UTILITY PERSPECTIVE ON TECHNOLOGY RELATED TO GREENHOUSE GAS ABATEMENT

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1.0 INTRODUCTION

The following data has been assembled with the goal of presenting a utility perspective on technologies which may benefit society, with regard to the generation of electrical energy while minimizing greenhouse gas emissions.

Momentum is growing globally such that action to reduce emissions of greenhouse gases (primarily CO2) may be required within the decade. For existing power plants, practical methods of reducing CO2 emissions are limited to those involving efficiency improvement. A potential for substantial CO2 decreases (actually CO2 per unit energy delivered) exists in cogeneration and/or district energy schemes, where more efficient use of fuel results. A number of energy generating schemes produce little or no greenhouse gases whatsoever; these include hydro, wind, solar, nuclear, tidal and possibly hydrogen-based systems. Other processes utilizing fossil fuels at greater efficiency to reduce CO2 emissions include Integrated Coal Gasification Combined Cycle, fuel cells, and advanced Pressurized Fluidized Bed Combustion. Use of biomass can be considered GHG neutral if managed on a sustainable basis. Removal of CO2 from stack gases is commercially proven, yet expensive, and incurs large energy penalties. Widespread application will be dependant on regional specifics and the cost of completing energy sources.

There is enormous enthusiasm for increased use of gas for power generation in North America (as well as possible use in transportation, etc.). Hundreds of utilities are planning for significant penetration of gas. The question arises "what is the projected supply/demand for gas and hence how sustainable is the contemplated use of gas on a long term basis (power plant life being traditionally 30 to 40 years)?". The Geological Survey of Canada has compiled data which presents a startling view of future Canadian gas supply and demand. Basically at some point in the next decade demand may outstrip supply, and by 2020() a 75%() shortfall in projected gas requirements may occur. The implications to cost of gas are obvious (in direction if not quantified value). The accuracy of the specific numbers is not so important as a general appreciation of the limits of a finite resource which has value far beyond that of a clean fuel. It is imperative that appropriate consideration be given to this possibility when planning future generation additions. Basically use of gas for power generation may be an interim measure at best, for near to mid term application only. There is a need to better understand the relevance of gas hydrate reserves, as well as the development of technology for harnessing this resource, which in fact may increase international methane reserves enormously.

To achieve the massive reductions in GHG emissions necessary to achieve atmospheric concentration stabilization, which is far beyond the goals of Kyoto, yet is the agenda for many groups, the use of low (zero) carbon energy sources is anticipated on a grand scale. None the less renewables are unlikely to be able to provide the lion's share of energy for the foreseeable future.

There is a growing political momentum away from the use of coal in Canada, and this has resulted in almost zero support for coal R&D. This is incredible considering coal is Canada's largest fossil reserve, representing 66.5% of the total inventory. Also the annual economic benefit of the coal industry is $7 billion [ref. Coal Association]. None the less as our greatest energy resource it will become essential that the means are available to utilize this resource in an acceptable manner, liberating the required energy, while minimizing emissions to the environment.

International interest is also focusing on the development of potentially low GHG emitting fossil based technologies as follows:

- Schemes involving separation of CO2 from flue gas.
- Schemes involving oxygen blown combustion, to produce a CO2 rich flue gas.
- Schemes involving conversion of fuel to hydrogen and CO2, e.g., Integrated Coal Gasification Combined Cycle.
- Schemes in which the carbon in the fuel is rejected as graphite.

- Electrochemical schemes, such as fuel cells.

Some of these schemes may be relatively inefficient whereas some may offer encouraging performance and economics. It must be stressed of course that processes which result in a concentrated CO2 byproduct must have a cost effective repository with long term use/storage capability.

Over the past two decades considerable utility effort has been focussed on the development of coal gasification. Canadian utilities have sponsored focussed R&D in appropriate areas. As a consequence of the USDOE Clean Coal Program, demonstration of utility scale IGCC has occurred (Cool Water, Tampa Electric, Wabash, Pinon Pine). Also, similar demonstrations are in place in Europe (Buggenum and Puertollano). In all cases the technology is not commercially competitive, without subsidy, due to the low cost of gas the present main competitor. None the less there are a large and growing number of IGCC facilities being built, using more economical fuels at present such as petroleum coke and refinery heavy bottoms. As a consequence of this confidence in the basic IGCC technology is growing rapidly and also associated costs should decrease considerably. Process developers are projecting significant cost reductions, particularly when advanced CT's are incorporated, and unit size is optimized such that beneficial scale impacts accrue.

Large scale application of IGCC will still result in emissions of CO2, which will not facilitate the meeting of GHG targets anticipated. Consequently, attention is being focussed internationally on cycles in which CO2 is extracted and either utilized or sequestered. CANMET is actively supporting R&D into CO2 recycle/deposition and this is anticipated to lead to more sustainable energy systems. It is early days in their development, and also understanding of the consequences of massive CO2 sequestration in geological structures, or the ocean, is far from mature.

CO2 scrubbing of power plant flue gases can be accomplished at great cost by absorption or adsorption stripping, molecular sieves, membranes, cryogenics, brine and seawater absorption, or combinations of these. There are large efficiency decreases (up to 35%) involved in CO2removal process.

Once CO2 is removed from the flue gas stream, it must be disposed of, or used in some manner. This will usually involve drying and compression, perhaps purification, pipeline transmission, and disposal or use. Options here include: injection into the deep ocean in gaseous, liquid or solid form; storage in depleted oil and natural gas wells; injection into aquifers, reservoir quality rock formations, or salt dome caverns; injection into oil fields for enhanced oil recovery (EOR); possibly injected into coal bed methane reserves to release CH4 and sequester CO2 as being studied in Alberta; storage in biomass such as micro algae or fast-growing trees which can later be used as fuel; conversion to useful products such as dry ice, plastics, urea fertilizer, methanol, pharmaceuticals, carbonated beverages, or soda ash, or use for inerting or for refrigeration purposes. However, all of these options have their drawbacks, associated with system understanding, environmental impact, varying degrees of impracticality, high cost, size of market, etc.

The importance to Canadian utilities of the foregoing is that in time should there be a need to apply coal based technology then IGCC, with CO2 removal, and sequestration in geological structures such as Coal Bed Methane regions, or possibly oil and/or gas fields, could provide an economic and sustainable alternative (should nuclear and renewables not provide a sufficient or acceptable product).

Fortunately, adoption of IGCC will also address a host of environmental issues as SO2, NOx, particulate, trace emissions, water use, and solid waste generation can be effectively managed.

When looking out to a time period of say 20 years advanced combined cycles (incorporating possibly Solid Oxide Fuel Cells/CT's as hybrid cycles) may achieve overall efficiencies approaching 70%(), without cogeneration. The concentration and removal of CO2 will incur efficiency penalties (10% points) and additional costs (as yet to be determined), none the less the environmental needs of the day may be achievable, while using coal, which may be the only fossil resource of practical use at that time.

Maximized usage of cogeneration of heat and power will tend to optimize fossil fuel utilization efficiency, as efficiencies of 80% plus are frequently attained. Whether it be industrial cogeneration or community energy cogeneration (i.e. district heat) significant GHG benefits may accrue to appropriate projects.

Canada possesses enormous hydroelectric resources, with a harnessed capacity of 62,000 MW. The preponderance of these resources are quite regionally specific with Quebec, Labrador, Ontario, Manitoba and British Columbia being blessed with the bulk of the potential. Further expansion of hydro utilization will necessitate significant capital spending on basic hydro infrastructure as well as the transmission system, as the resource remaining tends to be remotely located. The questions surrounding the economics, sustainability, and other environmental impacts, of these developments makes implementation far from certain.

The nuclear power industry is not enjoying strong public support at this time, because of concerns over costs and safety, hence further applications in Canada cannot be anticipated for the foreseeable future. None the less the zero GHG properties of this energy source are such that it is inconceivable to many utility players that nuclear power will not enjoy a renaissance in North America at some point in the not too distant future. However effective advocacy will be supremely challenging.

2.0 TECHNOLOGY SUMMARY

Table 1 presents data on power generation greenhouse gas treatment technologies, with comments relating to: technology status, reduction potential, time frame to commercial application, collateral aspects, barriers and risks and also Canadian potential benefits.

TABLE 1

Power Generation GHG Abatement Technology

Technology	State of Technology Development	Potential for Greenhouse Gas Reduction in Canada	Time Frame to Commercial	Collatoral Aspects	Barriers, Risks	Canadian Benefits
Coal Related: - Ash Utilization: - Concrete Products - Ash Alloys - Agricultural Use	Comm. Basic Research Pilot	Low/regional specific	Can be deployed now 3 - 5 years 3 - 5 years	Real estate optimization - Resource use optimization	Transportation Limits Market Acceptance	Economics Minimize waste Build expertise base International cooperation
- Bottoming Cycles (e.g. ammonia)	Pilot	Small (<5%) efficiency improvement	3 - 5 years	- Reduce fuel usage at opportunity sites	High capital cost	International cooperation
- Coal/Biomass/MSW/RDF Cofiring	Demonstration	Low (10% reduction)	3 - 5 years	- Fossil fuel displacement - Gas cleanup required - Possible boiler impacts	- Transportation limits - Recycle conflict (MSW)	
- Fluid Bed Combustion	Commercial	Domestic - low Export (J.I.) - medium	Available	- Retrofit of old coal plants globally - SOx, NOx, partic, CO_2benefits	Moderate efficiency gains possible	J.I. opportunities Canadian investment
- High Performance Power System Development	Demonstration Needed	Moderate (25%) effy. improvement	6 to 10 years	- Efficiency improvements - CO_2, SO_2, NOx, partic reduction	- Capital cost - May be inferior to IGCC	Collaboration with USDOE
- Partial Gasification (2nd Generation PFBC)	Pilot	Moderate (25%) effy. improvement	6 to 10 years	- Major efficiency improvement to fluid bed technology - Retrofit potential	- Hot gas cleanup development - Cost reduction - Utility scale demo cost	- Collaboration with Foster Wheeler - CANMET partial gasification of biomass, etc.
- IGCC	- Utility scale demos operating	Moderate (25%) effy. improvement	Commercial offerings available	- Key technology for clean use of coal - CO_2extraction possible - Use with low grade, low cost fuels	- Reduce costs - Economy of scale - Improve efficiency - HGCU/air blown development needed - Advanced CT benefits	- Primarily US technology - Possible niche opportunities for Cdn. development (i.e., O_2production)

Natural Gas Related: - Advanced Combustion Turbines: - ICAD - Catalytic Comb. - CHAT - H2Combustion	Concept Demonstration Concept Pilot	Moderate Moderate Moderate High	3 - 6 years 3 - 6 years 3 - 6 years Post Kyoto	High efficiency product Primarily a NOxabatement tech. IGCC implications, capital reduction Cost of hydrogen? Source of hydrogen	▪ Development cost - Development cost - Time frame to H2economy?	International development efforts therefore Collaboration opportunity
- Cogeneration: - Distributed Cogen. - District Heat - Energy Parks	Demo Commercial Demo (Denmark)	Moderate Moderate Moderate/high	3 - 6 years Commercial 6 - 10 years	▪ Need better taxation encouragement - Development time long	▪ High capital cost - Buy in by municipalities/ agencies - Synergism/long time perspective	CANMET interested in Cdn manuf. base Build on Cdn. expertise Establish Manuf. plants Climate encourages acceptance
- Fuel Cells: - PAFC - MCFC - Solid Polymer - SOFC - SOF/CT Hybrid	Demonstration Demonstration Demonstration Demonstration Pilot	Moderate Moderate Moderate Moderate Moderate/high	3 - 6 years 6 - 10 years 3 - 6 years 6 to 10 years 6 to 10 years	High efficiency goal Motive power market High efficiency goal Highest efficiency stationary power cycle	High cost. Use of H2 High cost. Material science. Materials science/efficiency Materials stability Integration design	International collaboration Ballard tech. International collaboration
Hydrogen Production	Evolving	High, depending on source of H2	Commercial post Kyoto	- High costs - Depends of gas - Could lead to zero CO2depending of H2 source	Manufacture and storage improvements required	Possible use of hydro, nuclear or tidal as a zero CO2energy source for electrolysis in longer term.
GHG Specific: - CO2Capture from Fossil Systems	Demonstration	High	6 to 10 years	▪ Need a low cost repository - Possible use in EOR and CBM enhancement	▪ Capital cost - Cycle efficiency penalty - Repository	Build on Cdn. expertise in solvents and contact devices
- CO2Recycle	Basic research/pilot	Moderate/high	Post Kyoto	- Retrofit potential to existing fossil plants - Possible use of lower purity oxygen	- Capital cost - Cycle effy. penalty - Metallurgy - Reduce O2costs	CANMET pilot of O2firing/ CO2recycle concept

					- Develop CO_2turbines	
- CO_2Sequestration: - Algae - Aquifer Storage - Biomass - Enhanced CBM - Enhanced Oil Recovery - Depleted Gas Well Storage - Ocean Storage - Soils	Pilot Concept Commercial Pilot Commercial Concept Concept Pilot	High	Post Kyoto 6 - 10 years Comm. 6 - 10 years 3 - 5 years 3 - 5 years Post Kyoto 6 - 10 years	▪ Various options may be applicable in different regions - Environmental soundness of ocean disposal highly questionable - Disposition vs retention?	▪ Costs - Effectiveness - CO_2retention - Environmental impacts - Env. impact - Social acceptance	ARC-CBM effort of national significance Prairie soils C sequestration effort significant Enhanced oil recovery of strategic importance Ocean disposal an international effort
- Methane: - Catalytic Oxydation (Coal Bed Methane) - Flare Technology - Landfill Gas - Hydrate Utilization	Pilot Commercial/Development Commercial Concept	High/site specific High Small High	3 - 6 years (demo pending) 3 - 6 years Available Post Kyoto	▪ Canadian application limited - Significant export potential - Conversion efficiency improvements will have significant impact - Electrical/cogen potential at municipal landfills - Reserve expansion hence security and larger benefits	▪ Development costs - Minimize cost - Location specific - Gathering technology not developed	▪ NRCAN development - J.I. opportunities - Canadian industrial development opportunity - J.I. opportunities - Expansion of gas reserve
Non Fossil: - Biomass: - Biogasification	Pilot	Moderate	6 - 10 years	▪ J.I. potential (China, India, Africa) - Northern Canadian potential	▪ Process simplification - Cost minimization	NRCAN process development
- Central Solar Power Tower	Demonstration	Moderate	Post Kyoto	- Regionally specific	- Capital cost - Efficiency	International collaboration
- Fission	Commercial	Significant	Commercial	- Carbon free energy source - Zero air emissions	- Long term waste mngt. - Economic viability - Public acceptance	- CANDU export
- Fusion	Pilot	Significant	Post Kyoto (2050?)	- Ultimate carbon free energy source	- Complexity	International collaboration

