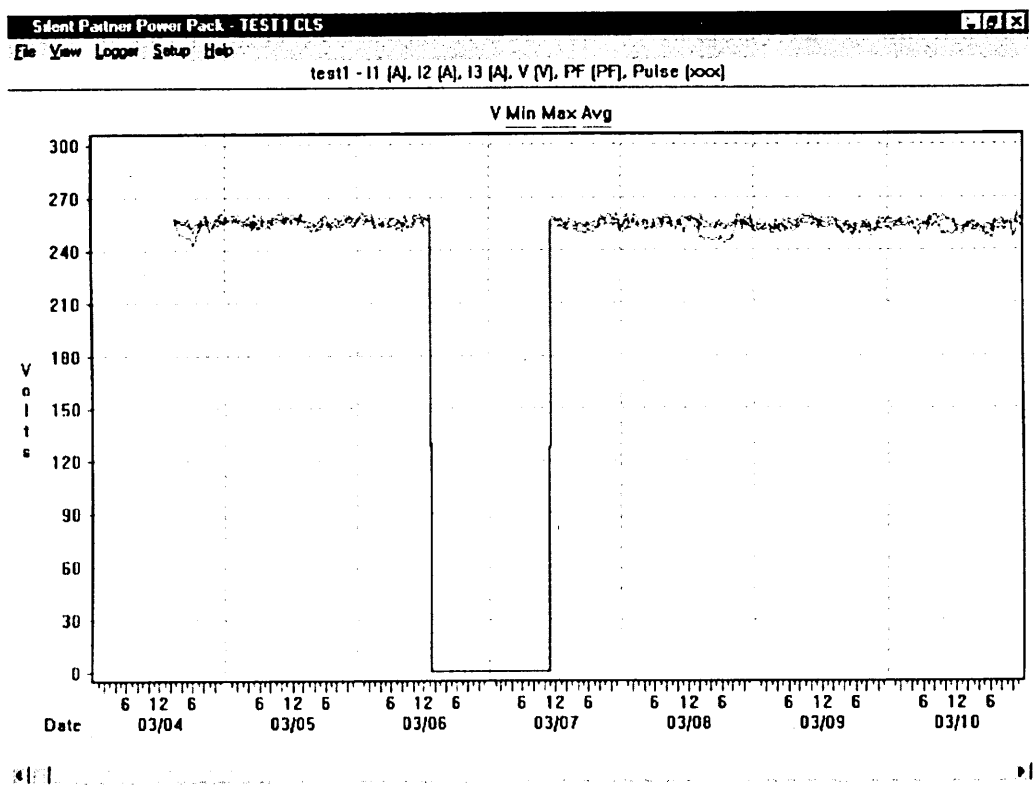


Figure 82. Viewing logged data as a graph (Elcomponent Ltd., 1999).

#### **8.2.4.5 Costing**

The electricity-tariff structure can be put into the software to calculate billing information from the logged data. Again this is done as part of the economic model in Chapter 8 using MS Excel instead.



## **Chapter 9. Evaluating a national cogeneration policy**

This thesis assesses the scope for cogeneration in Trinidad's industrial sector as an energy policy measure. It suggests cogeneration as one way to use the natural gas resource to provide energy for the country's development as efficiently as possible. The increase in energy-use efficiency through cogeneration is very significant and could have significant implications for the nation's energy security in the first half of this century. The thesis also compares natural-gas cogeneration to the Government's (GOTT's) main natural-gas use – producing LNG for export. LNG-production currently accounts for two thirds of the nation's natural gas use and so is taken as the GOTT's main thrust.

### **9.1 The basis for national cogeneration evaluation**

A theoretical national cogeneration assessment would evaluate cogeneration's feasibility with each energy user or user-group in Trinidad, regardless of size. This thesis focuses on the industrial sector; the number of industrial customers in 1998 was 1,967 (T&TEC, 1999). This is still too many to evaluate. The Trinidad and Tobago Electricity Commission (T&TEC) groups customers according to similarities in the types of facilities, hence consumption characteristics.

Table 32 describes these 15 subgroups and their designated codes. Chapter 4 describes electricity users in detail. This study assumes that each subgroup is homogeneous enough to allow a single case study per group to apply to all members within it. This is less likely to be the case in some groups, such as MF, FI, and ES. These would require a closer look at the variety of customers and more case studies, but this was not always possible as explained in Chapter 8.

Thus the approach is to evaluate cogeneration's feasibility in each group of industrial electricity users and collate the results to approximately assess cogeneration's feasibility nationally, over the whole spectrum of industrial customers. It will give aggregate figures on the total expenditure on such a programme at current levels, and the overall saving in money and natural resources compared with the current situation. T&TEC's own forecasted data of growth in the sector can be used to forecast future scope for cogeneration and the potential for the national utility to avoid costs through it. Also some policy measures to promote cogeneration will emerge.

|       |                                                                 | 1998 D1 INDUSTRIAL SUMMARY |             |           | 1998 D2 INDUSTRIAL SUMMARY |             |           |
|-------|-----------------------------------------------------------------|----------------------------|-------------|-----------|----------------------------|-------------|-----------|
| Code  | Description                                                     | Customers                  | Total kWh   | Total kVA | Customers                  | Total kWh   | Total kVA |
| BIC   | Bank, insurance company and credit union, financial institution | 155                        | 38,831,396  | 11,914    | 45                         | 79,740,218  | 18,826    |
| BUS   | Business – stores, groceries, etc.                              | 423                        | 90,960,039  | 34,826    | 131                        | 150,260,965 | 50,793    |
| CIN   | Cinema, and recreation centres                                  | 18                         | 3,963,030   | 1,784     | 6                          | 3,162,600   | 1,250     |
| ES    | Essential services & social services (utilities)                | 173                        | 46,621,737  | 21,608    | 72                         | 154,593,828 | 33,318    |
| FI    | Food/drink manufacturing industry & agro-based industries       | 56                         | 16,247,777  | 6,146     | 59                         | 128,581,378 | 35,456    |
| FOR   | Food outlet & restaurants                                       | 69                         | 24,093,527  | 6,557     | 8                          | 6,109,900   | 6,064     |
| GA    | Garment industries                                              | 8                          | 1,343,448   | 980       | 3                          | 2,126,140   | 933       |
| HL    | Hotels & resorts                                                | 15                         | 4,081,836   | 1,307     | 14                         | 30,177,874  | 6,704     |
| MF    | Manufacturing industry                                          | 108                        | 21,382,077  | 14,115    | 104                        | 157,040,275 | 51,581    |
| MIA   | Media                                                           | 8                          | 1,972,139   | 1,348     | 4                          | 6,083,400   | 1,434     |
| MIG   | Government ministries & offices                                 | 133                        | 20,707,374  | 9,842     | 58                         | 86,980,074  | 22,395    |
| NUN   | General                                                         | 69                         | 11,773,083  | 4,658     | 5                          | 2,241,340   | 953       |
| OIL   | Oil industry                                                    | 12                         | 942,549     | 636       | 25                         | 62,136,065  | 16,690    |
| ORG   | Private organisation                                            | 21                         | 1,867,307   | 1,396     | 3                          | 1,337,930   | 505       |
| SCH   | Schools & educational institutions                              | 39                         | 6,649,405   | 2,259     | 27                         | 32,249,664  | 8,348     |
| TOTAL |                                                                 | 1,307                      | 291,436,724 | 119,376   | 564                        | 902,821,651 | 255,249   |

Table 32. Industrial electricity customer-groups in T&amp;T

Assessing cogeneration's feasibility in a customer group requires a feasibility study of at least one of the customers in that group. The study must therefore follow standard business project-evaluation procedure. Cogeneration must be feasible in both technical and economic terms. Combined power and heat systems may offer clear advantages in energy terms but may not be viable propositions in money terms on account of capital and associated costs. The converse may also be true, i.e. money savings without energy savings. Any economic assessment must include effects of possible escalation in fuel costs, labour, inflation, changes in interest rates, etc. For normal commercial and industrial applications the emphasis is to minimise costs.

## 9.2 A cogeneration feasibility study

A rigorous cogeneration feasibility study would consider a comprehensive combination of engine sizes and financing options, and would employ an hourly simulation program (over a year) to predict costs and savings. The program would use part-load cogenerator performance data, as the unit's performance changes with load and ambient conditions (Figure 83).

Capital costs would come from competitive quotes for each major component of the proposed system. An additional complication would be considering multiple cogeneration

units as opposed to a single one. Such an exhaustive study is not strictly necessary to assess cogeneration's scope on a national industrial basis, and is beyond this thesis' scope.

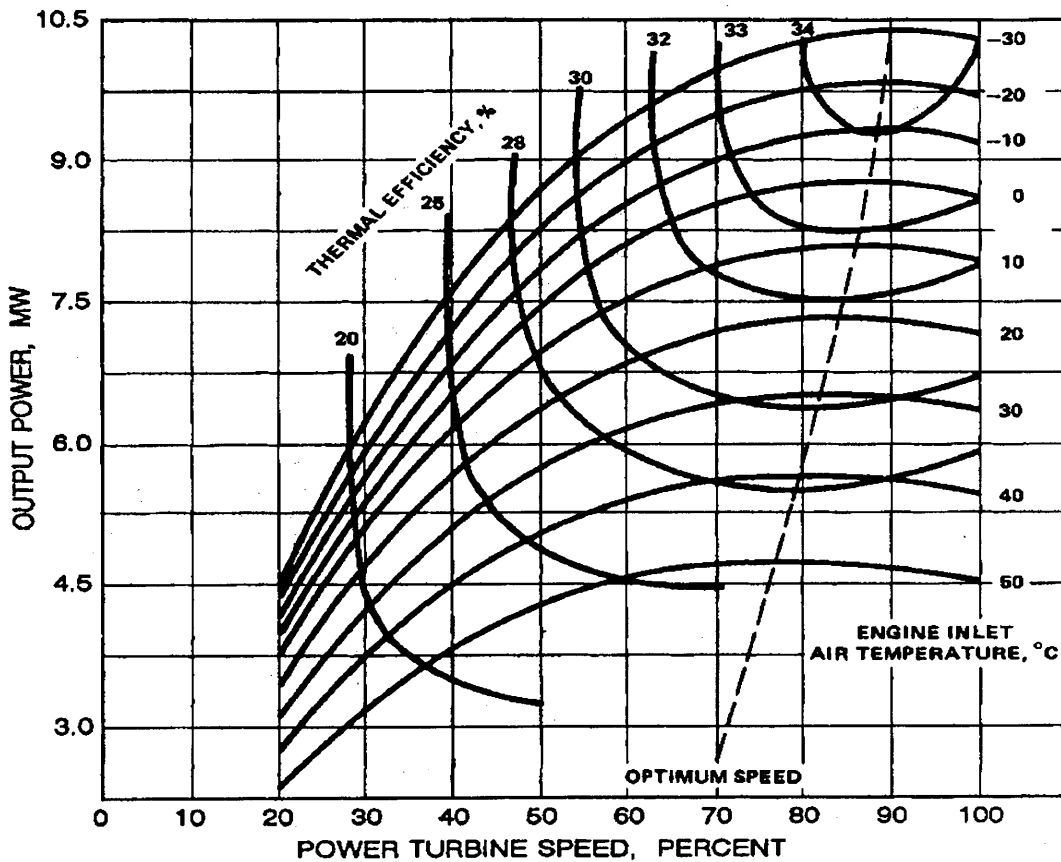


Figure 83. Turbine engine performance characteristics (ASHRAE, 2000).

The commercial interest in cogeneration may arise:

- at the time of a new project's inception, for which the power and heat demands may be arranged to optimise particular energy system designs, or
- by the need to replace or renovate existing systems with minimum disturbance to the continuing operation, i.e. retrofit; in this case, adding heat exchange equipment to the existing plant may be more attractive than providing a completely new energy system.

A GTs power output, unlike that of an ICE, is sensitive to the back pressure of any exhaust-gas heat exchanger. Fitting an exchanger retrospectively could jeopardise the engine's safety by overheating the turbine. It is better to design the two system-sections together in a cogeneration system, to optimise the overall heat and power performance. This has implications for any proposed cogeneration at the national utility, T&TEC, where natural-gas GTs generate all of the nation's power.

### 9.2.1 Technical cogeneration feasibility

Cogeneration converts a single energy source (i.e. a fuel) into two other useable energy outputs (i.e. electricity and heat). In a *topping cycle* a fuel generates power first, with the resulting thermal energy recovered for use, e.g. heat recovered from a prime mover. A *bottoming cycle* generates power last from the thermal energy left over after the high-level thermal energy is used to satisfy thermal loads, e.g. process heat recovery to generate power. A *combined cycle* uses the thermal output from a prime mover to generate additional shaft power, e.g. a combustion turbine exhaust generating steam for a steam turbine generator.

A cogeneration system is attractive only if there are long-term uses for the electrical power and thermal outputs, with appropriate heat/electricity ratios. If the heat/electricity balance varies greatly, or the power and thermal ranges are wide, a cogeneration system may need to incorporate such complexity that it is no more attractive than separate conventional power and thermal supply systems (Williams and Hessami, 1993). This aspect of balance is crucial to successful cogeneration.

The most fundamental starting point for assessing cogeneration's technical feasibility is the site's thermal and electrical load profiles. The facility's loads will vary with time over a day and over a year. Trinidad is a small, tropical island located at about 10°N latitude, so the weather hardly varies throughout the year (Moseley and Headley, 1994). Only facilities that are subject to seasonal variations in usage, e.g. schools and some manufacturing operations, will show significant seasonal variation in energy use. Daily variations come from the daily operating schedule and a difference between weekdays and weekends; the fieldwork undertaken during this study collected data concerning this (see Chapter 8).

Whenever the electrical and thermal load profiles coincide, cogeneration is technically feasible. All twenty industrial D3 electricity customers use natural gas as both fuel and feedstock, but of the 1,946 D1 and D2 electricity customers in 1998, only 60 were metered as natural gas users, all using natural gas as a fuel (as opposed to process input) (NGC, 1998). In most Trinidadian facilities the thermal load is the air conditioning demand, currently supplied by electric vapour-compression air conditioning systems. In some facilities, such as office blocks, the air conditioning load can be more than 60% of the electricity bill (see Chapter 10). This cooling load can be transformed into a heating load through an absorption chiller, which in turn reduces the site's electricity load and increases the overall heat/electricity ratio. Both of these impact strongly on sizing the cogenerator. Once technical feasibility is established, the ultimate aim is to determine the optimal cogenerator size.

Some facilities can be ruled out of consideration from the outset depending on their electricity profiles. Figure 84 shows the electricity demand over a day for the steel-working factory described in Chapter 8. The erratic profile renders it unsuitable for cogeneration. This facility is in the MF customer subgroup and demonstrates the potential

problem with conducting a single case study to represent a subgroup. Furthermore, it illustrates the weakness of metering over a single day at some facilities.

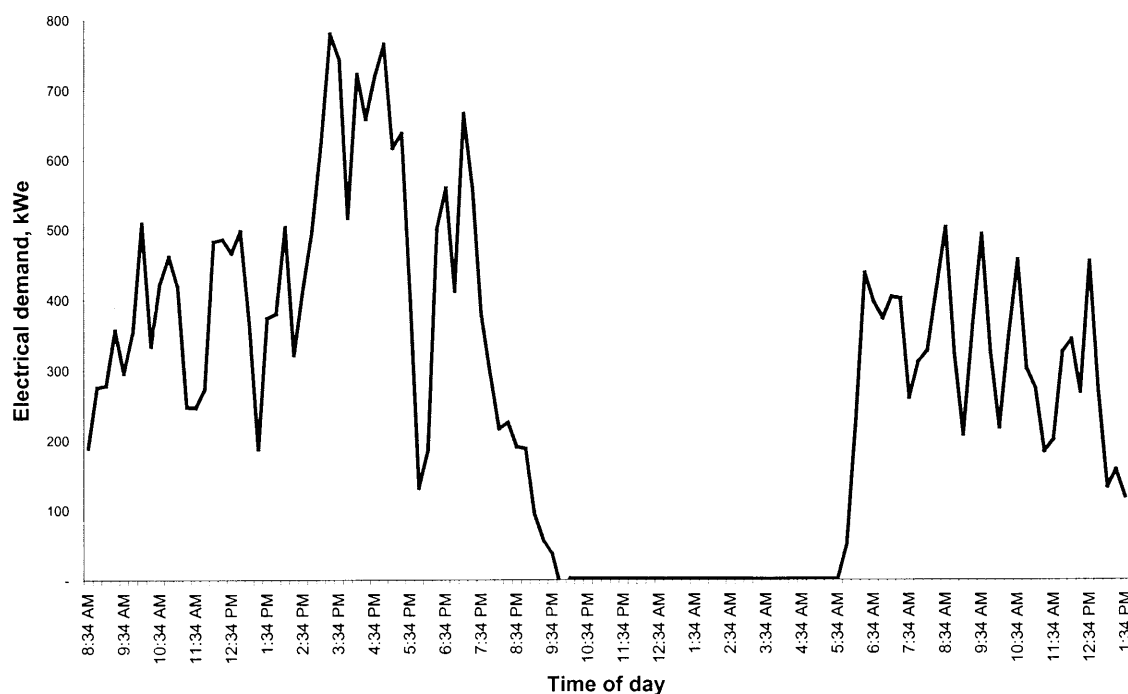


Figure 84. Electricity demand profile (kWe) over a day for a steel-working factory.

The fieldwork data thus provides the starting point for all analyses. Most of the metered data is recorded for every minute of a nominal 24-hour period (most often a few hours more or less), of both the site's overall electricity demand and the main cooling equipment where possible. Heating data, where available, could not be metered and has to be taken from fuel bills and nominal equipment performance ratings (name-plate data). A rigorous cogeneration sizing would use the detailed meter data in a simulation program, along with detailed manufactures' data on part-load performance of actual cogeneration engines, to work out accurate annual energy savings for a range of cogeneration plant sizes and types compared with the existing energy consumption. The optimal cogeneration size would emerge from applying cost data, i.e. capital, operation and maintenance (O&M), and energy costs, to these results. The aim is to maximise the net savings from cogeneration.

This detailed approach is not necessary for a preliminary technical-feasibility assessment. A very basic preliminary rule-of-thumb is: if the electricity cost in \$/kWh is more than 0.012 times the fuel cost in \$/MJ, the project is worth considering; if it is 0.024 times, there is a good chance for a simple payback period under three years (ASHRAE, 2000). Even comprehensive studies use simplifying assumptions. Prince (1995) assumes continuous cogeneration operation. The study constructs a model using MS Excel with three sections: turbine modelling, electrical and thermal load analysis, and economic analysis. The study bases the turbine modelling section on thermodynamic analysis of over fifty modern gas



turbines in the 3MWe to 30MWe range. It derives empirical relationships for variations of efficiency, air/fuel ratio, and compression ratio with the cogenerator's electricity output. The model thus estimates fuel consumption, exhaust-gas temperature, and flow rate for any given electrical output and specified machine type. For a wide range of machines, the calculation routine estimates exhaust gas temperature and fuel consumption to within  $\pm 6\%$  and  $\pm 10\%$  respectively of the corresponding manufacturers' data. So the model may just as well have used manufacturers' data directly as inputs. Prince (1995) also assumes that surplus electricity can always be sold to the grid. This simplifies the analysis as it removes one constraint on cogeneration sizing. It also recognises that cogeneration really only became a successful policy measure in the US after the 1978 Energy Act allowed electricity buy-back by the utilities.

Williams and Hessami (1993) make similar simplifying assumptions. In their study a computer model again analyses the different options' technical and economic performance, but this time the engine runs continuously at full load during the daily operating hours. The model formulates two sets of data, one based on the cogeneration system exporting excess power, the other with no benefit from power export.

*Load-duration curve analysis* is a method for choosing a likely optimal cogeneration engine size in a less comprehensive feasibility study (ASHRAE, 2000). The load-duration curve is a plot of hourly-averaged (or minutely-averaged in this thesis) instantaneous load data over a period, re-arranged to indicate the frequency, or hours per period, at which the load equals or exceeds a given value. Figure 85 displays this for one of this thesis' case studies. The area under the curve is the total energy consumed in that interval. This procedure is intuitively very clear as it is easy to pick out the base load at the 'knee', and to try different engine sizes for different cogeneration scenarios, such as heat-led and electricity buy-back. Note that the base load is not the minimum demand in the interval. So the curve is useful to quickly choose a cogenerator size as a starting point for sizing iterations.

In this thesis, once the electrical and thermal profiles reveal cogeneration's technical feasibility, a single engine size is chosen by borrowing elements of all the procedures described before. The steady Trinidadian climate, and additionally the constant nature of many of the industries, simplifies the sizing task. This becomes clearer in the case studies later where the standard deviation in both the thermal and electrical demands over a day gives a measure of the profiles' 'flatness'. The basic procedure is as follows.

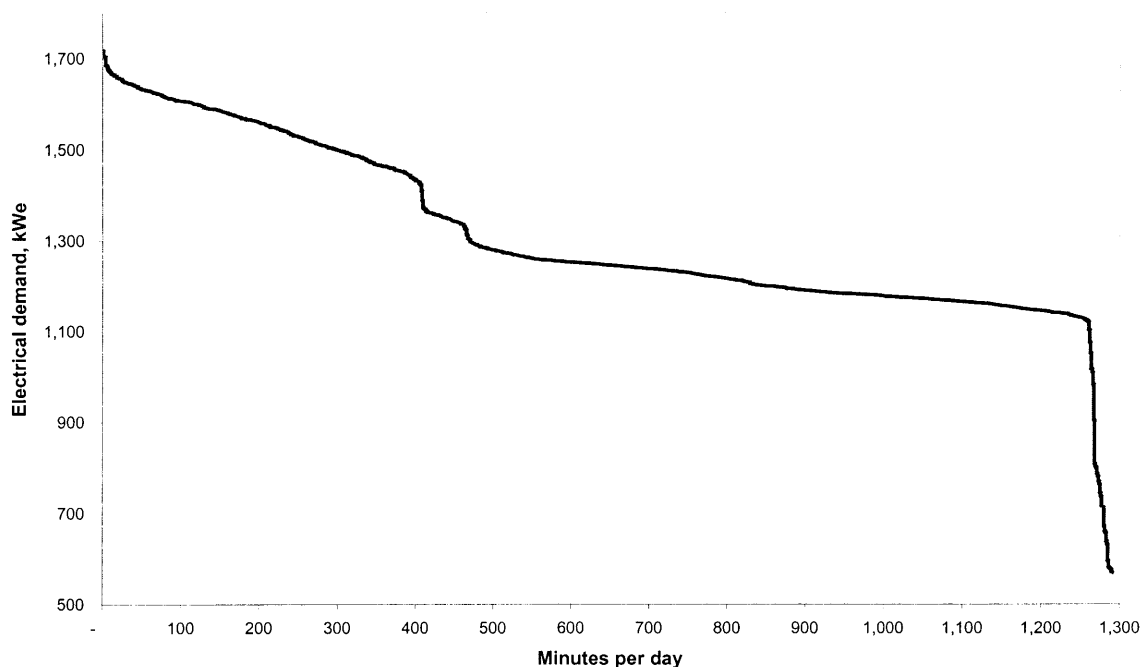


Figure 85. School's load-duration curve, kWe with cogeneration.

The cogenerator is either heat-led or electrical-led. For heat-led cogeneration, it is simply considered to exactly satisfy the site's thermal demand at all times with any shortfall in electricity bought from the utility, and any surplus taken up onto the grid. For electrical-led cogeneration, consider a case where the air conditioning load constitutes the thermal load on the cogenerator, and that air conditioning load is the major part of the current electricity demand (e.g. office blocks). An absorption chiller transforms that air conditioning electrical load into a heat load on the cogenerator. However, since the coefficient of performance (COP) of centrifugal chillers are on average 4.6 times that of absorption chillers (D'zurko, 1996), the air conditioning heat demand greatly inflates, at the same time that the electricity demand drops from substituting the electrical centrifugal chiller. The resulting heat/electricity ratio reflects this.

This study assumes centrifugal chillers supply all but the smallest air conditioning loads as this gives the greatest difference in COPs and the most conservative cogeneration analysis. Also, as far as cogeneration size allows, gas turbines (GTs) are considered before reciprocating engines (ICEs) because of their advantages described in Chapter 5, and because they allow two-stage absorption chillers which are the more efficient (see Chapter 7). However, GTs are also more expensive per kWe, giving the worst-case economic analysis as a starting point. Even so, the case studies in Chapter 10 show that the heat/electricity ratio can easily be over 4. A heat-led cogenerator in such a case could produce more than double the site's electricity demand. This study assumes the national electricity utility is always available to take excess cogenerated power, but assumes no revenue from it as a base-case, conservative, and simplifying assumption. But this amount

of excess electricity is disproportionate, and would transform the site from an independent power producer to an independent power supplier, which is not the intention, especially when assuming no benefit accruing from selling electricity to the grid. So consider these cases as electrical-led with either supplementary firing in the exhaust gases or a separate boiler to make up the extra thermal demand. The idea is to assess the site's overall cogeneration natural-gas demand without going into detail about the actual configuration and components of supplementary systems.

A general model to analyse all cases would become too complicated if it accommodates every difference between sites. A meticulous analysis *would* be essential for a *competitive* cogeneration project proposal on a site-by-site basis. A general model makes some simplifying assumptions to give conservative results – sensitivity analysis then explores the margins of error. The most fundamental technical difference among all sites is their energy-use profiles, obtained in each case from the fieldwork, which is thus the starting point for all analysis. All other differences arise from the proposed cogeneration system, capital cost, engine types and sizes and their operating characteristics. So these are the major inputs in any common-analysis model. The main differences between cogeneration systems that impact on the model are electrical-, thermal- and overall-efficiencies, and capital costs. Air conditioning systems differ in COP and capital cost.

The analysis uses historical data, so it assesses feasibility at *that* time. Escalation factors for costs are a forecasting element, but energy use cannot be said to escalate similarly, as it is a function of productivity at the site. So step-wise changes in energy-use are more likely. For example, a hotel cannot incrementally increase rooms by a certain factor each year, but it may have plans to add an extra block some time in the future. None of the sites visited during the fieldwork revealed forecasts for future productivity. T&TEC has provided energy-use forecasts on a national level and these are used as far as possible (see Chapter 11).

### 9.2.2 Economic cogeneration feasibility

For cogeneration uptake on a national scale it must be profitable at individual facilities. At that level cogeneration is a business investment decision subject to investment appraisal and financing decisions. The decision is between alternatives and the valuation basis is capitalism, which is a model of the real economic world.

An *investment decision* involves the firm in making a cash outlay with the aim of receiving future cash inflows in return. The *investment cost* is all cash outflows, and/or reduced cash inflows, through time that result from the investment decision. The *investment benefit* is all cash inflows, and/or reduced cash outflows, through time that result from the investment decision. Thus all costs and benefits of an investment are defined in terms of being *incremental* to the firm, through time, and expressed in cash terms. The *cash flow rule* states that the objective is to boil down the whole project to a series of cash flows that will occur on specific dates in the future (Hirst, 1988).

Business projects take time to generate their benefits. Money's value changes over time, and the *time value of money* is not concerned with inflation or deflation, but that money can earn *interest*. Capital-investment appraisal methods that account for an interest rate are called *discounted cash flow* (DCF) methods. The methods considered here are *net present value* (NPV) and *internal rate of return* (IRR).

NPV calculation converts all of a project's cash flows, including the initial outlay, into their equivalents in current value and sums them. It indicates how much the project would add to (positive NPV), or subtract from (negative NPV), the wealth represented by owning the business. The investment is worthwhile if the money got out is at least equal to the money put in.

A compound interest is used to work out future or terminal value:

$$A(1+r)^n$$

where

|   |   |                                 |
|---|---|---------------------------------|
| A | = | initial amount invested,        |
| r | = | annual interest rate, and       |
| n | = | number of years A is deposited. |

A *discount rate* is the compound interest rate in the discounting (backward) process.

$$NPV = \sum_{t=0}^n \frac{A_t}{(1+r)^t}$$

where  $A_t$  = project's cash flow (positive or negative) in year  $t$ , ( $0 \leq t \leq n$ )  
 $r$  = *annual discount rate*, assumed constant over the project's life.

In effect, NPV method evaluates projects by looking at the alternative between investing in the project or the capital market; so the return available from the capital market yields the discount rate (Lumby, 1999). A negative NPV would indicate the project:

- makes a loss relative to a capital market investment (i.e. opportunity loss) of similar risk level, and
- would not generate sufficient cash flow to repay the financial cost of undertaking it.

The IRR is the discount rate at which the project's NPV is zero. The *IRR decision rule* states that it should be at least the market rate of interest, which is thus taken as the *hurdle rate*.

So the relevant discount rate is normally taken as the marginal cost of finance or the *weighted average cost of capital* (WACC) (Hirst, 1988). From experience, there is no general agreement over what discount rate should be used, and investment decision-makers usually use a range of rates and choose one of them after lengthy discussion, considering

other elements of the firm's performance at the time. In fact, despite the rigorous computer modelling to simulate different cogeneration options and energy tariff structures, Prince (1995) uses simple payback as an indicator 'because of the relatively short-term nature of the investments and the desire to avoid applying arbitrary figures for depreciation, tax and interest rates.' *Payback* is the period of time before the cash inflows from a project match the initial cash outlay. But:

- it takes no account of the time value of money, and
- the net benefit from any project comes from cash flows after payback – payback appraisal calculation ignores this.

### 9.2.2.1 Guiding rules on investment appraisal and the relevant cash flows

Determining the correct year-by-year cash flow is essential for using a DCF method such as the NPV. *Depreciation* is an allocation of historical cost and not a cash item, but it affects the amount and timing of tax payments (Hirst, 1988). This is because the 'incremental asset' that the project's initial capital outlay represents will depreciate each year. So depreciation must be considered in determining cash flows. This study depreciates the capital in ten equal amounts in the first 10 years, to zero, with no salvage value.

*Financing flows* should be ignored when measuring project cash flows (Hirst, 1988), i.e. how the capital is raised: lease, part-lease, equity, bank loan, etc. However, interest payments are tax deductible, so this study assumes all capital is financed through bank borrowing.

*Inflation and deflation* refer to price movements within an economy. General inflation can be expected to have a similar effect on both costs and revenues. There is no need to build its impact into cash flow calculation as long as the cash flow is discounted by the real cost of finance (National Economic Development Council, 1971). The inflation rate is related to the retail price index (RPI).

Engineering project appraisals seem to follow these rules in varying degrees. Williams and Hessami (1993) use a computer program to estimate probable payback period, NPV and IRR for the various cogeneration system operating modes. The inputs are escalation factors and capital-financing method, including leasing as opposed to buying. The computations include sensitivity analyses over various cost ranges and revenue escalations.

### 9.2.2.2 Sensitivity analysis

Without risk and uncertainty, investment project appraisal would be *deterministic*. But in reality it involves making a great number of estimates (discount rate being a central one). The decision to accept or reject a project *pivots* around zero NPV – the *pivot point*. To determine the *margin of error* for each estimate, all the other estimated elements (e.g. capital outlay, project life, annual revenues, annual cost, and appropriate discount rate) are



held constant while it is varied. This helps determine which estimated element the NPV is most sensitive to, and indicates areas that need re-examining or tightening.

Limitations of sensitivity analysis are (Hirst, 1988):

- It varies only one element at a time, and in turn, and assumes all the other estimates are accurate.
- It does not formally analyse risk.
- It does not provide rules to guide the decision-maker to amend the initial appraisal advice in light of the sensitivity data.

### 9.2.3 Project appraisal procedure

Project appraisal in this study proceeds as follows:

**Step 1: Field-data technical analysis.** This yields the cogeneration type and size, with or without absorption cooling. Absorption chillers need additional cooling tower (CT), and condenser-water (CW) pump capacity, which must be accounted for.

**Step 2: Determining all capital costs for the proposed systems.** Capital cost for cogeneration engines is not a straightforward item. Unless competitive commercial quotes are available for each application, there is plenty of uncertainty about the cost. Prince (1995) uses a base-case quotation for one GT size (9.2MW) and then uses regression analysis for all other sizes in a 3MW to 35MW range. It assigns 40% of the cost to the turbine generator set and the rest for water treatment, boiler, civil works, electrical interconnection and control, engineering installation and commissioning. In the regression analysis a 0.8 scaling exponent applies to the 40% turbine cost, and a 0.65 scaling exponent to the rest to reflect economies of scale. Yet 'final capital cost are very site-specific and figures are expected to be at best  $\pm 15\%$  in that range.' This study uses the National Gas Company's (NGC) recommended cost/kWe (NGC, 1999).

**Step 3: Determining O&M costs for proposed systems.** Predict first-year O&M cost for the proposed cogeneration system. If this includes absorption cooling, then it must account for the increased CT and CW-pump capacities, and the consequently greater water cost and its related chemical treatment cost. D'zurko (1996) gives the average CT and CW power demand per unit chiller capacity for centrifugal chillers, and Dorgan, Leight and Dorgan (1995) give the corresponding figures for absorption chillers. NGC (1999) provides O&M costs, excluding gas and electricity, for cogeneration engines, absorption chillers, and centrifugal chillers. The Water and Sewerage Authority (WASA) water cost to industrial users is TT\$3.5/m<sup>3</sup>. Actual quotations for chemical water treatment provide a cost in TT\$ per litre (Accurate Chemicals Ltd., 1997).

The difference between the current energy bills and those of the proposed system, less the incremental O&M cost for the new system, is the revenue from the investment in the first year. If the cogeneration system offers no net saving, the investment will never be repaid

and the project is a non-starter. Unless costs can be reduced in any area the project will be abandoned. If the project yields revenue through reduced annual cost, this becomes the input to determining the annual cash flow.

Each year is different through cost escalations, which is again available from NGC (1999). Another forecasting method is to devise possible future scenarios to cover a wide number of possibilities, but neither Prince (1995), nor Williams and Hessami (1993), nor D'Zurko (1996) adopted this approach, nor does this study. Those studies use escalation factors instead. The project may return revenue due to the cost difference between electricity and gas, but represent no saving to the nation in primary-energy (i.e. natural gas) terms. It should be abandoned because the question of resource-rent arises in this case. This is explored further in Chapter 10 in the context of LNG.

**Step 4: Determining annual cash flows.** This adopts a straightforward, standard T&T company procedure for appraising projects of this type. The revenue from cogeneration is subject to corporate tax, currently 35%. Depreciation and interest payments affect tax payments – the taxable cash flow in a given year is that year's revenue less depreciation and interest payment on the cash outlay for the project. Interest is paid on the undepreciated amount at the current borrowing rate of 16% (Ministry of Finance, 1999). The net cash flow is the revenue less the tax payment.

**Step 5: Determine the NPV and IRR.**

D'zurko (1996) does life-cycle costing on alternative air conditioning systems over 20 years as this is assumed as the equipment's lifetime. Cogeneration is also a long-term investment and the study also determines NPV and IRR over 20 years. A simplifying assumption is no salvage value at the end of the 20 years – any such estimate would have little meaning. Because of disagreement on the correct discount rate, NPV and IRR should be determined over a 5% to 20% range of discount rates.

**Step 6: Sensitivity analysis**

Prince (1995) compared cogeneration in Australia and the UK and found that in the UK, lower gas prices and higher electricity prices render cogeneration projects more viable and less sensitive to thermal considerations. The study claims that the closer relative electricity and gas prices are the largest disincentives to investment in cogeneration; lack of experience and other operability issues are secondary. D'zurko (1996) found that capital-cost reduction is the most significant factor in improving gas technologies' economic competitiveness. Of the other parameters affecting NPV, the Central Bank determines interest rates and corporate tax from the perspective of the entire economy and these can hardly be changed for a cogeneration analysis. D'zurko (1996) also found that absorption chiller COP really hurts its energy performance, so as far as possible this current thesis considers double-effect chillers. Utility prices (gas, electricity, water) can probably be negotiated, but only for the largest users and the decision is bound to be political. For example, the single iron and steel company in Trinidad uses almost a quarter of all the nations electricity and pays a special industrial-E rate.

In this thesis, sensitivity analysis considers the estimated parameters of discount rate, capital cost, and gas and electricity price escalation. Currently discount rates lie in the 10% to 14% range (Ram, 2000). To explore sensitivity to capital, this study holds the price escalation factors at current rates (4% for both gas and electricity) and varies the project's capital cost, determining the NPV for discount rates ranging from 5% to 25% (see Figure 94). This gives an idea of the margin for error in estimating all of the project's capital costs.

To explore sensitivity to energy-price escalation factors it holds the capital cost at the original conservative estimate and determines the NPV over the same range of discount rates for nine different combinations of escalation factors, i.e. varying both gas and electricity escalation between 4% and 8%. This also demonstrates the effect of the price-differential between the two.

### 9.3 Constructing the project analysis model

A worked example for a Hotel demonstrates these 6 steps. The analysis is done using MS Excel, transferring data between worksheets to give the final NPV calculations, and displaying data graphically. All dollar figures are T&T dollars (TT\$). All of the cogeneration and air conditioning equipment would be imported so that all capital costs are converted to TT\$ using appropriate exchange rates and mark-ups for custom charges, insurance, and freight to give a landed-cost estimate in T&T.

#### 9.3.1 General data sheet

This sheet contains all of the fundamental data, including assumptions, which the analysis uses, *except* the actual metered energy-use data. Refer to Figure 86, taking each item in turn from the top.

- 1 **T&TEC data – 1998.** This is the facility's actual kWh and kVA consumption over the year as metered by T&TEC.
- 2 **Rate** – the D-rate category.
- 3 **Name** – a simple description used in the thesis to replace the customer's actual name for confidentiality.
- 4 **kWh** – T&TEC-recorded electricity energy use in kWh over 1998.
- 5 **kVA** - T&TEC-recorded maximum electricity demand in kVA in 1998.
- 6 **CODE** – one of the fifteen T&TEC-defined subgroup codenames (see Chapter 4).
- 7 **Electricity cost, D2, TT\$/kWh** – the D2 rate.
- 8 **Average generating efficiency** – T&TEC's average.
- 9 **Equivalent annual full-load hours** – useful for indicating the 'flatness' of the facility's energy-use profile over the year.

| General reference data and assumptions |                                          |             |                     |                                      |                                            |
|----------------------------------------|------------------------------------------|-------------|---------------------|--------------------------------------|--------------------------------------------|
|                                        |                                          |             |                     |                                      |                                            |
| T&TEC data - 1998                      |                                          |             |                     |                                      |                                            |
|                                        | RATE                                     | NAME        | kWh                 | Maximum<br>kVA                       | CODE                                       |
|                                        | D2                                       | HOTEL       | 11,236,000          | 1,920                                | HL                                         |
|                                        | Electricity cost, D2, TT\$/kWh           | TT\$0.28    |                     |                                      |                                            |
|                                        | Average generating efficiency            | 26.1%       |                     |                                      |                                            |
|                                        | Equivalent annual full-load hours        | 6,502       |                     |                                      |                                            |
| Fieldwork data                         |                                          |             | kWh                 | Maximum<br>kWe                       |                                            |
|                                        |                                          |             | 11,239,080          | 1,409                                |                                            |
|                                        | Type of day                              | weekday     |                     |                                      |                                            |
|                                        | Operating days per annum                 | 365         |                     |                                      |                                            |
| NGC data                               |                                          |             |                     |                                      |                                            |
|                                        | Gas cost, TT\$/mmBtu                     | TT\$10.44   | not industrial user |                                      |                                            |
|                                        | Gas cost, TT\$/kWh                       | TT\$0.0356  |                     |                                      |                                            |
|                                        | Diesel cost, TT\$/kWh                    | TT\$0.1160  |                     |                                      |                                            |
| WASA data                              |                                          |             |                     |                                      |                                            |
|                                        | Water cost, TT\$ per litre               | TT\$0.0035  |                     |                                      |                                            |
| Escalation factors                     |                                          |             |                     |                                      |                                            |
|                                        | Cost escalator: gas                      | 4%          |                     |                                      |                                            |
|                                        | Cost escalator: elec                     | 4%          |                     |                                      |                                            |
|                                        | Cost escalator: diesel                   | 3%          |                     |                                      |                                            |
|                                        | Cost escalator: water and maintenance    | 3%          |                     |                                      |                                            |
| Equipment data                         |                                          |             |                     |                                      |                                            |
|                                        | Chiller                                  | Centrifugal | Absorption          | Ratio:<br>centrifugal/<br>absorption | Difference:<br>absorption -<br>centrifugal |
|                                        | Cooling capacity, kW                     | 2,277       | 2,277               |                                      |                                            |
|                                        | Coefficient of performance (COP)         | 5.55        | 1.20                | 4.63                                 |                                            |
|                                        | Full-load power, kW                      | 410         |                     |                                      |                                            |
|                                        | Full-load power, kWth                    |             | 1,898               |                                      |                                            |
|                                        | Capital cost, TT\$/kW                    |             | TT\$798             |                                      |                                            |
|                                        | Condenser water makeup, L/m.kW           | 0.095       | 0.151               |                                      |                                            |
|                                        | Annual chemical water treatment, TT\$/kW | TT\$21      | TT\$34              |                                      |                                            |
|                                        | annual condenser water makeup, L         | 84,411,351  | 134,169,621         |                                      | 49,758,270                                 |
|                                        | annual chemical water treatment, TT\$    | TT\$47,827  | TT\$76,524          |                                      | TT\$28,696                                 |
|                                        | Annual maintenance cost, TT\$/kW         | TT\$29      | TT\$36              |                                      |                                            |
|                                        | annual mtce. cost, TT\$                  | TT\$66,047  | TT\$81,990          |                                      | TT\$15,942                                 |
|                                        | C/T & CW pump elec. demand, kW/kW        | 0.0189      | 0.0302              |                                      |                                            |
|                                        | C/T & CW pump elec. demand, kW           | 43.0        | 68.8                | 0.63                                 | 26                                         |
|                                        | Boiler demand, kW                        | 378         |                     |                                      |                                            |
| Cogeneration - gas turbine             |                                          |             |                     |                                      |                                            |
|                                        | Size, kW                                 | 1,200       |                     |                                      |                                            |
|                                        | Capital cost, TT\$/kW                    | TT\$4,000   |                     |                                      |                                            |
|                                        | Annual maintenance cost, TT\$/kW         | TT\$0.0300  |                     |                                      |                                            |
|                                        | Electrical efficiency                    | 27%         |                     |                                      |                                            |
|                                        | Thermal efficiency                       | 52%         |                     |                                      |                                            |
|                                        | Overall efficiency                       | 79%         |                     |                                      |                                            |
|                                        | Heat:electricity ratio                   | 1.93        |                     |                                      |                                            |
|                                        | Required heat:electricity ratio          | 2.35        |                     |                                      |                                            |
| Economic data                          |                                          |             |                     |                                      |                                            |
|                                        | Bank interest rate                       | 16%         |                     |                                      |                                            |
|                                        | Corporate tax rate                       | 35%         |                     |                                      |                                            |

Figure 86. Hotel - General data sheet.

$$\text{equivalent annual full-load hours} = \frac{\text{annual kWh}}{\text{maximum kWe demand that year}}$$

The facility's maximum electricity demand in kWe is the maximum demand in kVA times the site's overall power factor (see Chapter 8). The power factor is taken as 0.9 for all facilities as customers are careful to maintain a high power factor to avoid the demand penalties. T&TEC figures are better than the figures over a day from the fieldwork meter for estimating annual full-load hours due to:

- Expected error from a single day.
- The difference between weekdays and weekends.
- Incorrect information about the operating days per annum.