				- Zero air emissions	- Cost - Efficiency	Canadian site for demo?
- Hydro	Commercial	Significant	Commercial	- Regionally limited - Major T&D implications - Environmental implications	- Capital requirements - Environmental issues - Land usage conflicts - Lead time	- Comprehensive technical resource
Solar PV	Demonstration/Concept	Significant	Post Kyoto	- Integrated vs nonintegrated - Remote application - Enormous long term potential	- Cost reduction - Efficiency gain - Develop building materials for distributed application - Need for energy storage/ retiming	- J.I. opportunity - Investment opportunity - International cooperation
- Solar Thermal	Commercial	Moderate	Commercial	- Hot water heating	- Public acceptance - Capital cost	
- Tidal	Commercial	Significant	Commercial	- Regionally limited	- Capital cost - Need for energy retiming - Env. issues	N.S. unit generating since 1984
- Underground Thermal Energy Storage	Demonstration (US)	Moderate	6 - 10 years	- Region specific - Reduced fossil fuel usage	- Capital cost - Geological barriers	Canadian industrial development opportunity
- Wave Power (Ocean)	Basic Research/Pilot	Minimal	Post Kyoto	- Regionally limited - No system yet fool proof	- Harsh environment - Material science - Capital cost - O&M	
- Wind Power	Commercial	Significant	Commercial	- Non-firm energy	- Reduce capital cost - Reduce O&M costs - Climatic influence - Access (winter)	International collaboration
Utilization: - Electric Transportation Systems	Early Demonstration	Depends on electricity source Could be significant	6 - 10 years	▪ Need mkt. penetration to reduce cost - Significant urban air quality benefits - Fleet application - LRT application - Efficiency benefits of elec. motors vs I.C. engines	▪ Capital cost - Buyer acceptance	Cdn. expertise (LRT)

- Electro Technologies	Demo/Comm. in many areas	Depends on elec. energy source	6 - 10 years	- Benefits available to many sections of economy - Displace thermo mechanical systems	- Stock turnover - Capital costs - R.O.I. - Other pressures - Slow penetration	International collaboration
- Heat Pumps	Commercial	Depends on electricity fuel basis	Commercial	- Reduced oil/gas usage - Air vs ground source options	- Reduce costs - Improve COP	Canadian industrial development opportunity
- Superconductivity	Basic Research/Pilot	Moderate	6 - 10 years	- Reduction in losses and hence wasted fuel	- Cost reduction - Market penetration of cables, transformers, motors, energy storage	International cooperation

Table 2 presents a host of utility technologies which are in various stages of commercial development. Anticipated time frames to commercial readiness are shown.

TABLE 2

TECHNOLOGY ROSTER (July 1998)

TECHNOLOGY	PRESENT STATUS	TIME FRAME FOR POTENTIAL IMPLEMENTATION	COMMENTS
AFBC (CFB & BB)	Commercial	Available.	(1)
Battery Storage	Pilot/Demo/Comm	(c) Late 90's	(2)
Carbon Dioxide Scrubbing	Pilot/Demo/Comm	2010 (+)	(3)
Coal Refineries	Concept/Pilot	(c) 2010	(4)
Cogen./District Heat	Commercial	Available	(5)
Combined Cycle	Commercial	Available	(6)
Combustion Turbines	Demo/Commercial	Available	(7)
Compressed Air Energy Storage	Commercial	Available	(8)
Fuel Cell - Molten Carbonate	Demo	(c) 2000+	(9)
Fuel Cell - Phosphoric Acid	Demo/Commercial	(c) 2000+	(10)
Fuel Cell - Solid Oxide	Pilot	(c) 2005	(11)
Geothermal	Commercial	Available	(12)
Heat Pumps	Commercial	Available	(13)
Cascaded Humid Air Turbine (CHAT) Cycle	Concept	(c) 2000+	(14)
Hydro	Commercial	Available	(15)
Hydrogen	Pilot	(c) 2010+	(16)
IGCC	Demonstration	(c) 2000+	(17)
Medium/Low Speed Diesels/Spark Ignition	Commercial	Available 2000+	(18)
Magnetohydrodynamics (MHD) - Coal	Pilot	(c) 2010+	(19)
Mine Methane Utilization/CFRR	Concept	(c) 2003+	(20)
Nuclear	Development/Commercial	Available	(21)
Ocean Thermal Gradient	Pilot	(c) 2000+	(22)
Organic Vapour Cycle	Pilot	(c) 2000+	(23)
Orimulsion	Commercial	Available	(24)
Partial Gasification	Pilot	(c) 2005	(25)
PFBC	Demonstration	(c) Late 1990's	(26)
Solar Thermoelectric	Demo	(c) 2005	(27)
Solar Photovoltaic	Demonstration	(c) 2010+	(28)
Tidal	Demonstrated	(c) 2005+	(29)
Underground Coal Gasification	Pilot	(c) 2005+	(30)
Underground Thermal Energy Storage	Commercial	Available	(31)
Wave Power	Demo	(c) 2000+	(32)
Wood/Peat/RDF	Commercial	Available	(33)
Wind Farms	Commercial	Available	(34)

NOTES TO TABLE 2

(1) The Gardanne 250 MW unit is presently the largest circulating fluidized bed operating worldwide.

Retrofit of aging PC units is a future possibility to achieve life extension while increasing cycle efficiency and meeting acid gas emission legislation, however this may lead to increased greenhouse gas emissions. Application in developing world may result in GHG improvements.

Use in conjunction with partial gasification to significantly increase efficiency and reduce GHG emissions is a consideration in the longer term.

(2) Lead Acid storage is presently utilized up to 10 MW. High efficiency units are presently in various stages of development, in many cases driven by the needs of electric vehicles. Storage means may be required to retime energy derived from some renewable energy technologies, depending on system specifics.

(3) Removal and disposal of CO2 from existing stack gases is considered impractical at this time because of energy penalty, cost impact and disposal limitations. The alternatives of improving cycle efficiency significantly, or, reduction in coal usage are more attractive at this time. Slipstream removal for specific high value utilization options remains a site-specific opportunity. The enormous CO2 emission reductions anticipated to be required may require the implementation of CO2removal / sequestration technology, hence effort needs to be focused on improving understanding of options, costs and environmental consequences.

(4) Ultimate high efficiency/clean use of coal for electricity and chemical coproduction. Coal/oil coprocessing is under development as is direct liquefaction of coal. However, at this time economics are far from favourable.

(5) Should a multi unit, high capacity factor, reliable generation source be conveniently located, with regard to an industry or metro area then co-generation and/or district heating should be encouraged with enthusiasm if economically viable. Should distributed generation/cogen become a reality then excess heat could be managed via the D. Heat circuit.

(6) State-of-the-art natural gas fired combined cycle (cc) plants can presently achieve a 58% + cycle efficiency, depending on the location and conditions. Additional co-generation of steam can maximize overall fuel efficiency. Natural gas fired CC results in the lowest per unit CO2emissions from any fossil fuel, however, it is necessary to account for well head and transmission losses of methane.

(7) High efficiency, high inlet temp (2300F+) and reburn gas turbines are now commercially available. Further advances are imminent. The major issue is reliability risk and proven pedigree.

(8) CAES was first demonstrated in W. Germany in 1978. A 110 MW facility is presently in operation in Alabama. Implementation is a function of cost differential between peak and off peak generation. Should Tidal power be developed then application could be warranted. CAES in conjunction with IGCC is a recently developed concept facilitating cycling electrical loads.

(9) This technology coupled to a coal gasifier could offer significant long term fossil based potential. Cycle efficiencies on syn. gas of ~ 55% are anticipated, however, if expanded to co-generation or district heat > 80% may be achievable. Fuel cells are competing directly with gas turbines which are less capital intensive and more mature.

(10) Applicable to natural gas fuel only (hydrogen fraction). An 11 MW demo has been on line in Japan since 1991. Small-scale, 40 kW, units are now commercially available, however US application is only viable if heavily subsidized.

(11) This fuel cell development is being vigorously pursued, however, it is the farthest from commercial reality at this time. Commercialization in the 2000-5 time frame is anticipated. Use in conjunction with a combustion turbine (hybrid) may result in efficiencies 70%.

(12) Very regional specific.

(13) Use in conjunction with UTES may prove viable at certain sites (see Note 31).

(14) The CHAT cycle although theoretically offering high cycle efficiency (5560%) is in an early state of development; however, use of commercially available components may fast track development.

(15) Very regional specific.

(16) Hydrogen is seen as long term ultimate currency fuel, yet energy costs are as yet far from competitive. Could impact significantly on generation (most probably non fossil) station capacity should large scale electrolysis be desirable.

(17) Coal gasification is a commercially proven venture for the production of chemical feedstocks. IGCC for power production is in the demonstration phase. The Shell Buggenum unit (on line 1994) is the first utility scale commercial unit (cycle efficiency 41.4%). The Destec Wabash facility came on line in 1995, and TECO, Florida in 1996. Several utility scale units will come on line in 1998 (eg. Pinon Pine, Puertollano). Phased IGCC (ie. gas fired CT followed by CC, & then IGCC) may be of interest depending on load growth characteristics, fuel pricing and availability, and greenhouse gas considerations.

(18) Slow speed diesel units available up to 50 MW, offering high efficiency, but high capital cost. Lower cost medium speed diesels (multifuel) and spark ignition reciprocating engines (gas) offer high efficiencies and cogen possibilities. Co-generation could be attractive depending on site specifics and fuel availability / cost.

(19) Coal fired MHD unlikely to be viable unit well into 21st century, if at all. Global development effort low priority.

(20) Use of mine methane energy by means of catalytic oxidation/heat integration under investigation. Significant greenhouse gas reduction could result from the concept. R&D is underway at NRCan.

(21) Changing societal values may encourage nuclear implementation in the longer term. Greenhouse gas abatement may promote application, however recent experience in Ontario could set back the technology greatly.

(22) Trade off is high capital cost vs small performance benefit.

(23) Dual fluid (H2O/Ammonial) organic cycle development offers promise of higher efficiency (3% points). These concepts may eventually integrate with any of the developing steam cycles. A study of Kalina cycle in conjunction with Wabamun GS (Alberta) has been completed, however capital intensity was high.

(24) Following successful operation (NBEPC) application could be viable elsewhere depending on relative fuel economics. However, the higher S content will likely necessitate acid gas control in addition to particulate control.

(25) Partial Gasification is unlikely to be commercially demonstrated until after 2000. A US demo is under consideration. Use in conjunction with existing CFB's could offer significant cycle efficiency improvement.

(26) A major contender for retrofit/life extension (ie. replace several old coal or oil fired boilers by one PFBC boiler which could achieve 40% () cycle efficiency). The Tidd, Vartan, Escatron & Wakamatsu demos (on line 1990/91) are the first utility demos at 70 MW () unit size. A 350 MW Japanese unit is in design.

(27) Technology under demonstration (10 MW), several ventures under consideration globally.

(28) Solar photovoltaics are undergoing extensive development. Competitive application is anticipated in high insolation areas of U.S. by 2000. Third world application potential enormous.

(29) Large scale commercialization is unlikely until economic solutions are found to the energy retiming issue and environmental impact. Greenhouse gas emission limitations could accelerate consideration of this technology.

(30) Presently development activity is focused in Europe where a 3 phase, 15 year, demo program is underway. Could lead to utilization of enormous carbon reserves.

(31) Both aquifer UTES and borehole UTES is proven in Europe. Site specifics will determine whether viable as an energy source/receptor.

(32) Several European countries are developing options. Material life a major hurdle. Implementation in harsh climates (winter) is unlikely.

(33) These technologies could be viable projects particularly if co-generation, possibly in conjunction with district heating, was incorporated, however, as technology is capital intensive price of fuel needs to be minimized. Fuel transportation costs limit size of unit.

(34) Wind powered generation is commercially proven in various parts of the world. Advanced units under development are aimed at significantly reducing capital costs while prolonging life. Designs catering to the harsh Atlantic Canadian winter climate need to be proven. Greenhouse gas abatement could accelerate implementation

3.0 R & D OPPORTUNITIES

Table 3 presents a perspective on greenhouse gas friendly technologies which require R & D advancement. For each technology a time frame to commercialization is suggested (i.e. pre 2010 or post 2010). Also, whether the R & D effort can be addressed in Canada, as opposed to through international cooperation is suggested.

TABLE 3 (next page)

4.0 TECHNOLOGY CONCEPTS AND DEVELOPMENT NEEDS

Briefs have been prepared on technologies thought relevant to utility GHG abatement. These include a summary of the technology and also a listing of technology development needs.

COAL REFINERIES

Summary of Technology Concept

As a result of the current interest in the reduction of emissions of greenhouse gases, interest in coal conversion has re-emerged, with the goal being to transform a coal feedstock as completely and efficiently as possible into a host of useful products. Possible products include electricity, coke, methanol, gasoline, with an absolute minimum of waste. Thus ash becomes aggregate; CO_2 is used for enhanced oil recovery where appropriate; sulphur is sold as a valuable by-product; hot gases are combusted to produce power or are converted to liquid fuels or chemicals; and, heat is extracted to produce steam and thus more power (cogeneration and district heat).

An underlying principle behind coal refineries (with regard to greenhouse gas reduction) is to extract as much energy and usable products from the coal such that the conversion efficiency is maximized while the specific emission rate (kg/kWh produced) is minimized. This is achieved by taking a number of known (possibly technologically advanced) processes and marrying them into one large conglomerate. All coal refineries will take advantage of one or more of the following processes: pyrolysis, also known as distillation or mild gasification, wherein the volatiles are driven out of the coal, leaving a solid coke or char; gasification or partial oxidation, to convert the coal mainly into carbon monoxide (CO) and hydrogen (H_2) for further conversion to chemicals and fuels, or combustion for power production in a combustion turbine/steam turbine combined cycle; and, hydrogenation (or liquefaction) of the coal at high temperature/pressure for the production of liquid fuels.

Critical Development Needs

While the main processes which are used in coal refineries are established, there is little proven experience with their integration. Whereas SASOL has proven a successful venture, this is strongly site specific, and in fact changes in subsidy format may radically impact financial viability. The Great Plains gasification plant operates as a marginally profitable venture only because of subsidies, and because of its move recently into non-fuel markets, such as naphtha and fertilizer, and CO_2 sales to Canada. The capitally intensive nature of a plant is such that a product value of > $30 (US)/bbl is thought necessary for viability.

At this time indirect coal liquification, whereby coal is gasified and the products are catalytically processed in a Fischer Tropsh plant to create a liquid fuel, is the most advanced technology, albeit at limited efficiency (50%). Direct liquification, whereby coal is slurried in a heavy hydro-carbon solvent, followed by catalytic cracking and hydro-treating, is less advanced, yet offers the promise of high efficiency (85%) and reduced associated CO_2 emissions.

DISTRIBUTED GENERATION

Summary of Technology Concept

Distributed Generation philosophy is the antithesis of conventional utility thinking whereby the traditional central generating stations have always been believed to offer the most economical energy as a consequence of the economy of scale associated with the technology of choice.

Today, responding to a perceived desire by some customers to generate "in house" by taking advantage of economical fuels (primarily natural gas) process developers are investing in the advancement of a host of technologies which, in the right circumstances, could offer clients the technology to permit self-generation at a competitive price. Further, many generation sources also result in the production of waste heat which if appropriate can be used in process or space heating (i.e. cogeneration), thereby increasing the fuel utilization efficiency, possibly achieving tax advantages, and hence reducing production cost and emissions to the environment. The ratio of electrical power to heat is critical. Generating unit sizes of 100 kW (or perhaps less) up to 5 MW, or in some cases 20-40 MW are candidates for distributed generation / cogeneration.

Distributed generation opportunities include:

- - straight generation of electricity
- cogeneration of electricity and steam/hot water
- coupled cogeneration of electricity and say drying/preheat/furnace integration
- backup power
- remote power
- premium power (power quality)
- power from waste/biomass

Obviously, utilities can also pursue the distributed generation path by locating "friendly" plant throughout the community, and offering both electricity and heat energy (possibly via a district heating loop) to the locale in question.

There are a host of technologies in various stages of development which lend themselves to distributed generation:

- - Single cycle:
- Diesels (#6 oil)
- Spark ignition (natural gas) and dual fuel (#2/natural gas) engines
- Gas turbines (#2 oil and/or natural gas)
- Fuel cells (natural gas hydrogen)
- Solar cells
- Wind turbines
- Cogenerated heat and power
- Diesel plus heat recovery
- Spark ignition and dual fuel engines plus heat recovery
- Gas turbines/heat recovery steam generators
- Fuel cells plus heat recovery
- Biomass and waste fired boilers

Critical Development Needs

Understanding of the impacts of distributed generation, both dispatchable and non dispatchable on the distribution networks and overall G, T & D system power quality and reliability.

The cost of many technologies under development must decrease substantially [eg. fuel cells, small (micro) gas turbines, solar power, wind turbines] before significant penetration will be generally viable.

Fuel cells, which offer the potential of super clean use of gas for power production, are one of the farthest from commercial readiness, especially molten carbonate and solid oxide units; nonetheless, the R&D effort underway is geared to commercial readiness by early in the next decade.

Solar photovoltaics hold enormous long-term potential, and one day (20 years hence?) will possibly lead to the total restructuring of energy use in a large part of the world.

Performance and dependability of micro generators needs to be established.

METHANE USAGE

Summary of Technology Concept

Methane usage is viewed by many as a solution to the GHG emission problem associated with fossil fuel use. Methane occurs naturally as natural gas, gas hydrates, and as coal bed methane. It is produced by bacterial action at waste landfill sites, and can be generated through underground (or gasifier) coal gasification (plus methanation). Finally, it can be liquefied to facilitate transport. All of these sources and forms are discussed below.

Natural Gas

The proven conventional natural gas reserve in Canada is about 7,600 x 109 m3, while annual production is 0.42 x 109m3p.d. (15 x 109 CFD). Natural gas use represents 29% of total national energy demand, and is expected to increase to 38% by the year 2005, largely due to economic and environmental considerations. In the Canadian market place served by gas the following market share is achieved: residential +6%, industrial 35% and commercial 42% (vs. oil and electricity). One of the highest growth areas anticipated is the use of gas for electricity generation and cogeneration. Approximately 50% of Canadian gas production is presently exported to the USA, representing 13% of the US market. Data generated by the Geological Survey of Canada anticipates a significant short fall in availability versus demand by 2020 (+/-). A major uncertainty is the size and recoverability of gas hydrates.

Liquefied Natural Gas

Liquefied natural gas (LNG) use (at -160C allowing a volume reduction by a factor of 600) worldwide is on the increase; however, the economics presently favour its use in the Far East and Europe, because of the comparable fuel costs and locations of the major sources (i.e., Indonesia, Malaysia and Algeria). Japan consumes about two-thirds of the supply. Very little LNG is processed in the five US LNG facilities in existence, as only one is used to any degree at this time. To put this in perspective; whereas US gas consumption was 21.6 tcf pa, LNG import was 0.02 tcp pa in 1995. Global imports are growing at 4% p.a., and the total usage in 1995 was 66 x 106 tonnes, which by 2005 is projected to increase to 102 x 106tonnes. The capital commitment for 5 x 106 t p.a. LNG supply/buy facilities is in the region of $8 billion evenly split between supplier and buyer facilities. The delivered/regasified cost is projected to be $4-5/106Btu (US) to cover the costs. Actual spot market purchase prices have reached a low of $2.30/106Btu (US) in the US, hence removing any incentive for further capacity construction at the time. None the less PACRIM LNG Inc. are planning a 3.5 x 106 tpa LNG facility at Kitimat, BC, for the export of gas to KOREA, commencing 1999.

Coal Bed Methane

Coal bed methane (CBM) is considered to be a significant source of fuel, worldwide. The potential resource is suggested to be in the range of 113 - 340 tm3 (1012 m3), the breakdown being as follows: China 20-80 tm3, CIS 42-80 tm3, Australia 10tm3, US 11 tm3, Canada 14-74 tm3, Poland 1.4 tm3, Europe 7 tm3, South America 4 tm3 and Africa 3 tm3. In the US there are over 7000 operating CBM wells, producing about 5% (i.e. 1 tcf pa) of the nation's gas demand, most coming from the San Juan and the Black Warrior Basins.

A typical CBM well could be down to 1,000 metres or so in depth and would bore through many coal seams. Depending on the cleat characteristics of the coal (i.e. vertical cracking) and hence release pathway for the methane, methods may have to be implemented to improve the methane release potential of various seams by pressurizing, and hence fracturing the coal body. A simple reciprocating well pump would be located at the well. Both methane and water (ratio coal seam dependent) are pumped to the surface and separated. Depending on the coal characteristics, the number of wells installed depends on the flow required; perhaps one well every 100 hectares or so.

Typical CBM gas characteristics are that the heating value is in the range of 950 to 1,110 BTUs per cubic foot. The gas does not contain any appreciable hydrogen sulphide, if at all. CO_2knock-out may be required on some resources, however, this is site specific. Also, water quantity and hence dewatering needs are site specific. There is no known H_2S in any US CBM, and $CO_2$is generally less than 2% of total gas volume. Should a high CO_2 content exist, then an Amine scrubber could be used. In some cases, higher hydrocarbons than methane exist in the gas; however, this is not a negative point.

The gas is filtered to remove any salts and then would pass through a water slug catchment unit. From there, the flow of gas goes to the compressors which incorporate water extraction. The water is disposed of. The pressurized gas is then passed into a glycol dehydrator. This counter-current column is interconnected to a re-boiler to remove water from the glycol; again, the water being forwarded to the central collection facility. The de-watered and pressurized gas is then ready for the pipeline.

Aside from the obvious source of quality fuel, CBM development may potentially reduce the cost of coal mining in the future, through a reduction in mine ventilation requirements. Further, mine safety would be considerably improved, and potential "greenhouse gas" emissions would be reduced.

Underground Coal Gasification

Underground coal gasification (UCG) is achieved when various combinations of air, oxygen, hydrogen and steam are injected into deep coal seams to initiate partial combustion. The volatile gases, which are driven off by the heat produced, are subsequently recovered through a production well. In the early '70s, there was widespread activity in this field and tests were being conducted in many countries at pilot scale. The major European effort in Thulin, Belgium addressed a thin deep seam (1,000m) from 1978 to 1986. In the US, research has focused on relatively shallow (100m deep), both horizontal and sloping, coal seams. The Rocky Mountain 1 (RM1) UGC test at Hanna, Wyoming, was designed to provide a basis for understanding the environmental and hydrogeological variables through extensive site characterization, instrumentation and monitoring. The results indicate that UCG can be conducted in an environmentally benign manner although ground water quality was impacted locally at the test site. Also, aquifer head was impacted in the surrounding area.

In more recent times, there has been a much reduced level of activity. Without doubt, the expertise developed since 1934 in the USSR appears to lead the world and, in fact, they have had two commercially operating fields for decades. One field at Yuzhno-Abinsk, which is in Siberia, involves the gasification of bituminous coal, producing a low-BTU gas which is fed to various clients. At another site at Angren, Uzbekistan, brown coal is gasified with a certain amount of power generation from the product gas. These two fields each gasify in the region of 350,000-500,000 tonnes per year of coal at a depth of 130-350 meters. Useful energy recovery is 35-45% because of process instability, reaction control and heat loss limitations. A more optimized gasification regime, using perhaps staged (02/steam) injection could increase efficiency. At this time, there appears to be a resurgence in interest globally in UCG with developments at pilot scale taking place in Wyoming, New Zealand, Spain, China and India. It has been claimed that the New Zealand (Waikato Coalfield, ECNZ Huntly P.S.) site is the best example yet identified.

There are obviously significant environmental benefits with a technology of this nature as what comes out of the ground is purely gas. It is claimed that the tars, particulate and the hydrogen sulphide can be removed by conventional means, as per traditional integrated coal gasification, and that the noxious substances can be reinjected back into the seam where further gasification would take place. Hence, the environmental impacts of mining and also ash disposal are totally negated. However, there are some significant issues which still remain, one being subsidence. The main environmental question revolves around ground water contamination. The possible contamination of ground water by gasification hydrocarbons would required significant vigilance. The gasification of undersea deposits may not be constrained by the aforementioned issues of subsidence and ground water impact.

When comparing UCG to CBM, the primary differences are that with CBM, the product is essentially 100% methane or close to it, and hence is a high energy density fuel. With underground gasification, should oxygen be used as a partial oxidant, a medium BTU gas is produced with perhaps a heating value of 30% that of CBM. Should air be used, then a low BTU product gas will result with an energy content of about 10% that of CBM. With CBM, only perhaps 10% of the energy available in a coal body is released, whereas with UCG, typically 45% of the energy value is delivered to the surface. Hence, there could be a synergy whereby following CBM utilization at a site, the wells drilled could possibly be used to aid in the development of a UCG field. From the literature it is evident that there is general recognition of a need to increase the efficiency of the process. Conventional UCG is prone to severe energy losses, and also process controllability is somewhat of an art. Ground water quality control also is a major issue. Solutions to all of the foregoing issues are suggested in print, but actual implementation does not appear to be complete, hence, the technology as yet is not fully commercial.

In conclusion, there is little doubt that in the longer term, UCG offers great promise for resource recovery in difficult mining areas or inaccessible coal resources. UCG negates many of the safety issues and environmental issues associated with mining of coal, however, the issues of subsidence and ground water contamination remain. It is claimed that all of the technological issues have solutions known today, yet a 1-2 year commercial scale demo is required to prove the viability of the entire system. The most recent wave of international interest in the topic in almost all continents is evidence of the perceived benefits of this technology.

Synthetic Natural Gas

Coal gasification (in an IGCC gasifier, for instance) converts the coal fuel into hydrogen and carbon monoxide. By adjusting the ratio of these gases and initiating a methanation reaction, methane can be produced. This is termed synthetic natural gas (SNG). Should it become beneficial in the future to maximize use of an existing natural gas distribution network, minemouth gasification/SNG production and transmission to existing combined cycle facilities could considerably increase the significance of the indigenous coal resource.

Landfill Gas

As a result of the action of anaerobic bacteria on the organic fraction of municipal solid waste, landfill gas (about 50% methane and 50% carbon dioxide) is produced over time. Global methane emissions are estimated to be 30 x 106 tpa. A fraction of this is recovered in 500 CH4recovery schemes, including 80 CT or spark ignition generating plants in the US. The generation rate for MSW can be as high as 5m3 of methane per tonne. (This compares with about 12m3/t of coal in place for CBM generation). A project life of 10-20 years is not uncommon.

Clover Bar Generating Station (165 MW) in Alberta is supplementing the station natural gas fuel feed with about 2% landfill gas. The vast majority of the 114 North American landfill energy production systems (total capacity 300 MW) are in California.

Coal Mine Methane

Whereas CBM is recovered from drilling into undisturbed coal deposits, coal mine methane (mine return air (MRA) and mine drainage methane (MDM)) is pumped out of working mines to provide a safe environment for the miners.

Most recently CANMET have been pursuing R&D into a catalytic flow reversal (CFRR) reactor for capturing the energy in coal mine methane for the production of heat from the mine exhaust. A pilot facility is operating at CANMET, Varrenes, PQ, giving excellent results. A site test in Nova Scotia, is under consideration although larger scale application in-province is uncertain. Reactor heat energy utilization/integration is considered critical and Neill & Gunter, Dartmouth, NS, have conducted application studies.

There may be hundreds of potential application sites for this technology globally, although Canadian application appears of limited scope.

Critical Development Needs

- - Development of a better understanding of supply prospects versus demand so that national development and usage scenarios can be established.
- Successful demonstration of CFRR technology and optimization of heat integration. Clarification of future demo mine situation.
- Demonstration of UCG at appropriate scale in a Western country. Environmental soundness must be proven.

Delineation of future potential for the use of CO2 injection to liberate coal bed methane in Canada.

OIL OR GAS FIRED STEAM GENERATING PLANT

Summary of Technology Concept

Residual fuel oils are environmentally cleaner (lower CO_2, SO_2, NO_x and particulate emissions) have constant heating values and offer higher combustion efficiencies than coal, are also relatively easy to store and handle, and thus, all things being equal, are a preferred option for steam generation. Nonetheless, the issues of price stability and security of supply factor strongly against use in the longer term, particularly for new base load additions.