- 10 **Fieldwork data** – collected from meter readings, equipment nameplate data, and interviewing site personnel.
- 11 **kWh** – *derived* from measured kWh on the day and operating days per annum. Compare with 4.
- 12 **Maximum kWe** – the maximum demand recorded on the metered day. Compare with 5.
- 13 **Metering minutes per day** – the metering duration in minutes.
- 14 **Fraction of day** – metering minutes per day divided by 1,440; used to extrapolate the metered results to the entire day in cases where the meter could not record over the full 24 hours.
- 15 **Type of day** – for facilities that do not operate continuously. The types of day are weekday, weekend, and public holiday.
- 16 **Operating days per annum** – the number of days per annum that the facility operates as the metered day. Determined from interviews with site personnel.
- 17 **NGC data** – information gathered from interviewing personnel at the National Gas Company (NGC).
- 18 **Gas cost, TT\$/mmBtu and TT\$/kWh** – different rate for industrial- and non-industrial customers. These are the rates in the analysis' first year.
- 19 **Diesel cost, TT\$/kWh** – one rate for all users, the rate in the analysis' first year.
- 20 **WASA data** - information gathered from interviewing personnel at the Water and Sewerage Authority (WASA).
- 21 **Water cost, TT\$/liter** – commercial rate for using mains water (as opposed to natural ground water from a well or stream); the rate in the analysis' first year.
- 22 **Escalation factors** – the long-term average annual increase in gas, electricity, diesel, and water costs as determined from interviewing personnel at the utilities. The maintenance-cost escalation is assumed.
- 23 **Equipment data** – for existing and proposed systems.
- 24 **Chiller** – the existing air conditioning unit and the proposed absorption replacement.
- 25 **Ratio** – for some chiller parameters comparing the ratio centrifugal/absorption.



- 26 **Difference** - for some chiller parameters comparing the difference absorption - centrifugal.
- 27 **Cooling capacity, kW<sub>r</sub>** – the existing chiller’s maximum capacity in refrigeration-kW as the product of the chiller’s maximum kW<sub>e</sub> demand on the metered day and the COP. The absorption chiller’s capacity is taken as the same as the chiller it replaces.
- 28 **COP** – of a new machine in each case, as the COP decreases with age and level of maintenance.
- 29 **Full-load power, kW<sub>e</sub>** – taken as the maximum electricity demand for the existing chiller on the metered day, and used in 27. An absorption chiller’s electrical demand is typically 3W to 11W per kW cooling capacity (ASHRAE, 1998) and is ignored in this analysis.
- 30 **Full-load power, kW<sub>th</sub>** – the absorption chiller’s maximum thermal energy demand (kW<sub>th</sub>), taken as the product of the existing chiller’s maximum demand in 29 and the COP ratios of the two in 25.
- 31 **Capital cost, TT\$/kW<sub>r</sub>** – of the replacement absorption chiller. Table 33 displays budgeted quotations for electric and absorption chillers from some manufacturers. Notice that for all chillers the installed cost per unit capacity decreases with increasing chiller size, and that double-effect absorption chillers are much more expensive than similarly-sized single-effect chillers.
- 32 **Condenser water makeup, L/minute.kW<sub>r</sub>** – water-cooled chillers lose water through evaporation in CTs. This is the amount of water to make up for the loss in the condenser-water circuit (ASHRAE, 1998). Absorption chillers need more CT capacity per unit cooling than centrifugal chillers due to their lower COP.
- 33 **Annual chemical water-treatment cost, TT\$/kW<sub>r</sub>** – from a budget quote (Accurate Chemicals Ltd., 1997). Water treatment slows down fouling of heat exchange surfaces.
- 34 **Annual condenser water makeup, L** – the volume over the year from 32 x 27 x 9 in minutes.
- 35 **Annual maintenance cost, TT\$/kW<sub>h</sub>** – from Figure 87, the first-year cost for the existing and proposed chillers.
- 36 **Annual maintenance cost, TT\$** - from 27 x 35, the first-year cost in TT\$.
- 37 **CT and CW-pump electricity demand, kW<sub>e</sub>/kW<sub>r</sub>** – from (ASHRAE, 1998). The CT demand comes from the tower fans.
- 38 **CT and CW-pump electricity demand, kW<sub>e</sub>** – from 27 x 37. The difference between the centrifugal and absorption chillers is the additional electrical power for the extra condenser-water cooling that the absorption chiller needs, due to its lower COP.
- 39 **Boiler demand, kW** – of any existing boiler on site.
- 40 **Boiler annual fuel bill.**
- 41 **Cogeneration – engine type.** This depends on the required cogeneration size. A gas turbine is preferred because of its high-temperature recovered heat, especially at sites with significant air conditioning loads as it allows double-effect absorption chillers.
- 42 **Size, kW<sub>e</sub>** – from the facility’s maximum electricity demand after making the air conditioning changes, as indicated in Table 1 in Figure 88. Alternatively, the load-duration curve indicates the required engine-size.

|                          |                                                        |                                                                                    |                    | Capacity | FOB cost, |             | Installed cost | Unit cost, installed |
|--------------------------|--------------------------------------------------------|------------------------------------------------------------------------------------|--------------------|----------|-----------|-------------|----------------|----------------------|
| Absorption chillers      | Item                                                   | Manufacturer                                                                       | Model #            | kWr      | US\$      | TT\$        | TT\$           | TT\$/kWr             |
| 29-Jan-98                | Indirect fired, single stage absorption chiller        | York ISOFlow, FOB Miami, Agnes Toro                                                | YIA-ST-2A4-46      | 721      | \$57,800  | \$346,800   | \$578,000      | \$802                |
| 29-Jan-98                | Indirect fired, single stage absorption chiller        | York ISOFlow, FOB Miami, Agnes Toro                                                | YIA-ST-3B3-46      | 1,093    | \$67,700  | \$406,200   | \$677,000      | \$619                |
| 14-Feb-98                | Indirect fired, single stage absorption chiller        | York ISOFlow, FOB Miami, Agnes Toro                                                |                    | 1,821    | \$90,300  | \$541,800   | \$903,000      | \$496                |
| 24-Jan-98                | Indirect fired, single stage absorption chiller        | York ISOFlow, FOB Miami, Agnes Toro                                                | YIA-ST-8E1-46      | 2,792    | \$119,400 | \$716,400   | \$1,194,000    | \$428                |
| 24-Jan-98                | Indirect fired, single stage absorption chiller        | York ISOFlow, FOB Miami, Agnes Toro                                                | YIA-ST-9E2-46      | 3,193    | \$129,300 | \$775,800   | \$1,293,000    | \$405                |
| 01-Jun-98                | Indirect fired, double effect steam absorption chiller | York ParaFlow steam chiller, Budget price, FOB Houston                             |                    | 1,442    | \$115,000 | \$690,000   | \$1,150,000    | \$798                |
| 16-Jun-98                | Indirect fired, double effect steam absorption chiller | York ParaFlow steam chiller, Budget price, FOB Houston                             |                    | 1,547    | \$216,000 | \$1,296,000 | \$2,160,000    | \$1,396              |
| 24-Jan-98                | Indirect fired, double effect steam absorption chiller | York Paraflow, FOB Miami, Agnes Toro                                               | YPC-ST-19GL-46-L-S | 2,813    | \$350,000 | \$2,100,000 | \$3,500,000    | \$1,244              |
| 07-May-98                | Direct-fired, York, budget price                       |                                                                                    |                    | 703      | \$135,000 | \$810,000   | \$1,350,000    | \$1,920              |
| 12-Nov-98                | Direct-fired, York, budget price                       |                                                                                    |                    | 1,055    | \$146,000 | \$876,000   | \$1,460,000    | \$1,384              |
| 07-May-98                | Direct-fired, York, budget price                       |                                                                                    |                    | 1,406    | \$179,000 | \$1,074,000 | \$1,790,000    | \$1,273              |
|                          | Direct-fired absorption chiller                        | From Raymond Franco:                                                               | Installed          | 7,032    |           |             | \$6,704,500    | \$953                |
| 17-Jun-97                | Ex-works maimi, Carrier                                |                                                                                    |                    | 1,406    | \$97,866  | \$587,196   | \$978,660      | \$696                |
|                          | Absorption chiller                                     |                                                                                    |                    | 3,164    |           | \$1,200,000 | \$2,000,000    | \$632                |
|                          | Ice making absorption chiller                          | Pazgal                                                                             |                    | 1,055    | \$270,000 |             |                |                      |
| <b>Electric chillers</b> |                                                        |                                                                                    |                    |          |           |             |                |                      |
| 07-May-98                | Screw                                                  | York, budget price                                                                 |                    | 703      | \$65,000  | \$390,000   | \$650,000      | \$924                |
| 16-May-98                | Screw                                                  | FOB Miami, York, budget price                                                      |                    | 1,582    | \$96,480  | \$578,880   | \$964,800      | \$610                |
| 15-May-98                | Centrifugal                                            | FOB Miami, York, budget price                                                      |                    | 1,406    | \$90,560  | \$543,360   | \$905,600      | \$644                |
| 09-May-98                | Centrifugal                                            | FOB Miami, York, budget price                                                      |                    | 1,758    | \$102,375 | \$614,250   | \$1,023,750    | \$582                |
|                          | Centrifugal                                            | From Raymond Franco:                                                               | Installed          | 7,032    |           |             | \$3,542,000    | \$504                |
| 14-May-98                | Engine-driven                                          | Alturdyne, FOB California, compressor, transmission, engine, evaporator, condenser |                    | 1,758    | \$266,087 | \$1,596,522 | \$2,660,870    | \$1,514              |
| 13-May-98                | Engine-driven                                          | Tecogen, FOB Factory natural gas engine-driven water-cooled screw                  |                    | 1,786    | \$310,900 | \$1,865,400 | \$3,109,000    | \$1,741              |

Table 33. A selection of chiller capital costs from manufacturers.

43 **Capital cost, TT\$/kWe** – from Table 34. This is summary information for the wide variety of commercially available cogeneration engines, thus there is a range of values



for each parameter. The capital and maintenance cost information reflects the variation in these parameters for each type of engine and emphasises the need for competitive quotations in any actual cogeneration project. The table's data is adequate for this study as it allows worst-case and best-case scenarios in evaluating the project's performance.

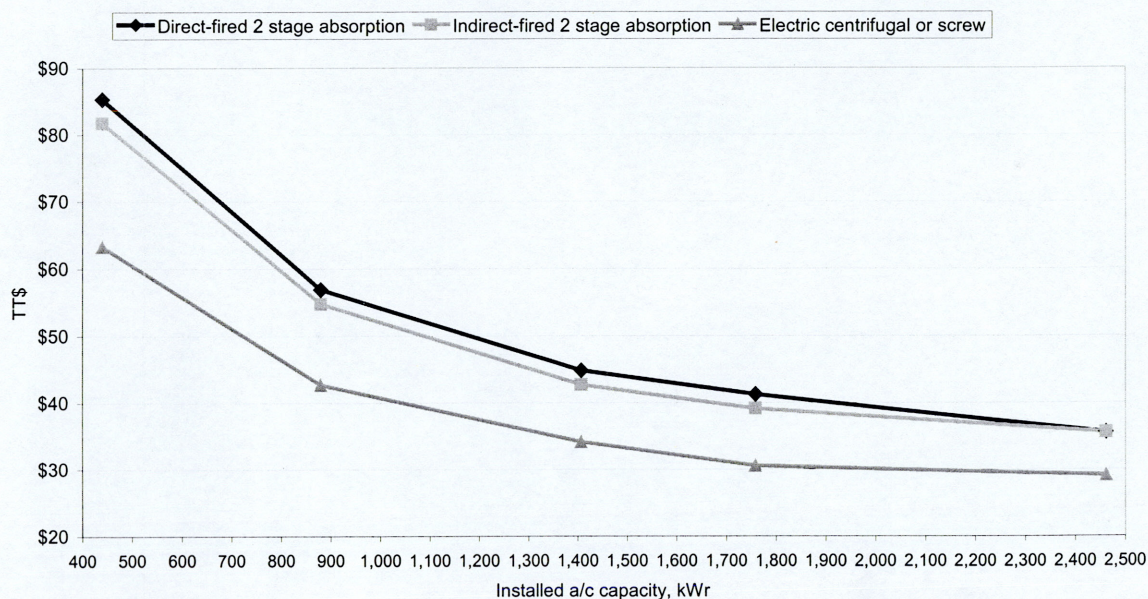


Figure 87. Annual chiller maintenance cost, TT\$/kW (NGC, 1998).

44 **Annual maintenance cost, TT\$/kWh** – from Table 34.

45 **Electrical efficiency** – from Table 35. Again the data is presented as ranges of values.

46 **Thermal efficiency** – from Table 35.

47 **Overall efficiency** – from 45 + 46.

|                           | Spark<br>ignition ICE | Compression<br>ignition ICE | Simple-cycle<br>GT | Combined-<br>cycle GT |
|---------------------------|-----------------------|-----------------------------|--------------------|-----------------------|
| Typical elec. rating, Mwe | 0.01 - 5              | 0.1 - 30                    | 1 - 100+           | 4 - 100+              |
| Heat:power ratio          | 1:1 - 2:1             | 0.7:1 - 1.5:1               | 1.5:1 - 3:1        | 0.5:1 - 2:1           |
| Elec. efficiency, %       | 25 - 40               | 30 - 45                     | 25 - 40            | 35 - 50               |
| Overall efficiency, %     | 65 - 80               | 65 - 80                     | 65 - 85            | 70 - 80               |
| Capital cost, TT\$/kWe    | 5000 - 9000           | 5000 - 8000                 | 4000 - 10000       | 3500 - 10000          |
| O&M cost, TTc/kWe         | 7 - 15                | 5 - 10                      | 3 - 9              | 3 - 10                |

Table 34. Cogeneration plant options and characteristics (NGC, 1999).



| Item                                   | % of fuel input energy, lower heating value |             |               |                 | Temperature, °C |        |
|----------------------------------------|---------------------------------------------|-------------|---------------|-----------------|-----------------|--------|
|                                        | Engine size range, kW                       |             |               |                 | Flow            | Return |
|                                        | 400 - 600                                   | 800 - 1,200 | 4,000 - 6,000 | 14,000 - 24,000 |                 |        |
| Power output                           | 22                                          | 27          | 32            | 37              |                 |        |
| Variation within each size range       | 16 - 22                                     | 20 - 28     | 24 - 36       | 32 - 39         |                 |        |
| Exhaust gases                          | 77                                          | 72          |               |                 | 500             |        |
| Lubricating oil cooling system         | <1                                          | <1          | <1            | <1              | 70              | 50     |
| Outer engine surfaces                  | <1                                          | <1          | <1            | <1              |                 |        |
|                                        | 100                                         | 100         | 100           | 100             |                 |        |
| Heat recoverable at high temperature   | 43                                          | 40          | 38            | 36              | 200             | 190    |
| Heat recoverable at medium temperature | 55                                          | 52          | 49            | 46              | 120             | 110    |
| Heat recoverable at low temperature    | 60                                          | 57          | 53            | 49              | 80              | 70     |

Table 35. Typical GT performance data (Griffith, 1995).

48 **Heat/electricity ratio** – from 46/45.

49 **Required heat/electricity ratio** – from Table 1, Figure 88. The worksheet determines the ratio for each minute using the metered data and incorporating any changes necessary for cogeneration at the site, e.g. absorption cooling. The average over the day is taken as the required heat/electricity ratio.

50 **Economic data** – rates needed to work out the project's economic performance over its life.

51 **Bank interest rate** – the rate of interest that the project pays on the capital investment. This assumes that a bank loan funds the entire project capital.

52 **Corporate tax rate** – applied to the annual profit or loss derived from the project. A loss reduces the company's overall revenue that year and acts like a tax break.

All the worksheets in the MS Excel model exchange information, but the information on the 'General data' sheet is used as the starting point for most calculations. Changing data on this automatically runs through the whole analysis, making easy fine-tuning and sensitivity analysis. The model updates easily for each new set of metered data from the different case studies.

### 9.3.2 Energy budget sheet

This sheet (Figure 88) contains the fundamental, raw metered energy-use data directly imported into Table 1, second and fourth columns from the left. Minute-by-minute kW records for the facility's overall power-use, and air conditioning power where available, over a 24-hour period, comprises 1,440 records. Table 1 in Figure 88 shows only the first few records. Also, because the data in Table 1 is so extensive, it is placed at the bottom,

and the worksheet should actually be read from the bottom up, placing Table 3 at the top. Calculations on the sheet also flow in this direction.

| 1999 field data analysis                      |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
|-----------------------------------------------|----------------------------------|-----------------------------------------|----------------------------|----------------------------------------------|---------------------------------------------|-----------------------------------|--------------------------------|-----------------------------------------------|---------------------------------------------------|----------------------------|
| Table 3 Table incorporating escalation        |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| Year                                          | 1                                | 2                                       | 3                          | 4                                            | 5                                           | 6                                 | 7                              | 8                                             | 9                                                 | 10                         |
| Annual electricity bill without cogen., TT\$  | \$3,179,536                      | \$3,306,717                             | \$3,438,986                | \$3,576,545                                  | \$3,719,607                                 | \$3,868,391                       | \$4,023,127                    | \$4,184,052                                   | \$4,351,414                                       | \$4,525,471                |
| Annual diesel bill, TT\$                      | \$384,000                        | \$395,520                               | \$407,386                  | \$419,607                                    | \$432,195                                   | \$445,161                         | \$458,516                      | \$472,272                                     | \$486,440                                         | \$501,033                  |
| Annual electricity bill with cogen., TT\$     | \$0                              | \$0                                     | \$0                        | \$0                                          | \$0                                         | \$0                               | \$0                            | \$0                                           | \$0                                               | \$0                        |
| Annual gas bill with cogen., TT\$             | \$1,296,997                      | \$1,348,877                             | \$1,402,832                | \$1,458,945                                  | \$1,517,303                                 | \$1,577,995                       | \$1,641,115                    | \$1,706,760                                   | \$1,775,030                                       | \$1,846,031                |
| Additional annual water and maintenance costs | \$461,445                        | \$475,288                               | \$489,547                  | \$504,233                                    | \$519,360                                   | \$534,941                         | \$550,989                      | \$567,519                                     | \$584,544                                         | \$602,081                  |
| Net annual saving                             | \$1,805,094                      | \$1,878,072                             | \$1,953,993                | \$2,032,974                                  | \$2,115,139                                 | \$2,200,617                       | \$2,289,539                    | \$2,382,045                                   | \$2,478,280                                       | \$2,578,392                |
| Table 2 Analysing the field data              |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| First-year saving - bills                     |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| Current                                       |                                  |                                         |                            |                                              | Grid elec. bought with cogen.               |                                   |                                |                                               |                                                   |                            |
| First-year elec. bill, TT\$                   | \$3,179,536                      |                                         |                            |                                              | Yearly kWh                                  |                                   |                                |                                               |                                                   |                            |
| First-year diesel bill, TT\$                  | \$384,000                        |                                         |                            |                                              | Daily kWh                                   |                                   |                                |                                               |                                                   |                            |
| Cogen.                                        |                                  |                                         |                            |                                              | Cogen.-generated elec.                      |                                   |                                |                                               |                                                   |                            |
| New elec. bill, TT\$                          | \$0                              |                                         |                            |                                              | Current kWh                                 |                                   |                                |                                               |                                                   |                            |
| New gas bill, TT\$                            | \$1,296,997                      |                                         |                            |                                              | 9,828,107                                   |                                   |                                |                                               |                                                   |                            |
| First-year saving, TT\$                       | \$2,266,539                      |                                         |                            |                                              | Cogen. equivalent full-load operating hours |                                   |                                |                                               |                                                   |                            |
|                                               | 63.6%                            |                                         |                            |                                              | Daily                                       |                                   |                                |                                               |                                                   |                            |
| First-year saving - primary energy use        |                                  |                                         |                            |                                              | Per annum                                   |                                   |                                |                                               |                                                   |                            |
| Current                                       |                                  |                                         |                            |                                              | 8,317                                       |                                   |                                |                                               |                                                   |                            |
| First-year Hotel gas use, kWh                 | 0                                |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| First-year T&TEC gas use, kWh                 | 43,061,609                       |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| Cogen.                                        |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| First-year cogen. gas use, kWh                | 36,400,395.6                     |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| New T&TEC gas use, kWh                        | 0                                |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| First-year gas saving, kWh                    | 6,661,214                        |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
|                                               | 15.5%                            |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| Table 1 Field-meter readings & derived data   |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |                            |
| Cost per kWh, TT\$                            |                                  |                                         | \$0.2829                   |                                              |                                             |                                   |                                |                                               |                                                   | \$0.1320                   |
| First-year cost, TT\$                         | \$955,249                        |                                         | \$3,179,536                |                                              |                                             |                                   |                                |                                               |                                                   | \$1,296,997                |
| First-year kWh                                | 3,376,632.6                      | 15,616,925.7                            | 11,239,080.0               | 8,088,391.2                                  | 3,311,280.0                                 | 18,928,205.7                      |                                | 15,577,642.2                                  | 1,739,715.6                                       | 36,400,395.6               |
| Daily kWh                                     | 9,251.0                          | 42,786.1                                | 30,792.0                   | 22,160.0                                     | 9,072.0                                     | 51,858.1                          |                                | 42,678.5                                      | 4,766.3                                           | 99,727.1                   |
| Equivalent full-load hours/day                | 23.01                            | 23.01                                   | 21.85                      | 21.13                                        |                                             |                                   |                                |                                               |                                                   | 22.79                      |
| Standard deviation                            | 7.94                             | 36.74                                   | 69.05                      | 67.44                                        |                                             | 36.74                             | 0.18                           | 129.88                                        | 67.33                                             | 70.66                      |
| as % of Average                               | 2.1%                             | 2.1%                                    | 5.4%                       | 7.3%                                         | 0.0%                                        | 1.7%                              | 7.7%                           | 33.9%                                         | 42.5%                                             | 1.7%                       |
| Maximum                                       | 410.4                            | 1,897.9                                 | 1,409.4                    | 1,048.6                                      | 378.0                                       | 2,275.9                           | 3.5                            | 2,019.6                                       | 507.8                                             | 4,376.8                    |
| Average                                       | 385.5                            | 1,782.8                                 | 1,283.0                    | 923.3                                        | 378.0                                       | 2,160.8                           | 2.4                            | 1,778.3                                       | 198.6                                             | 4,155.3                    |
| Time of day                                   | Centrifugal chiller elec. demand | Proposed absorption chiller heat demand | Hotel's electricity demand | Hotel's elec. demand with absorption chiller | Boiler gas demand                           | Total heat demand on cogen. plant | Hotel's heat/electricity ratio | For electrical-led cogen., actual heat supply | For heat-led cogen., electricity excess/shortfall | Heat-led cogen. gas demand |
|                                               | kWe                              | kWh                                     | kWe                        | kWe                                          | kWh                                         | kWh                               |                                | kWh                                           | kWe                                               | %                          |
| 10:01 AM                                      | 395.3                            | 1,828.4                                 | 1,316.4                    | 946.8                                        | 378                                         | 2,206.4                           | 2.33                           | 1,823.6                                       | 198.8                                             | 21.0%                      |
| 10:02 AM                                      | 395.3                            | 1,828.0                                 | 1,354.4                    | 984.9                                        | 378                                         | 2,206.0                           | 2.24                           | 1,896.9                                       | 160.5                                             | 16.3%                      |
| 10:03 AM                                      | 395.0                            | 1,826.7                                 | 1,313.4                    | 944.2                                        | 378                                         | 2,204.7                           | 2.34                           | 1,818.4                                       | 200.6                                             | 21.2%                      |
| 10:04 AM                                      | 394.8                            | 1,826.0                                 | 1,356.2                    | 987.2                                        | 378                                         | 2,204.0                           | 2.23                           | 1,901.3                                       | 157.2                                             | 15.9%                      |
| 10:05 AM                                      | 394.4                            | 1,824.3                                 | 1,361.9                    | 993.2                                        | 378                                         | 2,202.3                           | 2.22                           | 1,912.9                                       | 150.3                                             | 15.1%                      |
| 10:06 AM                                      | 395.0                            | 1,826.8                                 | 1,361.9                    | 992.7                                        | 378                                         | 2,204.8                           | 2.22                           | 1,911.8                                       | 152.1                                             | 15.3%                      |
| 10:07 AM                                      | 394.1                            | 1,822.5                                 | 1,356.0                    | 987.7                                        | 378                                         | 2,200.5                           | 2.23                           | 1,902.3                                       | 154.9                                             | 15.7%                      |

Figure 88. Hotel - 'Energy budget' sheet.

- Table 1** – Field-meter readings and derived data. The facility's overall and air conditioning minute-by-minute electricity demand on the metered day and derived data, also minute-by-minute.
- Time of day.**
- Centrifugal chiller electricity demand, kWe** – this does not include the condenser water circuit (CT fan and CW pumps). This is electricity-demand data from the fieldwork meter for the facility's overall air conditioning system.



- 4 **Proposed absorption chiller heat demand, kWth** – the proposed absorption chiller’s thermal power demand (kWth) from the product of 3 and the COP ratio from the ‘General data’ sheet, i.e. consider the absorption chiller to simply follow the existing air conditioning demand profile.
- 5 **Site’s electricity demand, kWe** – in this case Site is the Hotel. This is electricity-demand data from the fieldwork meter for the overall facility. This is the last of the metered data input; all other columns are derived.
- 6 **Site’s electricity demand with absorption chiller, kWe** – from 5 - 3 plus the extra condenser water power for the absorption chiller from the ‘General data’ sheet. This is effectively the cogeneration demand profile.
- 7 **Boiler gas demand, kWth** – at sites with a boiler. This is not metered data but is taken from the nameplate or from fuel bills and is considered constant throughout operating hours, i.e. an average demand.
- 8 **Total heat demand on cogeneration plant, kWth** – from 4 + 7.
- 9 **Site’s heat/electricity ratio** – from 8/6.
- 10 **For electrical-led cogeneration, actual heat supply, kWth** – exploring the different cogeneration operating modes to determine the excess or shortfall in heat and electricity. Considering the cogeneration is sized to exactly supply the electricity demand in 6, the thermal and electrical efficiencies from the ‘General data’ sheet yield the actual heat supply.
- 11 **Heat shortfall/excess, kWth** – from 8 - 10.
- 12 **For heat-led cogeneration, electricity excess/shortfall, kWe and %** – similar to 10, except considering that cogeneration is sized to exactly supply the total heat demand on the plant.
- 13 **Electrical-/heat-led cogeneration gas demand with supplementary firing or boiler as needed** – determine the cogeneration operating mode from 10, 11 and 12. The main concern is to avoid dumping heat as this is done at a premium in a hot, humid country like T&T, besides being energy-wasteful. Dumping heat via water cooling, i.e. a CT is done through evaporation, which needs more CT capacity the higher the ambient humidity. Dumping via air-cooled condensers would need a greater heat exchange area for a higher ambient air temperature. The national electricity grid can readily take up extra electricity, but the facility would not want to produce excessive amounts.

Figure 89 displays some of the columns’ data. Above each of the columns the worksheet displays summary statistics of the 1,440 records. Again these should be read from the bottom up.

- 14 **Average** – the statistical average of the values in the column.
- 15 **Maximum** - the maximum value in the column.
- 16 **Standard deviation** – a measure of the extent of variation in the column’s values over the metered day. Notice the standard deviation in the power over the period for both the chiller and overall facility, and how it compares with the average kWe demand, 2.1% and 5.4% respectively. This gives an idea of the profiles flatness as shown in Figure 89, and also demonstrates that the air conditioning load in Trinidad hardly varies over night and day. This results from the continuously high humidity year-round,

meaning the latent heat-load (as opposed to the sensible internal loads from equipment, etc.) on the cooling equipment is always high. This flatness means that both the cogenerator and the chiller can be sized for the maximum demand and not suffer part-load performance to any great degree. The Hotel is especially favourable for cogeneration with its continuous operation.

- 17 **As % of average** – intuitively clearer as a flatness indicator.
- 18 **Equivalent full-load hours per day** – equals the kWh consumption that day divided by the maximum kW. Comparing this figure to 24-hours also gives an idea of the profile's flatness.
- 19 **Daily kWh** – the sum of all the instantaneous minute kW readings divided by sixty.
- 20 **First-year kWh** – from 19 multiplied by the number of operating days per annum from the 'General data' sheet.
- 21 **First-year cost, TT\$** - from 20 multiplied by the cost per kWh on the 'General data' sheet.
- 22 **Cost/kWh, TT\$/kWh** – derived only for cogeneration in Table 1's last column. It is the first-year gas cost per kWh of cogenerated electricity and it indicates how cogeneration compares to the grid-electricity cost to the customer, i.e. the D-rate.
- 23 **Table 2** – analysing the field data. This table collates the data in Table 1 to give first-year energy and cost reductions/increases and the electricity generated/bought. The basis for the Table's calculation is to compare the facility with and without cogeneration in overall terms.
- 24 **First-year saving – bills.** TT dollar savings on energy bills
- 25 **Current** – summarises the existing energy bills (electricity, gas, diesel).
- 26 **Cogeneration** – predicted bills with cogeneration: the gas bill, and electricity bill if grid power is still needed.
- 27 **First-year saving, TT\$** - from 25 - 26. The calculated percentage is of the existing T&TEC electricity bill. This is *not* the net cogeneration saving as it does not include O&M costs; these are strictly energy-related figures.
- 28 **First-year saving – primary energy use.** kWh energy savings on energy use.
- 29 **Current** – summarises the existing primary energy use associated with the site, i.e. the natural gas used at the utility to provide the site's electricity at 26.1% generating efficiency on average, and any natural gas already used on site.
- 30 **Cogeneration** – the engine's gas use plus the primary energy for any additional grid electricity.
- 31 **First-year saving, kWh** – from 30 - 29. The calculated percentage is of the primary energy the utility used to generate the site's electricity use in 1998.
- 32 **Grid electricity bought with cogeneration** – if cogeneration is sized for an electricity shortfall, then 12 indicates the daily quantity in kWh from which the yearly amount derives.
- 33 **Cogeneration full-load operating hours** – daily hours derive from 6 for electrical-led, and from 13 for heat-led cogeneration. Annual hours derive from daily hours as before.

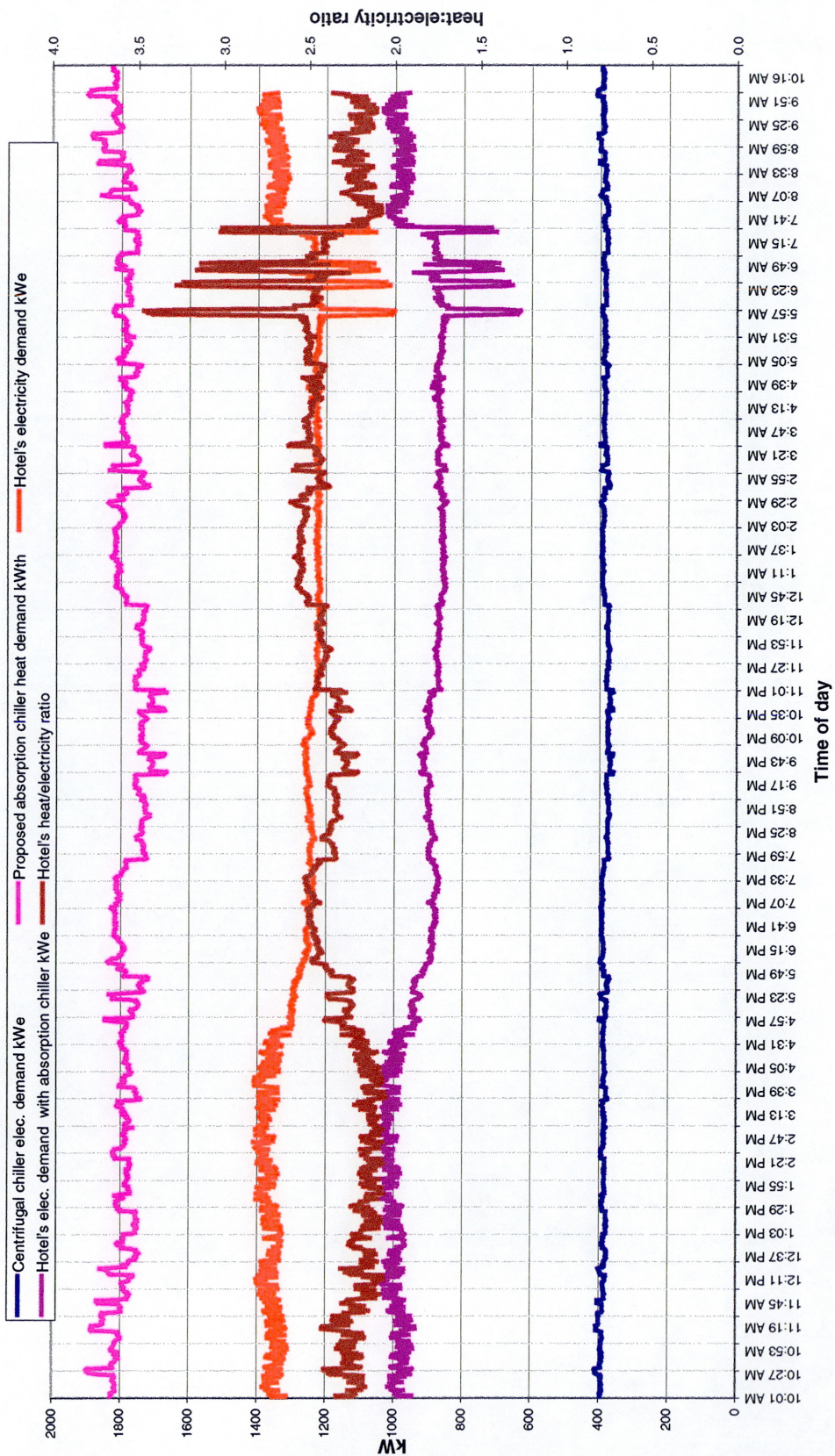


Figure 88. Hotel's energy-use profiles, kW.



- 34 **Table 3** – Table incorporating escalation. The cogeneration analysis on the worksheet up to this point refers to first-year data. Escalation in all costs means that they change every year over the project's 20-year analysis. The 'General data' sheet has the information on escalation factors.
- 35 **Year** – consider all recurring costs and related savings to occur at the end of each year. Figure 88 shows only the first 11 years.
- 36 **Annual electricity bill without cogeneration, TT\$** - the Year-1 figure is the current bill.
- 37 **Annual diesel and/or gas bill, TT\$** - the Year-1 figure is for any other energy bill on site that cogeneration would replace, including propane for cooking.
- 38 **Annual electricity bill with cogeneration, TT\$** - for any grid electricity that might be needed to supplement cogeneration.
- 39 **Annual gas bill with cogeneration, TT\$** - for the engine consumption and any supplementary firing.
- 40 **Additional annual water and maintenance cost, TT\$** - from the 'O&M' sheet. This comprises the *additional* CW capacity (water and chemical treatment) for the absorption chiller, plus cogeneration maintenance.
- 41 **Net annual saving, TT\$** – from  $36 + 37 - (38 + 39 + 40)$ . This row of values plug directly into the cash flow calculation on the 'Cash flow' sheet.

### 9.3.3 O&M sheet

This sheet (Figure 90) determines the first-year recurrent costs and savings from operating and maintaining the cogeneration/heat recovery system compared to the existing systems. It uses information from both of the previous sheets.

- 1 **Chiller and CT** – water and maintenance costs. The difference in these costs between the absorption and centrifugal chillers.
- 2 **Condenser water cost** – the 'General data' sheet provides the difference in makeup water volume and the unit water cost.
- 3 **First-year maintenance cost difference** – from the 'General data' sheet.
- 4 **Extra first-year chemical-cost difference** - from the 'General data' sheet.
- 5 **Recurrent cost sub-total** – from  $2 + 3 + 4$ .
- 6 **Cogeneration engine maintenance cost** – the product of the engine maintenance cost per kWh from the 'General data' sheet and the annual cogenerated electricity in kWh from Table 2 on the 'Energy budget' sheet.
- 7 **Total first-year recurrent cost** – from  $5 + 6$ . This is the first-year cost input to Table 3 on the 'Energy budget' sheet; costs in subsequent years increase through the escalation factors.
- 8 **Savings** – first-year energy-bill savings from 'Energy budget' sheet. Taken directly from Table 2.
- 9 **Net first-year savings from cogeneration and absorption cooling** – from  $8 + 9 - 7$ . The same as for the first year in Table 3, 'Energy budget' sheet.

| First-year recurrent costs/savings for the cogen./heat recovery system |            |   |           |   |        |        |           |
|------------------------------------------------------------------------|------------|---|-----------|---|--------|--------|-----------|
| <b>Costs</b>                                                           |            |   |           |   |        |        |           |
|                                                                        |            |   |           |   |        |        |           |
| <b>Chiller and cooling towers - water and maintenance costs</b>        |            |   |           |   |        |        |           |
| Extra first-year condenser water cost per 'General data' sheet         |            |   |           |   |        |        |           |
|                                                                        | 49,758,270 | x | 0.0035    | = |        | \$     | 174,154   |
| First-year maintenance cost difference per 'General data sheet'        |            |   |           |   |        |        |           |
|                                                                        |            |   |           | = |        | \$     | 15,942    |
| Extra first-year chemical cost per 'General data' sheet                |            |   |           |   |        |        |           |
|                                                                        |            |   |           | = |        | \$     | 28,696    |
| <b>Recurrent cost subtotal</b>                                         |            |   |           |   |        |        |           |
|                                                                        |            |   |           |   |        | \$     | 218,793   |
| <b>Cogen. engines - maintenance cost</b>                               |            |   |           |   |        |        |           |
| Maintenance cost per 'General data' sheet :                            |            |   |           |   | 0.0300 | \$/kWh |           |
|                                                                        | 0.0300     | x | 8,088,391 | = |        | \$     | 242,652   |
| <b>Total first-year recurrent cost</b>                                 |            |   |           |   |        |        |           |
|                                                                        |            |   |           |   |        | \$     | 461,445   |
| <b>Savings</b>                                                         |            |   |           |   |        |        |           |
|                                                                        |            |   |           |   |        |        |           |
| <b>First-year energy-bill savings from 'Energy budget' sheet</b>       |            |   |           |   |        |        |           |
|                                                                        |            |   |           |   |        | \$     | 2,266,539 |
| <b>Net first-year savings from cogen. and absorption cooling is</b>    |            |   |           |   |        |        |           |
|                                                                        |            |   |           |   |        | \$     | 1,805,094 |

Figure 90. Hotel - 'O&amp;M' sheet.

### 9.3.4 Load-duration data sheet

This sheet (Figure 91) rearranges in ascending order the 1,440 minute-by-minute values in the column 'Total heat demand on cogeneration plant, kWth', in Table 1 on the 'Energy budget' sheet. Again, the sheet should be read from the bottom up.

- 1 **Site's total heat demand on the cogeneration plant** – from the sorted data, the number of minutes per day for which the thermal demand exceeds a certain kW can be determined. The Hotel uses thermal load-duration data as the cogeneration there is heat-led; electrical-led sites would use data from the 'Site's electricity demand with absorption cooling' column in Table 1, 'Energy budget' sheet.