Typical oil fired boilers are much smaller and less elaborate than coal-fired boilers with comparable heat rates. In addition, they require potentially less costly systems and hardware for environmental control, fuel handling, fuel preparation, and waste handling. Oil-fired steam generation systems are the product of the development of conventional boiler technology over the years. This technology has exhibited highly reliable and efficient operations, and has thus earned utility acceptance. Residual oil quality characteristics have changed in recent years. Oil gravity, viscosity, sulfur and metal content have undergone operations-impacting changes. Aspects of utility operations of increasing concern include: stability in tankage, pipeline handling, oil filtering, emissions, solid waste management, opacity, heat transfer surface fouling, and corrosion.

For comparability, the furnace volumetric size ratio for natural gas, #6 fuel oil and pulverized coal is approximately 1:1.6:2.5. Because of the high purity and superior combustion characteristics of natural gas, higher heat loading and gas velocities can be used within a more compact combustion chamber. Further, the gas-fired chambers exhibit a more uniform heat release pattern. Commercially available natural gas burners are capable of providing more heat input per burner than those using oil or pulverized coal. Gas-fired steam generating systems are the products of conventional boiler technologies. Over the years, the technology has exhibited highly reliable operation. Gas-fired steam generating systems are also less elaborate and considerably less environmentally demanding than coal or fuel oil systems. Gas-fired boilers are fed directly from pipeline systems, leading to relatively low fuel-handling and facility costs. However, most gas-fired boilers are also designed for alternate fuel firing, usually petroleum. Storage and handling facilities for alternate fuel are needed for reliable production of electricity. No technical limitations are seen to achieving operational and environmental emission control needs. All future combustion based, base load, gas fired generating facilities are anticipated to be gas turbine combined cycle plant because of both efficiency and capital cost advantages.

Both oil and coal fired boilers can be converted to gas firing, the latter being the simplest conversion option. Alternatively existing steam turbines can be repowered in combined cycle mode by topping with a gas fired combustion turbine/HRSG combination, resulting in a significant cycle efficiency improvement.

The reliability of long-term gas supplies and corresponding price present the greatest cost risk.

Critical Development Needs

The major issues with oil fired plant include:

- - potential needs for emissions control (opacity, smut, SOx/NOx, trace emissions).
- solid waste processing/management/utilization.

With regard to gas firing, the major goal is to maximize cycle efficiency.

ORIMULSION (BITUMEN/WATER EMULSION)

Summary of Technology Concept

Orimulsion is a stabilized emulsion of Venezuelan Orinoco bitumen in water, marketed in North America by Bitor America, a subsidiary of PDVSA (Venezuela). The Orinoco bitumen reserves are huge (1.2 trillion barrels, 22 percent of which are recoverable) and their properties are very consistent. Emulsification is necessary to reduce the viscosity sufficiently to allow handling similar to conventional liquid fuels. The emulsion consists of droplets of bitumen, (70 percent), and water as the continuous phase (30 percent). It is stabilized using a surfactant and other minor additives. Orimulsion contains relatively high levels of sulphur, vanadium, nickel, sodium, and nitrogen. Small quantities of magnesium oxide have been added to the fuel to counteract corrosion and slagging potential in the boiler. The MgO also helps preserve the emulsion's integrity during storage (at least 2 years).

Orimulsion resembles black latex paint and exhibits non-Newtonian pseudoplastic flow properties. Stability and viscosity, at a given temperature, are dependent on the mean droplet size, the droplet size distribution, the bitumen/water ratio and shear rate, and are not affected to an appreciable extent by long periods of storage. Some care must be taken to ensure its integrity: if heated above 80C, the effectiveness of the surfactant is reduced; above 120C, the emulsion breaks down. If cooled below 0C, its water phase will freeze. Pumping is recommended to take place when the fuel is between 5C and 50C. Stability is not affected by low shear (<1800 rpm) pumping, but pressure drops greater than 100 psi are not recommended.

Orimulsion combustion is similar to fuel oil in many ways, but there are important differences. Mechanical atomizers cannot be used to fire Orimulsion; steam atomizers are preferred. At 20 microns the hydrocarbon droplets are already significantly smaller than a fuel oil atomizer can produce. When Orimulsion is introduced into the combustion chamber the water flashes off, producing a secondary atomization. The dramatic increase in surface area leads to a carbon conversion rate over 99.99%, with excess air as low as 0.2%, and significantly reduced burn out dwell time. CO2 emissions are considerably lower than those from coal firing. Nox emissions have been found to be lower than expected due to cooler flame temperatures as a result of the fuel's water content, but low NOx burners may also be required depending on the results of site specific evaluation. Testing in utility grade boilers has found that, when compared to burning fuel oil:

- \- Fouling can be expected to be greater although the deposits are easily removed.
- Heat transfer is better in the upper part of the furnace, but worse in the lower part.

Furnace exit gas temperatures are significantly higher.

Burning Orimulsion will cause an approximate 5% derating of the boiler due to: the water content of the fuel (2%), fouling effect (1.9%), and other fuel effects (0.7%). In addition to this will be an increased station service load to operate the scrubber (and precipitator, if not already in place).

Conversion of existing plant facilities to burn Orimulsion include:

- \- Possible replacement of transfer and high pressure pumps to ensure shear is kept within acceptable limits.
- Replacement of the fuel heating system from steam to glycol to ensure temperatures are kept below 80C.
- Conversion to steam atomization.
- Modifications to the heat absorption surfaces, primarily in the economizer.
- Addition/rearrangement of sootblowers.
- Provision of steam temperature controls (sprays, burner tilt), modification of flame scanners, new mass flow meters.
- New precipitators or modifications to existing precipitators.
- New FGD.
- New fans.
- New fly/bottom ash disposal system.

Critical Development Needs

- \- wider global acceptance/experience of operation of environmental compliance
- long term ash adherence/ corrosion/erosion behaviour in boilers
- limestone injection efficiency/waste disposal
- minimize impact of vanadium/sulphur, etc.

PULVERIZED COAL-FIRED POWER PLANT

Summary of Technology Concept

The conventional Pulverized Coal-Fired (PC) plant is the workhorse of the electric utility industry. PC units range in commercial size up to about 1,300 MW, with the most common size in Canada being in the 150-600 MW range.

A conventional 150 MW Pulverized Coal-Fired (PC) Plant is typically a 124bar/538C/538C (1800 psig/1,000F/1000F) unit of subcritical design. Should 300 MW units be considered the 166bar (2400 psi) steam would likely be adopted. Supercritical units are designed for 241bar/538C/552C/565C (3,500 psig/1,000F/1,025F/1050C) steam conditions. However, the selection of supercritical or subcritical steam conditions depends on a project specific evaluation. The PC plant is based on a thermodynamic cycle known as the Rankine Cycle. The limits of the Rankine Cycle are determined by the ratio of the maximum and minimum temperatures of the thermodynamic cycle. The maximum practical temperature limit is currently in the 538C to 593C range due primarily to boiler material constraints. It is anticipated that in advancing from conventional subcritical conditions of 176bar/538/538 to 290bar/580/580/580 that a heat rate improvement of 10%() can be achieved.

As PC units are a mature technology the greatest concerns for the technology are associated with increasing environmental regulation (i.e. CO_2, SO_2, NO_x, particulates, trace elements, etc.), the need for added pollution control equipment and cycle efficiency limits.

The Danish Elsam project is a noteworthy venture to push the performance of PC plant to the limits. The Esbjerg #3 unit, commissioned in 1992 is the highest efficiency coal fired unit in the world, thereby offering a significant challenge to other developing technologies. Several units of similar, or slightly improved design are due to come on line in Denmark and Holland in the late 1990's.

EPRI is bringing together the entire set of improvements in pulverized coal plant technology into one project design called State-Of-The-Art Power Plant or SOAPP. This plant design is expected to use recent advances in commercially available components of pulverized coal plant technology from around the world. The base case plant will be a 350 MW supercritical pulverized coal plant with a once-through, double reheat, full-variable pressure boiler, with spiral-wound waterwalls designed for cycling duty. The design conditions will be 310bar/593C/593C/593C (4,500 psig/1100F/1100F/1100F). One of the greatest technical concerns with SOAPP is materials selection. Design of SOAPP will use newer corrosion-resistant tubing selected on the basis of fuel characteristics for superheater and reheater sections. Advanced 9 Cr steel is an option for tubing, headers, and steam piping. Modified 12 Cr steel would be used for high pressure and intermediate pressure rotors which are acceptable for use up to 593C. EPRI has developed a "superclean" 3.5 Ni Cr Mo V steel for use in the low pressure rotor which is acceptable for use up to 454C (850F). SOAPP is not an economically viable option at this time for electricity generation.

Ultra super critical or Ultra-High Pressure Pulverized Coal Fired-Power Plant is defined by steam conditions of 345bar (5,000 psig) and 649C with single or double reheat conditions that could range from 566C to 649C. Only one plant with Ultra-high pressure steam conditions has been built in North America, Philadelphia Electric Company's 325 MW Eddy Stone 1. The unit was designed for steam conditions of 345bar/649C/566C/566C. The 357 MW Drakelow "C" Unit 12 in the United Kingdom was also designed with very advanced steam conditions. Operational experience at these plants has been unsatisfactory since their original commissioning in the 1960's, and the steam conditions of both plants have been reduced. Technical limitations for the Ultra-PC are defined by metallurgical considerations, particularly performance of the austenitic steels used.

The USDOE initiated two programs to advance the efficiency and performance of coal fired plant: the Low Emission Boiler System (LEBS), and the High Pperformance Power System (HIPPS).

Critical Development Needs

The major hurdles with this technology in North America are: limited cycle efficiency proven, overall environmental performance, material science for advanced steam conditions, and economics as compared to some developing technologies. Consequently, successful application of advanced (e.g. high chrome) materials to permit desirable operation and reliability at advanced steam conditions is paramount. Further, proven net cycle efficiencies of 42% (HHV) and high reliability will be required to compete with many of the advancing technologies, particularly if CO_2 emission limits become a critical issue.

RECIPROCATING ENGINES

Summary of Technology Concept

The slow-speed diesel (400-750 rpm) has a long record of operation as the prime mover for ships, as well as a history in small and medium-sized power plants. In stand-by and emergency installations diesels can provide short start-up times and rapid load-taking capability. For peak-shaving and baseload duty, they offer low operating costs, the ability to run on gas, diesel, or No. 6 fuel oil. An efficiency of 40-45% (LHV) when generating electricity alone is increased to 75-80% in the cogeneration mode (heat and power), and this can be further increased with installation of an after burner to the 85-90% range.

Medium speed (720-1000 RPM) diesel, dual fuel, and spark ignition engines are designed for base load operation in both industrial and marine markets. Whereas diesels are predominantly geared to the use of liquid fuels (#2 - #6 oil) the dual fuel (3% oil) and spark ignition reciprocating engines are geared to the use of methane.

Since 1985, Cooper-Bessemer and Arthur D. Little have been developing the concept of coal/water slurry firing for slow-speed diesels. Testing was initiated on a one-cylinder research engine operating at 400 rpm and developing 161-215 bHp. It progressed to a six-cylinder production engine operating at 400 rpm and developing 2616 bHp. The work culminated in the award of a CCT V contract to construct and demonstrate (72 months in total) a 6.3MW plant in Alaska. The plant will employ one LSVC-20 diesel (20-cylinder, 400 rpm, producing 8720 bHp or 6.3 MW). Coal will be cleaned via a 2-stage beneficiation/slurrying process (1.8% ash, 0.6% S, 15,300 Btu/lb, slurried to 50% concentration), and will be fed to the diesel at a rate of 45 t(dry)/day. Emission levels will be controlled to 50-70% below NSPS by the coal cleaning, a dry flue gas scrubber system (sorbent injection), SCR and a baghouse.

Critical Development Needs

- - Capital cost reduction.
- Improve performance through high efficiency of combined cycle demonstration.
- Adapt to be fired on coal or Orimulsion (this will be facilitated through the coal/water slurry demonstration in Alaska).
- Develop low-cost, efficient means of reducing NOx emissions.
- Improve ability to handle high-vanadium fuels.

REFUSE DERIVED FUELS AND MASS BURNING

Summary of Technology Concept

There are two standard methods of recovering energy from municipal solid waste (MSW): mass burning, and conversion to a refuse-derived fuel (RDF) followed by combustion. Both methods reduce waste volume by up to 90 percent; both obtain about 600 kWh per tonne of MSW; however, mass burning requires a specially designed moving grate furnace to efficiently combust the non-uniform, slow-burning MSW. On the other hand, RDF, which is produced by removing glass, metals, and other non-combustible materials from MSW, followed by size reduction, is a more uniform fuel which can be combusted in standard utility boilers or fluidized bed combustors either separately or as an addition to the primary fuel with a minimum of modification in most cases.

Japan, Germany, Sweden, and certain other highly industrialized Western European countries practice combustion of MSW as a means of waste disposal far more extensively than the United States. The United States combusts only 17% of its MSW in waste to energy (WTE) facilities, to produce 2500 MWe [the remainder is landfilled (66%), recycled (15%) and composted (2%)]. Refuse-derived fuel (RDF) firing, which is primarily a U.S. practice, accounts for only about 25% of the U.S. WTE capacity; mass burn facilities, which are simpler and less expensive, comprise 75% of the U.S. capacity.

Incineration can transform municipal waste into usable forms of energy, such as steam or electricity. In this way, landfilling is largely negated, and hence methane generation prevented. Unfortunately, incineration creates pollutant emissions. Municipal waste combustors (MWCs), sophisticated facilities that reduce waste while generating energy, use advanced pollution controls to minimize these emissions thereby meeting regulatory requirements.

Even though state-of-the-art WTE plants have been proven to be reliable and operable at high annual availabilities, and to have controlled emissions of acid gases, heavy metals, dioxins, and furans to very low levels, the early public perception of WTE plants as dirty does not seem to have improved significantly, except in those communities that have model WTE facilities.

Critical Development Needs

For conversion of existing plant, erosion/corrosion (eg. chlorine impacts) and slagging prevention need addressing.

- - Ability to mass burn widely variable fuel must be designed for.
- Safety of RDF handling/firing (dust explosions).
- Organics, HCl in flue gas must be managed.

ATMOSPHERIC CIRCULATING FLUIDIZED BEDS

Summary of Technology Concept

Circulating fluidized bed technology utilizes a recirculating loop of solid particles to suspend and combust solid or liquid fuels at controlled temperature (normally 800-900C). Fuel (1% of bed inventory), air, and where necessary limestone are mixed by the recirculating solids (normally circulating at 40 to 60 times the fuel feed rate). Heat is extracted directly from the recirculating loop by combustor water walls, cooled cyclones, and/or an external fluid bed heat exchanger (FBHE), depending on the supplier and application specific design. Normally 40% of the combustor energy exits the recirculating loop to be absorbed in conventional back pass boiler surface.