- 2 **Frequency, minutes** – shows how often in minutes each recorded kW<sub>e</sub> demand (or corresponding calculated kW<sub>th</sub> demand) occurs on the metered day.
- 3 **Cumulative frequency, minutes** – the amount of minutes on the metered day that the demand exceeds a given value. This data, along with the data in 1, generates the load-duration curve.
- 4 **Base load, kW** – the thermal or electrical demand at the pronounced ‘knee’ on the curve.
- 5 **Minimum demand, kW** – not the base load.
- 6 **Maximum demand, kW.**
- 7 **Average demand on the metered day, kW.**

| Load duration analysis for heat demand with cogeneration<br>for metered day |                                                                                     |                                                                                     |                                                         |                                    |
|-----------------------------------------------------------------------------|-------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------|---------------------------------------------------------|------------------------------------|
| From curve:                                                                 |                                                                                     |                                                                                     |                                                         |                                    |
| Base<br>load,<br>kW <sub>th</sub>                                           | Minimum<br>demand, kW <sub>th</sub>                                                 | Maximum<br>demand, kW <sub>th</sub>                                                 | Average<br>demand on<br>metered day<br>kW <sub>th</sub> |                                    |
| 2,087                                                                       | 2,046                                                                               | 2,277                                                                               | 2,161                                                   |                                    |
|                                                                             |                                                                                     |                                                                                     |                                                         |                                    |
|                                                                             | Total heat<br>demand on<br>cogen. plant,<br>sorted<br>ascending<br>kW <sub>th</sub> | Total heat<br>demand on<br>cogen. plant,<br>sorted<br>ascending<br>kW <sub>th</sub> | Frequency<br>minutes                                    | Cumulative<br>frequency<br>minutes |
| 9:31 PM                                                                     | 2,046                                                                               | 2,046                                                                               | 0                                                       | 1,440                              |
| 10:59 PM                                                                    | 2,046                                                                               | 2,047                                                                               | 2                                                       | 1,440                              |
| 9:51 PM                                                                     | 2,051                                                                               | 2,048                                                                               | 0                                                       | 1,438                              |
| 10:39 PM                                                                    | 2,051                                                                               | 2,049                                                                               | 0                                                       | 1,438                              |
| 9:30 PM                                                                     | 2,051                                                                               | 2,050                                                                               | 0                                                       | 1,438                              |
| 11:00 PM                                                                    | 2,051                                                                               | 2,051                                                                               | 0                                                       | 1,438                              |
| 9:50 PM                                                                     | 2,052                                                                               | 2,052                                                                               | 6                                                       | 1,438                              |

Figure 91. Hotel - load-duration data, kW<sub>th</sub>.

### 9.3.5 Capital sheet

This sheet (Figure 92) determines the cost of the cogenerator and the absorption chiller only. The unit costs include installation. It determines the lowest cost as a starting point for the financial analysis, using the lowest values in the Table 34. Working out the capital costs that would deliver a 12% IRR as a hurdle rate then gives an idea of how much the total capital outlay can vary, and how much margin for error there is in estimating the project's capital costs. This would be unnecessary if competitive quotes for all of the project's costs are available. The ‘Cash flow’ sheet uses the indicated capital outlay as the initial outlay in year 0.

| Capital costs - cogen/heat recovery option |      |          |          |                 |                     |
|--------------------------------------------|------|----------|----------|-----------------|---------------------|
|                                            |      |          |          |                 |                     |
| Item                                       | Unit | Capacity | Quantity | Unit cost, TT\$ | Total cost          |
| Absorption chiller                         | kWr  | 2,277    | 1        | TT\$798         | \$ 1,817,443        |
| Gas turbine                                | kWe  | 1,200    | 1        | TT\$4,000       | \$ 4,800,000        |
| <b>Total initial cost</b>                  |      |          |          |                 | <b>\$ 6,617,443</b> |
|                                            |      |          |          |                 |                     |
| <b>Capital outlay</b>                      |      |          |          |                 | <b>\$ 6,617,443</b> |

Figure 92. Hotel – 'Capital cost' sheet.

### 9.3.6 Cash flow sheet

This sheet (Figure 93) determines the yearly cash flows, incorporating bank interest payments and tax. The NPV and IRR derive from these cash flows over the 20-year project life.

| Life cycle costing for cogen./heat recovery option                                  |                |                |               |               |              |              |  |
|-------------------------------------------------------------------------------------|----------------|----------------|---------------|---------------|--------------|--------------|--|
|                                                                                     |                |                |               |               |              |              |  |
| Cash flow calculation                                                               |                |                |               |               |              |              |  |
|                                                                                     |                |                |               |               |              |              |  |
| Year                                                                                | 0              | 1              | 2             | 3             | 4            | 5            |  |
| 1 Capital outlay                                                                    | \$ (6,617,443) |                |               |               |              |              |  |
| 2 Net annual savings                                                                |                | \$ 1,805,094   | \$ 1,878,072  | \$ 1,953,993  | \$ 2,032,974 | \$ 2,115,139 |  |
| 3 Depreciation                                                                      |                | \$ (661,744)   | \$ (661,744)  | \$ (661,744)  | \$ (661,744) | \$ (661,744) |  |
| 4 Undepreciated amount at year end                                                  | \$ 6,617,443   | \$ 5,955,699   | \$ 5,293,955  | \$ 4,632,210  | \$ 3,970,466 | \$ 3,308,722 |  |
| 5 Interest expense                                                                  |                | \$ (1,058,791) | \$ (952,912)  | \$ (847,033)  | \$ (741,154) | \$ (635,275) |  |
| 6 Taxable saving                                                                    |                |                |               |               |              |              |  |
| 2+3+5                                                                               |                | \$ 84,559      | \$ 263,416    | \$ 445,216    | \$ 630,076   | \$ 818,120   |  |
| 7 Tax payment                                                                       |                | \$ (29,596)    | \$ (92,196)   | \$ (155,826)  | \$ (220,527) | \$ (286,342) |  |
| 8 Net cash flow                                                                     |                |                |               |               |              |              |  |
| 1+2+7                                                                               | \$ (6,617,443) | \$ 1,775,498   | \$ 1,785,877  | \$ 1,798,167  | \$ 1,812,448 | \$ 1,828,797 |  |
|                                                                                     |                |                |               |               |              |              |  |
| IRR                                                                                 | 27.36%         |                |               |               |              |              |  |
| Discount rate                                                                       | 5%             | 10%            | 14%           | 20%           | 25%          |              |  |
| NPV                                                                                 | TT\$17,370,492 | TT\$9,460,230  | TT\$5,745,097 | TT\$2,358,198 | TT\$618,229  |              |  |
|                                                                                     |                |                |               |               |              |              |  |
| Straight-line depreciation over 10 years; interest on declining 'incremental asset' |                |                |               |               |              |              |  |
| Bank interest rate                                                                  | 16%            |                |               |               |              |              |  |
| Corporate tax rate                                                                  | 35%            |                |               |               |              |              |  |

Figure 93. Hotel – 'Cash flow' sheet.

- 1 **Year** – the capital outlay occurs in year 0, then other cash flows at the end of each subsequent year.
- 2 **Capital outlay** – from 'Capital' sheet.
- 3 **Net annual savings** – directly from Table 3, 'Energy budget' sheet.

- 4 **Depreciation** – the entire capital depreciates in ten equal amounts over the project's first ten years. Depreciation is determined strictly for working out the corporate tax payments.
- 5 **Undepreciated amount at year-end** – the bank interest is applied to this amount each year, starting with the initial capital outlay, and decreasing each year by the amount of depreciation.
- 6 **Interest expense** – at the indicated commercial bank rate. Interest expense is determined strictly for working out the corporate tax payments.
- 7 **Taxable savings** – from 3 – (4 + 6).
- 8 **Tax payment** – at the corporate tax rate on the taxable savings. This is positive as long as 7 is positive, i.e. there is a cogeneration saving that year. Otherwise it is a tax saving to the company as a whole.
- 9 **Net cash flow** – this is the capital outlay at year 0, and 1 - 8 in the other years.
- 10 **Internal rate of return (IRR)** – this is the IRR at the underestimated project capital cost and is higher than the maximum return that can be expected from the project.
- 11 **Discount rate** – the analysis uses a range of rates because of the uncertainty in determining the correct discount rate, which can be expected to change over the project's life. It includes the 10% and 14% discount rates Ram (2000) uses in his analysis (Chapter 9).
- 12 **Net present value (NPV)** – determined for the range of discount rates, again using the underestimated project cost. Notice that for the Hotel in Figure 93 the project is feasible even at a 25% discount rate at this project-cost.

### 9.3.7 Sensitivity analysis sheet

Apart from the metered data and utility rates, the rest of the data in each feasibility study is estimated. Sensitivity analysis for some of the key estimated inputs demonstrates to what extent cogeneration feasibility depends upon them.

Table 1 in Figure 94 displays the NPV's sensitivity to project capital cost at different discount rates, all other parameters kept constant. The project cost can more than double the lowest estimate to over TT\$15,000,000 in this example before the NPV becomes negative at 14% discount rate, and more than triple for a negative NPV at 10% discount rate. This results from substantial net positive annual cash flows through cogeneration savings, over 50% of the current electricity bill, i.e. the project is very profitable.

Table 2 in Figure 94 displays NPV's sensitivity to the cost difference between gas and electricity as results from their different escalation rates. The capital cost is held constant at a level that delivers a 12% IRR at the original escalation rates (4% for both gas and electricity), i.e. TT\$19,000,000 in this example. Table 2 reveals that if the gas cost escalates faster than the electricity cost both costs converge and the project becomes unfeasible even at lower discount rates. This emphasises the importance of the gas/electricity cost differential.

| NPV sensitivity analysis                                                              |                             |               |                |                |                |  |
|---------------------------------------------------------------------------------------|-----------------------------|---------------|----------------|----------------|----------------|--|
| <b>Table 1 With capital cost and discount rate, O&amp;M-cost escalation unchanged</b> |                             |               |                |                |                |  |
| Gas & elec. escalation - 4%                                                           |                             | Discount rate |                |                |                |  |
|                                                                                       | Capital cost, TT\$          | 5%            | 10%            | 14%            | 20%            |  |
|                                                                                       | \$ 9,000,000                | \$ 16,239,793 | \$ 8,104,470   | \$ 4,253,424   | \$ 712,679     |  |
|                                                                                       | \$ 11,000,000               | \$ 15,290,646 | \$ 6,966,398   | \$ 3,001,263   | \$ (668,626)   |  |
|                                                                                       | \$ 13,000,000               | \$ 14,341,499 | \$ 5,828,327   | \$ 1,749,102   | \$ (2,049,932) |  |
|                                                                                       | \$ 15,000,000               | \$ 13,392,352 | \$ 4,690,255   | \$ 496,941     | \$ (3,431,237) |  |
|                                                                                       | \$ 17,000,000               | \$ 12,443,204 | \$ 3,552,183   | \$ (755,220)   | \$ (4,812,543) |  |
|                                                                                       | \$ 19,000,000               | \$ 11,494,057 | \$ 2,414,111   | \$ (2,007,382) | \$ (6,193,848) |  |
| <b>Table 2 With gas and elec. cost escalators</b>                                     |                             |               |                |                |                |  |
| At capital cost \$ 19,000,000                                                         |                             | Discount rate |                |                |                |  |
| Cost escalator: gas                                                                   | Cost escalator: electricity | 5%            | 10%            | 14%            | 20%            |  |
| 4%                                                                                    | 4%                          | \$ 11,494,057 | \$ 2,414,111   | \$ (2,007,382) | \$ (6,193,848) |  |
| 6%                                                                                    | 4%                          | \$ 8,581,588  | \$ 859,866     | \$ (2,999,936) | \$ (6,743,962) |  |
| 8%                                                                                    | 4%                          | \$ 4,915,485  | \$ (1,059,693) | \$ (4,206,594) | \$ (7,397,217) |  |
| 4%                                                                                    | 6%                          | \$ 18,633,858 | \$ 6,224,280   | \$ 425,825     | \$ (4,845,267) |  |
| 6%                                                                                    | 6%                          | \$ 15,721,389 | \$ 4,670,035   | \$ (566,729)   | \$ (5,395,380) |  |
| 8%                                                                                    | 6%                          | \$ 12,055,286 | \$ 2,750,476   | \$ (1,773,387) | \$ (6,048,636) |  |
| 4%                                                                                    | 8%                          | \$ 27,621,160 | \$ 10,930,002  | \$ 3,383,899   | \$ (3,243,836) |  |
| 6%                                                                                    | 8%                          | \$ 24,708,691 | \$ 9,375,756   | \$ 2,391,345   | \$ (3,793,950) |  |
| 8%                                                                                    | 8%                          | \$ 21,042,588 | \$ 7,456,197   | \$ 1,184,687   | \$ (4,447,206) |  |

Figure 94. Hotel – ‘Sensitivity analysis’ sheet.

So the Excel analysis model is basically a template. Field data slots into columns in the ‘Energy budget’ sheet, and depending on the indicated cogeneration-size (and chiller-size if relevant), some fields on the ‘General data’ sheet change. The process repeats for all case studies, with some slight modification for D3 customers. Chapter 10 examines each case, summarises the overall results, and explores their significance. It also makes a comparison with LNG.

## Chapter 10. Cogeneration evaluation results

### 10.1 Targeting the analysis

Ideally a national cogeneration study would evaluate every individual electricity customer. The number of customers in Trinidad and Tobago (T&T) in 1998 was 309,397. With limited time and resources, the research has to be targeted. The first step was to consider only industrial customers – 1,967 in 1998. In classifying any large sample, facilities with similar characteristics, electricity-use characteristics in this case, can be grouped together. The idea is to determine and rank the groups that represent the largest fraction of the country's electricity use in order to prioritise the study, assuming that a single feasibility study within each major group will reasonably apply to the whole group. Table 36 shows the fifteen T&TEC-defined industrial-user *subgroups* according to electricity-use characteristics. T&TEC also groups industrial customers into *rate categories* D1, D2, D3, and E according to size, i.e. installed capacity in kVA. Chapter 4 explains this in detail. Thus, each subgroup will have customers of some or all of the D rate categories. The E rate category is not considered in this study as it comprises a single customer, an iron and steel foundry using ~22% of the nation's electricity in 1998, and is not a cogeneration candidate.

| Code | Description                                                               |
|------|---------------------------------------------------------------------------|
| BIC  | Banks, insurance companies and credit unions, and financial institutions. |
| BUS  | Businesses, e.g. stores and groceries.                                    |
| CIN  | Cinemas and recreation centres.                                           |
| ES   | Essential and social services.                                            |
| FI   | Food/drink manufacturing industry and agro-based industries.              |
| FOR  | Food outlets and restaurants.                                             |
| GA   | Clothes-making industries.                                                |
| HL   | Hotels and holiday resorts.                                               |
| MF   | Manufacturing industry.                                                   |
| MIA  | Media.                                                                    |
| MIG  | Government ministries (including Health) and offices.                     |
| NUN  | General.                                                                  |
| OIL  | Oil industry.                                                             |
| ORG  | Private organisations.                                                    |
| SCH  | Schools and educational institutions.                                     |

Table 36. Industrial electricity user subgroups (Sitahal, 1999).



Successful cogeneration depends on adequate annual running hours, which is a function of the daily energy-use profile and the number of operating days per annum. The daily profile is related to the type of facility as described in Table 36, and so this is the first level for grouping customers. A facility's subgroup relates to its daily and yearly electricity-use profile; its rate category relates to its size and not so much its energy profiles and operating characteristics. Size is important for selecting the cogeneration engine-type. So the rate category is the second level for grouping customers, i.e. within subgroups.

Maximum demand in kVA and energy use in kWh are two measures of a facility's annual electricity use. The kVA determines its rate category. The maximum demand can occur for a single instant in the entire year and is not as good a basis for comparing sites for cogeneration as the energy use over the year. Thus, sites are best grouped according to energy use. T&TEC supplies figures for maximum demand and total energy use in 1998; fieldwork metering provides maximum demand and energy-use figures for a single day in 1999. Targeting the analysis is best done using T&TEC figures.

|              | Rate category electricity use in<br>1998, MWh |                |                |                  | Rate category<br>electricity use in<br>1998, % of subgroup |              |              | Subgroup electricity<br>use     |                               |
|--------------|-----------------------------------------------|----------------|----------------|------------------|------------------------------------------------------------|--------------|--------------|---------------------------------|-------------------------------|
| Subgroup     | D1                                            | D2             | D3             | Total            | D1                                                         | D2           | D3           | % of total D<br>category<br>use | % of total<br>national<br>use |
| MF           | 21,382                                        | 157,040        | 422,105        | 600,527          | 3.6%                                                       | 26.2%        | 70.3%        | 31.9%                           | 13.8%                         |
| OIL          | 943                                           | 62,136         | 207,074        | 270,152          | 0.3%                                                       | 23.0%        | 76.7%        | 14.3%                           | 6.2%                          |
| BUS          | 90,960                                        | 150,261        |                | 241,221          | 37.7%                                                      | 62.3%        |              | 12.8%                           | 5.5%                          |
| ES           | 46,622                                        | 154,594        | 38,593         | 239,809          | 19.4%                                                      | 64.5%        | 16.1%        | 12.7%                           | 5.5%                          |
| FI           | 16,248                                        | 128,581        |                | 144,829          | 11.2%                                                      | 88.8%        |              | 7.7%                            | 3.3%                          |
| MIG          | 20,707                                        | 86,980         | 21,982         | 129,669          | 16.0%                                                      | 67.1%        | 17.0%        | 6.9%                            | 3.0%                          |
| BIC          | 38,831                                        | 79,740         |                | 118,572          | 32.7%                                                      | 67.3%        |              | 6.3%                            | 2.7%                          |
| SCH          | 6,649                                         | 32,250         |                | 38,899           | 17.1%                                                      | 82.9%        |              | 2.1%                            | 0.9%                          |
| HL           | 4,082                                         | 30,178         |                | 34,260           | 11.9%                                                      | 88.1%        |              | 1.8%                            | 0.8%                          |
| FOR          | 24,094                                        | 6,110          |                | 30,203           | 79.8%                                                      | 20.2%        |              | 1.6%                            | 0.7%                          |
| NUN          | 11,773                                        | 2,241          |                | 14,014           | 84.0%                                                      | 16.0%        |              | 0.7%                            | 0.3%                          |
| MIA          | 1,972                                         | 6,083          |                | 8,056            | 24.5%                                                      | 75.5%        |              | 0.4%                            | 0.2%                          |
| CIN          | 3,963                                         | 3,163          |                | 7,126            | 55.6%                                                      | 44.4%        |              | 0.4%                            | 0.2%                          |
| GA           | 1,343                                         | 2,126          |                | 3,470            | 38.7%                                                      | 61.3%        |              | 0.2%                            | 0.1%                          |
| ORG          | 1,867                                         | 1,338          |                | 3,205            | 58.3%                                                      | 41.7%        |              | 0.2%                            | 0.1%                          |
| <b>TOTAL</b> | <b>291,437</b>                                | <b>902,822</b> | <b>689,754</b> | <b>1,884,012</b> | <b>15.5%</b>                                               | <b>47.9%</b> | <b>36.6%</b> | <b>100.0%</b>                   | <b>43.2%</b>                  |

Table 37. 1998 electricity use in subgroups, kWh (T&TEC figures).

So a targeted analysis first considers the subgroup that uses the most electricity, and the largest customer in that subgroup, most likely a D3 customer if such exists. Then in turn the next largest subgroup and customer, etc. Table 37 shows a matrix of electricity use in 1998 for all subgroups and D rate-categories. For example, for the Manufacturing Industry (MF), D3 customers use 70.3% of the total subgroup's annual electricity use. So a

feasibility study for a D3 MF customer would represent the largest portion of electricity use for the MF subgroup. Table 37 also shows that MF represents 31.9% of all D-industrial energy use, and 13.8% of the entire country's electricity use in 1998. So this subgroup has the top priority for analysis. Table 37 ranks all the other subgroups in descending order according to their share of all D-industrial and national electricity use.

The top nine subgroups cover 96.5% of all D electricity use and a corresponding 41.7% of the country's electricity use. Altogether, industrial-D electricity use accounts for 43.2% of the nation's electricity use. So Table 37 focuses the effort in a limited analysis.

| Subgroup | Site                 | Rate category | Site annual elec. use, MWh | Subgroup annual elec. use, MWh | Site annual electricity use |                             |                   |
|----------|----------------------|---------------|----------------------------|--------------------------------|-----------------------------|-----------------------------|-------------------|
|          |                      |               |                            |                                | % of Subgroup               | % of all D industrial users | % of national use |
| OIL      | Refinery             | D3            | 207,074                    | 270,152                        | 76.7%                       | 11.0%                       | 4.7%              |
| MF       | Ammonia & urea plant | D3            | 186,037                    | 600,527                        | 31.0%                       | 9.9%                        | 4.3%              |
| MF       | Methanol plant       | D3            | 114,466                    | 600,527                        | 19.1%                       | 6.1%                        | 2.6%              |
| MIG      | Hospital             | D3            | 21,982                     | 129,669                        | 17.0%                       | 1.2%                        | 0.5%              |
| SCH      | School               | D1 & D2       | 21,302                     | 38,899                         | 54.8%                       | 1.1%                        | 0.5%              |
| FI       | Mill                 | D2            | 15,600                     | 144,829                        | 10.8%                       | 0.8%                        | 0.4%              |
| HL       | Hotel                | D2            | 11,236                     | 34,260                         | 32.8%                       | 0.6%                        | 0.3%              |
| BUS      | Mall                 | D2            | 10,350                     | 241,221                        | 4.3%                        | 0.5%                        | 0.2%              |
| BIC      | Bank                 | D1 & D2       | 7,470                      | 118,572                        | 6.3%                        | 0.4%                        | 0.2%              |

Table 38. Ranking individual facilities by electricity use in 1998 (T&TEC figures).

Table 38 summarises the electricity use for the actual facilities analysed in Section 10.2 in this Chapter. The refinery represents 76.7% of the OIL subgroup, and the two MF sites together represent 50.1% of that subgroup. On the other end, the Shopping Mall is just 4.3% of the BUS subgroup and the Bank 6.3% of BIC. This does not automatically mean that a single case study in the latter subgroups is less representative of those subgroups. For BUS and BIC subgroups, one site is much like all the others. These subgroups have many, relatively small, but similar members.

This procedure to target the analysis hinges on applying a single feasibility study within a T&TEC-defined subgroup to all members of that group. Clearly every electricity customer is unique and it would be useful to develop a parameter that indicates how much the studied site varies from the 'average' subgroup facility. The ratio of the site's annual electricity use in kWh to its maximum demand in kVA that year can provide such an indicator. kVA and kW essentially represent instantaneous power, the latter being the product of kVA and the site's overall power factor. The ratio kWh/kVA thus represents the site's equivalent annual full-load running hours, which is an indication of the *average* degree of flatness in the yearly profile (NOT the actual profile which could have instantaneous peaks of short duration). It is best to use annual data from T&TEC for this ratio and not a single day's

data from the metering. In fact, the ratio can be used to show the deviation between the two, and indicate to what extent the daily metering represents the annual operation.

The ratio of the equivalent annual full-load running hours to the actual annual operating hours at the site (estimated or measured) indicates the average load factor that year. Where the actual operating hours cannot be estimated, using the full number of hours in a year (i.e. 8,760 hours) as a common basis for comparison for all sites will introduce some error. This can account for some of the difference between site and subgroup in Table 39, where the annual operating hours in all facilities, except the D3 customers, could only be roughly estimated. The D3 customers operate continuously. Still there is a surprisingly good agreement in some cases. The subgroups with the largest variation between the site and the subgroup merit more than a single feasibility study, or a closer look at the members of those subgroups to see how they can be further classified.

| Subgroup | Site                 | Rate category | Site annual elec. use, MWh | Site maximum demand, kVA | Subgroup annual elec. use, MWh | Subgroup maximum demand, kVA | Equivalent annual full-load running hours |          | Average load factor*, % |          |
|----------|----------------------|---------------|----------------------------|--------------------------|--------------------------------|------------------------------|-------------------------------------------|----------|-------------------------|----------|
|          |                      |               |                            |                          |                                |                              | Site                                      | Subgroup | Site                    | Subgroup |
| OIL      | Refinery             | D3            | 207,074                    | 42,678                   | 270,152                        | 60,004                       | 4,852                                     | 4,502    | 55.4                    | 51.4     |
| MF       | Ammonia & urea plant | D3            | 186,037                    | 53,228                   | 600,527                        | 170,258                      | 3,495                                     | 3,527    | 39.9                    | 40.3     |
| MF       | Methanol plant       | D3            | 114,466                    | 19,905                   | 600,527                        | 170,258                      | 5,751                                     | 3,527    | 65.6                    | 40.3     |
| MIG      | Hospital             | D3            | 21,982                     | 4,294                    | 129,669                        | 36,531                       | 5,119                                     | 3,550    | 58.4                    | 40.5     |
| SCH      | School               | D1 & D2       | 21,302                     | 4,656                    | 38,899                         | 10,607                       | 4,575                                     | 3,667    | 52.2                    | 41.9     |
| FI       | Mill                 | D2            | 15,600                     | 4,136                    | 144,829                        | 41,602                       | 3,772                                     | 3,481    | 43.1                    | 39.7     |
| HL       | Hotel                | D2            | 11,236                     | 1,920                    | 34,260                         | 8,011                        | 5,852                                     | 4,277    | 66.8                    | 48.8     |
| BUS      | Mall                 | D2            | 10,350                     | 2,310                    | 241,221                        | 85,619                       | 4,481                                     | 2,817    | 51.1                    | 32.2     |
| BIC      | Bank                 | D1 & D2       | 7,470                      | 1,776                    | 118,572                        | 30,741                       | 4,205                                     | 3,857    | 48.0                    | 44.0     |

\* based on 8,760 operating hours per annum

Table 39. Comparing site and subgroup operating hours (T&TEC figures).

## 10.2 The feasibility studies

Chapter 8 described in detail the general analysis procedure for a feasibility study. This section describes a single study for each major subgroup emphasising each case's unique features. All analyses carried out, using the model developed with MS Excel, are available on diskettes accompanying this thesis. D2-customer feasibility studies appear first, as these used data from the fieldwork meter. As a result these are the most comprehensive analyses, and serve best to demonstrate the procedure. The D3-customer analyses make slight modifications to this procedure.

### 10.2.1 The Hotel

The Hotel is a D2 customer in the HL subgroup. The Hotel has a 450-room capacity in three multi-level blocks, 3 kitchens, 4 restaurants, a 25-metre swimming pool, 8 tennis courts, 4 conference centres, and enough in-house laundry capacity to cover the Hotel's

operation. It is situated inland, some distance from the coast, and within the county's capital, Port of Spain. It is therefore popular for business persons as well as regular holiday-makers.

The Hotel has an existing heat load for domestic hot water and steam for the laundry. A 378 kW oil-fired boiler provides this, as there is no natural gas supply to the facility. The Hotel uses propane for cooking and natural gas could also replace this if it ever becomes available at the site. This would represent a substantial saving as natural gas is the cheaper fuel, but the analysis does not consider this.

The hotel operates continuously, as expected. Figure 95 shows that the air-conditioning system's chiller works close to full-load continuously with no discernible difference at night. This is common in a humid, tropical country like T&T, where the latent heat load on the air conditioning system is significant both night and day, despite the sensible heat load varying between day and night, and with occupancy. Table 40 shows that the standard deviation in the chiller's power demand is quite small over the metered day. This could also mean that the 20-year old chiller is no longer capable of providing its rated cooling capacity (a nominal 2,250 kW<sub>r</sub>), or undersized for the facility in the first place, or poorly maintained and improperly controlled.

| <b>Current</b>                                 |             |             |                                            |
|------------------------------------------------|-------------|-------------|--------------------------------------------|
|                                                |             |             | Annual<br>equivalent<br>full-load<br>hours |
| Annual electricity use                         | kWh         | kVA         |                                            |
| T&TEC                                          | 11,236,000  | 1,920       | 6,502                                      |
| Meter                                          | 11,239,080  | 1,409       | 7,974                                      |
| Average Hotel power demand on the day, kWe     | 1,283       |             |                                            |
| % standard deviation                           | 5.4%        |             |                                            |
| Average chiller power demand on the day, kWe   | 385         |             |                                            |
| % standard deviation                           | 2.1%        |             |                                            |
| Chiller demand as % of Hotel demand            | 30.0%       |             |                                            |
| <b>Proposed</b>                                |             |             |                                            |
| Cogenerator size, kWe                          | 1,200       | gas turbine |                                            |
| Hotel heat:electricity ratio with cogeneration | 2.35        |             |                                            |
| Cogenerator heat:electricity ratio             | 1.93        |             |                                            |
| % difference                                   | 22.2%       |             |                                            |
| Cogeneration mode                              | Heat-led    |             |                                            |
| Average excess electricity onto the grid, kW   | 199         |             |                                            |
| as % of average cogenerated power              | 22.2%       |             |                                            |
| Cogenerator annual equivalent full-load hours  | 8,317       |             |                                            |
| Cogenerated electricity cost, TT\$/kWh         | \$0.1320    |             |                                            |
| First-year energy bill saving, TT\$            | \$2,266,539 |             |                                            |
| as % of T&TEC electricity bill                 | 63.6%       |             |                                            |
| Annual natural gas saving, kWh                 | 6,661,214   |             |                                            |
| as % of T&TEC's use for site's electricity     | 15.5%       |             |                                            |
| Payback period on minimum capital cost, years  | <4          |             |                                            |

Table 40. Hotel – summary statistics.



# Hotel energy demand profiles

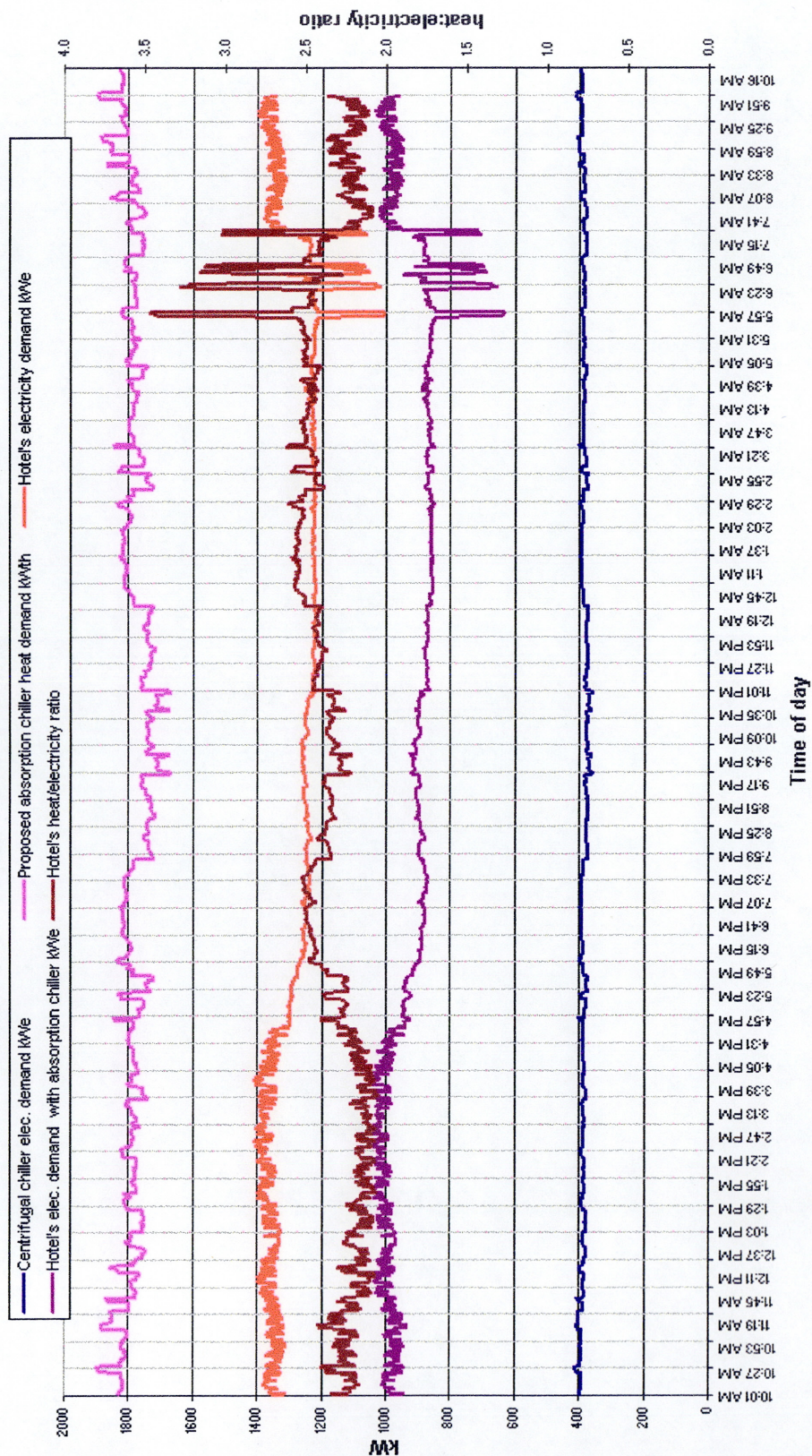


Figure 95. Hotel – 1999 energy profiles.

Table 40 also shows other summary statistics for the Hotel study drawn from all of the worksheets in the analysis, including the ‘Energy budget’ sheet shown in Figure 96. The entire Hotel itself has a largely flat energy-use profile on the metered day. However, the difference between meter-derived annual equivalent full-load hours and T&TEC data indicates some seasonal change in Hotel operations over the year. The chiller’s electricity demand is ~30% of the Hotel’s overall demand, and when this is substituted with an absorption chiller, the resulting Hotel’s heat/electricity ratio is 2.35 on average, including the boiler heat load. This exceeds that of the proposed gas turbine cogenerator, so a heat-led mode would produce on average 199 kWe for exporting to the grid. Despite this, the proposal is profitable and delivers an annual natural gas saving of 6,661,214 kWh. Section 10.3 in this Chapter gives the detailed financial statistics for all feasibility studies.

| Table 3 Table incorporating escalation        |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
|-----------------------------------------------|----------------------------------|-----------------------------------------|----------------------------|----------------------------------------------|---------------------------------------------|-----------------------------------|--------------------------------|-----------------------------------------------|---------------------------------------------------|-------------|----------------------------|
| Year                                          | 1                                | 2                                       | 3                          | 4                                            | 5                                           | 6                                 | 7                              | 8                                             | 9                                                 | 10          | 11                         |
| Annual electricity bill without cogen., TT\$  | \$3,179,536                      | \$3,306,717                             | \$3,438,986                | \$3,576,545                                  | \$3,719,607                                 | \$3,868,391                       | \$4,023,127                    | \$4,184,052                                   | \$4,351,414                                       | \$4,525,471 | \$4,708,490                |
| Annual diesel bill, TT\$                      | \$384,000                        | \$395,520                               | \$407,386                  | \$419,607                                    | \$432,195                                   | \$445,161                         | \$458,516                      | \$472,272                                     | \$486,440                                         | \$501,033   | \$516,064                  |
| Annual electricity bill with cogen., TT\$     | \$0                              | \$0                                     | \$0                        | \$0                                          | \$0                                         | \$0                               | \$0                            | \$0                                           | \$0                                               | \$0         | \$0                        |
| Annual gas bill with cogen., TT\$             | \$1,296,997                      | \$1,348,877                             | \$1,402,832                | \$1,458,945                                  | \$1,517,303                                 | \$1,577,995                       | \$1,641,115                    | \$1,706,760                                   | \$1,775,030                                       | \$1,846,031 | \$1,919,872                |
| Additional annual water and maintenance costs | \$461,445                        | \$475,288                               | \$489,547                  | \$504,233                                    | \$519,360                                   | \$534,941                         | \$550,989                      | \$567,519                                     | \$584,544                                         | \$602,081   | \$620,143                  |
| Net annual saving                             | \$1,805,094                      | \$1,878,072                             | \$1,953,993                | \$2,032,974                                  | \$2,115,139                                 | \$2,200,617                       | \$2,289,539                    | \$2,382,045                                   | \$2,478,280                                       | \$2,578,392 | \$2,682,538                |
| Table 2 Analysing the field data              |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| First-year saving - bills                     |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| Current                                       |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| First-year elec. bill, TT\$                   | \$3,179,536                      |                                         |                            |                                              | Grid elec. bought with cogen.               |                                   |                                |                                               |                                                   |             |                            |
| First-year diesel bill, TT\$                  | \$384,000                        |                                         |                            |                                              | Yearly kWh                                  |                                   |                                |                                               |                                                   |             |                            |
| Cogen.                                        |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| New elec. bill, TT\$                          | \$0                              |                                         |                            |                                              | Cogen-generated elec.                       |                                   |                                |                                               |                                                   |             |                            |
| New gas bill, TT\$                            | \$1,296,997                      |                                         |                            |                                              | Current kWh                                 |                                   |                                |                                               |                                                   |             |                            |
| First-year saving, TT\$                       | \$2,266,539                      |                                         |                            |                                              | Cogen. equivalent full-load operating hours |                                   |                                |                                               |                                                   |             |                            |
| 63.6%                                         |                                  |                                         |                            | Daily                                        |                                             |                                   |                                |                                               |                                                   |             |                            |
|                                               |                                  |                                         |                            | Per annum                                    |                                             |                                   |                                |                                               |                                                   |             |                            |
| First-year saving - primary energy use        |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| Current                                       |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| First-year Hotel gas use, kWh                 | 0                                |                                         |                            |                                              | Daily                                       |                                   |                                |                                               |                                                   |             |                            |
| First-year T&TEC gas use, kWh                 | 43,061,609                       |                                         |                            |                                              | Per annum                                   |                                   |                                |                                               |                                                   |             |                            |
| Cogen.                                        |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| First-year cogen. gas use, kWh                | 36,400,395.6                     |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| New T&TEC gas use, kWh                        | 0                                |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| First-year gas saving, kWh                    | 6,661,214                        |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| 15.5%                                         |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| Table 1 Field-meter readings & derived data   |                                  |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             |                            |
| Cost per kWh, TT\$                            | \$0.2829                         |                                         |                            |                                              |                                             |                                   |                                |                                               |                                                   |             | \$0.1320                   |
| First-year cost, TT\$                         | \$955,249                        |                                         |                            | \$3,179,536                                  |                                             |                                   |                                |                                               |                                                   |             | \$1,296,997                |
| First-year kWh                                | 3,376,632.6                      | 15,616,925.7                            | 11,239,080.0               | 8,088,391.2                                  | 3,311,280.0                                 | 18,928,205.7                      | 15,577,642.2                   | 1,739,715.6                                   | 36,400,395.6                                      |             |                            |
| Daily kWh                                     | 9,251.0                          | 42,786.1                                | 30,792.0                   | 22,160.0                                     | 9,072.0                                     | 51,858.1                          | 42,678.5                       | 4,766.3                                       | 99,727.1                                          |             |                            |
| Equivalent full-load hours/day                | 23.01                            | 23.01                                   | 21.85                      | 21.13                                        |                                             |                                   |                                |                                               | 22.79                                             |             |                            |
| Standard deviation                            | 7.94                             | 36.74                                   | 69.05                      | 67.44                                        | -                                           | 36.74                             | 0.18                           | 129.88                                        | 67.33                                             | 9.4%        |                            |
| as % of Average                               | 2.1%                             | 2.1%                                    | 5.4%                       | 7.3%                                         | 0.0%                                        | 1.7%                              | 7.7%                           | 7.3%                                          | 33.9%                                             | 42.5%       |                            |
| Maximum                                       | 410.4                            | 1,897.9                                 | 1,409.4                    | 1,048.6                                      | 378.0                                       | 2,275.9                           | 3.5                            | 2,019.6                                       | 507.8                                             | 80.0%       |                            |
| Average                                       | 385.5                            | 1,782.8                                 | 1,263.0                    | 923.3                                        | 378.0                                       | 2,160.8                           | 2.4                            | 1,778.3                                       | 198.6                                             | 22.2%       |                            |
| Time of day                                   | Centrifugal chiller elec. demand | Proposed absorption chiller heat demand | Hotel's electricity demand | Hotel's elec. demand with absorption chiller | Boiler gas demand                           | Total heat demand on cogen. plant | Hotel's heat/electricity ratio | For electrical-led cogen., actual heat supply | For heat-led cogen., electricity excess/shortfall |             | Heat-led cogen. gas demand |
|                                               | kWe                              | kWth                                    | kWe                        | kWe                                          | kWth                                        | kWth                              |                                | kWth                                          | kWe                                               | %           | kW                         |
| 10:01 AM                                      | 395.3                            | 1,828.4                                 | 1,316.4                    | 946.8                                        | 378                                         | 2,206.4                           | 2.33                           | 1,823.6                                       | 198.8                                             | 21.0%       | 4,243.0                    |
| 10:02 AM                                      | 395.3                            | 1,828.0                                 | 1,354.4                    | 984.9                                        | 378                                         | 2,206.0                           | 2.24                           | 1,896.9                                       | 160.5                                             | 16.3%       | 4,242.4                    |
| 10:03 AM                                      | 395.0                            | 1,826.7                                 | 1,313.4                    | 944.2                                        | 378                                         | 2,204.7                           | 2.34                           | 1,818.4                                       | 200.6                                             | 21.2%       | 4,239.9                    |
| 10:04 AM                                      | 394.8                            | 1,826.0                                 | 1,356.2                    | 987.2                                        | 378                                         | 2,204.0                           | 2.23                           | 1,901.3                                       | 157.2                                             | 15.9%       | 4,238.5                    |

Figure 96. Hotel - Energy budget sheet.



## 10.2.2 The Shopping Mall

The Mall is a D2 customer in the BUS subgroup and does not have a natural gas supply. It is a typical Shopping Mall in Port of Spain, with a wide variety of shops and facilities, including a food court, and a gymnasium. The Mall is seven stories high and the entire facility is air conditioned, including a large central atrium that extends through all of the levels and is covered with a large skylight.

The Mall does not operate continuously but Figure 97 shows that it is not shut down overnight, contrary to claims made during the fieldwork. Leaving the chiller running may be due to fears that it would not be able to pull down the building's temperature sufficiently for opening hours if it is shut down for any length of time overnight. The profile shows that the chiller works close to full-load over the 24-hour metered period, with a standard deviation 9% of average power demand. Figure 97 also shows that the Mall's profile follows basically the same large-scale variations over a day as the chiller, probably because the chiller accounts for ~39% of the overall electricity demand (Table 41). The percentage standard deviation for the Mall is 13.6%, so there is an appreciable difference between night and day for this type of facility.

| <b>Current</b>                                |             |             |                                   |
|-----------------------------------------------|-------------|-------------|-----------------------------------|
| Annual electricity use                        | kWh         | kVA         | Annual equivalent full-load hours |
| T&TEC                                         | 10,350,000  | 2,310       | 4,978                             |
| Meter                                         | 12,371,829  | 2,069       | 5,980                             |
| Average Mall power demand on the day, kWe     | 1,730       |             |                                   |
| % standard deviation                          | 13.6%       |             |                                   |
| Average chiller power demand on the day, kWe  | 674         |             |                                   |
| % standard deviation                          | 9.0%        |             |                                   |
| Chiller demand as % of Mall demand            | 39.0%       |             |                                   |
| <b>Proposed</b>                               |             |             |                                   |
| Cogenerator size, kWe                         | 1,400       | gas turbine |                                   |
| Mall heat:electricity ratio with cogeneration | 2.91        |             |                                   |
| Cogenerator heat:electricity ratio            | 1.93        |             |                                   |
| % difference                                  | 51.2%       |             |                                   |
| Cogeneration mode                             | elec.-led   |             |                                   |
| Average heat shortfall, kW                    | 988         |             |                                   |
| Cogenerator annual equivalent full-load hours | 5,725       |             |                                   |
| Cogenerated electricity cost, TT\$/kWh        | \$0.1638    |             |                                   |
| First-year energy bill saving, TT\$           | \$2,205,206 |             |                                   |
| as % of T&TEC electricity bill                | 63.0%       |             |                                   |
| Annual natural gas saving, kWh                | 11,063,344  |             |                                   |
| as % of T&TEC's use for site's electricity    | 23.3%       |             |                                   |
| Payback period on minimum capital cost, years | <5          |             |                                   |

Table 41. Mall – summary statistics.

Mall's enegy demand profiles over a day

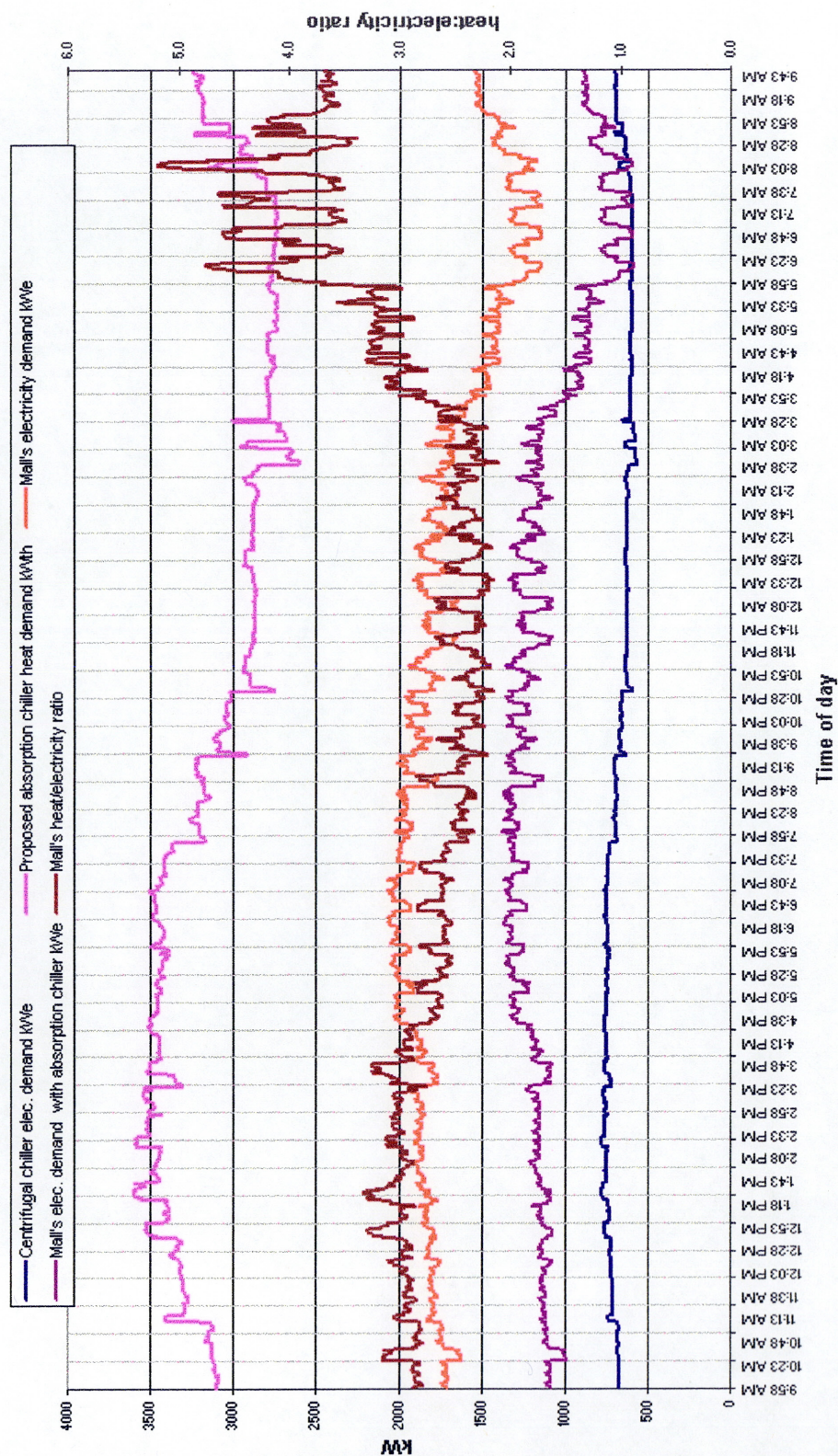


Figure 97.1. Mall – 1999 energy profiles.

An absorption chiller replacing the Mall’s centrifugal chiller would present a 2.91 facility heat/electricity ratio for cogeneration. This exceeds a gas turbine’s ratio by over half so cogeneration should be electrical-led with supplementary firing in the exhaust to make up the average heat shortfall of 988 kW (Table 41). A heat-led mode would generate more than half of the site’s demand as excess electricity, 513.2 kWe on average (Figure 98), which would be a disproportionate amount to export to the grid. The project is profitable and the annual natural gas saving is 11,063,344 kWh.

| Table 3                                      | Table incorporating escalation      |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
|----------------------------------------------|-------------------------------------|-----------------------------------------|---------------------------|---------------------------------------------|----------------|-----------------------------------|-------------------------------|-----------------------------------------------|----------------|-----------------------------------------|--------------------------------------------------------------------|-------------|
| Year                                         | 1                                   | 2                                       | 3                         | 4                                           | 5              | 6                                 | 7                             | 8                                             | 9              | 10                                      | 11                                                                 | 12          |
| Current first-year elec bill, TT\$           | \$3,499,990                         | \$3,639,990                             | \$3,785,590               | \$3,937,013                                 | \$4,094,494    | \$4,258,274                       | \$4,428,604                   | \$4,605,749                                   | \$4,789,979    | \$4,981,578                             | \$5,180,841                                                        | \$5,388,074 |
| Current first-year gas bill, TT\$            | \$0                                 | \$0                                     | \$0                       | \$0                                         | \$0            | \$0                               | \$0                           | \$0                                           | \$0            | \$0                                     | \$0                                                                | \$0         |
| New electricity bill, TT\$                   | \$0                                 | \$0                                     | \$0                       | \$0                                         | \$0            | \$0                               | \$0                           | \$0                                           | \$0            | \$0                                     | \$0                                                                | \$0         |
| New gas bill, TT\$                           | \$1,294,784                         | \$1,346,576                             | \$1,400,439               | \$1,456,456                                 | \$1,514,715    | \$1,575,303                       | \$1,638,315                   | \$1,703,848                                   | \$1,772,002    | \$1,842,882                             | \$1,916,597                                                        | \$1,993,261 |
| Annual water, chemical and maintenance costs | \$574,908                           | \$592,155                               | \$609,919                 | \$628,217                                   | \$647,064      | \$666,475                         | \$686,470                     | \$707,064                                     | \$728,276      | \$750,124                               | \$772,628                                                          | \$795,807   |
| Net annual saving                            | \$1,630,298                         | \$1,701,259                             | \$1,775,231               | \$1,852,340                                 | \$1,932,715    | \$2,016,495                       | \$2,103,819                   | \$2,194,837                                   | \$2,289,701    | \$2,388,572                             | \$2,491,616                                                        | \$2,599,007 |
| Table 2                                      | Analysing the field data            |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year saving - bills                    |                                     |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| Current                                      |                                     |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year elec. bill, TT\$                  | \$3,499,990                         |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year gas bill, TT\$                    | 0                                   |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| Cogen.                                       |                                     |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| New elec. bill, TT\$                         | 0                                   |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| New gas bill, TT\$                           | \$1,294,784                         |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year saving, TT\$                      | \$2,205,206                         |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
|                                              | 63.0%                               |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year saving - primary energy use       |                                     |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| Current                                      |                                     |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year Mall gas use, kWh                 | 0                                   |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year T&TEC gas use, kWh                | 47,401,644                          |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| Cogen.                                       |                                     |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year cogen. gas use, kWh               | 36,338,300                          |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| New T&TEC gas use, kWh                       | 0                                   |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year gas saving, kWh                   | 11,063,344                          |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
|                                              | 23.3%                               |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| Table 1                                      | Field-meter readings & derived data |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| Cost per kWh, TT\$                           | \$0.2829                            |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year cost, TT\$                        | \$3,499,990                         |                                         |                           |                                             |                |                                   |                               |                                               |                |                                         |                                                                    |             |
| First-year kWh                               | 4,819,240                           | 22,288,987                              | 12,371,829                | 7,902,739                                   | -              | 22,288,987                        | -                             | 15,220,090                                    | 7,068,897      | 3,670,389                               | -                                                                  | \$1,294,784 |
| Daily kWh                                    | 16,171.9                            | 74,795.3                                | 41,516.2                  | 26,519.3                                    | -              | 74,795.3                          | -                             | 51,074.1                                      | 23,721.1       | 12,316.7                                | -                                                                  | 36,338,300  |
| Equivalent full-load hours per day           | 20.76                               | 20.76                                   | 20.07                     | 19.21                                       | -              | 20.76                             | -                             | 20.76                                         | 351.69         | 182.61                                  | -                                                                  | 20.61       |
| Standard deviation                           | 60.85                               | 281.43                                  | 235.80                    | 200.42                                      | -              | 281.43                            | 0.57                          | 385.99                                        | 35.6%          | 29.4%                                   | -                                                                  | 550.11      |
| as % of Average                              | 9.0%                                | 9.0%                                    | 13.6%                     | 18.1%                                       | -              | 9.0%                              | 19.4%                         | 18.1%                                         | 35.6%          | 57.4%                                   | -                                                                  | 10.8%       |
| Maximum                                      | 778.9                               | 3,602.5                                 | 2,068.9                   | 1,380.4                                     | -              | 3,602.5                           | 5.2                           | 2,658.5                                       | 1,959.1        | 1,017.2                                 | -                                                                  | 5,917.3     |
| Average                                      | 673.8                               | 3,116.5                                 | 1,729.8                   | 1,105.0                                     | -              | 3,116.5                           | 2.9                           | 2,128.1                                       | 988.4          | 513.2                                   | -                                                                  | 5,080.9     |
| Time of day                                  | Centrifugal chiller elec. demand    | Proposed absorption chiller heat demand | Mall's electricity demand | Mall's elec. demand with absorption chiller | Boiler gas dem | Total heat demand on cogen. plant | Mall's heat/electricity ratio | For electrical led cogen., actual heat supply | Heat shortfall | For heat-led cogen., excess electricity | Electrical-led cogen. gas demand with supplementary exhaust firing |             |
|                                              | kWe                                 | kWth                                    | kWe                       | kWe                                         | kWth           | kWth                              |                               | kWth                                          | kWth           | kWe                                     | %                                                                  | kW          |
| 9:58 AM                                      | 671.6                               | 3,106.2                                 | 1,705.5                   | 1,082.9                                     | 0              | 3,106.2                           | 2.87                          | 2,085.6                                       | 1,020.6        | 530.0                                   | 48.9%                                                              | 5,031.4     |
| 9:59 AM                                      | 670.7                               | 3,102.0                                 | 1,706.6                   | 1,084.9                                     | 0              | 3,102.0                           | 2.86                          | 2,089.4                                       | 1,012.7        | 525.8                                   | 48.5%                                                              | 5,030.6     |
| 10:00 AM                                     | 670.5                               | 3,101.0                                 | 1,710.5                   | 1,089.0                                     | 0              | 3,101.0                           | 2.85                          | 2,097.3                                       | 1,003.7        | 521.2                                   | 47.9%                                                              | 5,037.0     |
| 10:01 AM                                     | 671.3                               | 3,104.9                                 | 1,720.2                   | 1,097.8                                     | 0              | 3,104.9                           | 2.83                          | 2,114.3                                       | 990.6          | 514.4                                   | 46.9%                                                              | 5,056.6     |

Figure 98. Mall - Energy budget sheet.

### 10.2.3 The School

The School is a D2 customer in the SCH subgroup. The metered energy demand profiles shown in Figure 99 reveal that it is not shutdown overnight as claimed, but only over weekends and public holidays to give 246 operating days per annum. This results in good agreement between meter-derived annual operating hours and T&TEC figures. Again the chiller profile reveals that it works flat-out and continuously, so it could be undersized, or



old and overworked. The School's overall profile is also very flat and follows the chiller's closely, as the chiller accounts for over 69% of the School's electricity demand. This translates into a 9.32 heat/electricity ratio for the facility using absorption cooling (Table 42). This is nearly four times the ratio for a gas turbine of the indicated 1,700 kWe capacity and would need a separate boiler to make up the 9,415 kW average heat shortfall. Heat-led cogeneration would produce an excessive 4,889 kWe for export on average (Figure 100).

The large air-conditioning load renders the School a borderline case in both energy and financial terms. The annual natural gas saving is 55,111kWh, just 0.1% of what T&TEC uses as primary energy to generate the School's electricity. The cost per kWh of cogenerated electricity is TT\$0.388 compared to a D2 cost of TT\$0.283. So facilities with a high air conditioning load pay a high penalty regarding cogeneration, especially the smaller facilities that would be forced to use single-effect absorption chillers. Chiller COP becomes the biggest constraint to effective cogeneration at such sites.

| <b>Current</b>                                  |             |             |                                   |
|-------------------------------------------------|-------------|-------------|-----------------------------------|
|                                                 | kWh         | kVA         | Annual equivalent full-load hours |
| Annual electricity use                          |             |             |                                   |
| T&TEC                                           | 21,302,342  | 4,656       | 5,084                             |
| Meter                                           | 22,000,000  | 4,120       | 5,340                             |
| Average School power demand on the day, kWe     | 3,726       |             |                                   |
| % standard deviation                            | 5.3%        |             |                                   |
| Average chiller power demand on the day, kWe    | 2,581       |             |                                   |
| % standard deviation                            | 0.8%        |             |                                   |
| Chiller demand as % of School demand            | 69.3%       |             |                                   |
| <b>Proposed</b>                                 |             |             |                                   |
| Cogenerator size, kWe                           | 1,700       | gas turbine |                                   |
| School heat:electricity ratio with cogeneration | 9.32        |             |                                   |
| Cogenerator heat:electricity ratio              | 1.93        |             |                                   |
| % difference                                    | 384.0%      |             |                                   |
| Cogeneration mode                               | elec.-led   |             |                                   |
| Average heat shortfall, kW                      | 9,415       |             |                                   |
| Cogenerator annual equivalent full-load hours   | 4,503       |             |                                   |
| Cogenerated electricity cost, TT\$/kWh          | \$0.3880    |             |                                   |
| First-year energy bill saving, TT\$             | \$3,222,351 |             |                                   |
| as % of T&TEC electricity bill                  | 51.8%       |             |                                   |
| Annual natural gas saving, kWh                  | 55,111      |             |                                   |
| as % of T&TEC's use for site's electricity      | 0.1%        |             |                                   |
| Payback period on minimum capital cost, years   | <7          |             |                                   |

Table 42. School – summary statistics.

### School's demand profiles

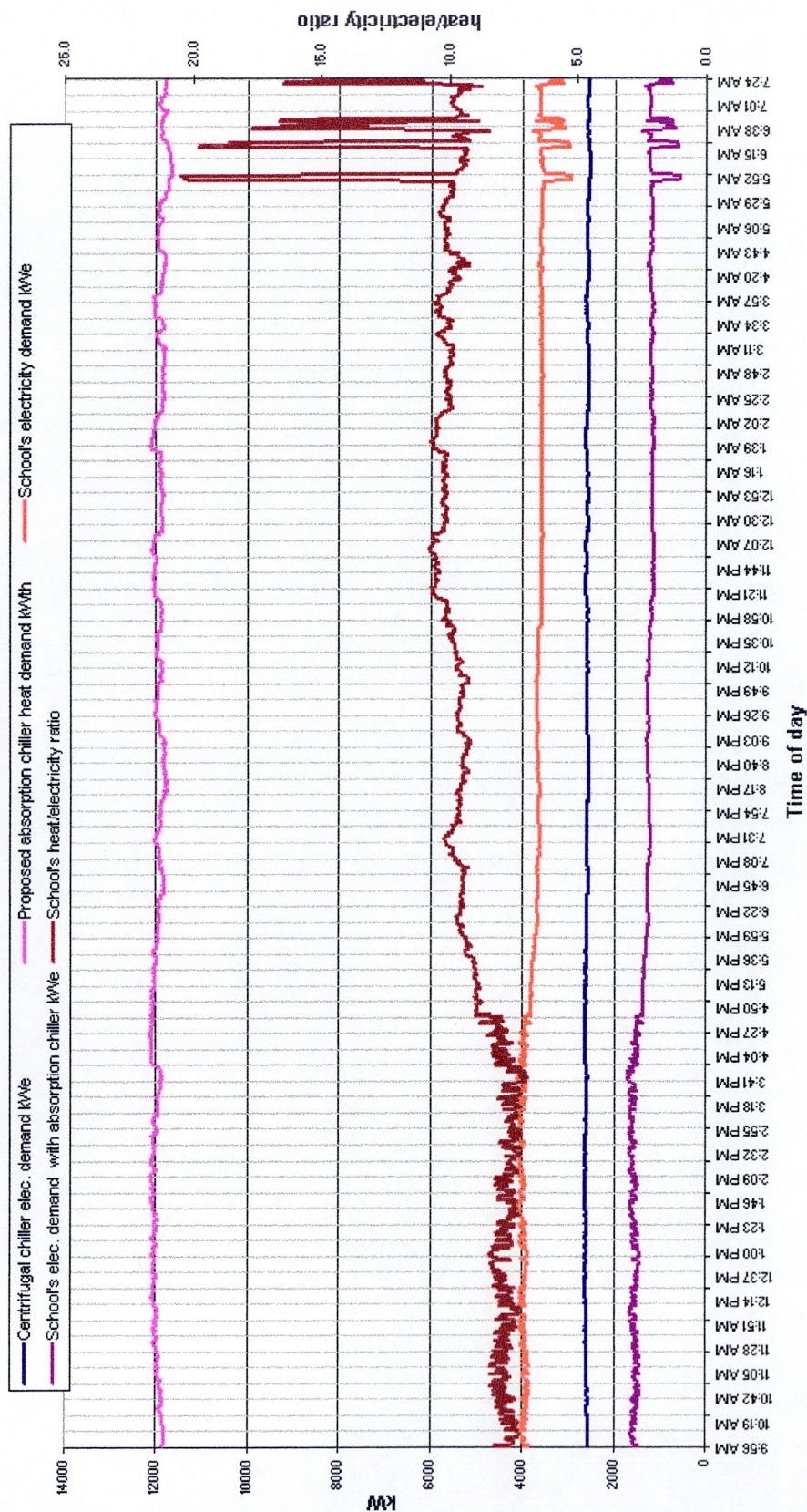


Figure 44. School – 1999 energy profiles.

Perhaps cogeneration's economics would improve without the supplementary boiler, or a smaller one, which would allow only partial conversion to absorption chilling. The school is a campus with multiple air conditioning units. This preliminary evaluation cannot investigate these extra options. However, it merits investigation considering the number of facilities in T&T that are likely to have such proportionally large air conditioning loads.

| Table 3 Table incorporating escalation      |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
|---------------------------------------------|----------------------------------|-----------------------------------------|-----------------------------|-----------------------------------------------|-------------------|-----------------------------------|---------------------------------|-----------------------------------------------|----------------|-----------------------------------------|------------------------------------------------------------|
| Year                                        | 1                                | 2                                       | 3                           | 4                                             | 5                 | 6                                 | 7                               | 8                                             | 9              | 10                                      | 11                                                         |
| Current first-year elec bill, TT\$          | \$6,223,800                      | \$6,472,752                             | \$6,731,662                 | \$7,000,929                                   | \$7,280,968       | \$7,572,204                       | \$7,875,093                     | \$8,190,096                                   | \$8,517,700    | \$8,858,408                             | \$9,212,744                                                |
| Current first-year gas bill, TT\$           | \$0                              | \$0                                     | \$0                         | \$0                                           | \$0               | \$0                               | \$0                             | \$0                                           | \$0            | \$0                                     | \$0                                                        |
| New electricity bill, TT\$                  | \$0                              | \$0                                     | \$0                         | \$0                                           | \$0               | \$0                               | \$0                             | \$0                                           | \$0            | \$0                                     | \$0                                                        |
| New gas bill, TT\$                          | \$3,001,449                      | \$3,121,507                             | \$3,246,368                 | \$3,376,222                                   | \$3,511,271       | \$3,651,722                       | \$3,797,791                     | \$3,949,703                                   | \$4,107,691    | \$4,271,998                             | \$4,442,878                                                |
| Annual water and maintenance costs          | \$1,389,637                      | \$1,431,327                             | \$1,474,266                 | \$1,518,494                                   | \$1,564,049       | \$1,610,971                       | \$1,659,300                     | \$1,709,079                                   | \$1,760,351    | \$1,813,162                             | \$1,867,557                                                |
| Net annual saving                           | \$1,832,713                      | \$1,919,918                             | \$2,011,028                 | \$2,106,212                                   | \$2,205,645       | \$2,309,512                       | \$2,418,002                     | \$2,531,315                                   | \$2,649,658    | \$2,773,248                             | \$2,902,310                                                |
| Table 2 Analysing the field data            |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year saving - bills                   |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| Current                                     |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year elec. bill, TT\$                 |                                  |                                         | \$6,223,800                 |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year gas bill, TT\$                   |                                  |                                         | \$0                         |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| Cogen.                                      |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| New elec. bill, TT\$                        |                                  |                                         | \$0                         |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| New gas bill, TT\$                          |                                  |                                         | \$3,001,449                 |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year saving, TT\$                     |                                  |                                         | \$3,222,351                 |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
|                                             |                                  |                                         | 51.8%                       |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year saving - primary energy use      |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| Current                                     |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year School gas use, kWh              |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year T&TEC gas use, kWh               |                                  |                                         | 84,291,188                  |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| Cogen.                                      |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year cogen. gas use, kWh              |                                  |                                         | 84,236,077                  |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| New T&TEC gas use, kWh                      |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| First-year gas saving, kWh                  |                                  |                                         | 55,111                      |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
|                                             |                                  |                                         | 0.1%                        |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| Table 1 Field-meter readings & derived data |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| Cost per kWh, TT\$                          |                                  |                                         | \$0.2829                    |                                               |                   |                                   |                                 |                                               |                |                                         | \$0.3880                                                   |
| First-year cost, TT\$                       | \$4,311,391                      |                                         | \$6,223,800                 |                                               |                   |                                   |                                 |                                               |                |                                         | \$3,001,449                                                |
| First-year kWh                              | 15,239,981                       | 70,484,914                              | 22,000,000                  | 7,735,029                                     | -                 | 70,484,914                        |                                 | 14,897,094                                    | 55,587,820     | 28,862,907                              | 84,236,077                                                 |
| Daily kWh                                   | 61,951.1                         | 286,524.0                               | 89,430.9                    | 31,443.2                                      | -                 | 286,524.0                         |                                 | 60,557.3                                      | 225,966.7      | 117,328.9                               | 342,423.1                                                  |
| Equivalent full-load hours/day              | 23.58                            | 23.58                                   | 21.71                       | 18.31                                         |                   |                                   |                                 |                                               |                |                                         | 22.80                                                      |
| Standard deviation                          | 21.02                            | 97.20                                   | 198.67                      | 188.80                                        | -                 | 97.20                             | 1.55                            | 363.61                                        | 333.94         | 173.39                                  | 387.20                                                     |
| as % of Average                             | 0.8%                             | 0.8%                                    | 5.3%                        | 14.4%                                         |                   | 0.8%                              | 16.6%                           | 14.4%                                         | 3.5%           | 3.5%                                    | 2.7%                                                       |
| Maximum                                     | 2,627.4                          | 12,151.9                                | 4,119.6                     | 1,717.6                                       | -                 | 12,151.9                          | 20.5                            | 3,308.0                                       | 10,616.2       | 5,512.3                                 | 964.6%                                                     |
| Average                                     | 2,581.3                          | 11,938.5                                | 3,726.3                     | 1,310.1                                       | -                 | 11,938.5                          | 9.3                             | 2,523.2                                       | 9,415.3        | 4,888.7                                 | 384.0%                                                     |
| Table 100 School - Energy budget sheet      |                                  |                                         |                             |                                               |                   |                                   |                                 |                                               |                |                                         |                                                            |
| Time of day                                 | Centrifugal chiller elec. demand | Proposed absorption chiller heat demand | School's electricity demand | School's elec. demand with absorption chiller | Boiler gas demand | Total heat demand on cogen. plant | School's heat/electricity ratio | For electrical-led cogen., actual heat supply | Heat shortfall | For heat-led cogen., excess electricity | Electrical-led cogen. gas demand with supplementary boiler |
|                                             | kWe                              | kWth                                    | kWe                         | kWe                                           | kWth              | kWth                              |                                 | kWth                                          | kWth           | kWe                                     | kW                                                         |
| 9:56 AM                                     | 2560.6                           | 11,842.7                                | 3,847.7                     | 1,452.3                                       | 0                 | 11,842.7                          | 8.15                            | 2,797.0                                       | 9,045.7        | 4,696.8                                 | 14,424.6                                                   |
| 9:57 AM                                     | 2562.4                           | 11,851.1                                | 3,958.9                     | 1,561.6                                       | 0                 | 11,851.1                          | 7.59                            | 3,007.6                                       | 8,843.5        | 4,591.8                                 | 14,627.3                                                   |
| 9:58 AM                                     | 2561.7                           | 11,847.8                                | 3,838.9                     | 1,442.4                                       | 0                 | 11,847.8                          | 8.21                            | 2,777.9                                       | 9,069.8        | 4,709.3                                 | 14,412.0                                                   |
| 9:59 AM                                     | 2561.7                           | 11,847.8                                | 3,964.2                     | 1,567.7                                       | 0                 | 11,847.8                          | 7.56                            | 3,019.2                                       | 8,828.6        | 4,584.1                                 | 14,634.7                                                   |

Figure 100. School - Energy budget sheet.

## 10.2.4 The Hospital

The Hospital is a D3 customer in the MIG subgroup and has a metered natural gas supply. The hospital operates continuously, and the average gas demand over 1998 was 1,407 kW. The chiller's profile is reasonably flat (Figure 101) with a 10.3% standard deviation and the Hospital's overall electricity-use profile varies to a similar extent on the metered day (Table 43). The air conditioning constitutes ~16% of hospital's electricity use and absorption cooling does not greatly inflate the site's existing heat/electricity ratio (i.e. to a value of

1.53). The indicated cogenerator size is a 3,500 kWe gas turbine with a 1.37 ratio. Heat-led cogeneration is appropriate to avoid dumping any heat. The engine can be modulated to supply the Hospital's instantaneous heat demand and the grid supplies any shortfall in electricity from cogeneration, 330.1 kWe on average (Figure 102), representing 10.3% of the average electricity demand with cogeneration.

| <b>Current</b>                                    |             |             |                                   |
|---------------------------------------------------|-------------|-------------|-----------------------------------|
|                                                   | kWh         | kVA         | Annual equivalent full-load hours |
| Annual electricity use                            |             |             |                                   |
| T&TEC                                             | 21,981,884  | 4,294       | 5,688                             |
| Meter                                             | 30,508,422  | 4,008       | 7,611                             |
| Average Hospital power demand on the day, kWe     | 3,483       |             |                                   |
| % standard deviation                              | 11.0%       |             |                                   |
| Average chiller power demand on the day, kWe      | 566         |             |                                   |
| % standard deviation                              | 10.3%       |             |                                   |
| Chiller demand as % of Hospital demand            | 16.2%       |             |                                   |
| <b>Proposed</b>                                   |             |             |                                   |
| Cogenerator size, kWe                             | 3,500       | gas turbine |                                   |
| Hospital heat:electricity ratio with cogeneration | 1.37        |             |                                   |
| Cogenerator heat:electricity ratio                | 1.53        |             |                                   |
| % difference                                      | -10.3%      |             |                                   |
| Cogeneration mode                                 | heat-led    |             |                                   |
| Average excess electricity, kW                    | -330        |             |                                   |
| Cogenerator annual equivalent full-load hours     | 8,084       |             |                                   |
| Cogenerated electricity cost, TT\$/kWh            | \$0.0595    |             |                                   |
| First-year energy bill saving, TT\$               | \$3,204,362 |             |                                   |
| as % of T&TEC electricity bill                    | 58.7%       |             |                                   |
| Annual natural gas saving, kWh                    | 46,218,861  |             |                                   |
| as % of T&TEC's use for site's electricity        | 39.5%       |             |                                   |
| Payback period on minimum capital cost, years     | <6          |             |                                   |

Table 43. Hospital – summary statistics.

An extra complication for the Hospital is that cogeneration reduces the site's maximum kVA demand to a D2 rate, at which it would purchase the cogeneration electricity shortfall. D2 electricity's cost per kWh is 1.65 times D3's. However, the Hospital pays industrial rate for natural gas, which is just over half the cost for non-industrial users, and so somewhat offsets the rate-category change. The result is that the cost per kWh of cogenerated electricity is TT\$0.0595/kWh and the project is profitable, and also saves 42,218,861 kWh of natural gas per annum on average.



### Hospital energy demand profiles

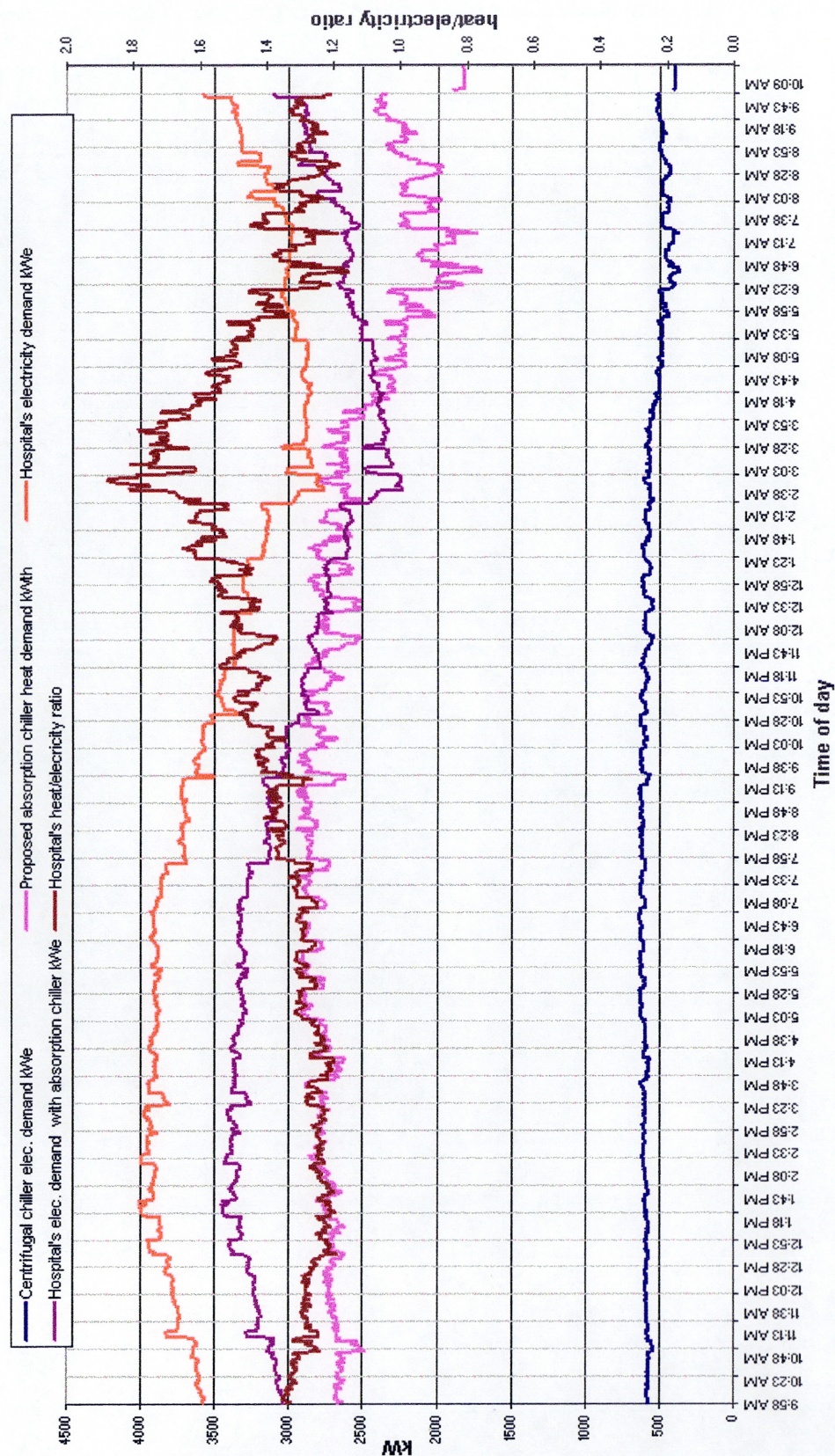


Figure 101. Hospital – 1999 energy profiles.



| Table 3 Table incorporating escalation      |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
|---------------------------------------------|----------------------------------|-----------------------------------------|-------------------------------|-------------------------------------------------|----------------|-----------------------------------|-----------------------------------|-------------------------------------------------|-----------------------------------------|----------------------------|--------------|
| Year                                        | 1                                | 2                                       | 3                             | 4                                               | 5              | 6                                 | 7                                 | 8                                               | 9                                       | 10                         | 11           |
| Current first-year elec bill, TT\$          | \$5,223,042                      | \$5,431,964                             | \$5,649,242                   | \$5,875,212                                     | \$6,110,220    | \$6,354,629                       | \$6,608,814                       | \$6,873,167                                     | \$7,148,093                             | \$7,434,017                | \$7,731,378  |
| Current first-year gas bill, TT\$           | \$234,728                        | \$244,117                               | \$253,882                     | \$264,037                                       | \$274,598      | \$285,582                         | \$297,006                         | \$308,886                                       | \$321,241                               | \$334,091                  | \$347,455    |
| New electricity bill, TT\$                  | \$883,774                        | \$919,125                               | \$955,890                     | \$994,125                                       | \$1,033,890    | \$1,075,246                       | \$1,118,256                       | \$1,162,986                                     | \$1,209,506                             | \$1,257,886                | \$1,308,201  |
| New gas bill, TT\$                          | \$1,369,634                      | \$1,424,419                             | \$1,481,396                   | \$1,540,651                                     | \$1,602,277    | \$1,666,369                       | \$1,733,023                       | \$1,802,344                                     | \$1,874,438                             | \$1,949,416                | \$2,027,392  |
| Annual water and maintenance costs          | \$996,806                        | \$1,026,711                             | \$1,057,512                   | \$1,089,237                                     | \$1,121,914    | \$1,155,572                       | \$1,190,239                       | \$1,225,946                                     | \$1,262,724                             | \$1,300,606                | \$1,339,624  |
| Net annual saving                           | \$2,207,556                      | \$2,305,826                             | \$2,408,327                   | \$2,515,235                                     | \$2,626,736    | \$2,743,025                       | \$2,864,302                       | \$2,990,776                                     | \$3,122,667                             | \$3,260,201                | \$3,403,615  |
|                                             |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| Table 2 Analysing the field data            |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
|                                             |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| First-year saving - bills                   |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| Current                                     |                                  |                                         |                               |                                                 |                | Grid elec. bought with cogen.     |                                   |                                                 |                                         |                            |              |
| First-year elec. bill, TT\$                 |                                  | \$5,223,042                             |                               |                                                 |                | First-year kWh                    |                                   | 3,123,980                                       |                                         |                            |              |
| First-year gas bill, TT\$                   |                                  | \$234,728                               |                               |                                                 |                | Daily kWh                         |                                   | 8,559                                           |                                         |                            |              |
| Cogen.                                      |                                  |                                         |                               |                                                 |                | Cogen.-generated elec.            |                                   |                                                 |                                         |                            |              |
| New elec. bill, TT\$                        |                                  | TT\$883,774                             |                               |                                                 |                | First-year kWh                    |                                   | 23,013,770                                      |                                         |                            |              |
| New gas bill, TT\$                          |                                  | TT\$1,369,634                           |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| First-year saving, TT\$                     |                                  | \$3,204,362                             |                               |                                                 |                | Cogen. full-load operating hours  |                                   |                                                 |                                         |                            |              |
|                                             |                                  | 58.7%                                   |                               |                                                 |                | Daily                             |                                   | 22.15                                           |                                         |                            |              |
|                                             |                                  |                                         |                               |                                                 |                | Per annum                         |                                   | 8,084                                           |                                         |                            |              |
| First-year saving - primary energy use      |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| Current                                     |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| First-year hospital gas use, kWh            |                                  | 12,325,320.0                            |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| First-year T&TEC gas use, kWh               |                                  | 116,890,507                             |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| Cogen.                                      |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| First-year cogen. gas use, kWh              |                                  | 71,918,031.82                           |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| New T&TEC gas use, kWh                      |                                  | 11,078,933.90                           |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| First-year gas saving, kWh                  |                                  | 46,218,861                              |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
|                                             |                                  | 39.5%                                   |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
|                                             |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| Table 1 Field-meter readings & derived data |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| Cost per kWh, TT\$                          |                                  |                                         | \$0.1712                      |                                                 |                |                                   |                                   |                                                 |                                         |                            | \$0.0595     |
| First-year cost, TT\$                       | \$848,209                        |                                         | \$5,223,042                   |                                                 | \$234,728      |                                   |                                   |                                                 |                                         |                            | \$1,369,634  |
| First-year kWh                              | 4,954,489.9                      | 22,914,515.6                            | 30,508,422.3                  | #####                                           | 12,325,320.0   | 35,239,835.6                      |                                   | 39,667,600.8                                    | - 2,891,601.7                           |                            | 71,918,031.8 |
| Daily kWh                                   | 13,573.9                         | 62,779.5                                | 83,584.7                      | 70,973.6                                        | 33,768.0       | 96,547.5                          |                                   | 108,678.4                                       | - 7,922.2                               |                            | 197,035.7    |
| Equivalent full-load hours/day              | 21.57                            | 21.57                                   | 20.85                         | 20.56                                           |                |                                   |                                   |                                                 |                                         |                            | 22.15        |
| Standard deviation                          | 58.08                            | 268.61                                  | 381.53                        | 345.38                                          | -              | 268.61                            | 0.14                              | 528.87                                          | 284.39                                  | 9.4%                       | 548.17       |
| as % of Average                             | 10.3%                            | 10.3%                                   | 11.0%                         | 11.7%                                           | 0.0%           | 6.7%                              | 10.5%                             | 11.7%                                           | -86.2%                                  | -91.4%                     | 6.7%         |
| Maximum                                     | 638.3                            | 2,952.1                                 | 4,008.5                       | 3,451.4                                         | 1,407.0        | 4,359.1                           | 1.9                               | 5,284.9                                         | 508.4                                   | 22.7%                      | 8,896.1      |
| Average                                     | 565.6                            | 2,615.8                                 | 3,482.7                       | 2,957.2                                         | 1,407.0        | 4,022.8                           | 1.4                               | 4,528.3                                         | 330.1                                   | -10.3%                     | 8,209.8      |
|                                             |                                  |                                         |                               |                                                 |                |                                   |                                   |                                                 |                                         |                            |              |
| Time of day                                 | Centrifugal chiller elec. demand | Proposed absorption chiller heat demand | Hospital's electricity demand | Hospital's elec. demand with absorption chiller | Boiler gas dem | Total heat demand on cogen. plant | Hospital's heat/electricity ratio | For electrical-cogeneration, actual heat supply | For heat-led cogen., excess electricity | Heat-led cogen. gas demand |              |
|                                             | kWe                              | kWth                                    | kWe                           | kWe                                             | kWth           | kWth                              |                                   | kWth                                            | kWe                                     | %                          | kW           |
| 9:58 AM                                     | 574.8                            | 2,658.7                                 | 3,577.0                       | 3,042.3                                         | 1,407          | 4,065.7                           | 1.34                              | 4,658.5                                         | 387.2                                   | -12.7%                     | 8,297.3      |
| 9:59 AM                                     | 577.5                            | 2,670.8                                 | 3,576.6                       | 3,039.3                                         | 1,407          | 4,077.8                           | 1.34                              | 4,653.9                                         | 376.2                                   | -12.4%                     | 8,322.0      |
| 10:00 AM                                    | 569.6                            | 2,634.3                                 | 3,575.7                       | 3,046.3                                         | 1,407          | 4,041.3                           | 1.33                              | 4,664.6                                         | 407.1                                   | -13.4%                     | 8,247.5      |
| 10:01 AM                                    | 576.1                            | 2,664.6                                 | 3,577.1                       | 3,041.1                                         | 1,407          | 4,071.6                           | 1.34                              | 4,656.6                                         | 382.1                                   | -12.6%                     | 8,309.3      |
| 10:02 AM                                    | 577.6                            | 2,671.6                                 | 3,576.1                       | 3,038.6                                         | 1,407          | 4,078.6                           | 1.34                              | 4,652.8                                         | 375.0                                   | -12.3%                     | 8,323.7      |

Figure 102. Hospital - Energy budget sheet.