Atmospheric fluidized bed combustion offers little GHG benefit in Canada; nonetheless from a developing world perspective there may be significant benefits in efficiency and hence GHG emissions when replacing old inefficient boiler plant.

Critical Development Needs

As CFB rapidly emerges as a dominant coal burning technology in the 20 MWe to 250 MWe range, several critical developments are occurring, addressing existing issues:

- - Commercial unit designs and installations are being built which will reinforce the fairly extensive but short term industrial experience on smaller units, ie. 20 to 100 MWe.
- Resolution of several unit design problems including: metallurgical issues, dust collection techniques, sorbent and fuel sizing, improvement in limestone utilization (by reactivation and reinjection), waste disposal and utilization, N2O minimization (possibly by reburning or by fuel modification, by cofiring, to reduce nitrogen content and increase volatile matter content), and deep NOx reduction (by NH3 injection).
- Resolution of numerous component design issues including hot cyclones, fluid bed heat exchangers, cyclones located inside of combustor, fuel feed mechanisms, combustor sensors, impact separators, refractory design, high pressure fans, air heaters (such as heat pipes or plate exchangers), combined coal and limestone handling.
- Commercialization of partial gasification for retrofit to CFB's to dramatically improve efficiency.

There are economic, technological, environmental, political and public perception issues associated with the use of non-conventional fuels, none the less the potential economic benefits encourage further consideration and R&D will be required to some extent, following which capital equipment additions will most likely be required to facilitate utilization.

There are issues which must be addressed before one can confidently pursue use of low grade/alternate fuels as follows:

Tires

Whereas there is an experience base accumulating regarding co-fuelling with tires the following issues will have to be addressed:

- - Determine actual reduction size appropriate for the CFB in question.
- Removal of bead wire.
- Determine if any impact of Zinc Oxide on combustor surfaces.
- Evaluate prepared fuel cost vs. hardware capital requirement.

Coal Cleaning Waste

- - Fuel preparation (primarily drying) to minimize transportation costs to site.
- Determination of blend ratio to minimize performance impacts, if any.
- Concentration of trace elements in the cleaning plant refuse stream.

Pulp & Paper Wastes

- - Determination of actual potential waste streams which would advantageously be consumed in the CFB through discussion with mill operators.
- Fuel preparation (eg., drying) and handling requirements to promote effective use.
- Should any potential fuels possess deleterious qualities (PCB content, etc.), determination of combustion/destruction efficiency.
- Determine plant operational impacts (efficiency penalties, fouling potential, emission of organics).

Municipal Solid Waste

- - The potential impact of elevated chlorine in the fuel feed needs to be quantified.
- Should experience develop whereby CFB incineration (without back end clean up scrubber facilities) is shown to appropriately perform then consideration could be given to a waste recycling/RDF combustion concept. The remoteness of the site would factor against economic haulage of low fuel density material.

Petroleum Coke

- - Pilot testing of coke as a prime fuel and also a co-fuel is required to ascertain impacts on sulphur capture, NOx and N2O emissions, need for additional NOx control measures (such as ammonia injection).
- Enhanced corrosion potential, due to elevated vanadium concentration.
- Assess fouling and sulphate agglomeration potential and the impact on heat transfer surfaces.
- Impact on ash properties (unburned carbon, vanadium and nickel concentration and mobility) and disposal requirements.

COMBINED CYCLES

Summary of Technology Concept

In the context of electrical power generation, a conventional combined cycle is understood generally to mean the joint operation of a gas turbine and steam turbine cycle, in which exhaust heat from the gas turbine is used in a heat recovery steam generator (HRSG) to generate steam which is then fed to a steam turbine. Various equipment arrangements are possible; for example, the steam for the steam turbine can be provided from several gas turbine/HRSG sets; multiple pressure levels with or without reheat are possible configurations, their selection depends on the gas turbine exhaust temperature and also economic considerations. Overall plant thermal efficiencies of up to 58% (LHV) are presently claimed with combined cycles when fired by natural gas. The attached unit data tabulation lists combined cycle data for most process suppliers.

Developers are pursuing advanced CT's to push overall combined cycle efficiencies to 60%. Meanwhile steam turbine developers are also pushing the envelope with the promise of small supercritical ST's, also providing significant cycle efficiency improvement.

HAT (Humid Air Turbine) Cycle

The HAT cycle is an intercooled, regenerated cycle with a saturator to add moisture to the compressor discharge air, thereby significantly increasing the overall cycle efficiency at comparatively low cost. There is no steam turbine associated with this cycle. The combustor air can contain as much as 40% water vapour, depending on the type of fuel being burned. While much of the HAT cycle work has been aimed at synfuels applications, natural gas and fuel oil operation are possible.

CHAT (Cascaded Humidified Advanced Turbine) Cycle

The CHAT cycle is a gas turbine based cycle incorporating intercooling, reheat and humidification. The cycle integrates an existing heavy duty combustion turbine with an additional shaft comprising industrial compressors and an expander. There are currently no operating commercial CHAT plants; however, the marketers are offering a 300 MW plant. The proposed plant would use a modified 501 FA Combustion turbine and Dresser Rand turbo expander and compressors package. Once demonstrated this offering could be a very aggressive energy generator. Developers are also investigating potential for distributed generation scale CHAT options in the 2-20 MW range (eg. Allison 501KB7, 9.6 MW, 46% LHV).

A mature CHAT may be less risky than a conventional combined cycle plant because: it can produce power 10-20% more cheaply; it requires less water; it will produce only 1-2 ppm NOx(at 15-20% humidification) thus not requiring SCR; and output drops only 1-2% at summer temperature (95F) compared with about 15% drop in output for combined cycles.

EFCC (Externally Fired Combined Cycle)

The EFCC concept is not new and has in fact been around for many years. Advances in materials have, however, led to a re-evaluation of the cycle. Coal is burned in an atmospheric combustor and the hot gases are passed through a slag screen and then to a ceramic tubed heat exchanger. The combustion gas then passes through a Heat Recovery Steam Generator (HRSG) before being cleaned and exhausted through the stack. At the same time, air is drawn into the compressor before being heated in the ceramic tubed heat exchanger. The hot gases pass through the expander and drive the compressor and a generator. They then go to the combustor and the cycle continues.

Ceramics have meant that temperatures of as high as 1400C are possible in the heat exchanger.

The concept is being tested in a 2 MW pilot plant and a commercial demonstration is being planned. Funding of this development is currently in jeopardy hence further pursuit is uncertain.

The Kalina Cycle

The Kalina cycle was initially designed to replace the standard water based Rankine cycle in combustion turbine combined cycle applications. The Kalina cycle uses a binary (ammonia and water) working fluid to produce a variable boiling temperature. Boiling starts at the saturation temperature corresponding to the partial pressure of the ammonia in the vapour phase. As the concentration, and partial pressure of ammonia in the vapour phase increases, the boiling temperature also increases. This means that the temperature difference between the heating source and the working fluid are smaller over a wider temperature range. Irreversible thermodynamic availability losses are reduced and greater cycle efficiencies are achieved. A 3% point cycle efficiency improvement over a non binary fluid cycle of similar design is suggested by Exergy Inc. In the Kalina cycle, the working fluid is restored to its starting condition by means of a distillation/condensation system operating as an absorption refrigeration cycle.

Though introduced 10 years ago, development work has been slow. A 6 MW pilot plant was constructed at Canoga Park, CA, and test work is ongoing. This work is being partially funded by the DOE.

Though originally perceived as a bottoming cycle option for combustion turbines, the Kalina cycle is now also being considered for solid fuel single cycle operation. Stone & Webster were commissioned to carry out an engineering study into the potential of repowering a coal fired unit at the Wabamun Generating Station. Based on this it was deduced that a typical 150 MW unit could be repowered to create a 193 MW unit.

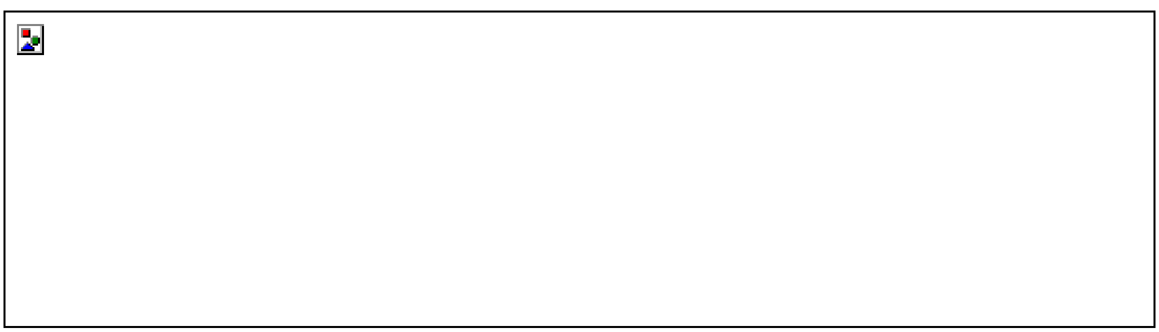
B&W/SFA computed that the cost of a CT/CC plant would increase 10% if as a Kalina (880 vs 800/kW). The incremental cost of capacity is 1500/kW. Hence economic viability will depend on the price of gas. At $2/106 Btu it is unlikely to be attractive; if $4/106 - it could be so. Site specifics will dictate.

Ocean Thermal Energy Conversion

An OTEC system is a bottoming cycle using an ammonia working fluid/turbine to extract usable energy to generate additional electrical output, thereby increasing efficiency and decreasing per unit GHG emissions. The technology is at an early stage of development and application is most likely where a large temperature differential can be found in the ocean environment.

Multiple Rankine Topping Cycles

By making use of multiple working fluids (e.g., sodium, potassium, mercury, diphenyl, etc.) then the temperature range on which the cycle functions can be dramatically increased, leading to large increases in overall cycle efficiency. For example:



Critical Development Needs

Combined cycle technology has followed gas turbine technology development and thus development needs are, to a large extent the same. A particular area for research includes maximizing steam conditions (P&T).

Operational experience with high efficiency CT's to provide confidence in reliability/availability/maintainability is required to be built up. Risk areas continue to be long term performance of high efficiency CT's and, performance of HRSG's in typical utility operating regimes. Also a requirement is the demonstration, at utility scale of the CHAT and KALINA cycles, so that operational and material design issues can be addressed.

FUEL CELLS

Summary of Technology Concept

A fuel cell is a device which produces electricity directly from specific fuels electrochemically. Several derivatives are undergoing development which are pertinent to the electrical utility industry, i.e., acidic cells (largest unit 11 MW, 200C, 1-8 atm, 48%), molten carbonate cells (2 MW, 650C, 1-8 atm, 50%) and solid oxide cells (100 kW, 1000C, 50%). Solid polymer, or Proton Exchanger Membrane, cells (5 kW-250 kW, 80C, 1-2 atm, 45%) have a possible long term utility application, however, motive power appears to be the primary niche for development. Alkaline fuel cells are used in the space program and may find a niche in the motive power field eventually.

The development closest to commercialization in the utility area is the phosphoric acid fuel cell. Fuel, H2, is fed into a porous anode electrode. If natural gas reforming is used to produce H2, the final CO content after shift reaction is 1%. Oxygen or air is fed into a porous cathode electrode. The electrodes contain a platinum or sintered nickel catalyst which breaks the fuel down to an atomic level, hence increasing its reactivity. Electrode porosity is important so that fuel and electrolyte can penetrate and hence achieve proper contact. The injected fuel is ionized (i.e., gives up electrons, which flow to the load as a direct current) while the hydrogen ions flow through the phosphoric acid electrolyte to the other electrode where they combine with the cathode reactant feedstock, O2, to form water vapour which is rejected. The overall principle of energy release is due to a change in the enthalpy of formation. The chemical energy not converted to electrical energy appears in the cell as heat which must be removed. As the thermal energy regime is not passed through then the conversion efficiency is not limited by an external reversible heat engine cycle, hence high efficiencies are potentially achievable (i.e. 40% for 200 kW units) however, if heat recovery (100 kW @ 120C and 100 kW @ 60C) is maximized by cogeneration then 80% is anticipated as being possible. The major issue is the high cost of hydrogen production at this time.

The molten carbonate fuel cell is considered to offer the potential of the highest overall cycle efficiency of any single cycle fossil fuel based technology (i.e. 57%). When cogeneration is included an overall efficiency of >80% is anticipated. Initial development efforts are concentrating on the use of natural gas as a feedstock; however, in the longer term gasified coal is a primary goal. As a consequence of the 650C operating temperature of the MCFC internal reforming of natural gas (CH4) into hydrogen and carbon monoxide is possible. Further, by means of the water shift reaction a portion of the CO is shifted to CO2with the coproduction of hydrogen. In this way the efficient use of fuel is maximized.

Natural gas enters the power plant and is mixed with hydrogen recycle from the electrochemical hydrogen transfer device. The mixture is desulphurized in the fuel clean-up system to ensure the H2S content is 0.1 ppm. Steam for reforming the CH4 to CO2, H2 and CO, is added from the boiler, and the mixture is fed to the molten carbonate fuel cell fuel inlet. The fuel is reformed and consumed producing D.C. power which is processed by the self commutating power conditioning system to produce A.C. power. The hot spent fuel from the fuel cell is passed through a boiler and provides heat to raise steam. The cooled spent fuel is then passed through a hydrogen transfer device, where unutilized hydrogen is extracted and recycled back to the fuel cell inlet. The remaining gas, which is rich in carbon dioxide and water is cooled to recover the water which is pumped to the boiler, thereby making the plant water self sufficient. The dry gas, which is rich in carbon dioxide is mixed with air to provide the oxidant gas needed for the cathode side of the fuel cell. The carbonate ions so produced migrate through the electrolyte to the anode where CO and H2 are oxidized and electricity is generated. A recycle stream around the fuel cell cathode recirculates carbon dioxide, and provides heat to pre-heat the air required. The exhaust gases leaving the fuel cell cathode are released to the atmosphere directly. Optional cogeneration equipment can be installed to recover heat from the exhaust gases.