## 10.2.5 The Mill

The Mill is a D2 customer in the FI subgroup and operates continuously. It is primarily a flour Mill, State-owned, and the only one in the country. It has expanded its activities to providing rice and refining vegetable cooking oils, the latest addition being a soya oil plant.

The site has a metered natural gas supply, and the Mill's average demand in 1998 was 7,617 kW. The air conditioning load at the site is insignificant compared to the Mill's total electricity demand. The new soya-oil plant began sporadic operation in 1999. Altogether the site's electricity demand profile is very erratic (Figure 104) putting the emphasis on trial and error in sizing cogeneration, and giving extra importance to the load-duration curve (Figure 103). The curve is useful for trying different engine sizes and determining the corresponding running hours and electricity excess or deficit it provides. Generally, a major concern is avoiding any heat-dumping or exporting excessive electricity to the grid.

A starting point in a conservative estimate is always the facility’s base-load, but the Mill has no clear base-load value from its load-duration curve due to its erratic demand profile. The curve shows that picking a 1,500 kWe gas turbine gives almost continuous full-load operation (Table 44), as the minimum demand on the metered day is 1,315 kWe or 88% of full-load, i.e. hardly any part-load modulation. The ‘Goal Seek’ feature in MS Excel confirms that this engine size gives the best compromise, modulating back by at most 185 kWe, or simply exporting that much to the grid. The site’s heat demand easily absorbs all of the turbine’s heat output, which in fact has to be supplemented (Figure 105), so heat-dumping is not a concern here, and cogeneration is electrical-led. 1,500 kWe is less than half the site’s maximum electricity demand, and the grid provides any additional demand.

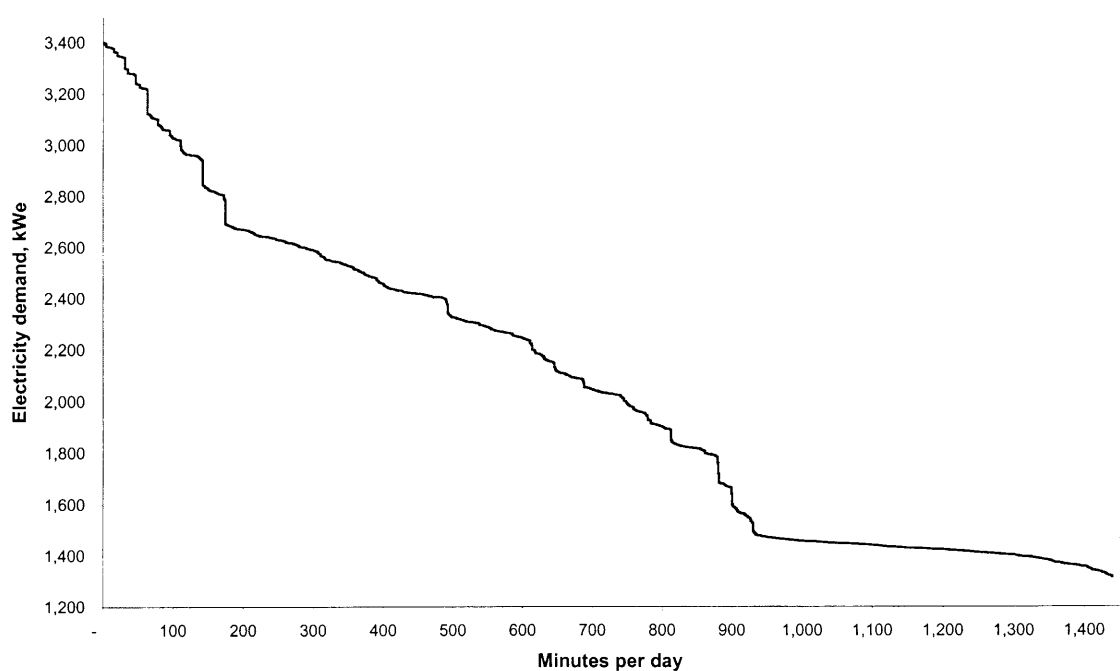


Figure 103. Mill load-duration curve for metered day

Mill's energy demand profiles

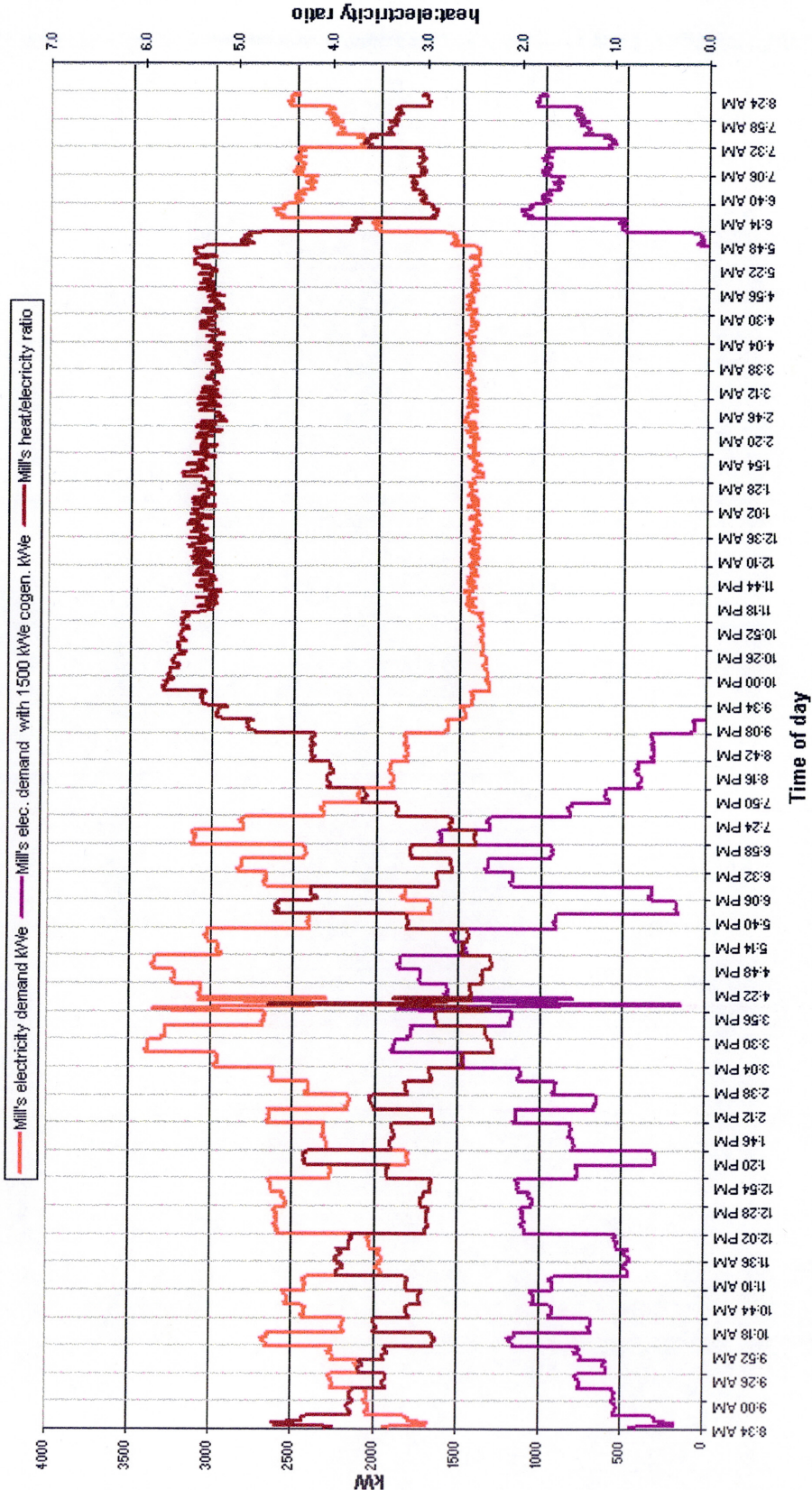


Figure 104. Mill – 1999 energy profiles.

| <b>Current</b>                                |                |             |                                   |
|-----------------------------------------------|----------------|-------------|-----------------------------------|
|                                               | kWh            | kVA         | Annual equivalent full-load hours |
| Annual electricity use                        |                |             |                                   |
| T&TEC - 1998                                  | 14,832,400     | 3,676       | 4,483                             |
| Meter - 1999                                  | 17,962,444     | 3,400       | 5,283                             |
| Average Mill power demand on the day, kWe     | 2,051          |             |                                   |
| % standard deviation                          | 28.7%          |             |                                   |
| Average chiller power demand on the day, kWe  |                |             |                                   |
| % standard deviation                          |                |             |                                   |
| Chiller demand as % of Mill demand            | 0.0%           |             |                                   |
| <b>Proposed</b>                               |                |             |                                   |
| Cogenerator size, kWe                         | 1,500          | gas turbine |                                   |
| Mill heat:electricity ratio with cogeneration | 4.03           |             |                                   |
| Cogenerator heat:electricity ratio            | 1.93           |             |                                   |
| % difference                                  | 109.2%         |             |                                   |
| Cogeneration mode                             | electrical-led |             |                                   |
| Average heat shortfall, kW                    |                |             |                                   |
| Cogenerator annual equivalent full-load hours | 8,716          |             |                                   |
| Cogenerated electricity cost, TT\$/kWh        | \$0.1320       |             |                                   |
| First-year energy bill saving, TT\$           | \$2,901,116    |             |                                   |
| as % of T&TEC electricity bill                | 38.9%          |             |                                   |
| Annual natural gas saving, kWh                | 27,438,348     |             |                                   |
| as % of T&TEC's use for site's electricity    | 39.9%          |             |                                   |
| Payback period on minimum capital cost, years | <3             |             |                                   |

Table 44. Mill – summary statistics.

The Mill's actual T&TEC bills over 363 days, starting 23 December 1997, were also made available (Table 45). This does not include bills for the new soya-oil plant, which would account for the difference in total and maximum demand between Table 44 and Table 45. A site's monthly bills over an entire year give an idea of its electricity-use profile over that year. The Mill shows a standard deviation in daily electricity consumption of 14% of the average over 1998, and an 11% standard deviation in maximum demand. Comparing this to Table 44 shows that the variation over the 24-hour metering period was even larger, as expected.

The conservative cogeneration sizing saves 27,438,348 kWh natural gas per annum, and produces electricity at TT\$0.132/kWh. The project is very profitable.

| Table 3 Table incorporating escalation      |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
|---------------------------------------------|----------------------------------|-----------------------------------------|---------------------------|-----------------------------------------|----------------|-----------------------------------|-------------------------------|-------------------------------------------|----------------------------------------|-------------|---------------------------------------------------|
| Year                                        | 1                                | 2                                       | 3                         | 4                                       | 5              | 6                                 | 7                             | 8                                         | 9                                      | 10          | 11                                                |
| Current first-year elec bill, TT\$          | \$5,081,575                      | \$5,284,838                             | \$5,496,232               | \$5,716,081                             | \$5,944,724    | \$6,182,513                       | \$6,429,814                   | \$6,687,007                               | \$6,954,487                            | \$7,232,666 | \$7,521,973                                       |
| Current first-year gas bill, TT\$           | \$2,377,428                      | \$2,472,525                             | \$2,571,426               | \$2,674,284                             | \$2,781,255    | \$2,892,505                       | \$3,008,205                   | \$3,128,533                               | \$3,253,675                            | \$3,383,822 | \$3,519,175                                       |
| New electricity bill, TT\$                  | \$1,364,269                      | \$1,418,840                             | \$1,475,594               | \$1,534,618                             | \$1,596,002    | \$1,659,842                       | \$1,726,236                   | \$1,795,285                               | \$1,867,097                            | \$1,941,781 | \$2,019,452                                       |
| New gas bill, TT\$                          | \$3,193,618                      | \$3,321,363                             | \$3,454,217               | \$3,592,386                             | \$3,736,082    | \$3,885,525                       | \$4,040,946                   | \$4,202,584                               | \$4,370,687                            | \$4,545,515 | \$4,727,335                                       |
| Annual water and maintenance costs          | \$394,200                        | \$406,026                               | \$418,207                 | \$430,753                               | \$443,676      | \$456,986                         | \$470,695                     | \$484,816                                 | \$499,361                              | \$514,342   | \$529,772                                         |
| Net annual saving                           | \$2,506,916                      | \$2,611,135                             | \$2,719,640               | \$2,832,608                             | \$2,950,220    | \$3,072,665                       | \$3,200,142                   | \$3,332,855                               | \$3,471,017                            | \$3,614,851 | \$3,764,589                                       |
| Table 2 Analysing the field data            |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year saving - bills                   |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| Current                                     |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year elec. bill, TT\$                 |                                  | \$5,081,575                             |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year gas bill, TT\$                   |                                  | \$2,377,428                             |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| Cogen.                                      |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| New elec. bill, TT\$                        |                                  | TT\$1,364,269                           |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| New gas bill, TT\$                          |                                  | TT\$3,193,618                           |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year saving, TT\$                     |                                  | \$2,901,116                             |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
|                                             |                                  | 38.9%                                   |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year saving - primary energy use      |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| Current                                     |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year Mill gas use, kWh                |                                  | 66,722,844                              |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year T&TEC gas use, kWh               |                                  | 68,821,624                              |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| Cogen.                                      |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year cogen. gas use, kWh              |                                  | 89,629,324                              |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| New T&TEC gas use, kWh                      |                                  | 18,476,797                              |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| First-year gas saving, kWh                  |                                  | 27,438,348                              |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
|                                             |                                  | 39.9%                                   |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| Table 1 Field-meter readings & derived data |                                  |                                         |                           |                                         |                |                                   |                               |                                           |                                        |             |                                                   |
| Cost per kWh, TT\$                          |                                  |                                         | \$0.2829                  | \$0.2829                                |                |                                   |                               |                                           |                                        |             | \$0.1320                                          |
| First-year cost, TT\$                       | \$0                              |                                         | \$5,081,575               | \$1,364,269                             | \$2,377,428    |                                   |                               |                                           |                                        |             | \$3,193,618                                       |
| First-year kWh                              | -                                | -                                       | 17,962,443.9              | 4,822,443.9                             | 66,722,843.9   |                                   |                               | 24,815,353.0                              | 16,682,109.6                           |             | 89,629,323.6                                      |
| Daily kWh                                   | -                                | -                                       | 49,212.2                  | 13,212.2                                | 182,802.3      |                                   |                               | 67,987.3                                  | 45,704.4                               |             | 245,559.8                                         |
| Equivalent full-load hours/day              | #DIV/0!                          | #DIV/0!                                 | 14.47                     |                                         |                |                                   |                               |                                           |                                        |             | 23.88                                             |
| Standard deviation                          | #DIV/0!                          | #DIV/0!                                 | 589.16                    | 589.16                                  | -              |                                   | 1.12                          | 87.38                                     | 589.16                                 | 58.2%       | 80.66                                             |
| as % of Average                             | #DIV/0!                          | #DIV/0!                                 | 28.7%                     | 107%                                    | 0.0%           |                                   | 27.8%                         | 3.1%                                      | 30.9%                                  | 53.3%       | 0.8%                                              |
| Maximum                                     | -                                | -                                       | 3,400.0                   | 1,900.0                                 | 7,616.8        |                                   | 5.8                           | 2,888.9                                   | 2,639.8                                | 200.7%      | 10,283.4                                          |
| Average                                     | #DIV/0!                          | -                                       | 2,050.5                   | 550.5                                   | 7,616.8        |                                   | 4.0                           | 2,832.8                                   | 1,904.4                                | 109.2%      | 10,231.7                                          |
| Time of day                                 | Centrifugal chiller elec. demand | Proposed absorption chiller heat demand | Mill's electricity demand | Mill's elec. demand with 1500 kW cogen. | Boiler gas dem | Total heat demand on cogen. plant | Mill's heat/electricity ratio | For electrical cogen., actual heat supply | For heat-led cogen, excess electricity |             | 1,500 kW cogen. + supplementary firing gas demand |
|                                             | kWe                              | kWh                                     | kWe                       | kWe                                     | kWh            | kWh                               |                               | kWh                                       | kWe                                    | %           | kW                                                |
| 8:34 AM                                     | -                                | -                                       | 1,900.3                   | 400.3                                   | 7616.8         | 7,616.8                           | 4.01                          | 2,888.9                                   | 2,054.6                                | 108.1%      | 10,283.4                                          |
| 8:35 AM                                     | -                                | -                                       | 1,902.1                   | 402.1                                   | 7616.8         | 7,616.8                           | 4.00                          | 2,888.9                                   | 2,052.8                                | 107.9%      | 10,283.4                                          |
| 8:36 AM                                     | -                                | -                                       | 1,940.0                   | 440.0                                   | 7616.8         | 7,616.8                           | 3.93                          | 2,888.9                                   | 2,014.9                                | 103.9%      | 10,283.4                                          |
| 8:37 AM                                     | -                                | -                                       | 1,901.7                   | 401.7                                   | 7616.8         | 7,616.8                           | 4.01                          | 2,888.9                                   | 2,053.1                                | 108.0%      | 10,283.4                                          |

Figure 105. Mill - Energy budget sheet.

| Period             |           |           | Electricity use, kWh |           |            | Maximum demand, kVA |         |       | Average daily elec. use, kWh |
|--------------------|-----------|-----------|----------------------|-----------|------------|---------------------|---------|-------|------------------------------|
| From               | To        | # of days | Meter 1              | Meter 2   | Total      | Meter 1             | Meter 2 | Total |                              |
| 23-Dec-97          | 26-Jan-98 | 34        | 564,000              | 774,400   | 1,338,400  | 1,440               | 2,156   | 3,596 | 39,365                       |
| 26-Jan-98          | 26-Feb-98 | 31        | 544,000              | 488,400   | 1,032,400  | 1,440               | 2,200   | 3,640 | 33,303                       |
| 26-Feb-98          | 24-Mar-98 | 26        | 504,000              | 202,400   | 706,400    | 1,320               | 1,056   | 2,376 | 27,169                       |
| 24-Mar-98          | 30-Apr-98 | 37        | 708,000              | 567,600   | 1,275,600  | 1,440               | 2,024   | 3,464 | 34,476                       |
| 30-Apr-98          | 22-May-98 | 22        | 607,200              | 440,000   | 1,047,200  | 2,200               | 1,440   | 3,640 | 47,600                       |
| 22-May-98          | 24-Jun-98 | 33        | 564,000              | 602,800   | 1,166,800  | 1,520               | 2,200   | 3,720 | 35,358                       |
| 24-Jun-98          | 22-Jul-98 | 28        | 616,000              | 426,800   | 1,042,800  | 1,480               | 1,936   | 3,416 | 37,243                       |
| 22-Jul-98          | 21-Aug-98 | 30        |                      |           |            |                     |         |       |                              |
| 21-Aug-98          | 22-Sep-98 | 32        | 620,000              | 558,800   | 1,178,800  | 1,440               | 2,200   | 3,640 | 36,838                       |
| 22-Sep-98          | 23-Oct-98 | 31        | 596,000              | 554,400   | 1,150,400  | 1,480               | 2,068   | 3,548 | 37,110                       |
| 23-Oct-98          | 23-Nov-98 | 31        | 688,000              | 501,600   | 1,189,600  | 1,440               | 2,024   | 3,464 | 38,374                       |
| 23-Nov-98          | 21-Dec-98 | 28        | 580,000              | 567,600   | 1,147,600  | 1,480               | 2,112   | 3,592 | 40,986                       |
| Annual             |           | 363       | 6,591,200            | 5,684,800 | 12,276,000 |                     |         |       | 33,818                       |
| Average            |           |           | 19,793               | 17,071    |            | 1,516               | 1,947   | 3,463 | 37,075                       |
| Standard deviation |           |           |                      |           |            | 232                 | 366     | 372   | 5,051                        |
|                    |           |           |                      |           |            | 15%                 | 19%     | 11%   | 14%                          |

Table 45. Mill - 1998 T&amp;TEC bills.



## 10.2.6 The Bank

The Bank is a D2 customer in the BIC subgroup and does not have a natural gas supply. Figure 106 shows that the building is shut down outside of working hours. The small electricity demand after hours is mainly due to the Bank's computers and the special air conditioning unit that supplies them with under-floor cooling. During operating hours' the main air conditioning accounts for over 60% of the Bank's electricity demand (Table 46). Cogeneration at this site would run only during main operating hours (7:36 AM to 8:40 PM on the metered day), as only then would an absorption chiller present a substantial heat load. This affects the number of running hours per annum. The small step in the air conditioning load around 6:30 PM is probably from some people working extra hours and running the chiller at part-load.

### Current

|                                              | kWh       | kVA | Annual equivalent full-load hours |
|----------------------------------------------|-----------|-----|-----------------------------------|
| Annual electricity use                       |           |     |                                   |
| T&TEC - 1998                                 | 1,738,200 | 360 | 5,365                             |
| Meter - 1999                                 | 1,874,580 | 361 | 5,196                             |
| Average Bank power demand on the day, kWe    | 215       |     |                                   |
| % standard deviation                         | 53.4%     |     |                                   |
| Average chiller power demand on the day, kWe | 131       |     |                                   |
| % standard deviation                         | 88.1%     |     |                                   |
| Chiller demand as % of Bank demand           | 61.0%     |     |                                   |

### Proposed

|                                               |                |                     |
|-----------------------------------------------|----------------|---------------------|
| Cogenerator size, kWe                         | 170            | small-scale package |
| Bank heat:electricity ratio with cogeneration | 7.92           |                     |
| Cogenerator heat:electricity ratio            | 1.27           |                     |
| % difference                                  | 524.0%         |                     |
| Cogeneration mode                             | electrical-led |                     |
| Average heat shortfall, kW                    |                |                     |
| Cogenerator annual equivalent full-load hours | 4,185          |                     |
| Cogenerated electricity cost, TT\$/kWh        | \$0.1771       |                     |
| First-year energy bill saving, TT\$           | \$156,980      |                     |
| as % of T&TEC electricity bill                | 29.6%          |                     |
| Annual natural gas saving, kWh                | - 1,690,163    |                     |
| as % of T&TEC's use for site's electricity    | -23.5%         |                     |
| Payback period on minimum capital cost, years | never          |                     |

Table 46. Bank – summary statistics.

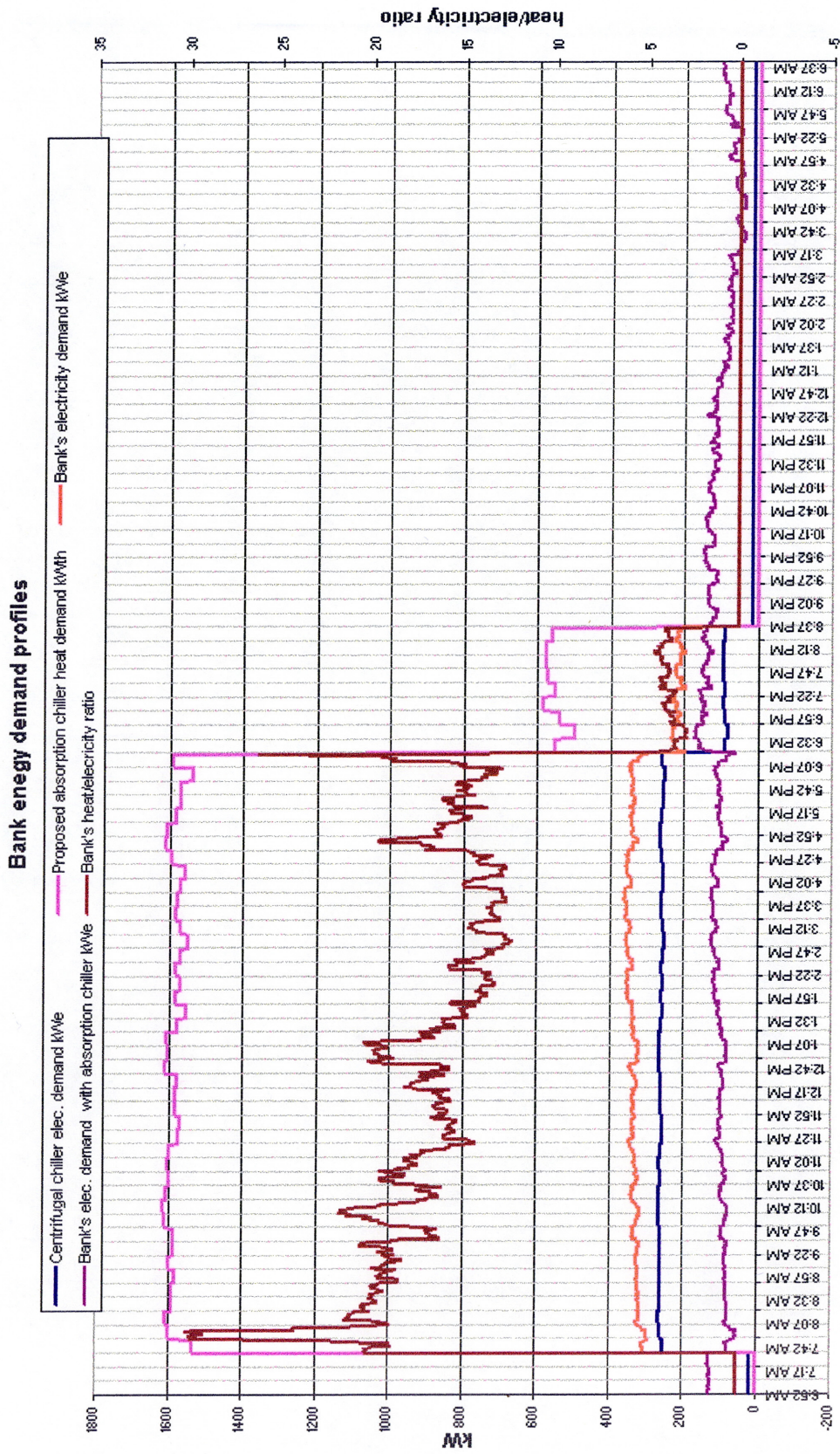


Figure 106. Bank – 1999 energy profiles.

On the whole, the Bank is a relatively small energy user, and the appropriate cogenerator is a small-scale packaged reciprocating engine, which in turn limits the absorption cooling to single-effect. Single-effect absorption chillers have the lowest COPs, and this (in addition to the proportionally high air conditioning load) greatly inflates the site’s heat/electricity ratio to 7.92 on average, well above the engine’s 1.27 ratio. The disproportionate heat load actually renders the project *less* energy efficient with cogeneration, with primary natural gas use increasing by 1,690,163 kWh per annum. Cogeneration at such facilities is unfeasible, even though it reduces the site’s energy *costs*, as natural gas is that much cheaper than electricity. An energy policy proposal that encourages less efficient energy use is contradictory.

| Table 3 Table incorporating escalation |           |           |           |           |           |           |           |           |           |           |           |
|----------------------------------------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|-----------|
| Year                                   | 1         | 2         | 3         | 4         | 5         | 6         | 7         | 8         | 9         | 10        | 11        |
| Current first-year elec bill, TT\$     | \$530,319 | \$551,531 | \$573,593 | \$596,536 | \$620,398 | \$645,214 | \$671,022 | \$697,863 | \$725,778 | \$754,809 | \$785,001 |
| Current first-year gas bill, TT\$      | \$0       | \$0       | \$0       | \$0       | \$0       | \$0       | \$0       | \$0       | \$0       | \$0       | \$0       |
| New electricity bill, TT\$             | \$110,547 | \$114,969 | \$119,568 | \$124,351 | \$129,325 | \$134,498 | \$139,878 | \$145,473 | \$151,292 | \$157,343 | \$163,637 |
| New gas bill, TT\$                     | \$262,791 | \$273,303 | \$284,235 | \$295,605 | \$307,429 | \$319,726 | \$332,515 | \$345,816 | \$359,648 | \$374,034 | \$388,996 |
| Annual water and maintenance costs     | \$161,376 | \$166,217 | \$171,204 | \$176,340 | \$181,630 | \$187,079 | \$192,691 | \$198,472 | \$204,426 | \$210,559 | \$216,876 |
| Net annual saving                      | -\$4,396  | -\$2,958  | -\$1,414  | \$241     | \$2,014   | \$3,911   | \$5,938   | \$8,103   | \$10,412  | \$12,872  | \$15,493  |

| Table 2 Analysing the field data       |  |  |             |  |  |  |  |           |  |  |  |
|----------------------------------------|--|--|-------------|--|--|--|--|-----------|--|--|--|
| First-year saving - bills              |  |  |             |  |  |  |  |           |  |  |  |
| Current                                |  |  |             |  |  |  |  |           |  |  |  |
| First-year elec. bill, TT\$            |  |  | \$530,319   |  |  |  |  | 390,765   |  |  |  |
| First-year gas bill, TT\$              |  |  | 0           |  |  |  |  | 1,071     |  |  |  |
| Cogen.                                 |  |  |             |  |  |  |  |           |  |  |  |
| New elec. bill, TT\$                   |  |  | \$110,547   |  |  |  |  | 1,483,815 |  |  |  |
| New gas bill, TT\$                     |  |  | \$262,791   |  |  |  |  |           |  |  |  |
| First-year saving, TT\$                |  |  | \$156,980   |  |  |  |  |           |  |  |  |
|                                        |  |  | 29.6%       |  |  |  |  |           |  |  |  |
| First-year saving - primary energy use |  |  |             |  |  |  |  |           |  |  |  |
| Current                                |  |  |             |  |  |  |  |           |  |  |  |
| First-year Bank gas use, kWh           |  |  | 0           |  |  |  |  |           |  |  |  |
| First-year T&TEC gas use, kWh          |  |  | 7,182,299   |  |  |  |  |           |  |  |  |
| Cogen.                                 |  |  |             |  |  |  |  |           |  |  |  |
| First-year cogen. gas use, kWh         |  |  | 7,375,278   |  |  |  |  |           |  |  |  |
| New T&TEC gas use, kWh                 |  |  | 1,497,184   |  |  |  |  |           |  |  |  |
| First-year gas saving, kWh             |  |  | - 1,690,163 |  |  |  |  |           |  |  |  |
|                                        |  |  | -23.5%      |  |  |  |  |           |  |  |  |

| Table 1 Field-meter readings & derived data |           |           |           |         |   |           |      |           |           |           |           |
|---------------------------------------------|-----------|-----------|-----------|---------|---|-----------|------|-----------|-----------|-----------|-----------|
| Cost per kWh, TT\$                          |           |           | \$0.2829  |         |   |           |      |           |           |           | \$0.1771  |
| First-year cost, TT\$                       | \$323,436 |           | \$530,319 |         |   |           |      |           |           |           | \$262,791 |
| First-year kWh                              | 1,143,288 | 6,668,908 | 1,874,580 | 886,763 | - | 6,668,908 |      | 1,124,998 | 5,543,910 | 4,369,908 | 7,375,278 |
| Daily kWh                                   | 3,132.3   | 18,271.0  | 5,135.8   | 2,429.5 | - | 18,271.0  |      | 3,082.2   | 15,188.8  | 11,972.3  | 20,206.2  |
| Equivalent full-load hours per day          | 11.96     | 11.31     | 14.23     | 13.79   |   |           |      |           |           |           | 11.47     |
| Standard deviation as % of Average          | 115.61    | 757.01    | 114.93    | 27.01   | - | 757.01    | 8.34 | 34.27     | 759.71    | 598.83    | 657.7%    |
| Maximum                                     | 261.9     | 1,615.1   | 360.8     | 176.2   | - | 1,615.1   | 30.1 | 223.6     | 1,531.7   | 1,207.4   | 2269.7%   |
| Average                                     | 131.2     | 765.5     | 215.2     | 101.8   | - | 765.5     | 7.9  | 129.1     | 636.4     | 501.6     | 524.0%    |

| Time of day | Centrifugal chiller elec. demand | Proposed absorption chiller heat demand | Bank's electricity demand | Bank's elec. demand with absorption chiller | Boiler gas dem | Total heat demand on cogen. plant | Bank's heat/electricity ratio | For electrical-led cogen., actual heat supply | Heat shortfall | For heat-led cogen., excess electricity | Electrical-led cogen. gas demand with supplementary boiler |
|-------------|----------------------------------|-----------------------------------------|---------------------------|---------------------------------------------|----------------|-----------------------------------|-------------------------------|-----------------------------------------------|----------------|-----------------------------------------|------------------------------------------------------------|
|             | kWe                              | kWth                                    | kWe                       | kWe                                         | kWth           | kWth                              |                               | kWth                                          | kWth           | kWe                                     | %                                                          |
| 6:52 AM     | 15.5                             | -                                       | 127.7                     | 127.7                                       | 0              | -                                 | 0.00                          | 162.0                                         | - 162.0        | - 127.7                                 | -100.0%                                                    |
| 6:53 AM     | 15.5                             | -                                       | 125.2                     | 125.2                                       | 0              | -                                 | 0.00                          | 158.8                                         | - 158.8        | - 125.2                                 | -100.0%                                                    |
| 6:54 AM     | 15.5                             | -                                       | 125.3                     | 125.3                                       | 0              | -                                 | 0.00                          | 158.9                                         | - 158.9        | - 125.3                                 | -100.0%                                                    |
| 6:55 AM     | 15.5                             | -                                       | 124.5                     | 124.5                                       | 0              | -                                 | 0.00                          | 158.0                                         | - 158.0        | - 124.5                                 | -100.0%                                                    |

Figure 107. Bank - Energy budget sheet.

The Bank pays a high penalty for the air conditioning’s large contribution to overall energy demand, and the facility’s overall small size constrains cogeneration to a small-scale packaged unit supplying a single-effect absorption chiller. The chiller’s COP is the main parameter rendering cogeneration unfeasible. The School analysed in Section 10.2.3 has an

even higher proportional air conditioning load, but its size just about allows it to break even in energy terms. Also, the relatively higher operation and maintenance costs of the small engine and chiller means that there is no net cost saving in the Bank project's first three years (Figure 107 and Figure 108).

Thus, all facilities similar to the Bank cannot be considered for cogeneration. This is unfortunate as the T&TEC bills over 1998 reveal a reasonably uniform average daily consumption profile (low standard deviation) pointing to relatively simple operations at the Bank (Table 47). Despite the low annual running hours due to distinct Bank operating hours, the profile during operation is flat allowing easy cogeneration sizing. The BIC subgroup represents a significant 6.3% of all industrial D electrical energy consumption in 1998. There may well be a number of BIC facilities in T&T that are large enough to render cogeneration feasible, but the fieldwork did not determine this. This conservative evaluation rules the entire BIC subgroup out of consideration for cogeneration.

| Annual recurrent costs/savings for the cogen./heat-recovery system |                                                                     |   |         |        |         |    |            |
|--------------------------------------------------------------------|---------------------------------------------------------------------|---|---------|--------|---------|----|------------|
| <b>Costs</b>                                                       |                                                                     |   |         |        |         |    |            |
|                                                                    |                                                                     |   |         |        |         |    |            |
|                                                                    | <b>Chiller and cooling towers - water and mtce. costs</b>           |   |         |        |         |    |            |
|                                                                    | Extra annual condenser water cost per 'General data' sheet          |   |         |        |         |    |            |
|                                                                    | 20,439,932                                                          | x | 0.0035  |        | =       | \$ | 71,540     |
|                                                                    | Annual maintenance cost difference per 'General data sheet'         |   |         |        |         |    |            |
|                                                                    |                                                                     |   |         |        | =       | \$ | 9,448      |
|                                                                    | Extra annual chemical cost per 'General data' sheet                 |   |         |        |         |    |            |
|                                                                    |                                                                     |   |         |        | =       | \$ | 18,315     |
|                                                                    | Recurrent cost subtotal                                             |   |         |        |         |    | \$ 99,302  |
|                                                                    | <b>Cogen. engines - maintenance cost</b>                            |   |         |        |         |    |            |
|                                                                    | Maintenance cost per 'General data' sheet :                         |   |         | 0.0700 | \$ /kWh |    |            |
|                                                                    | 0.0700                                                              | x | 886,763 |        | =       | \$ | 62,073     |
|                                                                    | Total annual recurrent cost                                         |   |         |        |         |    | \$ 161,376 |
| <b>Savings</b>                                                     |                                                                     |   |         |        |         |    |            |
|                                                                    |                                                                     |   |         |        |         |    |            |
|                                                                    | First-year energy savings from 'Energy budget' sheet                |   |         |        |         |    | \$ 156,980 |
|                                                                    | Avoided diesel cost - boiler diesel consumption                     |   |         |        |         |    | \$ -       |
|                                                                    | <b>Net first-year savings from cogen. and absorption cooling is</b> |   |         |        |         |    |            |
|                                                                    |                                                                     |   |         |        |         | \$ | (4,396)    |

Figure 108. Bank – O&amp;M sheet.

| Period             |           |           |                     |                |                              |
|--------------------|-----------|-----------|---------------------|----------------|------------------------------|
| To                 | From      | # of days | Maximum demand, kVA | Elec. use, kWh | Average daily elec. use, kWh |
| 24-Mar-98          | 21-Feb-98 | 31        | 336                 | 162,000        | 5,226                        |
| 24-Apr-98          | 24-Mar-98 | 31        | 354                 | 164,400        | 5,303                        |
| 28-May-98          | 24-Apr-98 | 34        | 354                 | 183,000        | 5,382                        |
| 23-Jun-98          | 28-May-98 | 26        | 348                 | 135,000        | 5,192                        |
| 24-Jul-98          | 23-Jun-98 | 31        | 366                 | 161,400        | 5,206                        |
| 20-Aug-98          | 24-Jul-98 | 27        | 312                 | 120,600        | 4,467                        |
| 25-Sep-98          | 20-Aug-98 | 36        | 360                 | 194,400        | 5,400                        |
| 22-Oct-98          | 25-Sep-98 | 27        | 360                 | 144,000        | 5,333                        |
| 25-Nov-98          | 22-Oct-98 | 34        | 372                 | 164,400        | 4,835                        |
| 22-Dec-98          | 25-Nov-98 | 27        | 360                 | 124,200        | 4,600                        |
| 21-Jan-99          | 22-Dec-98 | 30        | 348                 | 145,200        | 4,840                        |
| 02-Mar-99          | 21-Jan-99 | 40        | 342                 | 192,000        | 4,800                        |
| Annual             |           | 374       |                     | 1,890,600      |                              |
| Average            |           |           | 351                 |                | 5,049                        |
| Standard deviation |           |           | 16                  |                | 323                          |
|                    |           |           | 5%                  |                | 6%                           |

Table 47. Bank – 1998 T&amp;TEC bills.

### 10.2.7 The Methanol plant

The Methanol plant is a D3 customer in the MF subgroup and operates continuously. It is a major natural gas consumer, both for processing ('process') and for heat ('fuel'). The space-conditioning load is too insignificant for consideration. The Methanol plant is one of four similar existing plants in T&T.

D3 sites are too large for the fieldwork power-monitoring meter. The Methanol plant's electricity-use data comes from the plant's own Distributed Control System (DCS), and from T&TEC. The DCS provides daily data for December 1998 (Table 48) and monthly data for a year starting March 1998 (Table 49). The site information is thus much less detailed, but because operations are so continuous and constant, and also on such a large scale, evaluating cogeneration feasibility for large, D3 petrochemical facilities is generally very simple. The analysis uses basically the same MS Excel model, with some modifications reflecting this simplicity. The DCS supplied data for Methanol Plant 1 only, but the analysis can extend to all four methanol plants.

The data show that the Plant's heat load is on average 48 times the electricity load (Table 49), so that any heat the cogenerator produces will be readily used. The average daily full-load hours are also high at 19 hours. However, the standard deviation over the year as a percentage of this is 8.3%, indicating some variation in operations over the year. Over December 1998 operation was much flatter (Table 48). Figure 109 and Figure 110 display the data in Table 48 and Table 49 respectively more clearly.



| Table 1 Daily data from the plant's DCS |                     |                                 |                      |                                  |
|-----------------------------------------|---------------------|---------------------------------|----------------------|----------------------------------|
| Sum                                     |                     |                                 | 2,785                |                                  |
| Maximum                                 | 4,608               |                                 | 92.0                 | 22.2                             |
| Average                                 | 4,182               |                                 | 89.8                 | 21.5                             |
| Standard deviation                      | 188.1               |                                 | 1.4                  | 0.7                              |
| As % of average                         | 0                   |                                 | 0.0                  | 0.0                              |
| Date                                    | Maximum demand, kVA | Cumulative total elec. use, MWh | Daily elec. use, MWh | Daily equivalent full-load hours |
| 30-Nov-98                               | 4,595               | 15,752                          |                      |                                  |
| 01-Dec-98                               | 4,432               | 15,843                          | 91.0                 | 20.5                             |
| 02-Dec-98                               | 4,186               | 15,933                          | 90.0                 | 21.5                             |
| 03-Dec-98                               | 4,184               | 16,025                          | 92.0                 | 22.0                             |
| 04-Dec-98                               | 4,167               | 16,117                          | 92.0                 | 22.1                             |
| 05-Dec-98                               | 4,050               | 16,205                          | 88.0                 | 21.7                             |
| 06-Dec-98                               | 4,062               | 16,295                          | 90.0                 | 22.2                             |

Table 48. Methanol Plant 1 – Energy Budget sheet: Table 1 - daily electricity use for December 1998 (shows only first 6 days).

| Table 2 Monthly data from plant's management records over a year |           |                      |                     |                                        |                          |           |           |                            |            |                        |
|------------------------------------------------------------------|-----------|----------------------|---------------------|----------------------------------------|--------------------------|-----------|-----------|----------------------------|------------|------------------------|
| T&TEC electricity data                                           |           |                      |                     |                                        | NGC natural gas data     |           |           | Average daily use, MWh/day |            |                        |
|                                                                  |           |                      |                     |                                        | NGC natural gas use, MWh |           |           |                            |            |                        |
| Month                                                            | # of days | Electricity use, MWh | Maximum demand, kVA | Average equivalent full-load hours/day | Process                  | Fuel      | Total     | Electricity                | Gas (fuel) | Gas (fuel)/electricity |
| Mar-98                                                           | 31        | 2,581                | 4,923               | 17                                     | 117,750                  | 80,149    | 197,900   | 83                         | 2,585      | 31.0                   |
| Apr-98                                                           | 30        | 2,581                | 4,923               | 17                                     | 354,672                  | 134,868   | 489,540   | 86                         | 4,496      | 52.2                   |
| May-98                                                           | 31        | 3,195                | 4,955               | 21                                     | 334,381                  | 143,101   | 477,482   | 103                        | 4,616      | 44.8                   |
| Jun-98                                                           | 30        | 3,058                | 4,955               | 21                                     | 368,585                  | 130,177   | 498,762   | 102                        | 4,339      | 42.6                   |
| Jul-98                                                           | 31        | 2,870                | 4,955               | 19                                     | 354,817                  | 124,212   | 479,029   | 93                         | 4,007      | 43.3                   |
| Aug-98                                                           | 31        | 2,583                | 4,955               | 17                                     | 343,432                  | 144,190   | 487,621   | 83                         | 4,651      | 55.8                   |
| Sep-98                                                           | 30        | 2,698                | 4,955               | 18                                     | 336,673                  | 134,462   | 471,135   | 90                         | 4,482      | 49.8                   |
| Oct-98                                                           | 31        | 2,222                | 4,302               | 17                                     | 204,683                  | 83,562    | 288,245   | 72                         | 2,696      | 37.6                   |
| Nov-98                                                           | 30        | 2,702                | 4,673               | 19                                     | 335,357                  | 143,861   | 479,218   | 90                         | 4,795      | 53.2                   |
| Dec-98                                                           | 31        | 2,784                | 4,608               | 19                                     | 349,567                  | 154,204   | 503,771   | 90                         | 4,974      | 55.4                   |
| Jan-99                                                           | 31        | 2,754                | 4,549               | 20                                     | 353,917                  | 157,376   | 511,292   | 89                         | 5,077      | 57.1                   |
| Feb-99                                                           | 28        | 2,401                | 4,103               | 21                                     | 292,097                  | 125,961   | 418,058   | 86                         | 4,499      | 52.5                   |
| Total                                                            | 365       | 32,431               |                     |                                        | 3,745,930                | 1,556,124 | 5,302,054 |                            |            | 48.0                   |
| Average                                                          |           | 2,703                | 4,738               | 19                                     | 312,161                  | 129,677   | 441,838   | 89                         | 4,268      | 48.0                   |
| Standard deviation                                               |           | 265                  | 295                 | 2                                      | 75,265                   | 24,558    | 97,628    | 8                          | 811        | 7.8                    |
|                                                                  |           | 9.8%                 | 6.2%                | 8.3%                                   | 24.1%                    | 18.9%     | 22.1%     | 9.4%                       | 19.0%      | 16.2%                  |

Table 49. Methanol Plant 1 – Energy Budget sheet: Table 2 - monthly energy use.

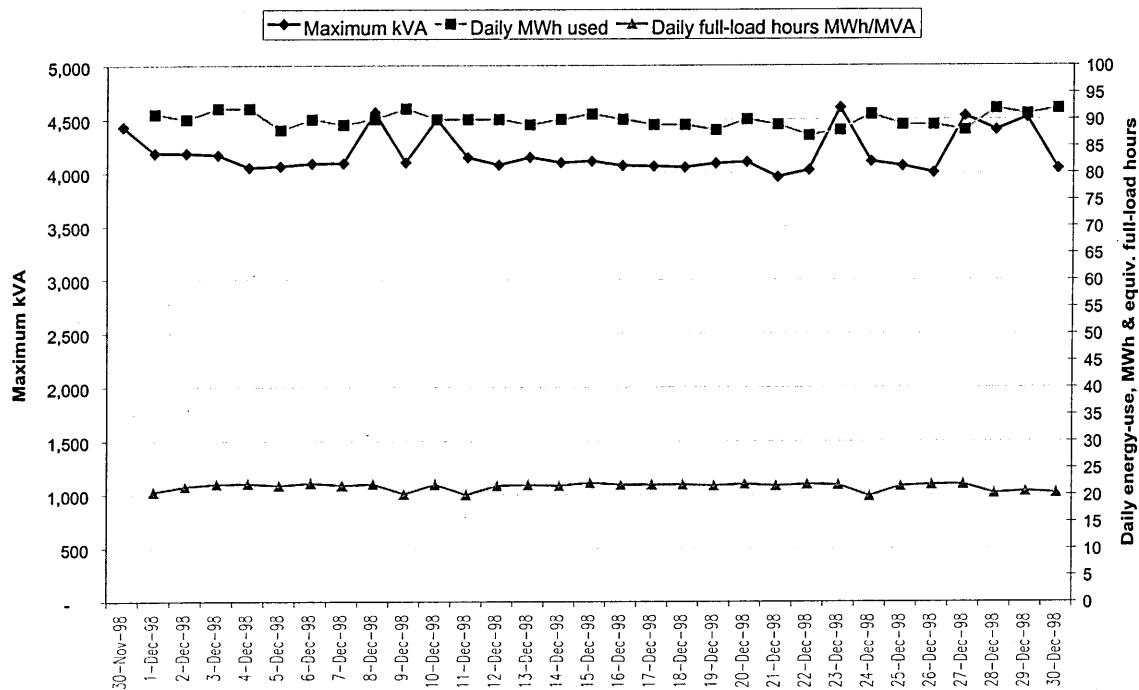


Figure 109. Methanol Plant 1 – daily energy use data for December 1998.

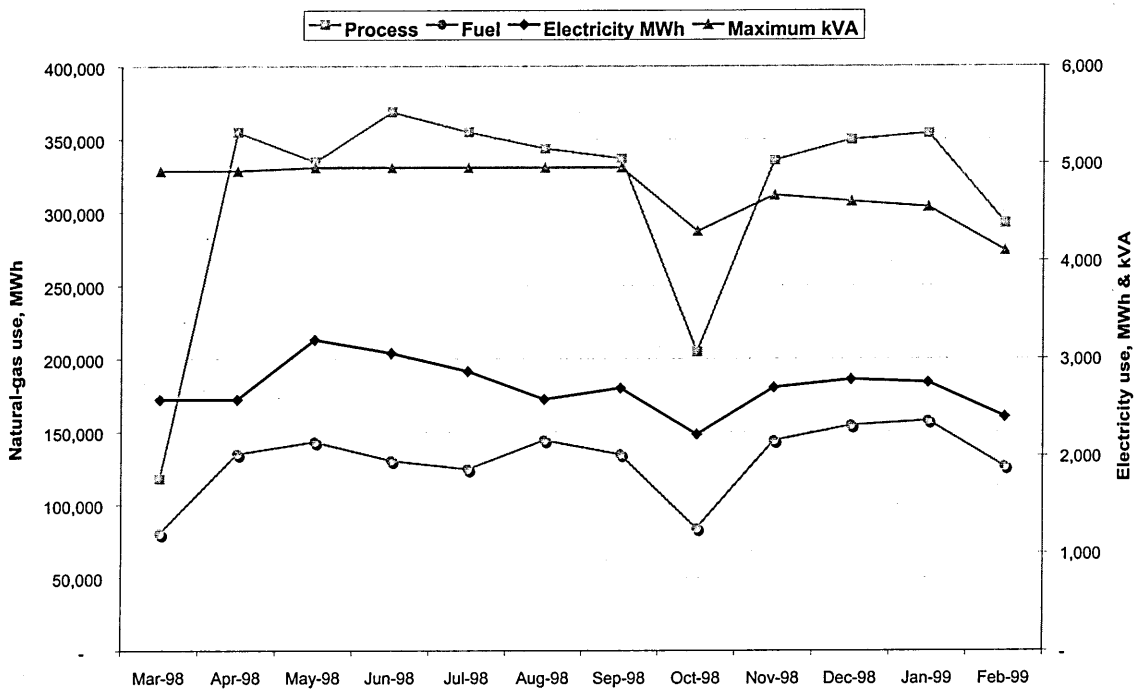


Figure 110. Methanol Plant 1 – monthly energy use data.

Figure 111 shows the resulting savings. The project is hugely profitable (Table 50).

| <b>Table 3</b>            | <b>Savings</b>                                    |  |  |                |  |
|---------------------------|---------------------------------------------------|--|--|----------------|--|
| <b>Energy bill saving</b> | <b>Methanol plant 1</b>                           |  |  |                |  |
|                           | Avgerage plant natural gas fuel use/elec. use     |  |  | 48             |  |
|                           | First-year elec. use, MWhe                        |  |  | 32,431         |  |
|                           | First-year elec. bill, TT\$                       |  |  | TT\$5,552,181  |  |
|                           | First-year on-site gas saving from cogen., MWh    |  |  | 49,660         |  |
|                           | First-year on-site gas fuel bill saving, \$TT     |  |  | TT\$945,742    |  |
|                           | First-year cogen. gas use, MWh                    |  |  | 101,347        |  |
|                           | First-year cogen. gas bill, TT\$                  |  |  | TT\$1,930,085  |  |
|                           | First-year cogenerated electricity cost, TT\$/kW  |  |  | TT\$0.0595     |  |
|                           | First-year cogen. O&M bill, TT\$                  |  |  | TT\$972,929    |  |
|                           |                                                   |  |  |                |  |
|                           | First-year cogen. saving, TT\$                    |  |  | TT\$3,594,909  |  |
|                           | as % of current electricity bill                  |  |  | 64.7%          |  |
|                           |                                                   |  |  |                |  |
|                           | <b>All Methanol plants</b>                        |  |  |                |  |
|                           | Saving per MWh electricity at Plant 1             |  |  | TT\$111        |  |
|                           | Electricity use in that year for all plants, MWhe |  |  | 114,466        |  |
|                           |                                                   |  |  |                |  |
|                           | Overall saving for all plants, TT\$               |  |  |                |  |
|                           | pro-rating to all 6 plants                        |  |  | TT\$12,688,365 |  |
|                           |                                                   |  |  |                |  |
| <b>Natural gas saving</b> | <b>Methanol plant 1</b>                           |  |  |                |  |
|                           | T&TEC primary gas use, MWh                        |  |  | 124,257        |  |
|                           | Displaced on-site gas fuel use, MWh               |  |  | 49,660         |  |
|                           | First-year cogen. gas use, MWh                    |  |  | 101,347        |  |
|                           |                                                   |  |  |                |  |
|                           | Net First-year gas saving, MWh                    |  |  | 72,570         |  |
|                           |                                                   |  |  | 58.4%          |  |
|                           | <b>All Methanol plants</b>                        |  |  |                |  |
|                           | Gas saving per MWh elec. at Plant1, MWh           |  |  | 2.24           |  |
|                           | Overall elec. use in that year, MWhe              |  |  | 114,466        |  |
|                           |                                                   |  |  |                |  |
|                           | Overall saving for all plants, MWh                |  |  |                |  |
|                           | pro-rating to all 6 plants                        |  |  | 256,138        |  |
|                           |                                                   |  |  |                |  |

Figure 111. Methanol Plant 1 – Energy budget sheet, net cogeneration savings.

| <b>Current</b>                                      |                |             |                                   |
|-----------------------------------------------------|----------------|-------------|-----------------------------------|
|                                                     | kWh            | kVA         | Annual equivalent full-load hours |
| Annual electricity use                              |                |             |                                   |
| T&TEC - 1998                                        | 32,430,964     | 4,955       | 7,272                             |
| <b>Proposed</b>                                     |                |             |                                   |
| Cogenerator size, kW <sub>e</sub>                   | 5,000          | gas turbine |                                   |
| Methanol 1 heat:electricity ratio with cogeneration | 47.95          |             |                                   |
| Cogenerator heat:electricity ratio                  | 1.53           |             |                                   |
| % difference                                        | 3031.7%        |             |                                   |
| Cogeneration mode                                   | electrical-led |             |                                   |
| Cogenerator annual equivalent full-load hours       | 6,852          |             |                                   |
| Cogenerated electricity cost, TT\$/kWh              | \$0.0595       |             |                                   |
| First-year energy bill saving, TT\$                 | \$3,594,909    |             |                                   |
| as % of T&TEC electricity bill                      | 64.7%          |             |                                   |
| Annual natural gas saving, MWh                      | 72,570         |             |                                   |
| as % of T&TEC's use for site's electricity          | 58.4%          |             |                                   |
| Payback period on minimum capital cost, years       | <5             |             |                                   |

Table 50. Methanol Plant 1 – summary statistics

### 10.2.8 The Ammonia and Urea Plant (Nitrogen plant)

The Nitrogen Plant 1 is one of six plants in T&T. They are all D3 customers in the MF subgroup, operating continuously. They are also major natural gas users, for process and fuel. Nitrogen Plant 1 is the only one independently generating some of its own electricity with a 23 MW gas turbine that it owns and operates, but it does not recover any of the heat from the turbine (i.e. no cogeneration). The Plant retains a full 23 MVA reserve capacity with T&TEC and draws any demand in excess of the turbine from the grid. This explains the very low annual equivalent full-load hours from T&TEC data in Table 51. There are two process streams, I and II, further separated into Ammonia 1, 2, and 3. The generator does not supply all processes on site.

The Plant has DCS, but only summary data for 1998, and the month of December 1998 were made available during the fieldwork. Although Nitrogen 1 is unique in producing most of its own electricity, it is otherwise very typical of all ammonia and urea plants. Table 52 and Table 53 give the available Plant energy use data and reveal that the heat/electricity ratio is over 20. Again, cogeneration is very likely feasible here as it is for Methanol, assuming a reasonably flat daily profile in the absence of confirming data.

| <b>Current</b>                                      |                |             |                                   |
|-----------------------------------------------------|----------------|-------------|-----------------------------------|
|                                                     | kWh            | kVA         | Annual equivalent full-load hours |
| Annual electricity use                              |                |             |                                   |
| T&TEC - 1998                                        | 22,240,130     | 17,366      | 1,423                             |
| <b>Proposed</b>                                     |                |             |                                   |
| Cogenerator size, kWe                               | 4,000          | gas turbine |                                   |
| Nitrogen 1 heat:electricity ratio with cogeneration | 20.88          |             |                                   |
| Cogenerator heat:electricity ratio                  | 1.53           |             |                                   |
| % difference                                        | 1263.6%        |             |                                   |
| Cogeneration mode                                   | electrical-led |             |                                   |
| Cogenerator annual equivalent full-load hours       |                |             |                                   |
| Cogenerated electricity cost, TT\$/kWh              | \$0.0595       |             |                                   |
| First-year energy bill saving, TT\$                 | \$3,923,910    |             |                                   |
| as % of T&TEC electricity bill                      | 64.7%          |             |                                   |
| Annual natural gas saving, MWh                      | 79,211         |             |                                   |
| as % of T&TEC's use for site's electricity          | 58.4%          |             |                                   |
| Payback period on minimum capital cost, years       | <4             |             |                                   |

Table 51. Nitrogen Plant 1 – summary statistics.

| <b>Table 1 Electricity use</b> |               |                        |               |                  |                |               |                |
|--------------------------------|---------------|------------------------|---------------|------------------|----------------|---------------|----------------|
| <b>Electricity</b>             | <b>Demand</b> | <b>Energy use, MWh</b> |               |                  |                |               |                |
| <b>Dec-98</b>                  | <b>kVA</b>    | <b>T&amp;TEC</b>       |               | <b>Generator</b> |                | <b>Total</b>  |                |
|                                |               | <b>Dec-98</b>          | <b>1998</b>   | <b>Dec-98</b>    | <b>1998</b>    | <b>Dec-98</b> | <b>1998</b>    |
| Ammonia 1                      | 4,500         | -                      | 1,125         | 3,089            | 34,388         | 3,089         | 35,513         |
| Ammonia 2                      | 3,750         | 2,129                  | 19,984        | 4,448            | 48,180         | 6,577         | 68,164         |
| Ammonia 3                      | 3,750         | -                      | 1,275         | 5,027            | 56,830         | 5,027         | 58,105         |
| Ammonia 3 storage              |               | 1,197                  | 13,015        | -                | -              | 1,197         | 13,015         |
| Generator                      |               | -                      | -             | 13               | 190            | 13            | 190            |
| <b>Total</b>                   | <b>12,000</b> | <b>3,326</b>           | <b>35,399</b> | <b>12,577</b>    | <b>139,588</b> | <b>15,903</b> | <b>174,987</b> |

Table 52. Nitrogen Plant 1 – Energy budget sheet: Table 1 - electricity use in 1998.

Table 54 gives some idea of the plant's operation over the whole of 1998 from the production figures. The table shows that the average monthly ammonia production is very similar to December's production. So at least December is an average month, and possibly production is fairly uniform over all months giving a flat operating profile. In the absence of more detailed data this can only be speculation. Figure 112 shows the net savings in 1998 from cogeneration. The project is hugely profitable.



| <b>Table 3</b>                  | <b>Natural gas use</b> |                  |                   |                  |
|---------------------------------|------------------------|------------------|-------------------|------------------|
| <b>Natural gas</b>              | <b>Process I</b>       |                  | <b>Process II</b> |                  |
|                                 | <b>Dec-98</b>          | <b>1998</b>      | <b>Dec-98</b>     | <b>1998</b>      |
| Electricity use, MWh            | 6,577                  | 68,164           | 5,027             | 58,106           |
| Gas receipts, MWh:              | 539,352                | 6,095,439        | 471,854           | 5,342,859        |
| Gas fuel use, MWh               | 228,928                | 2,493,853        | 104,132           | 1,159,880        |
| Gas process use, MWh            | 310,424                | 3,601,586        | 367,722           | 4,182,979        |
| Subtotal                        | 539,352                | 6,095,439        | 471,854           | 5,342,859        |
| Gas generator use, MWh          | 53,979                 | 621,625          | -                 | -                |
| Gas fuel/generator use          | 4.2                    | 4.0              |                   |                  |
| <b>Total gas for energy use</b> | <b>282,907</b>         | <b>3,115,478</b> | <b>104,132</b>    | <b>1,159,880</b> |
| <b>Total gas use</b>            | <b>593,331</b>         | <b>6,717,065</b> | <b>471,854</b>    | <b>5,342,859</b> |

- Note:
1. Gas receipts are for fuel and process only and NOT for generator.
  2. The fuel use is >4 times the generator gas use, and generator efficiency is 23%

Table 53. Nitrogen Plant 1 – Energy budget sheet: Table 3 – natural-gas use in 1998.

| <b>Table 4</b>              | <b>Production</b> |             |                   |             |               |             |
|-----------------------------|-------------------|-------------|-------------------|-------------|---------------|-------------|
| <b>Production</b>           | <b>Process I</b>  |             | <b>Process II</b> |             | <b>Total</b>  |             |
|                             | <b>Dec-98</b>     | <b>1998</b> | <b>Dec-98</b>     | <b>1998</b> | <b>Dec-98</b> | <b>1998</b> |
| Ammonia production, MT      | 40,797            | 457,444     | 45,779            | 530,803     | 86,576        | 988,247     |
| Avg. monthly production, MT |                   | 38,120      |                   | 44,234      |               | 82,354      |
| Dec'98 % difference         | 7.0%              |             | 3.5%              |             | 5.1%          |             |

Table 54. Nitrogen Plant 1 – Energy budget sheet: Table 4 – production in 1998.

| <b>Table 5 Savings</b>    |                                                     |  |  |                |
|---------------------------|-----------------------------------------------------|--|--|----------------|
| <b>Energy bill saving</b> |                                                     |  |  |                |
|                           | <b>Nitrogen plant 1</b>                             |  |  |                |
|                           | Avgerage plant natural-gas fuel use/electricity use |  |  | 20.9           |
|                           | First-year grid-electicity use, MWh                 |  |  | 35,399         |
|                           | First-year grid-electricity bill, TT\$              |  |  | TT\$6,060,309  |
|                           | First-year on-site gas fuel saving, MWh             |  |  | 54,205         |
|                           | First-year on-site gas fuel bill saving, \$TT       |  |  | TT\$1,032,295  |
|                           | First-year new cogen. gas use, MWh                  |  |  | 110,622        |
|                           | First-year new cogen. gas bill, TT\$                |  |  | TT\$2,106,724  |
|                           | First-year cogenerated elec. cost, TT\$/kWh         |  |  | TT\$0.0595     |
|                           | First-year new cogen. O&M bill, TT\$                |  |  | TT\$1,061,970  |
|                           | First-year new cogen. saving, TT\$                  |  |  | TT\$3,923,910  |
|                           | as % of current electricity bill                    |  |  | 64.7%          |
|                           | <b>All Nitrogen plants</b>                          |  |  |                |
|                           | Saving per MWhe grid electricity                    |  |  | TT\$111        |
|                           | Overall grid-electricity use in that year, MWhe     |  |  | 186,037        |
|                           | Overall saving for all plants, TT\$                 |  |  |                |
|                           | pro-rating to all 6 plants                          |  |  | TT\$20,621,826 |
| <b>Natural gas saving</b> |                                                     |  |  |                |
|                           | <b>Nitrogen plant 1</b>                             |  |  |                |
|                           | T&TEC primary gas use, MWh                          |  |  | 135,628        |
|                           | Displaced on-site gas fuel use, MWh                 |  |  | 54,205         |
|                           | First-year new cogen. gas use, MWh                  |  |  | 110,622        |
|                           | Net annual gas saving, MWh                          |  |  | 79,211         |
|                           | as % of T&TEC primary gas use                       |  |  | 58.4%          |
|                           | <b>All Nitrogen plants</b>                          |  |  |                |
|                           | Gas saving per MWhe grid-electricity, MWh           |  |  | 2.2            |
|                           | Overall grid-electricity use in that year, MWhe     |  |  | 186,037        |
|                           | Overall saving for all plants, MWh                  |  |  |                |
|                           | pro-rating to all 6 plants                          |  |  | 416,289        |

Figure 112. Nitrogen Plant 1 – Energy budget sheet: Table 5 - net cogeneration savings.

### 10.2.9 The Oil Refinery

The Refinery is a large, petrochemical D3 customer in the OIL subgroup and operates continuously. It has a metered natural gas supply, but is not a major user. This is a D3 site

for which the least amount of information was available during the fieldwork. Yet cogeneration is likely to be very feasible here again. It is also important to evaluate the refinery as it is a large petrochemical facility where *electricity* use dominates, unlike for Methanol and Ammonia. The electricity/heat ratio is 8.5 (Figure 113).

|                           |                                                        |  |  |  |                      |
|---------------------------|--------------------------------------------------------|--|--|--|----------------------|
| <b>From field data:</b>   |                                                        |  |  |  |                      |
|                           | Average natural gas demand, kW                         |  |  |  | 5,024                |
|                           | Average electricity demand, kVA                        |  |  |  | 42,678               |
|                           | Electricity demand/gas demand                          |  |  |  | 8.5                  |
|                           | Continuous operation - annual operating hours          |  |  |  | 8,760                |
|                           |                                                        |  |  |  |                      |
| <b>Energy bill saving</b> | <b>For all refineries</b>                              |  |  |  |                      |
|                           | Average gas fuel demand, MW                            |  |  |  | 5.02                 |
|                           | Cogen. size to provide this thermal load, MWe          |  |  |  | 3.28                 |
|                           | First-year electricity from cogen., MWhe               |  |  |  | 28,743               |
|                           | First-year electricity bill saving, TT\$               |  |  |  | TT\$4,920,769        |
|                           | First-year heat from cogen., MWth                      |  |  |  | 44,012               |
|                           | First-year gas fuel bill saving, \$TT                  |  |  |  | TT\$838,189          |
|                           | First-year cogen. gas use, MWh                         |  |  |  | 89,821               |
|                           | First-year cogen. gas bill, TT\$                       |  |  |  | TT\$1,710,590        |
|                           | First-year cogenerated electricity cost, TT\$/kWh      |  |  |  | TT\$0.0595           |
|                           | First-year cogen. O&M bill, TT\$                       |  |  |  | TT\$862,284          |
|                           |                                                        |  |  |  |                      |
|                           | First-year cogen. saving, TT\$                         |  |  |  | <b>TT\$3,186,084</b> |
|                           | as % of current electricity bill                       |  |  |  | 9.0%                 |
| <b>Natural gas saving</b> | <b>For all refineries</b>                              |  |  |  |                      |
|                           | T&TEC primary gas use, MWh                             |  |  |  | 110,126              |
|                           | Displaced on-site gas fuel use, MWh                    |  |  |  | 44,012               |
|                           | First-year cogen. gas use, MWh                         |  |  |  | 89,821               |
|                           |                                                        |  |  |  |                      |
|                           | Net first-year gas saving, MWh                         |  |  |  | <b>64,317</b>        |
|                           | as % of T&TEC gas-use for site's displaced electricity |  |  |  | 58.4%                |

Figure 113. Refinery – Energy budget sheet: field data and net cogeneration savings.

The field data in Figure 113 is the extent of the information on the Refinery. NGC meters provide the average natural gas demand (as fuel for heating) in kW over the year; T&TEC provide the overall annual electricity use in kWh and the maximum demand in kVA. Air conditioning at the Refinery must certainly account for some of the electricity use, but it is not likely to be a significant part of the Refinery's overall consumption. A significant air conditioning load would allow a bolder cogeneration sizing as the site would readily use any amount of cogenerated electricity because of its large electricity:heat ratio. It would

also reduce that ratio by reducing the site's overall electricity demand, and generate more savings. Air conditioning is ignored in the absence of relevant data.

Cogeneration at the Refinery is simply sized to exactly supply the average heat load, taken to be the site's fuel demand. Thus, the unit is assumed to run continuously at full load. The project reduces primary natural gas consumption associated with the Refinery and is hugely profitable (Table 55).

| <b>Current</b>                                    |             |             |                                   |
|---------------------------------------------------|-------------|-------------|-----------------------------------|
|                                                   | kWh         | kVA         | Annual equivalent full-load hours |
| Annual electricity use                            |             |             |                                   |
| T&TEC - 1998                                      | 207,073,646 | 42,678      | 5,391                             |
| <b>Proposed</b>                                   |             |             |                                   |
| Cogenerator size, kW <sub>e</sub>                 | 4,000       | gas turbine |                                   |
| Refinery heat:electricity ratio with cogeneration | 0.12        |             |                                   |
| Cogenerator heat:electricity ratio                | 1.53        |             |                                   |
| % difference                                      | -92.3%      |             |                                   |
| Cogeneration mode                                 | heat-led    |             |                                   |
| Cogenerator annual equivalent full-load hours     |             |             |                                   |
| Cogenerated electricity cost, TT\$/kWh            | \$0.0595    |             |                                   |
| First-year energy bill saving, TT\$               | \$3,186,084 |             |                                   |
| as % of T&TEC electricity bill                    | 9.0%        |             |                                   |
| Annual natural gas saving, MWh                    | 64,317      |             |                                   |
| as % of T&TEC's use for site's electricity        | 58.4%       |             |                                   |
| Payback period on minimum capital cost, years     | <5          |             |                                   |

Table 55. Refinery – summary statistics.

### 10.3 The collated results

Assuming that the feasibility study for a site can apply to its entire subgroup, the results for each study can be extrapolated proportionally to its subgroup by comparing electricity use, or maximum demand over a year, i.e. using 1998 T&TEC data. The fieldwork metered data is useful for cogeneration sizing in each study as it reveals the daily demand profiles and energy use, but overall yearly data from T&TEC is best for extrapolating the results. Cogenerator size depends on the base-load demand over a day, and not so much the peak demand of that day. So all statistics derive from the site's energy use and not the maximum demand. Table 56 collates the relevant energy statistics for each cogeneration study.

| Subgroup | Site                 | T&TEC electricity data |                  | Cogeneration:                     |                      |                            | Annual natural gas saving: |                                                                 | Average air conditioning elec. use/total elec. use, % |
|----------|----------------------|------------------------|------------------|-----------------------------------|----------------------|----------------------------|----------------------------|-----------------------------------------------------------------|-------------------------------------------------------|
|          |                      | Maximum demand kVA     | Energy uses, MWh | Annual generated electricity, MWh | Engine capacity, kWe | Engine type                | MWh                        | as a % of T&TEC's gas-use for generating the site's electricity |                                                       |
| MF       | Ammonia & urea plant | 53,228                 | 186,036          | 35,399                            | 4,000                | gas turbine                | 416,288                    | 58.4                                                            |                                                       |
| MF       | Methanol plant       | 19,905                 | 114,466          | 32,430                            | 5,000                | gas turbine                | 256,137                    | 58.4                                                            |                                                       |
| OIL      | Refinery             | 42,678                 | 207,074          | 28,742                            | 4,000                | gas turbine                | 64,316                     | 58.4                                                            |                                                       |
| MIG      | Hospital             | 4,294                  | 21,982           | 23,014                            | 3,500                | gas turbine                | 46,219                     | 39.5                                                            | 16.2                                                  |
| FI       | Mill                 | 3,676                  | 14,832           | 24,200                            | 1,500                | gas turbine                | 27,438                     | 39.9                                                            |                                                       |
| BUS      | Mall                 | 2,310                  | 10,350           | 7,903                             | 1,400                | gas turbine                | 11,063                     | 23.3                                                            | 39.0                                                  |
| HL       | Hotel                | 1,920                  | 11,236           | 9,828                             | 1,200                | gas turbine                | 6,661                      | 15.5                                                            | 30.0                                                  |
| SCH      | School               | 4,656                  | 21,302           | 22,000                            | 1,700                | gas turbine                | 55                         | 0.1                                                             | 63.8                                                  |
| BIC      | Bank                 | 360                    | 1,738            | 1,484                             | 170                  | internal combustion engine | -1,690                     | -23.5                                                           | 61.0                                                  |

Table 56. Collated energy statistics at the sites studied, with and without cogeneration.

The natural gas saving in Table 56 and Table 57 is the primary energy saving that results from cogenerating power at a site as opposed to generating it at the central T&TEC utility. The extrapolated 2,246,507,648 kWh natural gas saving in Table 57 is the potential fuel saving to T&TEC if all customers in the subgroups adopted cogeneration in 1998. The 91,500 kWe is the avoided central utility generating capacity from such cogeneration, about 8% of T&TEC's 1,188.7 MWe installed capacity in 1998 (Sitahal and Chong, 1998).

| Subgroup | Site                 | Site annual natural gas saving: | 1998 energy use (from T&TEC), MWh |           | Extrapolated total Subgroup annual natural-gas saving | Extrapolated total Subgroup cogen. capacity |
|----------|----------------------|---------------------------------|-----------------------------------|-----------|-------------------------------------------------------|---------------------------------------------|
|          |                      | MWh                             | Site                              | Subgroup  | MWh                                                   | kWe                                         |
| MF       | Ammonia & urea plant | 416,288                         | 186,036                           |           |                                                       |                                             |
|          | Methanol plant       | 256,137                         | 114,466                           |           |                                                       |                                             |
|          | Subtotal             | 672,425                         | 300,502                           | 600,527   | 1,343,782                                             | 20,139                                      |
| OIL      | Refinery             | 64,316                          | 207,074                           | 270,152   | 83,908                                                | 5,218                                       |
| MIG      | Hospital             | 46,219                          | 21,982                            | 129,669   | 272,641                                               | 20,646                                      |
| FI       | Mill                 | 27,438                          | 14,832                            | 144,829   | 267,918                                               | 14,647                                      |
| BUS      | Mall                 | 11,063                          | 10,350                            | 241,221   | 257,846                                               | 32,629                                      |
| HL       | Hotel                | 6,661                           | 11,236                            | 34,260    | 20,311                                                | 3,659                                       |
| SCH      | School               | 55                              | 21,302                            | 38,899    | 101                                                   | 3,104                                       |
| BIC      | Bank                 | -1,690                          | 1,738                             | 118,572   |                                                       | 11,597                                      |
| Total    |                      | 826,488                         | 589,017                           | 1,578,130 | 2,246,508                                             | 91,500                                      |

Table 57. Extrapolated energy statistics for studied subgroups.



Table 58 shows how the potential conservative natural gas saving from industry-wide cogeneration compares with electricity use in industry and overall natural gas use in T&T. The 13.5% saving in natural gas used to generate all electricity in T&T, from adopting cogeneration in the industrial sector alone, is significant. The industrial sector in 1998 used 43% of all electricity (T&TEC, 1999) and there could conceivably be more scope for cogeneration in the light-commercial and residential sectors, using district cooling for example. There is also scope for cogeneration at the T&TEC generating facilities themselves.

|                                     |                                      |                                                       |                         |                           |                                                                                          |                                                                      |
|-------------------------------------|--------------------------------------|-------------------------------------------------------|-------------------------|---------------------------|------------------------------------------------------------------------------------------|----------------------------------------------------------------------|
|                                     |                                      | T&TEC primary gas use, kWh (Sitahal and Chong, 1998): |                         |                           |                                                                                          |                                                                      |
|                                     | Cogen.<br>natural gas<br>saving, kWh | for<br>subgroups                                      | for all D<br>industrial | for the entire<br>country | Country's total<br>natural gas use<br>(power, fuel,<br>process), kWh<br>(BP Amoco, 2000) | Country's proven<br>natural gas<br>reserves, kWh<br>(BP Amoco, 2000) |
| 1998                                |                                      |                                                       |                         |                           |                                                                                          |                                                                      |
|                                     | 2,246,507,648                        | 6,039,501,972                                         | 7,210,114,804           | 16,700,726,903            | 90,052,356,021                                                                           | 5,445,026,178,010                                                    |
| Cogen. natural gas<br>saving as a % |                                      | 37.2%                                                 | 31.2%                   | 13.5%                     | 2.5%                                                                                     | 0.04%                                                                |

Table 58. Cogeneration natural gas saving – relative importance.

Although cogeneration is significant to electricity use, it makes little impact on overall national energy use in T&T, and even less on overall natural-gas use. In 1997 electricity generation accounted for 23.4% of all natural gas use (NGC, 1998). Table 58 shows that natural gas saving from industrial-sector cogeneration is only 2.5% of 1998 overall natural gas use (for power, fuel and process), and just 0.04% of the proven natural gas reserves in 1998. Cogeneration would hardly affect the reserves/production (R/P) ratio.

Table 60 presents each feasibility study's economics. Chapter 9 explains the uncertainty in determining discount rate. In analysing LNG economics, Ram (2000) uses lower and upper discount-rate estimates of 10% and 14% respectively, to determine NPV. Section 10.5 compares cogeneration to Ram's LNG analysis, so the NPVs presented in Table 60 are based on the same discount rates. The middle of this range, 12%, can be taken as the project's hurdle rate

There is also some uncertainty in determining all of the costs in the absence of competitive commercial quotations for all sizes and combinations: capital for both cogeneration units and air conditioning, and cogeneration maintenance cost. Competitive quotations also vary for the same project (see Chapter 9). So Table 60 shows the lowest cost estimate for each capital and maintenance cost, and the amount each can vary for a 12% IRR. This gives an idea of the margin for error in each estimate at a time. However, it cannot give an estimate of a national cogeneration-programme's overall cost. The lowest-estimate capital cost certainly underestimates the project's cost as it includes only the installed cost of the cogenerator and the chiller. Even so, of the feasible studies, the School is the only

borderline case, with a negative NPV at 14% discount rate and lowest capital cost. Again, this results from its relatively high cooling load.

Table 59 shows industrial cogeneration's economics extrapolated from the individual feasibility studies to their subgroups. The figures for total NPV and capital costs are relevant to *companies* in the industrial sector, but not directly to T&T as a nation. The figures give an idea of the amount of cogeneration-related business activity at the industry level, and would enhance those businesses where it is profitable and so contribute to overall GDP. There would also be a saving to the T&TEC utility through reduced natural-gas use and avoided future generating capacity. Most of the equipment would have to be imported, and the net effect on T&T is unclear from Table 59. The benefit to the *country* from cogeneration natural-gas saving can be determined using the natural-gas value from Ram's (2000) evaluation (see Section 10.5).

| Subgroup     | Site                 | NPV, TT\$, at the stated discount rate |             | Capital cost               |                     |            |
|--------------|----------------------|----------------------------------------|-------------|----------------------------|---------------------|------------|
|              |                      | 10%                                    | 14%         | lowest cost estimate, TT\$ | for a 12% IRR, TT\$ | % increase |
| MF           | Ammonia & urea plant |                                        |             |                            |                     |            |
| MF           | Methanol plant       |                                        |             |                            |                     |            |
| MF           | Subtotal             | 70,906,666                             | 38,400,673  | 71,942,837                 | 159,627,745         | 122%       |
| OIL          | Refinery             | 19,700,509                             | 13,138,967  | 7,827,715                  | 24,520,318          | 213%       |
| MIG          | Hospital             | 86,190,526                             | 45,280,647  | 94,382,689                 | 123,394,022         | 31%        |
| FI           | Mill                 | 91,104,352                             | 55,138,523  | 64,615,216                 | 183,060,298         | 183%       |
| BUS          | Mall                 | 159,866,896                            | 39,709,743  | 392,174,192                | 547,469,993         | 40%        |
| HL           | Hotel                | 20,756,372                             | 9,896,121   | 27,593,705                 | 38,013,801          | 38%        |
| SCH          | School               | 5,069,866                              | -3,100,469  | 33,666,170                 | 34,594,124          | 3%         |
| BIC          | Bank                 | -58,867,739                            | -64,604,875 |                            |                     |            |
| <b>Total</b> |                      | 453,595,187                            | 198,464,205 | 692,202,525                | 1,110,680,302       | 60%        |

Table 59. Extrapolated cogeneration economic statistics for studied subgroups.

| Subgroup | Site                 | NPV, TT\$, at discount rate: |            | Capital cost         |                     |            | Unit cogen. capital cost (installed) |                             |            | Unit absorption chiller cost (installed) |                            |            | Cogen. maintenance cost       |                             |            |
|----------|----------------------|------------------------------|------------|----------------------|---------------------|------------|--------------------------------------|-----------------------------|------------|------------------------------------------|----------------------------|------------|-------------------------------|-----------------------------|------------|
|          |                      | 10%                          | 14%        | first estimate, TT\$ | for a 12% IRR, TT\$ | % increase | lowest estimate, TT\$ per kWe        | for a 12% IRR, TT\$ per kWe | % increase | lowest estimate, TT\$ per kW             | for a 12% IRR, TT\$ per kW | % increase | lowest estimate, TT\$ per kWh | for a 12% IRR, TT\$ per kWh | % increase |
| MF       | Ammonia & urea plant | 20,103,293                   | 11,773,483 | 16,000,000           | 41,639,249          | 160.2%     | 4,000                                | 10,410                      | 160.3%     |                                          |                            |            | 0.0300                        | 0.1042                      | 247.3%     |
|          |                      |                              |            |                      |                     |            |                                      |                             |            |                                          |                            |            |                               |                             |            |
| MF       | Methanol plant       | 15,378,210                   | 7,442,109  | 20,000,000           | 38,238,041          | 91.2%      | 4,000                                | 7,648                       | 91.2%      |                                          |                            |            | 0.0300                        | 0.0877                      | 192.3%     |
|          |                      |                              |            |                      |                     |            |                                      |                             |            |                                          |                            |            |                               |                             |            |
| FI       | Mill                 | 15,100,581                   | 10,071,112 | 6,000,000            | 26,510,564          | 341.8%     | 4,000                                | 17,674                      | 341.9%     |                                          |                            |            | 0.0300                        | 0.1895                      | 531.7%     |
| OIL      | Refinery             | 14,611,243                   | 7,676,094  | 16,000,000           | 33,652,560          | 110.3%     | 4,000                                | 8,413                       | 110.3%     |                                          |                            |            | 0.0300                        | 0.0938                      | 212.7%     |
| HL       | Hotel                | 9,460,230                    | 5,745,097  | 6,617,443            | 18,930,928          | 186.1%     | 4,000                                | 14,261                      | 256.5%     | 798                                      | 6,176                      | 673.9%     | 0.0300                        | 0.1851                      | 517.0%     |
| MIG      | Hospital             | 7,061,496                    | 1,856,543  | 16,826,905           | 23,490,137          | 39.6%      | 4,000                                | 5,904                       | 47.6%      | 798                                      | 2,679                      | 235.7%     | 0.0300                        | 0.0601                      | 100.3%     |
| BUS      | Mall                 | 7,054,043                    | 3,431,966  | 9,049,781            | 17,107,071          | 89.0%      | 4,000                                | 9,755                       | 143.9%     | 798                                      | 2,642                      | 231.1%     | 0.0300                        | 0.1351                      | 350.3%     |
| SCH      | School               | 3,608,474                    | -1,069,223 | 18,436,644           | 20,092,594          | 9.0%       | 4,000                                | 4,974                       | 24.4%      | 798                                      | 914                        | 14.5%      | 0.0300                        | 0.0513                      | 71.0%      |
| BIC      | Bank                 | -780,033                     | -884,408   |                      |                     |            |                                      |                             |            |                                          |                            |            |                               |                             |            |

Table 60. Collated cogeneration economic statistics at the studied sites.