Solid oxide fuel cells are potentially the most economic of the developing cells because of the lack of exotic materials in manufacturing, and are highly efficient electrochemical devices that can operate at atmospheric or elevated pressures (thereby boosting output) and at temperatures in excess of 1000C to produce electricity from fossil fuels such as coal derived fuel gas, natural gas, or distillate fuel. The temperature of the exhaust gases from the cells is between 500 to 900C - a temperature which is attractive for cogeneration applications or for use in combined cycles with a gas turbine, the latter offering efficiencies of 70%(). Internal reforming of natural gas is accomplished within the unit.

The SOFC cells readily conduct oxygen ions from an air electrode (cathode), where they are formed, through a solid electrolyte to a fuel electrode (anode), where they react with carbon monoxide (CO) and hydrogen (H2) contained in the fuel gas to delivery electrons and produce electricity. The state-of-the-art tubular SOFC developed by Westinghouse features a porous air cathode electrode made of strontium-doped lanthanum manganite. A gas-tight electrolyte of yttria-stabilized zirconia (approximately 40 microns thick) covers the cathode electrode, except in an area about 9 mm wide along the entire active cell length. This strip of exposed cathode electrode is covered by a thin, dense, gas tight layer of magnesium-doped lanthanum chromite. This layer, termed the cell interconnection, serves as the electrical contacting area to an adjacent cell or to a power contact. The fuel anode electrode is a nickel-zirconia cermet and covers the electrolyte surface except in the vicinity of the interconnection. For operation, air is introduced to the fuel cell through an air injector tube. The air, discharged from the injector tube near the closed end of the cell, flows through the annular space formed by the cell and the coaxial injector tube. Fuel flows on the outside of the cell. Typically, 85% of the fuel is electrochemically utilized (reacted) in the active fuel cell section. At the open end of the cell, the remaining fuel is combusted using the oxygen depleted air stream exiting the cell. A cycle efficiency of 50% is anticipated for a mature SOFC facility (without a bottoming cycle). Development efforts are also underway with planar and monolithic SOFCs.

Critical Development Needs

- Certain aspects of fuel cell development are of concern:
- Very high capital cost and O&M.
- Due to limited manufacturing experience confidence in capital cost projection is low.
- O&M costs need to reduce, by increasing stack life (now 5 yrs. and 2 ¢/kW.h)
- Demonstrate reliability, operability, maintainability and unmanned operation.
- The development of higher temperature cells (i.e. molten carbonate and solid oxide) is anticipated to eventually improve operating costs. In the longer term the use of coal as a feedstock, say for a gasifier or methanol production facility, coupled with cogeneration, could lead to base load units due to the potential for high cycle efficiency.
- Long term fuel cell stability and lifetime must be proven. Minimization of cell voltage depreciation with time.
- The use of exotic catalyst materials and their associated high costs, point to the need to identify less costly alternatives.
- Development of a low cost, efficient multi fuel reformer for CO/H2 production (diesel, JP #8, etc.).
- Maximize power density of cell, as plant footprint is large C.F. other dist. gen. alternatives.
- Development of catalysts which will permit operation in conjunction with fuels contaminated with sulphur.
- Optimize design of PAFC and SOFC to facilitate CO2 removal and disposal.
- Optimization of thermally integrated MCFC and SOFC fuel cells/gasifier/ cogeneration.
- Development of hybrid FC/renewable energy mixes for off-grid remote locations.

GAS (COMBUSTION TURBINES)

Summary of Technology Concept

Utility use of combustion turbines has grown steadily, particularly for peaking power purposes. With the recent increase in natural gas utilization, particularly in utility scale combined cycle application (maximum cycle efficiency proven to date ~ 58% (LHV)) where the turbine exhaust gases are passed through a heat recovery boiler for raising of steam (and projected implementation of gasification combined cycle technology), there is a significant demand for further development of combustion turbines (i.e. maximize turbine inlet (firing) temperature, optimize cycle pressure ratio, minimize NOxformation, take advantage of increased outlet temperature of 600C, by implementing heat recovery with reheat capability). The high efficiencies proven facilitate use of fossil fuel with comparatively low GHG emissions. Various CT cycle improvements being pursued at this time (eg. intercooling, reheat, recuperation) could lead to the maximum potential for a single cycle efficiency of 55% ().

State of the art development has taken inlet temperatures to >1300C using conventional materials, and advanced cooling techniques. Further, the use of single crystal blades, and, steam cooling will facilitate further improvements in performance. It is postulated that should ceramic blade technology be successful then ultimately 1925C could eventually be attained.

For any of the advanced CT based cycles to be attractive they must generate energy cheaper than the larger utility frame (eg. 7F, etc.) based combined cycle units. Hence, either capital cost must be lower, or, efficiency higher. Also as development costs could be $100(+) million (US) the market must be assured. At this time the intercooled aeroderivative [ICAD] is the favoured option for successful development/application. This unit if successful would lead to further advanced cycle development (eg. HAT, etc.). Commercialization of ICAD by 2000() is a possibility.

NERC availability data for all GT's in the US 1991/95 was 90.3%, based on 3341 unit years of operation. Appropriate risk analysis must be undertaken when considering advanced machines as it is not uncommon for serious design flaws to become apparent with new lines.

Critical Development Needs

- - Minimize life cycle cost and technology risk
- Establish appropriate degree of confidence in reliability and availability of advanced units
- Internal blade cooling optimization (precooling air vs steam vs water vs film)
- Demonstration of high inlet temp gas turbines 1300C
- Maximize inlet temperature (1260 1925C)
- Dry Low NOx burner operational pedigree needs to be improved
- Development of higher efficiency units (ICAD) and cycles (e.g. Humid Air Turbine (HAT); intercooled steam injected gas turbine (ISTIG); chemically recuperated gas turbine (CRGT)
- Blade coatings for fuel specific properties
- Direct coal fired combustion turbine
- Catalytic combustion (lean fuel stabilization plus low NOx)
- Monitoring and control improvements
- Ceramic blades and coatings (advanced oxide dispersion strengthened ceramics).
- Demonstration of indirect coal firing of gas turbine using ceramic heat exchanger.
- Design of high effy units fired with low Btu gas (air blown gasifier).
- Development of fibre reinforced ceramics for high temp. rotors.
- High strength monolithic ceramic materials.
- Reinforced ceramics for rotors.

- Elimination of cooling air.
- Engine design simplification.
- Reduced clearances.
- Improved aerodynamic performance.
- Overcome brittleness hurdles.
- Alkali corrosion concerns with coal gas.
- Develop standardized industry approach to C.T. O&M. ATMOSPHERIC CIRCULATING FLUIDIZED BEDS

INTEGRATED GASIFICATION COMBINED CYCLE

Summary of Technology Concept

The benefits of high cycle efficiency and the need for strict environmental control for future thermal generating stations has led to the development of the Integrated Gasification Combined Cycle process. This technology offers the most cost effective means of minimizing CO2 emissions from a coal based generating system.

By contacting coal (or other carboneous feedstock such as refinery bottoms), oxygen or air, and in some cases steam, in a reactor (e.g., fixed bed, fluidized bed or entrained flow), at elevated temperatures and pressures, a product gas comprised of carbon monoxide, hydrogen and methane as well as carbon dioxide, water vapour, nitrogen, hydrogen sulphide and other trace gases (e.g. HCN, COS, HCl, etc.) is liberated (typical gas analysis for Shell gasifier: H2 31%, CO 61%, CH4 2%, CO2 4% etc.). The relative proportions of the various gases and the calorific value of the gas is fuel and process specific. The product gas is processed to remove the acidic and particulate components and finally combusted in a gas turbine. Any heat generated in the process can be utilized to generate steam. Hence, electricity production is maximized in this multi staged process. A further possibility is the co-production of electricity and chemical feedstock, thereby maximizing gasification potential, taking advantage of any utility cycling needs, and compensating for the part load performance limitations.

Demonstrations of this technology have proven to be superior environmentally to any alternate fossil fuel based technology (e.g. SO2 emission 0.1 lb/106 Btu; NOx emission 0.1 lb/106 Btu; particulate emission 0.01 lb/106 Btu; solid waste a non hazardous slag). Recent availability figures have indicated ~ 70-80% on single train facilities. The advent of high inlet temp gas turbines, concern over CO2, possible tightening of SO2 and NOx emission limits, solid waste emissions, and also improvements in reactor, gas cleanup and integration designs indicate that IGCC may posses a competitive edge in the appropriate circumstances. At this time a number of advanced, utility scale, demos are going through commissioning/initial operation. The performance of these units will be critical to the penetration of this technology into the marketplace.

With the enormous investment in natural gas delivery systems in North America, the scenarios where coal fired gasifiers (high pressure) generate synthetic natural gas (following methanation), which is then distributed to the appropriate generators, etc., is quite conceivable. However, for regions devoid of a gas infrastructure, conventional IGCC offers a workable option when economics are favourable.

The developer goal is to achieve an IGCC capital cost of $1,200 (US)/kW and 3.5 ¢/kWh energy cost. This may be achievable through: economy of scale; reduce EPC schedule to 24 months; use of low value fuels (heavy bottoms); trigeneration of electric/heat/chemicals, strict environmental constraints.

Critical Development Needs/Issues:

- - Long term operation of utility scale demonstration units to prove reliability, operability.
- Determine whether costs can be reduced, and performance acceptable, by following means:
  - Partial gasification/char burnout cycle
  - Air blown vs oxygen blown gasifiers
  - Dry fuel feed vs slurry feed
  - Dry gas cleaning vs wet gas cleaning
  - Maximize practical economic integration of all systems and minimize spare equipment.
- - hot gas clean up and high temp control valves
  - Optimize steam conditions and degree of integration

Process simplification should be promoted to improve operability and maintainability. Therefore CT technology improvements ('G', 'H', IG CHAT) can offer opportunities for efficiency improvement.

- - Minimization of coal pretreatment and fines control (BGL).
- Optimization of coal drying/energy source, if required.
- Advanced gasifier development: catalytic; transport reactors; pulsed gasifier.
- Hot gas cleaning process simplification with emphasis on low cost regenerable H2S sorbents; and higher temperatures; also cleanability as a function of fuel; metal/ceramic bonding; ceramic durability in the presence of water vapour and alkali; alternatives to candles (i.e., crossflow); and alternatives such as alumina fibrous materials and composite materials to improve strength and temperature withstand; control of trace element emissions. Significant problems have been experienced with HGCU (Buggenum, Wabash) hence application with 02 blown IGCC is not seen as a strong likelihood and in fact results in little efficiency improvement. Air blown gasification requires HGCU hence the Pinon Pine demo will be closely monitored.
- Identify low cost sorbents for gas cleaning (perhaps by-product, from other industries such as Cu/Ni compounds, Ca/Fe compounds). Also need to limit attrition losses.
- Improve efficiency of air separator system (better integration of process columns; dual reboiler process; maximize intercooler usage; minimize refrigeration requirements; minimize power consumption; use of ion transport membrane separators; recovery and sale of argon; pressure swing adsorption).
- Determination of benefits and practical limits of plant integration; thereby improving efficiency and reducing cost, while maintaining adequate availability:
- use of excess gas turbine compressor capacity, if available, to supply high pressure air to air separation unit.
- use of nitrogen for NOx control.
- recovery of low level energy (e.g. air separation heat of compression).
- use of heat recovery to heat fuel gas directly and hence maximize efficiency.
- optimization of steam cycle conditions taking into account other process improvements above.
- use of supplemental firing for peaking.
- single vs multi shaft gas turbine/steam turbine/generator.
- hot gas clean up impact on combined cycle performance.
- coal drying
- level of NOx control
- Optimization of heat recovery unit design (fuel specific), performance, materials, corrosion, erosion and fouling. Fire tube vs water tube SGC.
- Minimization of CO2 emissions by the conversion of CO to chemical feedstock leaving H2as the gas turbine fuel

- Removal of CO_2 for use elsewhere (i.e. enhanced oil recovery).
- Identify market potential for solid by-product - sulphur, ash.
- Commercialization of high inlet temp gas turbines (2300F to 2800F) to improve overall cycle efficiency. Also development of combustors which can accept hot fuel gas from gasifier.
- Optimization of advanced low NOx gas turbine burners on cool and hot (600C) syngas as opposed to natural gas.
- Development of microwave plasma H_2S dissociation process for S recovery.
- Commercialization of the HYSULF liquid redox system (H_2S H_2 & S)
- Use of Nitrogen from the air separation process for gas turbine NOx control.
- Particulate/alkali/and trace element removal for the protection of turbine blades, etc. (cyclones, ceramic filters, hot ESP's, metallic or fibre filters).
- Reactor and syngas cooler material performance and lifetime in reducing conditions, particularly with high sulphur, chloride and iron coals (e.g. refractory; high (>27%) chromium steels with vanadium or molybdenum).
- Control of down time corrosion (inerting).
- Ammonia control.
- Optimize design for high chloride coals.
- Maximize water reuse and minimize fresh water consumption, demineralization and waste water treatment.
- In slurry fed gasifier maximize slurry solids content.
- Improve confidence in cap/op costs for optimized IGCC process train using bituminous coals.
- Design development to ensure system wide overall availability of 85% +.
- Optimization of chemical feedstock/electricity co-production.
- Improve gasifier turndown ability.
- Improve burner lifetime & changeover time.
- Plant optimization to maximize efficiency and operability for the life of a facility.
- Safety issues CO, H_2S, high pressure O_2, need for hazard analysis.
- Testing of local coals in a demonstration unit to confirm design parameters and obtain process guarantees. Quantify impact of high chlorine and iron in coals.
- Quantification of benefits/penalties of phased construction on a site specific basis.
- Development of liquid phase methanol co-production.
- Development of dimethyl ether/gasoline/diesel co-production.
- Integration with fuel cell development (MCFC).
- Development of IGHAT, IGCHAT and IGCASH cycles to improve economics further. IGCHAT aims to capitalize on the latest proven gas turbine technology, which combined with a sophisticated thermal cycle configuration, is projected to result in substantial improvement in efficiency, while still maintaining typical advantages and merits of a combustion turbine plant. Built with a commercial combustion turbine and available industrial compressors and expanders, the CHAT plant is claimed not to require extensive product development.

MAGNETOHYDRODYNAMICS (MHD)

Summary of Technology Concept

MHD power generation is a process for the direct conversion of thermal energy to electrical energy. In theory an MHD generator channel and a conventional generator are based on the same electromagnetic induction principle. According to this principle, if a conductor, solid, liquid or gas, is moved through a magnetic field, an electric field will be induced in the conductor. In a conventional generator the conductor is the copper windings of the armature. In a open MHD channel, the conductor is the high temperature gases produced by the combustor which pass through the magnetic field and generate a direct current. The current must be conditioned by an inverter prior to feeding onto the grid.