## 10.4 The true value of natural gas

The collated results from the cogeneration analysis provide a conservative estimate of how much of the natural gas resource such a policy would save, and the costs and benefits to individual industrial users and user subgroups. A national energy policy would need to determine the costs and benefits to the country as a whole to compare cogeneration to other energy policy measures. Ram's (2000) analysis for LNG demonstrates the procedure.

The fair rate of return to a society from a depletable, finite natural resource like natural gas, i.e. the *rent* derived from it, depends upon (Ram, 2000):

- The present and future value of the proven and probable reserves.
- The cost of production.
- Market accessibility.
- Access to capital.
- The inter-generational component of fiscal planning.

Each different use for natural gas values it differently, and natural gas has many uses: fuel for heating, generating power, cogeneration; feedstock in many processes; primary export commodity. Generally, the highest value uses are: peak-power generation when it replaces dirtier fuels; household distribution (replacing LPG, kerosene, and electricity); and producing methanol. The lowest value use is for export as LNG (Ram, 2000). Chapter 6 showed that LNG in the buyer's country has to compete with other fuels, which sets a low ceiling on the natural-gas value via netback pricing.

On top of this netback valuation there is a *depletion premium* that adds to the resource's value. This relates to how fast a particular use for the finite resource depletes that resource, and is a function of resource *time phasing* (Ram, 2000). Time phasing recognises that a natural resource left in place can appreciate in value. In the long term, natural-gas price will only rise due to its environmental benefits compared with other fossil fuels, so there is an opportunity cost to using it now and not having it later. Allocating a substantial share of known reserves to a project influences the reserves/production (R/P) ratio and puts a strain on other users, so any new project must estimate the net economic cost of natural gas not being available for alternative uses. Due to time phasing a project's NPV may increase or decrease by delaying project implementation. Political considerations may favour early project starts. In T&T natural gas is primarily a foreign-exchange earner.

## 10.5 Comparing LNG and cogeneration policies

T&T national energy policy should be concerned with effective rent capture and rate of return to the resource's owner, i.e. the country's citizens represented by the Government (GOTT). Therefore any user must be charged the true economic cost of using the depletable resource. The *user cost*, i.e. the cost to the resource owner of depleting that resource, must be properly estimated to optimise using the depletable resource. For example, T&T LNG is currently sold to Spain and USA where it offsets CO<sub>2</sub> emissions from the more polluting fossil fuels it replaces. The cost to the buyer should include the

current and future value of this. The focus is on LNG as it is the single largest use for T&T's natural gas and significantly reduces the R/P ratio from 48 years to 27 years (2000 figures) (Ram, 2000).

The user cost dictates that any individual cogeneration project that results in an overall *increase* in primary energy use should not be pursued. The project may deliver savings on the energy bill at that specific site, due to the difference between national gas and electricity utility prices, but only because those prices do not incorporate the user cost.

### 10.5.1 Estimating the rent from LNG

Ram (2000) determines the netback natural gas value from LNG using: the natural gas production cost; forecasted export-market prices; contracted natural gas volume over the project life; capital and operating costs over the project life; gas lost through processing and transport. He concluded that a 20-year project life from 1999 to 2020 using a 10% discount rate would deliver a gas netback value for LNG of US\$0.0047/kWh, i.e. what the project could expect to pay for natural gas supplied to the LNG plant. This is for the single-train LNG plant that began operations in 1999. The present value of the project's revenue streams over its life is US\$8.8 billion with US\$6.5 billion NPV. The estimated GOTT revenues over the entire project are US\$6 billion with US\$2.3 billion present value. The corresponding simple gas netback value to the GOTT is US\$0.0022/kWh, less than half of what the project could expect to pay for gas.

### 10.5.2 Incorporating user costs

LNG user costs must be determined to estimate the rate of return of natural gas in LNG to T&T, which is the resource's true value to the GOTT. Ram's (2000) evaluation uses year-2000 figures for reserves at 603.4 billion m<sup>3</sup>, with gas contracted to LNG at 255.5 billion m<sup>3</sup> (42.3%). It considers three scenarios:

- A. Natural gas consumption remains constant at 4.7 billion m<sup>3</sup> per annum, and reserves taken as proven only.
- B. Conservative 5% escalation in consumption for all natural gas use, a 50% probability of recovering probable reserves, and 25% of recovering possible reserves leading to a 696.9 billion m<sup>3</sup> reserve estimate.
- C. Same 5% escalation with 100% probability of recovering all reserves (probable and possible) yielding an 838.5 billion m<sup>3</sup> reserve estimate.

Table 61 shows the resulting user costs and the corresponding benefit/cost ratios given a US\$0.0022/kWh LNG simple gas netback value (benefit) to the GOTT. The benefit/cost ratio indicates the net rate of return to the GOTT:

$$\text{benefit / cost ratio, \%} = \left[ \frac{\text{benefit}}{\text{cost}} - 1 \right] \times 100$$

|                                                               | Scenario A | Scenario B | Scenario C | Average |
|---------------------------------------------------------------|------------|------------|------------|---------|
| Total reserves, 10 <sup>9</sup> m <sup>3</sup>                | 603.4      | 696.9      | 838.5      |         |
| Natural gas contracted to LNG, 10 <sup>9</sup> m <sup>3</sup> | 255.5      | 255.5      | 255.5      |         |
| Time to depletion, years                                      | 26         | 19         | 23         |         |



|                                       |        |        |        |        |
|---------------------------------------|--------|--------|--------|--------|
| User cost with LNG, US\$/kWh          | 0.0021 | 0.0043 | 0.0030 |        |
| Time to depletion without LNG, years  | 45     | 26     | 28     |        |
| User cost without LNG, US\$/kWh       | 0.0003 | 0.0022 | 0.0018 |        |
| Hence, user cost due to LNG, US\$/kWh | 0.0018 | 0.0021 | 0.0012 | 0.0017 |
| Benefit/cost                          | 21%    | 7%     | 86%    | 30%    |

Table 61. Natural gas user cost (Ram, 2000).

The costs include user costs, subsidies, and project externalities. One externality is the project's effect on the immediate environment (e.g. the plant is built on a popular beach that is no longer available for recreation). The benefit/cost ratios in Table 61 incorporate only the user costs, and show that the rate of return could range from 7% to 86%. This must be compared to the return to the project shareholders to determine if this is the optimum benefit from the resource.

User costs occur throughout the project's life, and depreciating the project's capital over 20 years in twenty equal amounts yields (Ram, 2000):

- A US\$0.0009/kWh netback gas cost to the project, i.e. the cost per kWh of gas liquefied over the project's lifetime.
- A US\$0.0053/kWh netback gas value to the project, i.e. the revenue to the project per kWh.

Given that the GOTT takes US\$0.0022/kWh, the net natural gas value to the shareholder is US\$0.0031/kWh, and the benefit/cost rate of return is 344%. Over the three Scenarios in Table 61 this ranges from 56% to 344%. Even if a third is taken off for errors, it is still over 200% to the project's private investors (Ram, 2000). The 344% best-case rate of return from Scenario C compares with the best GOTT return of 86%. Scenario B is the most realistic, so effectively the rate of return to T&T is 7%, compared with 56% to the project shareholders.

The LNG project thus represents insufficient rent capture from the natural gas resource. The high return to the project shareholders compared with the GOTT's return, suggests that the project is paying too low a price for the gas. The policy makers have not identified the buyer's true willingness to pay for the gas and as a result exploiting the resource does not benefit its owners to the extent that it can.

If the GOTT charges the LNG project the full US\$0.0047/kWh, the value to the shareholder drops to US\$0.0006/kWh, which is less than the US\$0.0009/kWh netback gas cost to the project. This would render the project unfeasible. The GOTT can charge at a level that evens out the returns to both the country and the shareholders. Using the average US\$0.0017/kWh user cost due to LNG in Table 61, this charge would be US\$0.0035/kWh.

### 10.5.3 Natural gas saving in dollars from cogeneration

Table 58 shows that the conservative estimate of cogeneration primary natural gas energy savings for generating all D-industrial electricity is ~2.2 billion kWh, or 31.2%. Other electricity rate categories, e.g. light commercial B and residential A, cannot expect the same savings level but there will be some saving. So the results from evaluating industrial electricity cannot simply extrapolate to all other users. The 13.5% saving in natural gas used to generate all electricity in T&T, from adopting cogeneration in the D-industrial sector alone, is significant. The industrial sector in 1998 used 43% of all electricity (T&TEC, 1999) and there could conceivably be more scope for cogeneration in the light-commercial and residential sectors, using district cooling for example. There is also scope for cogeneration at the T&TEC generating facilities themselves. Despite paying a penalty for integration with absorption cooling for a large portion of electricity users, a cogeneration policy is on the whole significantly more energy efficient than the existing energy-supply regime.

Table 62 shows the dollar value of the natural gas saving from cogeneration using both derived gas netback values from the LNG analysis in Section 11.5.2. Simply using 1998 saving over 20 years, the resulting value can be compared to US\$6 billion revenues from the single LNG train over 20 years, i.e. both figures are just the sum of all revenue streams over the projects' lifetimes and not present value calculations. Cogeneration revenues are about 3% of LNG revenues. Cogeneration as assessed in D-industrial customers alone, would use about 2.7 billion kWh natural gas per annum, compared to about 48.1 billion kWh for the single LNG train, about 6%. So the two technologies would use natural gas on very different scales in T&T.

| 1998                                   | Gas value, US\$/kWh |               |
|----------------------------------------|---------------------|---------------|
|                                        | \$0.0047            | \$0.0035      |
| <b>Cogen. natural gas saving, US\$</b> | \$10,558,586        | \$7,862,777   |
| <b>per kWe cogen. capacity</b>         | \$115               | \$86          |
| <b>Saving over 20 years, US\$</b>      | \$211,171,719       | \$157,255,535 |

Table 62. Cogeneration natural gas saving in US dollars

More fundamental than the difference in scale is the difference in philosophy between cogeneration and LNG, i.e. conservation vs. depletion. They are opposites: cogeneration is entirely about optimising energy-use efficiency and using a finite natural resource as carefully as possible, whereas LNG is selling that resource wholesale to quickly relieve pressures on the national economy. Admittedly, in some cases absorption cooling renders cogeneration the same as, or worse off, than the conventional energy supply (e.g. the Bank and School case studies). Considering just the dollar value of natural gas saving, cogeneration is not especially profitable compared to LNG, though this ignores cogeneration's contribution to overall economic activity (see Section 11.3). LNG's return to T&T is insufficient because the GOTT undercharges for the natural gas, and it also rapidly depletes the resource; its revenue

comes at too high a price to the country. A national cogeneration policy saves the resource (energy savings at some individual sites are as high as 60%), but on such a different scale as to hardly offset LNG's wastefulness. This ultimately results from the share of overall primary natural-gas use that electricity generation represents – 16.7 billion kWh out of 90.1 billion kWh, or 19% in 1998. ALNG began operating in September 1999 and a single train takes ~48.1 billion kWh, over half of the nation's primary natural gas use (process and fuel) in 1998.

Chapter 2 describes the basic policy objective: 'the broad rationale underlying all national-level planning and policy-making is the need to ensure the best use of scarce resources in order to further socio-economic development efforts and improve the citizen's quality of life'. Given the returns to the electricity sector from a national natural-gas cogeneration policy, and that such a policy seeks to fulfill the basic policy objective, cogeneration is a worthwhile energy policy measure.

## **Chapter 11.     Discussing the findings and looking ahead**

The research set out to determine the benefit/cost of a nationwide natural-gas cogeneration energy policy. In comparing cogeneration with LNG, the benefit from the former derives from applying the netback resource value, as determined from LNG, to the overall cogeneration natural-gas saving. The overall policy's cost is more problematic, and the analysis uses an underestimated capital cost in every case for a first-pass evaluation (see Section 10.3, Chapter 10). Examples of other costs are labour, building works, all auxiliary equipment costs, and piping costs. The analysis assesses the scope for including these additional costs by determining in each case the potential increase in the project capital cost that would still render a 12% IRR, the chosen hurdle rate (see Table 59). At the most profitable sites the capital cost can more than double for a 12% IRR, but this is not excessive as the additional capital costs can be as much again as that of the main cogeneration and cooling equipment. IRR (and NPV) are preferred over simple payback for cogeneration projects due to the long project life, as payback ignores all net revenue beyond the payback period. This has to be made clear to facility-owners as the case studies show that even the most profitable cogeneration projects have paybacks exceeding three years.

All of the case studies necessarily analyse cogeneration in a retrofit scenario, as the sites already exist and have no imminent plans for replacing equipment. Project economics greatly improve in a replacement, or new-build scenario, as it then considers only the incremental capital cost between the different system options. A comprehensive national cogeneration policy would have to first estimate a likely average replacement rate for equipment and facilities, and forecast the rate of establishing new facilities. The electricity- and gas-utility's industrial forecasts give some clue of likely growth in this sector (see Section 11.2).

Another cost that this research does not consider on a national level is the natural-gas pipeline-distribution cost. A programme for expanding T&T's natural-gas distribution network already exists, and a cogeneration policy would place extra demands on it. An appropriate portion of the pipeline programme's cost would have to be assigned to the cogeneration policy. The analysis also ignores any externalities arising from the cogeneration policy, and how these compare with the externalities from the existing, conventional power and heat supplies.

A comprehensive national cogeneration policy would go far beyond assessing feasibility at every electricity customer. Before nationwide cogeneration is even considered the scope for improvement in energy-use efficiency throughout the country must be determined. This is because energy conservation and management at each individual site could significantly reduce that site's overall energy demand and thus fundamentally affect any proposed cogeneration. A national cogeneration policy must thus go hand in hand with a DSM policy.

A comprehensive national cogeneration policy could group sites as feasible, not feasible, or borderline, and then identify policy measures that would make borderline cases (or even unfeasible cases) become feasible. Such measures could be favourable electricity buyback rates, equipment subsidies, and favourable depreciation scenarios. A national cogeneration policy would also consider cogeneration in district-cooling schemes, at the national electricity utility for example. T&T's electricity utility generates at three sites, two in major urban centres (one being the capital city) and the third on an industrial estate. The overriding concern is that the net effect of all these considerations improves the country's energy picture, fulfils the main objective of any national policy (see Chapter 3, Section 3.1), and does not harm other national policies. For example, economic parameters such as corporate tax rate, discount rate and bank interest may render a cogeneration project economically unfeasible, though it is feasible in energy terms. These economic inputs may appear arbitrary, but a government can hardly alter fundamental economic indicators to promote cogeneration at the expense of the nation's economy. A country can also have access to international funding for a national cogeneration programme.

So assessing cogeneration's feasibility at individual sites is just one step in the overall policy formulation, and translating these results to a national level takes some effort. Measures *can* be taken to make a cogeneration policy work, but it must be clear that a cogeneration policy is worthwhile in the first place. Industrial-D electricity generation accounted for 8% of overall primary natural gas used in 1998 (see Table 58, Chapter 10) and a conservative industrial cogeneration policy could save about 2.5% of this primary natural gas use. To pursue a cogeneration policy, the fundamental consideration must be cogeneration's energy (as opposed to economic) performance, and such relatively small savings would hardly place it as a high priority in an overall energy policy. A comprehensive cogeneration policy, including all electricity sectors (not just industrial) would certainly incorporate measures that would improve its savings. The savings could be significant in the overall energy picture given that in 1998 electricity generation accounted for ~19% of all natural gas use. So a more detailed evaluation could be justified. However, now that LNG is a *fait accompli*, natural gas use for electricity is a smaller portion of the overall use and continues to shrink with each planned additional LNG train.

In T&T, absorption cooling damages cogeneration's hugely improved efficiency, and corresponding environmental performance compared to conventional energy supply, so that the combined cogeneration/absorption system is sometimes not significantly more energy efficient. This occurs especially at sites with relatively high air conditioning loads - the School and Bank had electric-chiller demand over 60% of the overall site demand. One possible solution is to use a combination of absorption and electric air conditioning as in the JPSCO example in Section 11.1. Another is to always use double-effect chillers, even at small sites. This would need additional natural gas consumption to sufficiently raise the temperature of the recovered heat.

Regarding the national interest, cogeneration would remove the national utility's largest customers. The utility can respond by becoming part owner to cogeneration plants, or by becoming an energy-services company. This would also relieve the facilities from operating their own power plant, and allow them to concentrate on their core business.



Another Caribbean country, Jamaica, has actually had some experience with cogeneration, as part of a demand-side management programme for which they secured international funding.

### 11.1 Jamaica's cogeneration policy

The national electricity utility, Jamaica Public Services Company Ltd. (JPSCO), issued a draft cogeneration policy in 1994, to buy up to 20 MW from cogenerators and small independent power producers. JPSCO would buy the power at different rates depending on whether the supply is firm or on an 'as available' basis. 'Firm' means that the supply is available ~85% of the time. JPSCO estimated an overall 30 to 50 MW cogeneration potential involving a few types of facilities.

A case study at a hotel considered three options (Moseley and Headley, 1994).

1. An 800 kWe diesel engine, with the waste heat driving a 700 kW<sub>r</sub> absorption chiller, which would provide nearly all of the cooling requirements. The existing boilers would provide hot water and steam. In this case only about 40% of the generated electricity would be used on site, with the rest sold to the grid. The project cost is US\$960,000, and has a payback period of 4.9 years, a 15.6% IRR, and the present value (PV) of the savings of US\$1.1 million over 10 years at a 12% discount rate.
2. A 650 kW generator, with the waste heat supplying the steam and hot water needs. There is no absorption cooling. All of the electricity is used on-site, and the grid supplies any needs in excess of the 650 kW. The project has a US\$650,000 cost, 3-year payback period, 31.7% IRR, and US\$1.29 million savings PV.
3. A 1,650 kW generator with the waste heat supplying all of the cooling, hot water and steam needs. A neighbouring hotel, owned by the same group, buys the excess power. The project has a US\$1.45 million cost, 2.8-year payback period, 33.5% IRR, and a US\$3.3 million savings PV. This is the most attractive option.

JPSCO also examined two options for each of two existing office buildings, one of them with some energy storage.

1. Size the cogeneration plant to meet the buildings' entire air conditioning loads with absorption cooling. The engines are 720 and 640 kWe respectively, and the corresponding absorption chillers are 630 and 560 kW<sub>r</sub>. The proportion of electricity used on site is 19% and 22% respectively, and the corresponding figures from the economic analysis are: 7.4- and 6.2-year payback periods; 5.2% and 9.5% IRR respectively.
2. Provide only part of the cooling load with absorption cooling, and the rest from an electric unit using cogenerated electricity on site. The engine sizes drop to 360 and 320 kWe, both absorption chillers to 280 kW<sub>r</sub>, and the proportion of cogenerated electricity used on site rises to 53% and 59% respectively. The payback periods fall to 3.5 and 2.8 years and the IRR to 26.3% and 34.3% respectively.

JPSCO considers these projects to be only marginally viable if at all. They conclude that the ideal configuration for an office would be to have enough energy storage to continuously operate an air conditioning unit, either to cool the building or to charge the

storage tank. This high load-factor could make cogeneration in office buildings as attractive as in a hotel.

## 11.2 Forecasting T&T's energy picture

An energy policy is basically about planning the nation's energy budget towards different planning horizons: short-, medium-, and long-term. So it necessarily concerns future energy use, and therefore forecasting is fundamental to policy formulation. Forecasting future energy needs is inherently ambiguous as the disagreement between separate forecasts in this section displays. The present and recent past is always a good starting point. For example, if cogeneration is a feasible policy measure now, and was also in the recent past, then it can be expected to be feasible in the future depending upon the anticipated changes in the energy picture.

Electricity and natural gas forecasts are directly relevant to a national cogeneration policy. The utilities' (T&TEC and NGC) forecasts are likely to be as reliable as can be expected and a cogeneration policy would simply use these to assess cogeneration's future potential.

## 11.3 T&TEC's electricity forecast

In forecasting the country's electricity use, the Trinidad and Tobago Electricity Commission (T&TEC) considers three scenarios: Base, Optimistic, and Very-optimistic. The latter two forecasts reflect the uncertainty that exists in the expected electricity demand over the forecast period. Existing and potential large industrial-D3 electricity users influence them directly, informing T&TEC of plans to increase their present demand or to establish a presence in the country. The Optimistic forecasts also consider growth rates for small industrial customers that are slightly greater than those projected for the Base forecast. 1998 is the first year that the forecasters use scenarios for sales by rate, energy purchased, and maximum demand. The Optimistic case assumes a sales growth rate 1% greater than the growth rate determined for the Base case. The Very optimistic case assumes a rate 1.5% greater.

T&TEC forecasts the number of customers, energy sales, energy generated, unsold energy, system maximum demand, fuel consumption, and generation efficiency, for a ten-year period from the current year. They consider *inter alia* historical data for the past ten years. The actual forecast method uses an econometric model and is updated periodically as more historical data becomes available. Maximum-demand and maximum-energy forecasts are essential inputs to the utility's generating capacity planning and financial planning. They help assess the need for additional contracted capacity, and for projecting revenues. The greatest demand for accuracy is over the initial three- to five-year period.

### 11.3.1 Reviewing the 1997 electricity forecast

The most recent published forecast document available during this research is T&TEC's History and Forecast 1998 (Sitahal and Chong, 1998), and this is used to describe the



utility’s forecast method. In this document the last full year of data is 1997, and the forecast covers 1998 to 2007. A fundamental input to the forecast is the state of T&T’s economy as described in *The Review of the Economy*, (Ministry of Finance, 1999). This helps T&TEC to gauge the scope for economic growth, hence energy consumption, in general terms.

Regarding the 1997 maximum-demand forecast, the country’s actual maximum demand in 1996 and 1997 was 710 MW and 746 MW respectively, showing a 36 MW, or 5.1% increase. The *daily* peak demand varied over 1997, and exceeded 720 MW for about 26 days only (Figure 114). This is an important consideration for forecasting future generating capacity. Comparing the actual and forecasted maximum demand over the ten years from 1988 to 1997 shows a tendency towards under-forecasting the near-term five-year forecast.

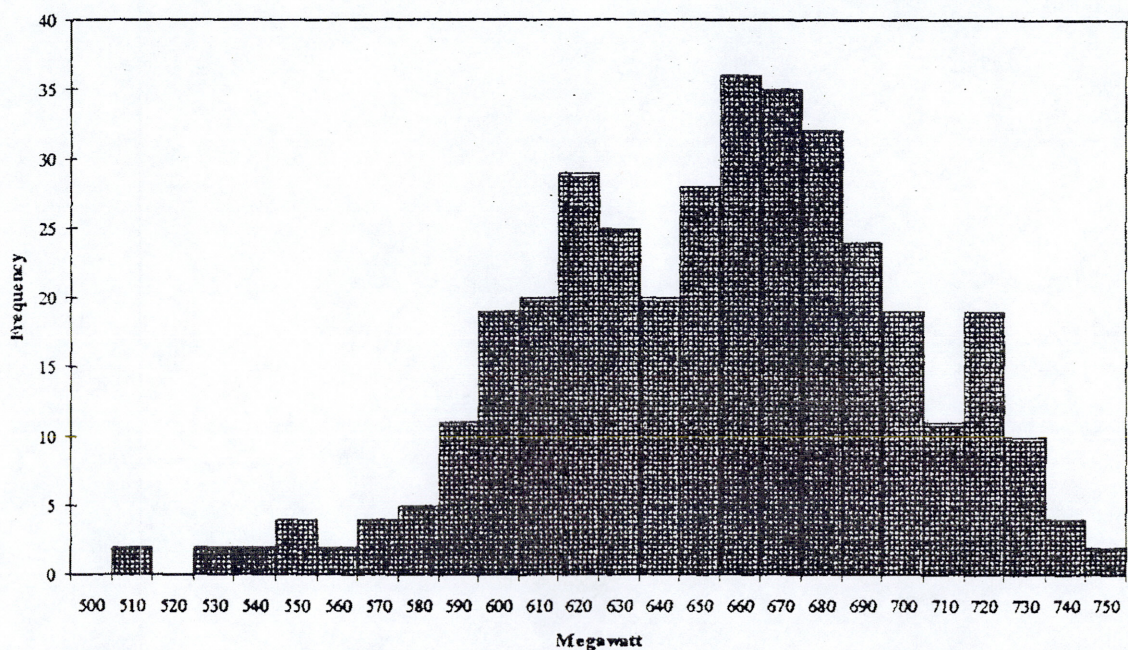


Figure 114. Daily peak electricity demand distribution (Sitahal and Chong, 1998).

Considering the 1997 energy forecast, Table 63 compares the actual and forecasted industrial electrical-energy use in 1997 by rate category. The over-forecasting (10.6%) for the heavy industrial sales (D3) is mainly due to two specific events: two new ammonia plants delayed commissioning in 1997; and an iron-carbide plant reduced its operations and energy consumption by 25%. This plant has now been completely shut down since February 1999 (see Table 64).

| Rate category        | 1997 energy sales, GWh |        |          |
|----------------------|------------------------|--------|----------|
|                      | Forecast               | Actual | Error, % |
| Industrial D1 and D2 | 1,196                  | 1,191  | 0.4      |
| Industrial D3        | 775                    | 701    | 10.6     |
| Industrial E         | 920                    | 965    | -4.7     |

Table 63. Forecasted and actual 1997 industrial energy sales (Sitahal and Chong, 1998).

### 11.3.2 Comments on the 1998 forecast

Regarding the 1998 maximum-demand forecast, the country's 1998 maximum demand was expected to be between 819 MW and 828 MW, i.e. 10% to 11% above 1997's 746 MW. Again, due to the nature of the industrial sector, where a small number of large D3 customers (20 in 1998) account for ~40% of all D electricity demand, and the single E customer contributes ~25% of the country's overall demand, a few individual customers can account for most of this increase. The iron and steel plant's (the E customer) demand in 1997 peaked towards the year-end at 202 MVA (~182 MW). In 1998 its demand was expected to rise by ~50 MW with a new direct-reduced iron (DRI) plant coming online. A new D3 customer, an iron ore plant, was expected to start operations in 1998 also, with a 4 MW demand. All the other electricity users were expected to contribute ~20 MW to the increase over 1997.

A further 8% increase in maximum demand was expected in 1999, to 888 MW. The large industrial customers contributing to this are:

- the Gas processor, 2 MW increase,
- the Iron ore plant, 7 MW increase,
- a new methanol plant, 3.5 MW,
- a new gas processor, 6.5 MW, and
- the national water utility, 5 MW increase.

Table 64 shows what actually happened in the industrial D3 sector up to March 1999, and the updated forecasts to 2001. The new methanol and gas processing plants had to be delayed, and the iron-carbide company shut down altogether.



| Site                              |             | 1998 | 1999 | 2000 | 2001 | Remarks                                                                              |
|-----------------------------------|-------------|------|------|------|------|--------------------------------------------------------------------------------------|
| Methanol companies,<br>4 accounts | Demand, MVA | 20   | 20   | 20   | 20   | Current production levels<br>to be maintained.                                       |
|                                   | Sales, GWh  | 115  | 115  | 115  | 115  |                                                                                      |
| Ammonia companies,<br>8 accounts  | Demand, MVA | 78   | 75   | 75   | 75   | Current production levels<br>to be maintained.                                       |
|                                   | Sales, GWh  | 277  | 277  | 277  | 277  |                                                                                      |
| Gas processor                     | Demand, MVA | 0    | 6    | 6    | 6    | Became a D3 Industrial<br>customer as of Jan. 1999.                                  |
|                                   | Sales, GWh  | 0    | 32   | 32   | 32   |                                                                                      |
| Oil refinery, 2<br>accounts       | Demand, MVA | 11   | 11   | 11   | 11   | Indicated that profitability<br>will only be assured with<br>full production.        |
|                                   | Sales, GWh  | 48   | 48   | 48   | 48   |                                                                                      |
| Iron carbide company              | Demand, MVA | 14   | 0    | 0    | 0    | Has shut down its<br>Trinidad operations as of<br>Feb. 1999.                         |
|                                   | Sales, GWh  | 66   | 0    | 0    | 0    |                                                                                      |
| Iron ore company                  | Demand, MVA | 0    | 5    | 10   | 15   | Due to commence<br>production in June 1999.<br>Full demand expected to<br>be 15 MVA. |
|                                   | Sales, GWh  | 0    | 27   | 39   | 59   |                                                                                      |
| Steel mill                        | Demand, MVA | 4    | 4    | 4    | 4    | Current production levels<br>to be maintained.                                       |
|                                   | Sales, GWh  | 7    | 7    | 7    | 7    |                                                                                      |
| <b>Total</b>                      | Demand, MVA | 127  | 121  | 126  | 131  |                                                                                      |
|                                   | Sales, GWh  | 513  | 506  | 518  | 538  |                                                                                      |

Table 64. Energy sales, GWh, and maximum demand, MVA, for large industrial D3 customers, (Sitahal, 1999a).

Beyond 1999 in T&TEC's History and Forecast 1998 (Sitahal and Chong, 1998), the Base forecast expects the maximum demand to grow between 1.3% and 4.7% annually. The Optimistic and Very-optimistic forecasts depend on the forecasted performance of large industrial customers again: two additional trains to the iron-carbide plant, yet another methanol plant, a new ethane plant as an offshoot from the expanded gas processor, a second iron ore plant, and expansion to the iron and steel plant. These forecasts expect sustained demand-growth. The Base and Optimistic cases forecast demand exceeding 1,000 MW in 2002, and the Very-optimistic case expects this to happen in 2001. Table 64 shows that in March 1999 the revised forecast to 2002 does not include any of the Optimistic-case developments. The iron and steel industry world-wide is actually contracting (Energy correspondent, 2001) (see Figure 115).

Figure 116 shows revised short-term projections in March 1999 for maximum electricity demand and contracted capacity to 2002. All electricity generation was divested to a single private company, PowerGen in 1995 from whom T&TEC purchase power under contract for transmitting and distributing, hence the term 'contracted' capacity. Note that the 195 MW contracted under a take-or-pay arrangement with InnCogen in 1999 are not needed in the forecast and actually represent excess capacity. That power plant is now in fact in receivership despite this arrangement.



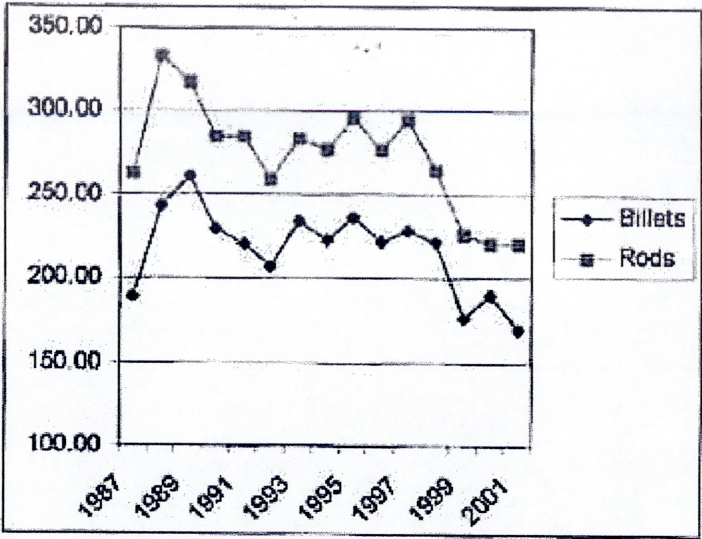
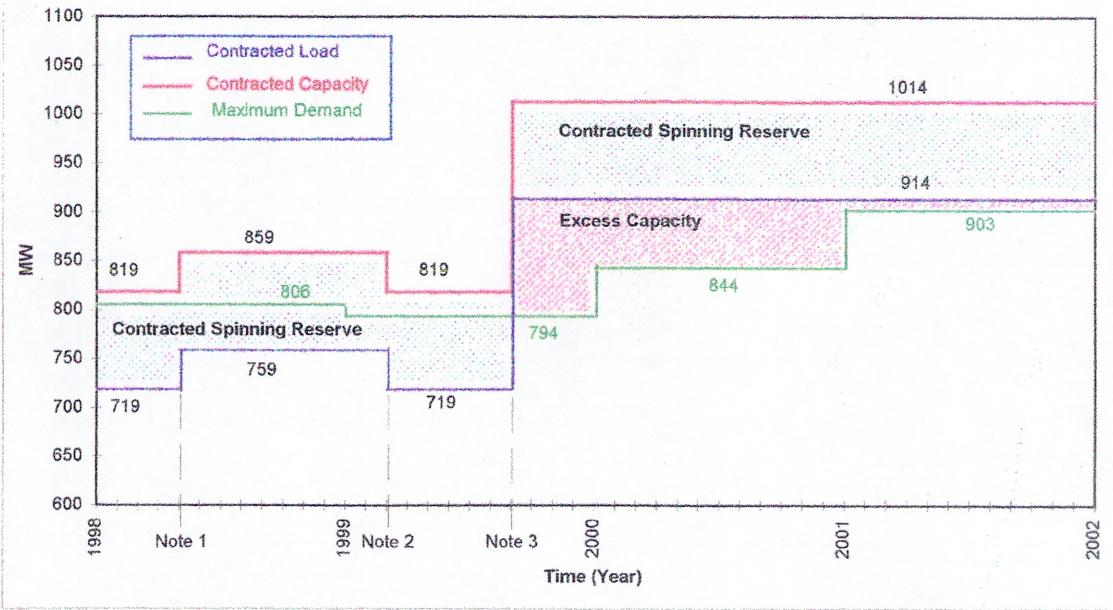


Figure 115. Steel product prices (US\$/tonne), 1987 to 2002 (Energy correspondent, 2001).



Note 1 : Contracted Additional 40MW Capacity from PowerGen  
Note 2 : Terminated Additional 40MW Capacity from PowerGen  
Note 3 : Contracted 195MW Capacity from InnCOGEN

Figure 116. Projecting maximum electricity demand and contracted capacity (Sitahal, 1999b).

Considering the 1998 energy forecast, the 1998 energy sales projections derive from econometric analysis for all rate categories apart from D3 and E. Industrial D3 and E sales projections derive from information from existing and new customers. Energy sales in D1 and D2 rate categories are forecasted to grow by between 2.5% and 5.6% over the forecasted period. D3 energy sales projections show the greatest uncertainty, which arises from uncertainties in the global markets for the products from these plants,

as already seen for the iron and steel industry. T&TEC's History and Forecast 1998 (Sitahal and Chong, 1998) forecasts energy sales in 1998 to exceed sales in 1997 by 80 to 90 GWh when two new ammonia plants and a new iron ore plant are commissioned. Another increase by 160 to 200 GWh forecasted for 1999 is due to commissioning further plants and expansion in existing ones as described before in this Section. 4% to 15% growth in energy use is expected throughout the forecasted period through continued plant expansion.

The Latin American Energy Organisation (OLADE) also provides historical and forecasted T&T energy statistics (OLADE, 1998). The OLADE data available to this research included full historical data up to 1996 and forecasts to 2010. OLADE gets data from the country's energy utilities and the two sets of data would be expected to agree well. Table 65 compares T&TEC's *Base* forecast and OLADE's forecast for overall electricity use to 2007. Apart from 1999 the figures differ significantly, and apart from 1998 T&TEC's forecast is larger although it is the *Base* forecast.

| Year | T&TEC -<br>total sales,<br>GWh | OLADE -<br>electricity<br>production,<br>GWh | %<br>difference |
|------|--------------------------------|----------------------------------------------|-----------------|
| 1998 | 4,615                          | 5,165                                        | -10.6%          |
| 1999 | 5,100                          | 5,073                                        | 0.5%            |
| 2000 | 5,330                          | 5,026                                        | 6.1%            |
| 2001 | 5,525                          | 5,024                                        | 10.0%           |
| 2002 | 5,679                          | 5,066                                        | 12.1%           |
| 2003 | 5,834                          | 5,154                                        | 13.2%           |
| 2004 | 5,992                          | 5,286                                        | 13.4%           |
| 2005 | 6,144                          | 5,463                                        | 12.5%           |
| 2006 | 6,298                          | 5,685                                        | 10.8%           |
| 2007 | 6,453                          | 5,951                                        | 8.4%            |

Table 65. T&TEC Base forecast for overall annual electricity sales compared with the corresponding OLADE forecast.

## 11.4 NGC's natural-gas forecast

The most recent published forecast document available during this research is NGC's Annual Report 1997 (The National Gas Company (NGC) of Trinidad and Tobago Ltd, 1998), and this is used to describe the gas utility's forecast method. In this document the last full year of data is 1997, and the forecast covers 1998 to 2002, a much shorter period than T&TEC's forecast. Table 66 displays the forecasted data and compares the first three forecasted years with actual production figures from BP Amoco.

NGC assigns the 2.2-billion m<sup>3</sup> increase in sales in 1998 to the same specific heavy industrial developments responsible for T&TEC's 1998 forecast, i.e. two new ammonia plants, one new methanol plant, and a new iron ore plant.

There is one fundamental change in the natural gas picture since this research started in 1997 – T&T started exporting LNG in the last quarter of 1999, and has plans to rapidly

expand the industry. None of the forecasts mention this although plans for a T&T LNG industry first began at the start of the 1990s. However, NGC's sales forecast for 1999 and 2000 agree remarkably well with the corresponding BP Amoco actual production figures (Table 66). OLADE forecasts 2000 natural gas production at 7.5 billion m<sup>3</sup>, and does not forecast production exceeding 9 billion m<sup>3</sup> until 2010.

| Year | NGC (The NGC of T&T Ltd., 1998)          | BP Amoco (BP Amoco, 2001)                 |
|------|------------------------------------------|-------------------------------------------|
|      | Actual sales, billion m <sup>3</sup>     | Actual production, billion m <sup>3</sup> |
| 1993 | 5.3                                      | 5.9                                       |
| 1994 | 5.7                                      | 6.2                                       |
| 1995 | 6.0                                      | 6.1                                       |
| 1996 | 6.9                                      | 7.1                                       |
| 1997 | 7.3                                      | 7.4                                       |
|      | Forecasted sales, billion m <sup>3</sup> |                                           |
| 1998 | 9.5                                      | 8.6                                       |
| 1999 | 10.9                                     | 10.9                                      |
| 2000 | 12.3                                     | 12.6                                      |
| 2001 | 13.6                                     |                                           |
| 2002 | 14.3                                     |                                           |

Table 66. T&T annual natural gas sales, 1993 to 2002 – actual and forecasted.

So depending on different perspectives, one forecast differs substantially from another. OLADE looks at developments in the region as a whole – Latin America and the Caribbean. The energy utilities, T&TEC and NGC, look at specific industrial developments together with general movements in T&T's economy. BP Amoco is the LNG plant's sole natural-gas supplier, and their actual and forecasted production figures tend to agree with NGC's corresponding figures. However, all forecasts indicate increasing industrialisation in T&T with corresponding increasing electricity and natural-gas use while the resource lasts. Cogeneration's potential can only increase in the future and can assume even greater importance when the fossil-fuel resource starts to dwindle.

## 11.5 Energy efficiency improvement through cogeneration

Energy utilities generally aim to meet customers' energy needs at least cost, a strategy known as *least-cost integrated resource planning*. Improving the efficiency with which customers use energy, for example through cogeneration, could be one way of doing this, and could help the utility avoid installing future generating capacity. This is called *demand-side management* (DSM). Ultimately, DSM can be considered as part of a strategy to eventually achieve sustainable-development.

T&T can use the US DSM experience as an example. Although the US is one of the leading industrialised nations and T&T is a developing country, T&T is already heavily industrialised and is expected to become even more so. Table 67 shows that energy conservation and efficiency improvements can cost much less than conventional electricity generation, and an even smaller fraction of the cost of any available

alternative. In Texas utilities avoided an estimated US\$1,000 million in capital investment between 1981 and 1991 at a cost of US\$500 million on DSM programmes. Throughout the country 890 out of 3,250 utilities operated DSM programmes in 1991. 439 of these, representing 80% of total electricity sales, reported spending US\$1.8 billion, or 1% of revenues, on DSM programmes in 1991, and saving ~26,700 MW of peak demand (4.8% of total), and 23,300 GWh of energy (0.9% of total).

| Resource                | Cost, US cents per kWh |
|-------------------------|------------------------|
| Solar                   | 8.6                    |
| Biomass                 | 7.5                    |
| Wind                    | 4.7 – 7.2              |
| Coal                    | 5.2 – 6.3              |
| Geothermal              | 5.1                    |
| Nuclear                 | 3.6 – 4.5              |
| Cogeneration            | 3.8 – 5.9              |
| Gas turbines            | Up to 3.6              |
| Hydroelectric           | 2.1 – 6.0              |
| Conservation            | 0.7 – 4.5              |
| Efficiency improvements | 0.3 – 0.5              |

Table 67. US energy-resource costs (Moseley and Headley, 1994).

### 11.5.1 DSM methods

The energy policy that governs the power utility must allow it to make a return from its DSM investment. Building a power plant is capital-intensive and involves a small number of highly skilled people. A DSM programme is less capital-intensive, and involves a large number of less skilled people, and so requires a large amount of data and organising. In Jamaica, experience shows that the most important DSM measure that the utility can adopt is sharing energy-conservation investment costs with the customer, as this can make the project profitable to the customer. Other methods include providing relevant information, services and equipment.

Brasil secured a World Bank (WB) loan for its DSM programme in 1990. The WB's Global Environmental Facility (GEF) granted US\$9.5 million to Thailand's US\$189 million DSM programme in 1993. The International Institute for Energy Conservation (IIEC) also assisted. In the Caribbean, Jamaica also implemented a pilot DSM programme with international assistance in 1993. In that year Jamaica had 348,000 electricity customers, ~1,800 GWh energy sales, and 380 MW peak demand, expected to reach ~1,000 MW by 2013. Trinidad in 1993 had corresponding figures of 300,000 customers, 3,345 GWh, 609 MW peak demand and 1,200 MW installed capacity. So Trinidad was already much more heavily industrialised, but this could mean even more DSM potential, and the Jamaica example is still very useful.

Out of the US\$19 million DSM programme, the WB/GEF contributed US\$3.8 million, the Inter-American Development Bank (IDB) US\$4.0 million, the Jamaican national utility US\$4.46 million, and the Rockefeller Foundation US\$0.24 million, a total of



US\$12.5 million. The five-year pilot project was expected to lower peak demand by 6.7 MW, and save 426,000 MWh in electricity use over its lifetime. So a national cogeneration policy for T&T must consider available international funding and the effect it can have on its success or failure.

## 11.6 Renewable energy considerations for the T&T

The latest reserves/production (R/P) ratio for T&T natural gas from BP Amoco (2001) is 48.2 years in 2000 (it was 51.5 years in 1999). Justin (2000) estimates that this would fall to 27 years with the first LNG train, but *without* the planned additional trains. Beyond natural gas and cogeneration T&T can look to renewable sources for its energy, which is also a likely ultimate energy future globally. Trinidad and Tobago is a typical tropical country lying at about 10° N latitude. The average temperature at Port of Spain (the capital) is 27°C, and the average relative humidity is 71% (Moseley and Headley, 1994). The annual average daily global sunshine irradiation is ~5 kWh/m<sup>2</sup>·day. Most of the statistics in this Section derive from Moseley and Headley (1994) and describe the potential in T&T and the rest of the Caribbean.

### 11.6.1 Solar energy

Due to the Earth's curvature it receives solar energy ranging from 105 W/m<sup>2</sup> in the UK, to 185 W/m<sup>2</sup> in the US, to 200 W/m<sup>2</sup> in Australia, to 405 W/m<sup>2</sup> in the Red Sea. The average solar radiation in Latin America and the Caribbean is estimated at 7 kWh per m<sup>2</sup> per day, or 2,555 GWh per km<sup>2</sup> per annum. Barbados on a clear day receives the solar energy equivalent of 1.44 million barrels of oil, the daily output of a medium sized OPEC state. This energy can be harnessed at a conservatively estimated 10% to 12% efficiency (Moseley and Headley, 1994).

*Solar water heaters* are *passive collectors* with about 40% efficiency at capturing the incident energy. Israel requires all new houses to have them, Western Australia requires them in all government-housing units, and they supply hot water in many hotels in the Bahamas. In Barbados in 1986 the heaters achieved a three-year payback period compared to electric heaters, but this would be much longer in T&T where electricity is much cheaper.

The solar water heater industry in Barbados is the best-known example of exploiting renewable energy technology in the Caribbean. It started in the 1970s with two competing local manufacturers and also benefits from the Barbados government's fiscal incentives. A householder could offset the water heater cost against the year's income tax. As a result, 22,000 out of the 70,000 households in Barbados have installed solar water heaters. The overall annual saving to the country is ~180,000 barrels of oil, or ~US\$2,700,000 on their fuel import bill.

*Solar distillation units* supply fresh water. In T&T, supermarkets sell distilled water for car batteries and appliances that need water without minerals, so there is a demand. Standard electric stills use cooling water in large amounts. A 3 kW still uses 300 to 500 litres per hour to produce 3 to 5 litres of distilled water. A solar still uses neither



cooling water nor electricity. A 2.2 m<sup>3</sup> still in the Caribbean produces 6 to 13 litres of water per day. There were over 50 stills of this type in T&T in 1994. Two larger ones, 9 and 11 m<sup>2</sup>, were operating for over 24 years at the time (1994).

*Solar crop and timber drying* is five times faster than sun- or air-drying. A 30m<sup>2</sup> one in T&T in 1986 dried 14 m<sup>3</sup> of timber to 16% moisture in 3 weeks instead of 3 months for air-drying. The technology is popular in Guyana.

*Semi-passive devices* are intermediate between passive and active solar collectors, and convert solar energy into a single form of mechanical work. *Solar refrigeration* uses a sealed ammonia pump. One at a fishing complex in Barbados produces 500 kg of ice per day. *Solar water pumps* use sun to vaporise a working fluid. A 23 kW unit in Mexico supplies drinking water to a town. It uses 1,500 m<sup>2</sup> of flat plate collectors to raise the water temperature to 71 °C, operates 5 to 6 hours per day, produces a 2.5 m<sup>3</sup> per minute flow rate, and pulls water from a 54 m depth. A French company, SOFRETES, produces a commercial 1 kW plant that pumps ~30 m<sup>3</sup> of water per day through a discharge head of ~20 m.

*Solar pond collectors* comprise a water mass with vertical temperature and salt density gradients, and can reach temperatures as high as 100 °C at the bottom. They are ~10% efficient at storing and converting energy.

*High intensity thermal devices* produce *solar thermal power*. They optically focus solar energy onto a central receiver with a carrier fluid, and achieve up to 5,000-fold energy concentration. A commercial parabolic trough typically harnesses 74% of the available energy. California has a 10 MW flat-mirror receiving tower. Photovoltaics (PV) are low-power producers, generating 10 to 40 mA/cm<sup>2</sup> at 0.5 to 1.0 V.

Harnessing solar energy appears to be a very land-intensive prospect because of solar radiation's low intensity, but this is not quite the case. The electrical-energy use in Latin America and the Caribbean combined, in 1994, would need a square 44 km by 44 km considering the 7 kWh per m<sup>2</sup> per day solar energy received, and a 12% conversion efficiency. T&T's power needs would require a square 3.8 km by 3.8 km in the same conditions, minuscule compared to a hydro-electric scheme of similar capacity. There are small, privately owned PV devices in the Caribbean but no large-scale solar projects. The systems' initial cost and the convenience of conventional generating systems work against any change.

### 11.6.2 Wind energy

A wind turbine needs at least 6.5 m/s mean annual wind speed to economically extract energy from it. Wind energy varies as the cube of the wind speed and is purely mechanical. The estimated average wind power density in the Caribbean is 300 W/m<sup>2</sup>.

Selecting a wind turbine site needs reliable wind speed data, not extrapolations and estimates. Even at a monitored site the wind speeds for one year can be off by  $\pm 30\%$  from the long-term average. Turbines need to be at least 100 m away from any turbulence-source and about 10 m above any obstacle. These machines run at high

speeds and endure high loads so maintenance must be particularly scrupulous. Even so, available wind power is estimated at a billion MW globally. In 1991 US utilities purchased 2,800 GWh of wind generated electricity. In the US capital costs have declined from US\$ 3,000/kW to US\$ 950/kW or less, while reliability has risen from 60% to >95%. A New York State Energy Office study found that wind power per unit energy creates 66% more total jobs than natural gas and 27% than advanced coal, particularly in the manufacturing sector.

### 11.6.3 Hydro-electric energy

There is considerable interest in small-hydro in the Caribbean. St. Vincent (in 1987) has two small hydro-electricity installations totalling 870 kW with 3,753 MWh annual production (49% of capacity). This constitutes 18% of the total installed power-generating capacity but contributes 35% of the total electricity requirement, and 20% of peak system demand. In 1987 JPSCO had five small-hydro sites producing 9.3 MW total, 10% of the annual JPSCO production and 2% of the grid capacity. Another 32 identified sites could produce 118 MW in total, and 457 GWh per annum. In 1985 Belize estimated that hydro-electricity could halve the electricity-generation cost and save US\$ 3 to 5 million. Dominica has 960 kW and 1,880 kW hydropower stations installed, which provide the bulk of the island's power.

### 11.6.4 Biomass energy

Biomass is any plant matter (including charcoal) or faecal matter, as long as it was once living. Plants convert sunlight into biomass at 0.5% to 3% efficiency. Biomass provides a convenient way to store solar energy as chemical energy. It is stable as a solid, liquid or gas, is exported in generic vessels, retains nearly all of its calorific value even after long storage, and converts to electricity and heat. Popular biomass forms are biogas, producer gas, ethanol, methanol, and vegetable oil.

Biomass energy is the fourth largest energy source in the World, and accounted for 14% to 15% of primary energy use in 1987 (55 exajoules per year, or 25 million barrels of oil equivalent per day). Sugar cane is one of the few crops that produces more energy than is used in commercially producing it. The energy output/input ratio for cane is 2.76:1. An experimental/demonstration biogas unit in T&T using sugar cane has a 6 m<sup>3</sup> capacity and generates ~2 m<sup>3</sup> of gas per day. The biogas (or digester gas) has a lower calorific value than propane and typically comprises ~60% methane and ~40% CO<sub>2</sub>. Even at this composition a spark-ignition engine can use the biogas or it can replace 80% to 90% of the liquid fuel in diesel engines.

### 11.6.5 Ocean thermal energy conversion (OTEC)

OTEC uses the temperature difference between cold seawater from great depths and warm surface seawater to vaporise seawater or ammonia, or both, so that the vapours spin turbines and generate electricity. Heat exchangers transfer heat to the cold water from the vapour, which condenses back to a liquid for recycling. Ammonia and seawater condense separately, and the seawater condensate is fresh water, fit for

drinking. OTEC is suitable at coastal regions between 20 °N and 20 °S latitudes, as it needs large amounts of heat and a sizeable temperature difference. The cold, deep-water source must be fairly close, as it has to be pumped up. This artificial upwelling is suitable for mariculture, as deep water is usually nutrient-rich. In Japan and Hawaii there are successful OTEC projects involving seaweed that achieves exceptionally high growth rates. This improves the OTEC system's economics. The US Virgin Islands conducted OTEC tests, but T&T also has potential with depths of 1,000 m to 3,000 within 50 km of the shore.



## **Chapter 12. Conclusions about a national cogeneration policy**

Natural gas will dominate T&T's energy sector for the first half of this century and any energy policy must reflect this. Natural gas is a versatile but finite resource, so that energy planning must carefully consider the competing claims on the resource to optimise the returns to the country, the fundamental energy policy aim. This thesis evaluates one such use – natural-gas cogeneration.

The analysis determines that cogeneration provides significant savings in the electricity sector. Assessing cogeneration in the industrial sector alone in 1998 delivers conservative natural-gas savings of 2.2 billion kWh, or 13.5% of the natural gas used to generate the entire country's electricity in that year. The dollar value of the savings from such a policy over 20 years is US\$0.2 billion, using LNG's natural-gas resource valuation. Considering that a single LNG train uses 48.1 billion kWh natural gas per annum and delivers US\$6 billion in revenues over 20 years, cogeneration is a minor policy measure compared to the petrochemical industry, and similarly in an overall natural-gas policy. The 1998 natural-gas saving from cogeneration represents 2.5% of all natural-gas use that year. However, cogeneration's significance to the electricity sector, and its importance in promoting a nationwide natural-gas infrastructure for the future, where the population *directly* benefits from the resource, renders it an important energy-policy measure.

Cogeneration fulfils the basic aim of energy policy, and its significance justifies further study to produce a comprehensive natural-gas cogeneration policy proposal.





## References

- Accurate Chemicals Ltd. *Quotation for chemical water treatment*. Trinidad and Tobago, 1997 (unpublished).
- Acord, H.K. LNG ventures raise economic, technical partnership issues. *Oil and Gas Journal*, 93(27), 1995. 33.
- Admiralty, G.B. *Examples in electrical calculations*. Her Majesty's Stationery Office, 1952.
- Andrews, E. Trinidad and Tobago oil, gas stocks a curse. *The Trinidad Publishing Co. Ltd.*, October 19, 2000.
- Anon. Gas takes leading role. *Petroleum Economist*, 66(8), August 1999. 27 – 28.
- Anon. LNG plant to expand following gas row. *Economist Intelligence Unit: country briefing*, June 26, 2000.
- Anon. LNG project's cost, competition analysed in news study. *Oil and Gas Journal*, 97(51), 1999. 134 – 137.
- Anon. Trinidad and Tobago: new LNG era begins. *Petroleum Economist*, 66(6), June 1999. 100.
- ASHRAE. *ASHRAE Handbook – Fundamentals*. Atlanta, GA: American Society for Heating, Refrigeration, and Air-conditioning Engineers Inc., 1997.
- ASHRAE. *ASHRAE Handbook – HVAC systems and equipment*. Atlanta, GA: American Society for Heating, Refrigeration, and Air-conditioning Engineers Inc., 2000.
- ASHRAE. *ASHRAE Handbook – Refrigeration*. Atlanta, GA: American Society for Heating, Refrigeration, and Air-conditioning Engineers Inc., 1998.
- Bellow Jr., E.J. *et al.* Technology advances keep LNG cost-competitive. *Oil and Gas Journal*, 95(22), 1997. 74 – 78.
- Berkovitch, I. *Energy sources and policy*. London: The British Library, 1996.
- Best, L. NGC thankful for small mercies. *Trinidad Express Newspaper Ltd.*, March 11, 2000.
- Best, L. The new natural gas economy. *Trinidad Express Newspaper Ltd.*, April 25, 2000.

Best Practice Programme. *A market and project study of gas turbine small-scale combined heat and power – research and development report*. Department of the Environment, 1992.

BP Amoco. *Statistical review of world energy June 2001*. BP Amoco, 2001.

Brown, R.L. and Clary, R. World economic growth pushing LNG-use. *Oil and Gas Journal*, 95(22), 1997. 60 – 65.

Chung, J.B. and Joyeau, A.M. Transportation statistics in T&T – from personal communication. The Trinidad and Tobago National Petroleum Marketing Company Ltd. (NP), 1999. (unpublished).

D’Zurko, D. Comparative analysis for natural gas cooling and space conditioning technologies in New York state. *ASHRAE Transactions*, 102(1), 1996. 275 – 283.

Department of primary Industries and Energy. *Issues in energy policy: an agenda for the Nineties*. Canberra: Australian Government Publishing Service, 1991.

Dorgan, C.B., Leight, S.P. and Dorgan, C.E. *Application guide for absorption cooling/refrigeration using recovered heat*. Atlanta, GA: American Society for Heating, Refrigeration, and Air-conditioning Engineers (ASHRAE) Inc., 1995.

Editorial. ECLAC paints unflattering picture. *The Trinidad Publishing Co. Ltd.*, Issue 1422, June 8, 2000.

Editorial. Gas plan by year end. *Trinidad Express Newspaper Ltd.*, April 15, 2001.

Elcomponent Ltd. SP Max user’s guide. Elcomponent Ltd, 1999.

Energy correspondent. Ispat facing steel meltdown. Express Business. *Trinidad Express Newspaper Ltd.*, December 12, 2001.

ERA Technologies. *Guide to combined heat and power and on-site generation, ERA report 95-0001*. ERA Technologies, 1995.

Evans, R.B. *Combined heat and power in building services*. Birmingham: CIBSE, 1991.

Feshararki, F. Bagladesh natural gas exports to India. *Oil and Gas Journal*, 98(25), 2000. 20 – 24.

Good Practice Guide 3. *Introduction to small-scale combined heat and power*. Department of the Environment, 1995.

Good Practice Guide 43. *Introduction to large-scale combined heat and power*. Department of the Environment, 1999.

- Griffiths, T. *Combined heat and power: a practical guide*. Cambridge: Energy Publications, 1995.
- Hirst, I.R.C. *Business investment decisions*. Philip Alan Publishers Ltd., 1988.
- Hosein, S. *Thesis – An integrated CHP/air conditioning system for Milton Keynes General Hospital*. Cranfield University, 1996.
- Howell, D.G. (editor). *The future of energy gases, US geological survey professional paper 1570*. Washington, DC: US Government Printing Office, 1993.
- International Energy Agency. *Energy in developing countries*. OECD, 1994.
- International Energy Agency. *Energy policies and programmes of IEA countries: 1987 review*. Paris: Organisation for Economic Co-operation and Development (OECD), 1988.
- Jackson, T. *Material concerns*. London: Routledge, 1996.
- Latin American Energy Organisation (OLADE). *Trinidad and Tobago energy statistics – MS Excel spreadsheet*. OLADE, 1998.
- Lumby, S. *Investment appraisal and financing decisions*. Chapman and Hall, 1999.
- Ministry of Energy and Energy Industries. *Energy Policy Green Paper*. Government of Trinidad and Tobago, 1997.
- Ministry of Finance. *Review of the economy 1998*. Government of Trinidad and Tobago, 1999.
- Ministry of Finance. *Review of the economy 1999*. Government of Trinidad and Tobago, 2000.
- Moseley, L.L. and Headley, O. Sustainable alternatives for tropical island states. *SATIS '94*, Bridgetown, Barbados, March 14 – 16 1994. The University of the West Indies Centre for Environment and Development, 1994.
- Muller-Schwarz, W. *Basic electrical theory and practice*. London: Heyden and Son Ltd., 1981.
- Munasinghe, M. *Energy analysis and policy*. London: Butterworths, 1990.
- National Economic Development Council. *Investment appraisal*. Her Majesty's Stationery Office, 1971.
- Nissen, D. et al. Strategic evaluation central to LNG project formation. *Oil and Gas Journal*, 93(27), 1995. 37.

- Noakes, G.R. *Electrical fundamentals*. Her Majesty's Stationery Office, 1956.
- Persad, S. LNG contracts signed without major changes. *Trinidad Express Newspaper Ltd.*, March 19, 2000.
- Prince, R.G.H. Comparative analysis of the factors affecting small and medium-scale gas turbine cogeneration in Australia and the UK. *Chemical Engineering Research and Development*, 73(A8), 1995. 967 – 978.
- Ram, J. *Thesis – rent capture rate of returns and natural resource utilisation: the case of Trinidad and Tobago*. University College London, 2000.
- Renwick, D. Gillete's Seoul LNG report spot-on. *The Trinidad Publishing Co. Ltd.*, June 7, 2001.
- Roadstrum, W.H. and Wolaver, D.H. *Electrical engineering for all engineers*. John Wiley and Sons Inc., 1987.
- Robinson, C. Energy Policy. *The Institute of Economic Affairs Occasional Paper 90*. London: The Institute of Economic Affairs, 1993.
- Singh, S.A. US\$177 million loan puts desalination plant on stream. *The Trinidad Publishing Co. Ltd.*, Issue 1477, August 1, 2000.
- Sitahal, R. *Energy sales and maximum demand of large, industrial D3 customers*. Trinidad and Tobago Electricity Commission, 1999a. (unpublished).
- Sitahal, R. *Projection of maximum demand and contracted capacity*. Trinidad and Tobago Electricity Commission, 1999b. (unpublished).
- Sitahal, R. *98D123.xls (MS Excel file)*. Trinidad and Tobago Electricity Commission, 1999c.
- Sitahal, R. and Chong, K.B. *Trinidad and Tobago Electricity Commission history and forecast 1998*. Trinidad and Tobago Electricity Commission (T&TEC) Engineering Services and Planning Department, 1998.
- Stauffer, K. and Croft, G.D. Opportunities in the Americas: Trinidad and Tobago. *Oil and Gas Journal*, 16(2), February 1996. LA54.
- Stauffer, T.R. The diseconomies of long-haul LNG trading. *Journal of Energy and Development*, 20(2), 1996. 159 – 174.
- The National Gas Company of Trinidad and Tobago Ltd. *Annual report 1997*. The National Gas Company (NGC) of Trinidad and Tobago Ltd, 1998.



The National Gas Company of Trinidad and Tobago Ltd. *Cogeneration plant options – operating characteristics and costs*. Summary data from personal communication with Raymond Franco, 1999. (unpublished).

Trinidad and Tobago Electricity Commission (T&TEC). *Financial report for the fourth quarter ended 1998 12 31*. Trinidad and Tobago Electricity Commission, 1999.

Trinidad and Tobago Electricity Commission Registry. *T&TEC industrial customers*. T&TEC, 1999. (unpublished).

True, W.R. LNG demand, shipping will expand through 2010. *Oil and Gas Journal*, 96(6), 1998. 53 – 57.

Williams, A. and Hessami, M. Two case studies of cogeneration systems design and economic feasibility. *Heat recovery systems and combined heat and power*, 13(2), 1993. 167 – 186.



## Bibliography

- Adeputun, S. and Segun, K. Nigeria: the LNG project. *Energy Policy*, 24 (6), June 1996.
- Agrech, A. *Thesis – Technical and economic considerations for selecting a gas turbine for a combined heat and power scheme*. Cranfield University, 1999.
- Aherne, M. Gas technologies for the environment. *Foundryman*, 87 (4), April 1994. 133 – 134.
- Anon. Cooling the air with natural-gas – new technology provides CFC-free air-conditioning. *Journal of Canadian Petroleum Technology*, 31 (8), 1992. 36.
- Anon. Deals boost Trinidad LNG expansion outlook. *Oil and Gas Journal*, 97 (32), 1999. 24 – 25.
- Anon. Gas technologies hone steel's competitive edge. *Gas Technology*, 10 (1), Spring 1997. A5 – A9.
- Anon. LNG industry takes stock. *Gas Engineering and Management*, 38 (5), 1998. 4 – 5.
- Anon. LNG production, supply deals proliferate. *Oil and Gas Journal*, 96 (51), 1998. 36 – 37.
- Anon. Natural gas to buoy Trinidad and Tobago petroleum sector. *Oil and Gas Journal*, 91 (9), March 1993. 52.
- Avati, H. Not a level playing field. *Petroleum Economist*, November 2000.
- Bramono, B. Indonesian LNG pricing concept: a producing country outlook. *Papers – International Conference on LNG*, 1, 1983.
- Christenson, C.D. Fuel cell system technologies and application issues. *Energy Engineering*, 94 (2), 1997. 36 – 46.
- Combined heat and Power Association. *Combined heat and Power – an agenda for action*. Combined heat and Power Association, 1992.
- Conant, M.A. International trade and natural gas. *Forum for Applied Research and Public Policy*, 4 (2), 1989. 82 – 84.
- Corley, D.I. and Marsden Jr., S.S. Relative merits of some options for Prudhoe Bay natural gas. *Petroleum Science Engineering*, 1 (1), August 1987. 51 – 63.

- DiNapoli, R.N. Economics of LNG projects. *Oil and Gas Journal*, 82 (8), February 1984. 47 – 50.
- Dutkiewicz, B. Methanol competitive with LNG on long haul. *Oil and Gas Journal*, 71 (18), 1973.
- Energy Technology Support Unit. *Potential for small-scale combined heat and power in UK public, commercial and domestic buildings*. Energy Publications, 1988.
- Fleming, W.S. Energy utilities: partners with the HVAC industry. *Strategic planning for energy and the environment*, 16 (3), Winter 1996-1997. 39 – 45.
- Fox, J.M. et al. Remote gas processing and marketing. *Energy Progress*, 8 (1), March 1988. 39 – 47.
- Geneshan, R. Methanol as fuel – cheaper than LNG. *Oil and Gas Journal*, 70 (30), 1972. 61 – 62.
- Gibson, R.B. Blue Bird's alternative fuelled buses. *SAE Special Publications*, 1124, 1995. 45 – 49.
- Good Practice Guide 115. *An environmental guide to small-scale combined heat and power*. Department of the Environment, Transport and Regions, 1996.
- Good Practice Guide 220. *Financing large-scale combined heat and power for industry and commerce*. Department of the Environment, Transport and Regions, 1998.
- Good Practice Guide 227. *How to appraise combined heat and power*. Department of the Environment, Transport and Regions, 1997.
- Hirschenhofer, J.H. fuel cell status: 1996. *IEEE Aerospace and Electronic Systems Magazine*, 12 (3), March 1997. 23 – 28.
- Horlock, J.H. *Cogeneration – combined heat and power thermodynamics and economics*. Pergamon Press, 1987.
- Jesson, M.A. *Thesis – Optimising the design of a combined heat and power/absorption system*. Cranfield University, 1995.
- Joseph, E. et al. Natural gas boilers are a food industry staple. *Natural solutions*, 2 – 1, 1996. A7 – A10.
- Kleinpeter, M. *Energy planning and policy*. John Wiley and Sons Ltd., 1995.
- Knott, D. 30 years of LNG trading. *Oil and Gas Journal*, 93 (18), 1995. 53 – 53.
- Knott, D. LNG's future hinges on cost containment. *Oil and Gas Journal*, 93 (30), July 1995. 18.

- Koen, A.D. CNG, LNG taxes. *Oil and Gas Journal*, 94 (6), 1996. 23 – 23.
- Kotler, V.R. and Goldberg, A.S. Natural gas use at USA electricity power plants: problems and prospects. *Teploenergetika*, 9, September 1996. 66 – 69.
- Larse, R. et al. Natural gas vehicle challenge 1992: advancing dedicated natural gas vehicle technology. *SAE Publications*, 929, 1992. 1 – 75.
- Lesourd, J. Percebois, J. and Valette, F. (editors). *Models for energy policy*. Routledge, 1996.
- Ly, K.H. Developments in natural gas vehicle technology. *Resources, usage, conservation and the environment national conference publication – Institute of Engineers*, 91 (10), July 1991. 70 – 74.
- Matthews, R.D. et al. Texas project: part 1 – emissions and fuel economy of aftermarket CNG and LPG. *SAE Special Publications*, 1208 October 1996. 347 – 366.
- Minyard, R.J. and Strobe, M.O. Financing LNG projects: the challenges ahead. *Journal of Project Finance*, 3 (3), 1997. 5 – 11.
- Munasinghe, M. Efficient management of the power sector in developing countries. *Energy policy*, February 1992. 94 – 103.
- Najjar, Y.S.H. Efficient use of energy by using gas turbine combined systems. *Applied Thermal Engineering*, 21 (4), March 2001. 407 – 438.
- Ojo, A.T. Energy planning and investment for increased earnings: the case of Nigeria's oil and gas resources. *Energy Policy*, 12 (1), March 1984. 22 – 32.
- Ovcharenko, V.A. Natural gas prospects in developing countries and the role of LNG transportation. *Natural resources forum*, 4 (3), 1980. 277 – 290.
- Picard, P. Sorption systems – the point-of-view of a gas utility. *Heat recovery systems and CHP*, 13 (4), 1993. 329 – 334.
- Posner, M., Eden, R. et al. *Energy economics – growth, resources, and policies*. Cambridge University Press, 1981.
- Royal, M.J. and Nimmo, N.M. Big methanol plants offer cheaper LNG alternatives. *Oil and Gas Journal*, 71 (6), 1973. 52 – 55.
- Sanchez-Sierra, G. Energy policy issues in Latin America and the Caribbean. *Resources, conservation and recycling*, 12 (1-2), October 1994. 37 – 41.
- Seay, J.G. et al. LNG industry: an overview of projects and costs. *ASME Paper*, 78 (32), 1978.



Shelton, S.V. Residential space conditioning with solid sorption technology. *Heat Recovery Systems and CHP*, 13 (4), July 1993. 353 – 361.

Springer, K.J. Global what? Control possibilities of CO<sub>2</sub> and other greenhouse gases. *Journal of engineering for gas turbines and power*, 113, July 1991. 440 – 447.

Steel, J. Natural-gas use to double. *Search*, 23 (8), 1992. 246.

Suzuki, K. Innovation in Osaka gas. *Gas Engineering and Management*, 34, January to February, 1994. 42 – 48.

Tago, Y. Recent reasearch, development, and engineering activities of gas utilisation with Osaka Gas. *Gas Waerme International*, 43 (6), June 1994. 267 – 271.

Teagan, W.P. Environmental benefits of gas fired heat pumps. *Proceedings of the Intersociety Energy Conversion Engineering Conference*, 6, 1991. 60 – 63.

Thomas, V. Where now for LNG? *Gas Engineering and Management*, 35, 1995.

Toichi, T. LNG development at the turning point and policy issues for Japan. *Energy Policy*, 22 (5), May 1994. 371 – 377.

Trimble, K.A. Natural gas vehicle market and infrastructure development. *Proceedings of the American Power Conference*, 56 (2), 1994. 1708 – 1711.

True, W.R. Gorgon: an Olympic effort. *Oil and Gas Journal*, 96 (23), 1998. 21.

Vrancken, P.L. Exporting natural gas in the form of LNG. *Energy (Oxford)*, 10 (2), February 1992. 217 – 225.

Waidhas, M. Direct-fueled fuel-cells. *Journal of Power Sources*, 61 (1-2), 1996. 91 – 97.

Wegrzyn, J. and Gurevich, M. Adsorbent storage of natural gas. *Applied Energy*, 55 (2), October 1996. 71 – 83.

Wijarso, I. Natural gas development in Indonesia. *Energy (Oxford)*, 10 (2) February 1992. 231 – 236.

Williams, M.C. Status of fuel cell development in the United States. *Materials Technology*, 10 (5-6), 1995. 104 – 112.

Yang, M. *et al.* CNG vehicles: motoring towards a cleaner Biejing. *Applied Energy*, 56 (3 –4), March – April 1997. 395 – 405.

Zongxin, W. and Zhihong, W. Mitigation assessment results and priorities for China's energy sector. *Applied energy*, 56 (3/4), 1997. 237 – 251.

## Appendix. Three-phase electricity

### A.1 Three-phase electricity

All T&T industrial-electricity customers are supplied with 3-phase power. 3-phase power is one type of electricity that is more generally known as *polyphase* power, and all electricity is generated as, transmitted to, and used by customers as *alternating current* (ac).

#### A.1.1 Generating polyphase power

A simple alternator comprising a single conductor loop (coil) rotating uniformly in a uniform magnetic flux field outputs a sine wave representing the voltage available at slip connections A and B in Figure 117. (Rotating a magnet within a conductor loop achieves the same effect). A second coil wound on the same armature at right angles to the first and connected at C and D (separate from A and B) provides two independent voltages differing in phase by  $90^\circ$ . This is a 2-phase generator. Three independently wound coils at  $120^\circ$  to one another generate three independent voltages at phases  $0^\circ$ ,  $-120^\circ$ , and  $-240^\circ$  with respect to AB. This is a 3-phase generator.

An armature can be wound with any number of symmetrically spaced turns and independent slip-connection pairs. But all the advantages of polyphase voltage are available with 3-phases, and as a rule there is little gained by having more than three (Noakes, 1956). 3-phase is most generally used to generate and transmit ac power.

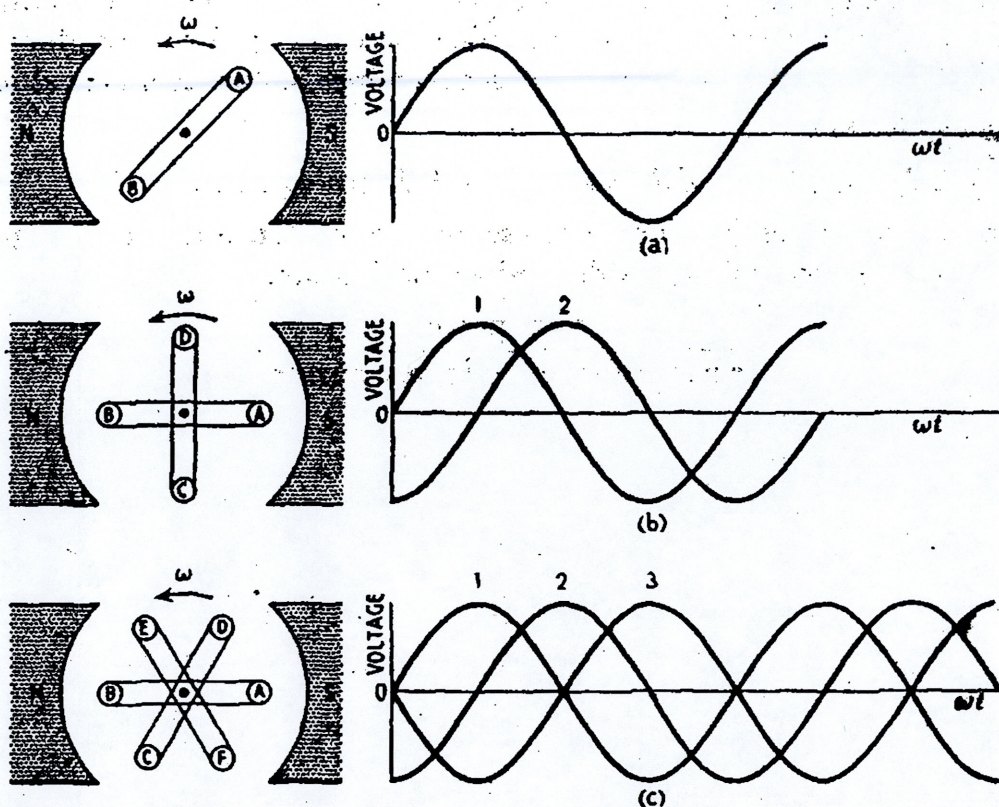


Figure 117. Generating alternating voltage (Noakes, 1956).

### A.1.2 Elements of 3-phase power

Power in ac circuits is made up of a number of electrical quantities that are important to metering. Applying an alternating voltage (av),  $E$ , across a pure resistance,  $R$ , always produces a current,  $I$ , in phase with the voltage, and dissipates power. Applying AV across a pure reactance,  $X$ , either inductive or capacitive, dissipates no power as the current and voltage are always  $90^\circ$  out of phase.

In a circuit with a load of both resistance and reactance there is a phase difference  $\alpha$  between current and voltage. The applied voltage,  $E$ , can be regarded as the resultant of two perpendicular components:  $IR$  in phase with  $I$ , and  $IX$  out of phase by  $90^\circ$  with  $I$ . Figure 118 indicates that  $E$ 's 'in-phase' component is  $E \cos \alpha$ , which produces a rate of working, i.e. power,  $EI \cos \alpha$ . The 'out of phase' component is  $E \sin \alpha$ , which produces no power at all.  $\cos \alpha$  is the circuit's *power factor*.



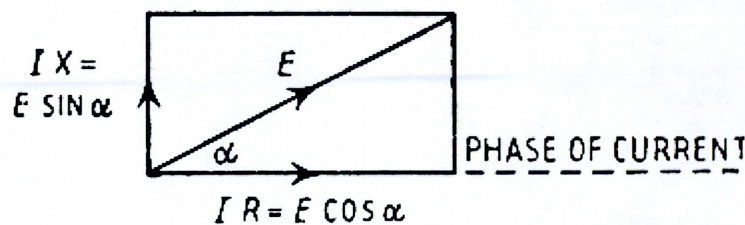


Figure 118. A general ac circuit vector diagram – the voltage,  $E$ , leads the current,  $I$ , by an angle  $\alpha$  (Noakes, 1956).

An ac ammeter in series with the load records the root-mean-square (r.m.s) value  $I$ ; an ac voltmeter across the load reads the r.m.s value  $E$ .  $EI$  is the product of the r.m.s voltage and current, called the *volt-amperes* (VA), whatever the *actual* power consumed. It is *apparent power*, a calculated value without any physical reality as  $E$  and  $I$  are out of phase and do not appear together (Admiralty, 1952).

The rate of working in watts is volt-amperes times power factor, i.e.

$$\text{true watts} = \text{r.m.s volts} \times \text{r.m.s amps} \times \text{power factor}$$

A wattmeter measures true watts.  $E$  and  $I$  usually refer to r.m.s quantities as all power calculations necessarily use r.m.s values. For a large power factor the ratio reactance/resistance, i.e.  $X/R$ , must be small, so that  $\alpha$  is small and  $\cos\alpha$  approaches one.

Consider the *current* vector diagram (Figure 119), another point of view representing the same conditions as Figure 118. The current,  $I$ , lags behind the voltage,  $E$ .  $I$  can be regarded as the resultant of  $I \cos\alpha$  (in phase with  $E$ ), and  $I \sin\alpha$  (lagging behind  $E$  by  $90^\circ$ ).  $I \sin\alpha$  is the *wattless*, *reactive*, or *idle* current component.  $I \cos\alpha$  is the *power*, *wattful*, or *energy* current component.

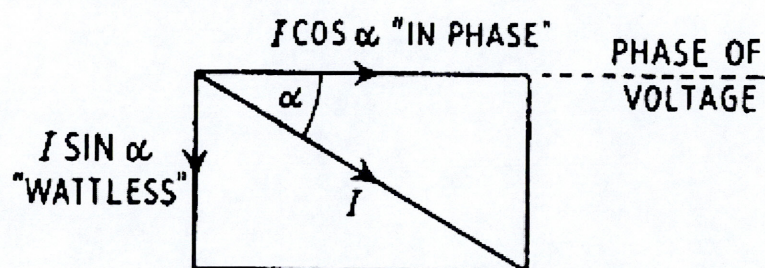


Figure 119. ac circuit current vector diagram (Noakes, 1956).

Reactive power represents storing and giving back energy in capacitors and inductors, the energy surging between generator and reactive load without doing useful work. For part of each ac wave cycle the load puts power back into the source, temporarily reversing their roles. Power is energy flow rate, thus energy flows from source to the

inductance or the capacitance, and then flows back to source. The energy is not expended (turned into heat as in a resistor), but is stored temporarily in the inductor's magnetic field or the capacitor's electrostatic field.

In all electrical *machines* the aim is to use or convert power, and a large power factor, as near to one as possible, is best. It might be supposed that a small power factor would be better since it would lead to a large current with a small power, with consequent economy. But it is the machine's *power* and not the current that is important, and a large power factor delivers the power with the minimum current, minimising loss in leads, etc.

### A.1.3 Power factor correction

The poorer the power factor the more current must be drawn from a supply for a given load power. Poor power factors come mainly from induction motors, which draw lagging currents ( $I$  lags  $E$ ). Industrial loads often include many large induction motors so that lagging power factor is normally an industrial problem. Power companies supply electrical power via transformers, transmission lines, and generators. Each device must be able to handle the required current. The more the current, the larger and more expensive the equipment, and the greater the heat ( $I^2R$ ) losses.

Electricity generating authorities demand that power factor must not drop below an agreed lowest value to keep power losses within reasonable limits. This is achieved by compensating inductive power with appropriate capacitors. It is not necessary to bring  $\cos\alpha$  back to unity as this would require a very high capacitance. Power factor between 0.9 and 0.95 is generally acceptable (Muller-Schwarz, 1981). Power rate schedules provide dollar penalties for poor power factor. Industrial electricity customers in T&T pay a monthly demand charge of TT\$21.75 per kVA, in addition to the kWh energy bill, based on their maximum demand that month, or on 75% of their reserve capacity (see Chapter 4, Section 4.2.1), whichever is greater. The installed capacity is decided with the electricity utility before the facility is even built. It is based on projected power requirements, from which the utility determines how much of its capacity to assign to the facility and the size of electrical infrastructure (cables, transformers, etc.) needed to take power to that point of use. Thus power factor correction is standard among industrial facilities and the fieldwork found high power factor at almost all the metered sites.

Figure 120 shows the power demand profile and the corresponding power factor profile over the metered day for a facility with poor power factor. This is a steel-working factory that makes nails, nuts and bolts, chain-link fence, etc., from steel rods. Besides a wide range of metalworking equipment the profile is overwhelmingly determined by a number of large arc-welding machines. This gives the erratic profile, especially as production is batch-based and unpredictable. The power factor actually swings from almost  $-1$  to unity on shutdown (necessarily), and is more generally between 0.6 and 0.7. Power factor correction at this site would have to be very sophisticated and costly, and is impractical.



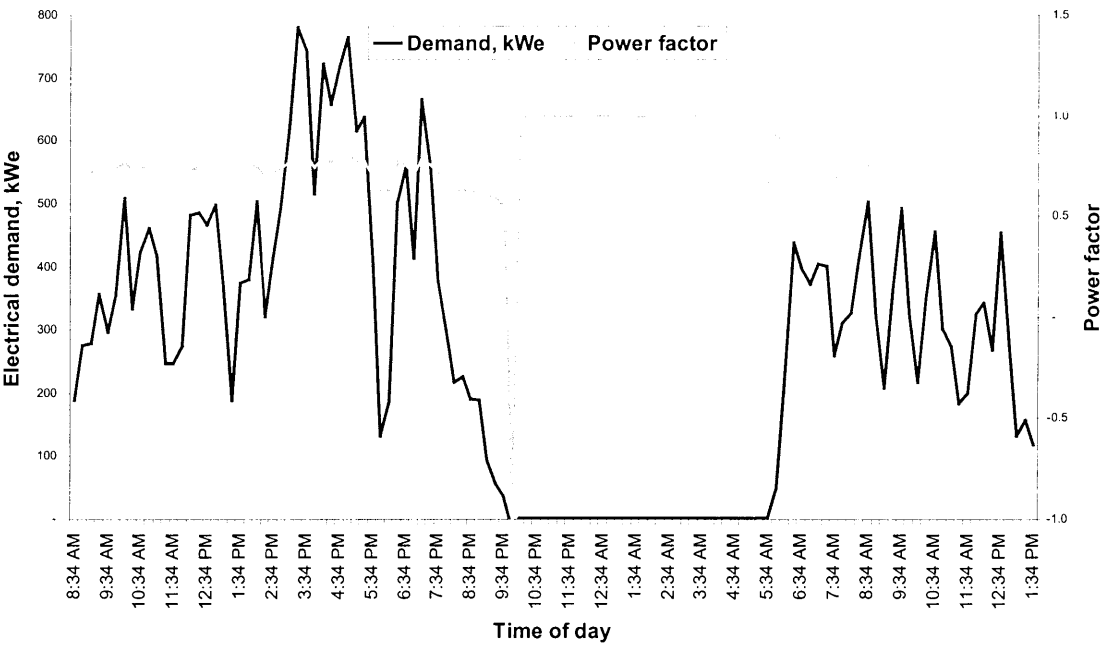


Figure 120. Steel-working factory - electricity demand and power factor profile over a day.