An MHD power plant has two major subsystems. The first subsystem is the MHD topping cycle and the second is the steam bottoming cycle. Both the topping and bottoming cycles produce electrical power which, when combined, represents the total output power from the plant. In theory this is a highly efficient process; however, significant technological hurdles exist.

The MHD process requires that the gas flowing through the MHD channel be electrically conductive, (i.e., a plasma), and of high velocity. To render the gas electrically conductive, it must be at a high temperature and have a small amount of an easily ionized seed added in the combustion chamber. The seed material is usually in the form of a salt, (i.e., potassium carbonate). The combustion gas temperature required by the MHD process is typically in the range of 2500 to 3800 C. The high combustion temperatures needed by the MHD process require the use of either high temperature combustion air, at about 1400 C, or oxygen enrichment of lower temperature air, (i.e., air enriched to ~ 34% oxygen). Early commercial MHD plants will probably be built with oxygen enrichment of the combustion air or separately-fired air heaters, however, NOxemission control will require addressing.

The potassium sulfate recovered must be regenerated to a non-sulphur containing form for reinjection into the combustor. Particulate matter (mostly submicron) is removed from the flow stream, prior to entering the exhaust stack, by either an electrostatic precipitator or a baghouse filter. It has been postulated that the presence of potassium in the flue gas, which is readily ionized, will improve precipitator performance. Oxidant staging can result in very low NOxemission levels.

Closed cycle MHD using a noble gas (Ar or He) achieves a suitable degree of conductivity at lower operating temperatures, thereby avoiding the extreme materials problem associated with high temp MHD. Japan is the only major proponent of closed cycle MHD.

Critical Development Needs

- - Proof of concept demo (2 MWe)
- cycle development & optimization
- high temp. air preheater development/material science
- material selection and performance (particularly electrodes)
- utility scale combustor development
- seed recovery and regeneration
- channel design and scale up (to 70 MWe +) linear vs disc
- superconductive magnet design and scale up
- nozzle development and scale up
- NOx/SOx/particulate reduction
- interfacing of bottoming and topping cycles
- inverter design and scale up (to 70 MWe +)
- high pressure coal conveying system
- electrical isolation of ancillary equipment (-40 kV DC ())
- demonstration of long duration operation of channel at utility stress conditions
- fully integrated system operation

PARTIAL (MILD) GASIFICATION

Summary of Technology Concept

Mild or partial gasification has been identified as a potential means of significantly improving the cycle efficiency of pressurized (hence also called second generation PFBC) and atmospheric fluidized bed combustion, thereby considerably reducing the emission of CO_2, SO_2 and NO_x per unit of generated electrical energy.

Mild gasification is a devolatilization process designed to produce a suite of alternative fuels by decomposing coal into simpler components at relatively mild temperatures (540C - 650C) and pressure (1 - 2 bar). The coal, which is heated by the presence of limited air, pyrolyses to yield: a solid carbon char (20-40% of feed); a complex of hydrocarbon liquids; hydrocarbon gas; and aqueous liquor.

The potential exists to combust the char in a conventional PFBC or ACFB boiler to raise steam and hence electricity. Meanwhile, the gaseous and liquid products could be cleaned and combusted in a gas turbine, also resulting in the production of electricity. Alternatively, the liquid hydrocarbons could be processed for use as a liquid fuel or chemical feedstock.

The significant advantage of partial gasification over total gasification is that initial volatilization and gasification of coal are achieved relatively easily, whereas the total gasification of the char requires more energy and time. Consequently by partially gasifying and then combusting the char in a fluid bed combustor to raise steam an optimum is claimed between the gasifier and combustor sizing, as well as the steam and gas turbines.

It has been postulated that the overall power generation cycle efficiency could be raised to approximately 45% by this means as compared to 34% for a conventional CFB unit and 40% in a PFBC. SO_2 emissions would be reduced by 90% by means of limestone sorbent in the CFB and gas cleaning prior to the combustion turbine. NO_x would be controlled by conventional means in the CFB and gas turbine. SCR may be required to meet very low NO_x levels.

Critical Development Needs

See coal gasification, also:

- - Scale-up. Spouted bed reactor geometry may necessitate multiple units.
- Spouted bed operation at high pressure needs demonstration.
- Optimization of partial gasification system/ costs.
- Determination of benefits and practical limits of plant integration; particularly when retrofitting to an existing CFB.
- Minimization of CO_2 emissions.
- Identify market potential for by-products
- Optimization of advanced gas turbines on Low Btu syn gas as opposed to natural gas.
- Improve confidence in cap/op costs for partial gasification process train using bituminous coals retrofitted to CFB unit.
- Determination of partial gasification potential and design ramification of specific coals in specific pilot gasifiers by testing specific fuels, considering both power production and co-production of chemicals.
- Market research for coproduct usage.
- Testing of local coals in a demonstration unit to confirm design parameters and obtain process guarantees.
- Long term operation of a near utility scale demonstration unit.

- Hot gas clean up system (materials, cleanability, trace element fate, etc.)

Uncertainties include: -

- Limestone addition effectiveness
- Oxidation of CaS CaSO4
- Solid waste inventory and disposal
- Hot particulate removal reliability
- Hot char transfer from gasifier to CFB
- Fate of chlorine and fluorine
- Tar handling/management
- Trace volatiles fate
- Ammonia NOx emissions
- CO emissions from low BTU gas
- Compatibility with CT's (Na, K, Ca, Cl, Sox), particularly the more complex advanced machines
- Hot desulphurization (effectiveness and temperature limits)
- Gasif. unit scale up
- Partial gasification for coproduction is at atmospheric pressure. There is a need to demonstrate high pressure operation for power production.

PRESSURIZED FLUIDIZED BED

Summary of Technology Concept

The pressurized fluidized bed technology consists of a fluidized bed operating at an elevated pressure (12-18 bar) which increases the gas density and reduces the bed area for a given heat release. Limestone or dolomite are used as SO2 sorbents. The combustion air is compressed, heated (within the combustor) and expanded through a suitable gas turbine, after part or all of the dust is removed. As the bed temperature (and hence gas temperature) is limited to <900C to prevent ash softening, etc., then to maximize cycle efficiency high pressure ratio CTs, with compression intercooling are used. The considerable thermal energy within the expanded flue gas is then recovered within a steam generating boiler. Hence the pressurized fluidized bed is a combined cycle design which substitutes a fluidized bed for the combustion chamber of a regular gas turbine.

- The concept can be incorporated into new or existing installations in a similar manner as atmospheric fluidized bed with the anticipated advantages of:
- smaller size for a given rating (bed cross-section 50 MW/m2 for PCFBC and 15 MW/m2for PFBC compared to 7 MW/m2for ACFB and 1.5 MW/m2 for AFBC) hence increased retrofit potential.
- higher cycle efficiency
- potential lower costs due to modular construction
- higher sorbent utilization efficiency

There is a growing interest in combining PFBC with partial coal gasification, as cycle efficiency improvements are postulated when high gas turbine inlet temperatures can be used to advantage. This has become known as second generation PFBC (see brief on partial (mild) gasification).

Critical Development Needs

Most PFBC designs included 100% post combustion particulate removal prior to expansion through the gas turbine. This requires high temp clean-up including fine particles. These techniques remain under development and are currently restricting the commercial application. HGCU problems have been experienced at TIDD and Wakamatsu, as well as at IGCC demonstrations.

ABB have chosen to use two levels of gas clean-up. The cyclone hot gas clean-up will only remove particles considered detrimental to the gas turbine (5-10 micron) and will utilize conventional back-end particulate removal for emission control. The projects detailed above will test the applicability of this design within 24 months of operation. Apparently the key area of concern is the wear rate of the small diameter high temperature cyclones used for hot gas cleanup.

Other areas of concern include:

- - Prevention of gas side corrosion by limiting bed temp.
- Effectiveness of gas turbine blade coatings to prevent particle erosion/alkali corrosion.
- Demonstration of hot gas cleaning (ie. high temp creep., thermal shock, dust cake reactivity, material degradation, alkali and vapour phase trace element fate), and the ability to fire a base load gas turbine, particularly considering upset conditions.
- Demonstration of in bed evaporator tube life suitable for commercial consideration.
- Demonstration of a hybrid partial gasification/PFBC combined cycle.
- Minimize N_2O formation.
- Improved cycle efficiency by maximizing steam conditions (e.g. supercritical).
- Safety issues concerning high pressure operation during trip conditions.
- Minimizing maintenance inside of the pressure vessel because of excessive downtime requirements.

REPOWERING

Summary of Technology Concept

Repowering is the integration of new state-of-the-art equipment with the usable, existing equipment at a site in order to boost plant thermal efficiency, reduce emissions of CO_2, $SO_2$and NO_x and extend service life and reliability. In most cases, a significant increase in total plant output can also be realized, thereby maximizing the energy supply intensity of existing sites. Also repowering benefits can be maximized if in conjunction with a fuel change.

A number of choices exist for repowering, running the gamut from a relatively simple fuel switch from coal to gas, or heavy fuel oil to Orimulsion, to a highly complex partial gasification or IGCC conversion. The following repowering options are available for consideration:

Fuel switching to gas would most likely in the longer term be coupled with a cycle change and would provide the benefits of lower emissions, higher efficiency, and increased generating capacity.

Gas Conversion of Conventional Coal/Oil Fired Boilers - In many cases gas can be fired directly, either as a partial feed or as a sole fuel feed, in boilers originally designed for oil or coal. Because of differences in the fuel combustion properties efficiency and capacity penalties may result which may be costly to overcome.

Conventional Combined Cycle - (CC) repowering adds a new gas-fired or distillate-fired combustion turbine (CT), and a heat recovery steam generator (HRSG), to an existing oil or pulverized coal fired plant steam turbine/generator and balance of plant equipment. Benefits include up to 30% improvement in heat rate, up to 150% increase in generating capacity, and a significant decrease in environmental emissions. Should long term, base load, operation be projected using gas then combined cycle conversion will most likely be the preferred long term option. In some cases the steam turbine may also be replaced, resulting in a more optimal solution.

Windbox Repowering - A gas or distillate-fired CT exhausts into the windbox of an existing pulverized coal (pc) or oil fired boiler providing all or part of the combustion air. This is most suited to newer, efficient units over 250 MW capacity. Hot windbox repowering refers to the hot exhaust going directly into the windbox, while the cold windbox option includes an HRSG before the windbox. The main advantages of this scheme include up to 30% increase in electrical output at up a 15% improved heat rate and moderate environmental emissions reductions. Drawbacks include possible modifications to the windbox, boiler pressure parts and air heaters, depending on original boiler design, hence, conversion could be complex and costly. The existing boiler is retained and hence this may not be attractive for older units.

Feedwater Heater Repowering - A gas or distillate-fired CT exhausts into a recuperative feedwater heater, where all or some of the feedwater for the existing oil or coal fired boiler is heated. This scheme involves minimal plant upgrade and has the potential to increase electrical output by up to 50%. However, heat rate improvement will likely be limited to 5% (). Capital requirement may be substantial. The existing boiler is retained and hence this may not be attractive for older units.

Orimulsion - This fuel, a bitumen in water emulsion, can be substituted in oil-fired or pc-fired units. The main benefit is the price stability, which is based on world coal prices and is locked into long-term (usually 20 years) contracts. The disadvantages are that O&M costs will increase due to an almost certain necessity of a sulphur dioxide scrubber addition, the possibility of derating, and a slight increase in heat rate.

Low-Grade/Low-Cost Fuels - The use of biomass waste, discarded tires, municipal waste, petroleum coke, or other opportunity fuels at low cost, as co-fired fuels at a fluidized bed repowering scheme, could provide a cost advantage, and depending on the fuel, an environmental benefit.

Coal Gasification Combined Cycle (IGCC) Repowering - This is essentially the same as the conventional gas combined cycle, except that the CT fuel is provided by gasifying coal. The benefits are similar to the CC case, except that the efficiency increase would not be as high (up to 25%), although output capacity would be increased somewhat, and there would be some, although quite small, SO2 emissions. This is the cleanest coal utilizing technology under development at this time. The main drawbacks of this repowering option are high initial capital costs, and significant physical space requirements.

Atmospheric Fluidized Bed Combustor Repowering - This involves replacing an existing boiler with a bubbling or circulating bed unit, and provides the benefits of fuel flexibility, lower NOxand lower SO2 emissions. However, output and efficiency may decrease marginally, and solid waste disposal requirements will increase considerably.

Pressurized Fluidized Bed Combustion Repowering - This is similar to repowering with an atmospheric fluid bed; however, to recover energy from the pressurized hot combustion gases, a gas turbine is installed (hence this is a combined cycle), resulting in perhaps a 10-20% heat rate improvement and a 20-40% power output improvement. Pressurization also brings a significant size reduction in footprint requirement. NOx and SO2 emissions will be decreased significantly, but solid waste disposal will increase (less so, on a per unit energy produced basis, than for an atmospheric fluid bed, however). In many cases this may be the most attractive coal burning technology, from an economic stand point, with highly retrofittable characteristics.

Partial Gasification Repowering - In this scheme, coal would be partially gasified in a PFBC reactor vessel to produce syngas and char. The char and supplemental fuel (most likely coal) could be combusted in a

CFB, while the syngas would enter a topping combustor, the exhaust from which would power a gas turbine/HRSG. A potential 20-30% heat rate improvement and up to a 150% increase in generation output are projected for this option. However, no commercial unit yet exists, hence this is a longer term option.

Kalina Cycle Repowering - The Kalina cycle proposed utilizes a power cycle with extensive regenerative heating of an ammonia-steam working fluid, as compared to steam in a conventional pc or oil fired plant. Efficiency improvement is based on raising the average temperature at which the power cycle accepts energy from the heat source. This involves totally reworking the existing boiler internals while providing an extensive heat recuperation system. Benefits claimed but not demonstrated include an efficiency increase of about 3 percentage points, and attendant CO2 emissions reduction, and a power output increase of about 35%. Drawbacks include the early state of development (3 MW pilot plant), the physical space requirements, and the safety concerns in handling ammonia.

Obviously, the main justification for implementing a repowering scenario is that cost savings and profits will be generated. With the capital intensiveness of these options the long term viability, say 20 years, of the investment has to be assured. The questions are what will the impact of de-regulation have on these investments? What is the likelihood of securing commitments from Purchasers? What are the relative fuel economics likely to be over a 20 year period?

Technology Development Needs & Measures

There are many technical issues which may require specialist input such as: steam cycle thermodynamic (Pinch Point) analysis to ascertain optimum gas turbine/HRSG/steam turbine integration; turbine analysis to determine the most appropriate steam flow, extraction/induction flows, blade loading and upgrade possibilities etc., boiler upgrade requirements when changing fuels (i.e. Orimulsion).

A key issue to be resolved is whether enough confidence exists in the highest efficiency units commercially available such that a firm commitment can be made in the near term to apply this technology.

Technologically the following advancements are required:

Further improvements to gas turbine technology so that 150 MW reheat units can be repowered efficiently with one gas turbine (e.g., 'G' M/C)

IGCC technology needs to advance to truly commercial readiness through efficiency improvements, cost reduction and operational simplicity.

PFBC needs to be truly commercialized and demonstrated at utility scale (300 MW).

Partial gasification has to be advanced from the near pilot scale to utility scale.

The Kalina cycle needs to be further developed so that a realistic appreciation of cost impacts and performance benefits is available.

COGENERATION/DISTRICT HEATING/COOLING

Summary of Technology Concept

When fossil fuels are burned in a typical power plant, only about 35% of the available energy is converted to electricity. The remaining 65% is released to the atmosphere as rejected heat in the cooling water, or up the stack as hot flue gas. Because the rejected heat is at a comparatively low temperature, it is not readily available for use for other purposes. It is possible to modify the steam cycle and remove some of the heat at a higher temperature and pressure and use this for space or process heating. This process, called cogeneration (of steam and electricity), can result in fuel utilization rates in the 80% range. In cogeneration mode steam can either be extracted from condensing or non-condensing (back pressure) steam turbines, with either simple or multiple pressure level extractions. The process/space heat produced in the cogeneration cycle results in fuel conservation and consequent lowering of greenhouse and acid gas emissions. Cogeneration in an appropriate setting may be one of the most cost effective means of minimizing GHG emissions.

A district heating network is formed of insulated pipes which convey a heat transfer fluid (i.e. water or steam) between the heat production centres and distribution centres supplying various users. Large cogeneration power plants provide the baseload heat production with other smaller sources possibly providing the peak loading in winter. District heating networks can be as large as 20 to 30 kilometres across and in the case of hot water can include several pumping stations for moving the heat transfer medium along. Heat consumers have their own individual metered heat exchangers. The choice of extraction point and heat carrier medium will primarily be governed by the existing load characteristics. For example, the presence of a large steam load may strongly influence the use of steam. It must be appreciated that there has in effect been a revolution in the technology of choice in recent years. For most domestic and institutional based district heating systems the preference today is for low/medium temperature hot water as a heat carrier. Some of the advantages of low/medium temperature hot water include; economical production costs, lower transport heat losses, lower system installation costs, lower risk of leakage and corrosion, simplicity of control and heat storage capacity within the system. All factors considered hot water systems have proven to be more efficient and cost effective than steam systems.

The incorporation of a district cooling infrastructure, using where practical the same right of way as a district heating network, appears attractive in many settings. Cooling options which could be considered include:

- - taking advantage of cold harbour water
- centrifugal vs steam absorption chillers (the latter only viable if very low cost steam available)
- ice storage

Critical Development Needs

This technology is well understood and currently being used in many countries. Maximization of penetration into Canadian municipalities needs to be promoted.

District energy systems are capitally intensive. To assist in the penetration of this environmentally attractive technology there will be a benefit of favourable taxation/depreciation conditions existing, thereby minimizing the initial financial burden. Efforts are continuing to encourage the Federal Department of Finance to consider this approach (Class 43).

UNDERGROUND THERMAL ENERGY STORAGE

Summary of Technology Concept

It is an established fact that the temperature of the strata below grade (i.e., rock, water, etc.) is comparatively stable when compared to surface fluctuations. The actual specific temperature will be somewhat regionally specific, however, for example at 30 - 50 meters depth a temperature of 8C may not be unreasonable all year round. Obviously, if there are site specific phenomena such as geothermal activity etc., then major local perturbations may exist, but in general the above holds true. Realization of this fact leads to the conclusion that advantage could be taken of this "mean temperature" for both cooling (in summer) and heating (in winter). Further, the underground medium (rock or water) can act as a heat battery so that in summer, heat can be transferred to the storage area (e.g. charging), whereas in winter heat can be extracted, resulting in a storage temperature below ambient (e.g. discharging), thereby amplifying the benefits of the stable environment underground. By this means, energy derived from fossil fuels can be reduced, with resultant GHG emission reductions.

The geology of the specific site will influence strongly the preferred means of application. For example, the most economic means of underground thermal energy storage (both heating and cooling) is called Aquifer Thermal Energy Storage (ATES), where an aquifer is tapped into and water is extracted for heating and/or cooling purposes, the water once used being returned to the aquifer. Should the geology be such that hard rock strata prevails (i.e., granite, etc.) then ATES will not be practical. In this case Duct Thermal Energy Storage (DTES) is a possibility, whereby deep holes are drilled into the bedrock, heat exchanger pipes installed and energy is transferred within the resulting construct.

UTES is gaining in popularity, particularly in Europe where energy prices tend to be higher. Nevertheless, the largest borehole storage project globally is at Stockton University, New Jersey. The International Energy Agency (IEA) has been conducting R&D into the topic since 1976.

There are a number of demonstration/commercial operations, including an ATES installation at a hospital in Sussex, NB.

Data cited from Sweden states that there are three prime options:

- Use of heat exchanger only for heating and cooling (C.O.P. 20) can lead to 90 - 95% energy conservation at low cost.
- Heat exchanger plus heat pump for heat and cool (C.O.P. 5) can lead to 80 - 85% energy conservation at medium cost.
- Heat exchanger plus heat pump for heat only (C.O.P. 3) can lead to 60 - 75% energy conservation at high cost.

The choice of system (economics) is dictated by both load characteristics and primarily the heat/cool resource parameters (aquifer volume, hydraulic conductivity, specific heat, porosity, transmissivity, low regional velocity, good water quality, etc.).

Technology Development Needs

There is a need to transfer the appropriate technological tools to the market place. The IEA effort should foster this.

A more in depth assessment of the regional geology in Canada is required to determine promising areas.

Test case economic studies of installation vs region (ATES vs DTES) need to be undertaken so that a reasonable understanding of economics and performance, and hence competitiveness with conventional heating and cooling technology can be established.

The environmental implication need to be understood (i.e., pollution/contamination prevention, aquifer protection, water treatment needs, subsidence prevention).

Legislation needs to be established to protect resources and ensure that future ATES systems do not become corrupted (i.e., prevention of future access points impacting existing extraction/injection location performance).

GEOTHERMAL ENERGY

Summary of Technology Concept

Geothermal energy originates from the earth's high temperature, molten interior. The geothermal energy conducted from the earth's interior to its surface is of the order of 100 PWh; orders of magnitude greater than the demand for primary energy. Generally this is of low temperature, and/or access is complex, and to date is very regionally specific. Accessible geothermal heat sources of sufficient temperature can be harnessed with present technology to produce electricity. The main geothermal zones of the earth lie at the boundaries between the crustal tectonic plates, which coincide with areas of high seismic activity. Three categories of geothermal energy systems exist, namely hydrothermal (low temp 80-200C, high temp 200-260C); hot dry rock; and particular (such as geopressurized, brine and magma). To date, all commercial development of geothermal energy has involved hydrothermal. Technologies for exploiting the other categories are still under development, with geopressurized brine and hot rock possibly being commercially viable by 2005 (). Hydrothermal energy is used for electricity generation by injecting water through a well into a permeable, high temperature bed of rock. There are several different power conversion systems used for gathering geothermal energy. In applications where temperatures are sufficient, steam is produced directly in the reservoir, drawn from a second well, and fed to a turbine to produce electricity. Medium temperature systems pump hot water, or a hot water/steam mixture, to a separator/flash tank from which lower pressure steam is directed to a turbine. Binary systems, using separate working fluids (refrigerants or hydrocarbons) have been found to be even more efficient than flash plants for low to moderate temperature resources. Direct steam/binary hybrid systems have recently been installed at two plants to improve system efficiency further. To date, all commercial geothermal plants have been based on the Rankine cycle. The Kalina cycle is a binary system using an ammonia/water mixture as the working fluid. Rock temperatures for power generation can range from 100-360C, hence cycle efficiencies are relatively low (15%).

Geopressurized systems are hot water (<150C) aquifers containing methane, trapped under high pressure. The potential exists for utilizing the high pressure and chemical energy. The Gulf of Mexico possesses the only known major resource.

Magma chambers at depths of 3-10 km, and temperatures of <1,200C offer long term potential, and research is continuing into the technical challenges involved.

The United States has had success with the application of hydrothermal energy on the commercial scale. Presently, 2800 MW of capacity exists in the U.S., all but 50 MW in California. Other significant applications world wide are located in the Philippines, Italy, New Zealand, Mexico, Japan and Iceland, with a total global capacity in 1995 of 6,800 MW. This is anticipated to grow to 10,000 MW by 2000.

Estimated geothermal energy for Canada has been placed at 447 GW, being the third largest country in the world for geothermal potential. This figure does not necessarily reflect the power which could be produced economically in Canada. Large hot dry rock reserves exist in British Columbia though this source type has not been harnessed widely for electricity generation. For Hot Dry Rock to be economically viable recovery temperatures of 200C will likely be needed at depths less than 5 km. The other main source of geothermal energy exists in the prairies, where the estimated resource base is thought to be 320 000 000 PJ. This is in the form of low temperature water, the potential of which for use in electricity generation is limited.

The use of geothermal energy for non-electrical generation purposes may offer opportunities for industrial/commercial niche applications.

Critical Development Needs

- - Increasing efficiency of the flashed steam power cycle (20 35%).
- Non condensible gas removal (e.g. H_2S)
- Commercialization of binary system for moderate temp (< 200C) fluids using ammonia as opposed to isobutane or isopentane (Kalina cycle).
- Geopressure resource assessment of deep deposits of methane, hydraulic and thermal energy (< 3000 metres).
- Geopressurized brine development, using binary processes.
- Hot dry rock resource development (5000 metres). This resource is widely dispersed and has good potential.
- Utilization of deep magma resource by injection of water.
- Scale control in brine system.

HEAT PUMPS

Summary of Technology Concept

Heat pumps are devices which transfer heat from a low temperature source to a high temperature sink. They are used for the heating and/or cooling of buildings, processes or products. Air conditioners and refrigerators are common examples of heat pumps, operating in the cooling mode. The main components of a heat pump are the compressor, evaporator and condenser, as well as the refrigerant which is the fluid that circulates through the system. This refrigerant is alternately evaporated, compressed and condensed by the above components. During evaporation, the refrigerant absorbs heat from the surrounding environment, for example, inside a refrigerator compartment. The vaporized refrigerant is then compressed, which increases the vapor temperature. When this high temperature vapor is condensed, heat is released into the surrounding environment, such as occurs through the coils on the back of a domestic refrigerator. Just as a refrigerator uses a heat pump cycle to cool an internal compartment by transferring heat, heat pumps are also used to heat internal areas like the home. In the heating mode, heat is transferred from external areas such as the ground or air, even on cold winter days. The three main types of heat pump systems are: air source; ground source, (ground, ground water, surface water) [whereas ground source units are inherently higher cost installations than air to air units the performance is somewhat better in northern climates]; and internal source (industrial process using process water/exhaust air). There are also multi-source heat pump systems which can recover heat from several sources.

The heat pump can deliver more heat energy than the equivalent electrical energy used by the compressor. Typically, the amount of heat delivered is 200% to 400% higher than the heat delivered by an electric resistance heating system of equal electric input. Hence associated GHG emissions per unit of energy delivered are significantly reduced. The term used to quantify how efficient a heat pump is compared to electric resistance heat is the Coefficient of Performance (COP):

where TH = temperature of high temperature sink

TL = temperature of low temperature source

The higher the COP, the more efficient the heat pump. The COP of electric resistance heating systems = 1.0; the COP of conventional oil and gas-fired heating systems = 0.7-0.8.

Based upon the heat pump COP calculated for a specific application, anticipated energy savings should be weighted against capital before choosing a heat pump. Traditionally, heat pump systems are more expensive to purchase than conventional heating systems. Often, heat pumps are found to be most economical when used in conjunction with a supplementary oil, gas or electric-powered furnace for peak heating loads.

Critical Development Needs

- - Lowering of the capital cost.
- Current units are limited to producing hot water below the boiling point.
- Air to air HP optimization for Canadian climate.
- Higher efficiency and lower cost via working fluid/cycle R&D.

The heat pump has been developed and used around the world for decades; development needs prior to implementation would comprise an analysis of each potential application classification:

- - The weighing of potential energy savings against capital costs, using fuel costs specific to this area.
- The determination of impact on the generating process and the environment.
- The analysis of existing energy flows within the plant to determine availability, accessibility, quantity and quality (i.e. high grade vs. low grade heat sources).

HYDRO ELECTRIC POWER

Introduction

Hydro power provides 19% (690,000 MW) of global electricity output including 62,000 MW in Canada. The output of hydro plants falls into four basic classifications:

- - Large hydro > 10 MW
- - Small hydro 1 - 10 MW
- - Mini hydro 100 kW - 1 MW
- - Micro hydro < 100 kW

The largest Canadian facility is Churchill Falls, at 5,428 MW, and the largest in North America is Grand Coulee at 6,809 MW (including 3 x 805 MW units), whilst the largest global operation is at Itaipu, Brazil, at 12,600 MW. The 3 Gorges project in China will become the largest at 18,000 MW.

Hydro projects generally take one of two forms. The simpler run-of-river involves low head dams spanning a river, often incorporating the power house as an integral part of the dam. These projects are attractive for small plants or in areas where high water volume compensates for low turbine head. From an environmental point of view the small storage associated with these developments minimizes their impact to surrounding areas, although their effect on aquatic life may be serious without mitigating measures such as fish ladders.

- A diversion project is a more complex hydro development allowing greater control of water supplies but with a larger environmental impact. This type of development normally consists of:
- A dam to divert and/or store water
- A forebay, canal, tunnel or penstock (and surge tank) to deliver water from the storage area to the powerhouse
- The powerhouse itself
- A tailrace or draft tube to carry water downstream and back to the river

Water is stored during high flow periods in the spring to allow for relatively constant energy production throughout the year. The higher head normally associated with these plants produces more energy per volume of water than low head developments, an important factor in areas with limited water. These developments often result in water being diverted from the natural river channel. Water storage at a reservoir also requires flooding land and perhaps creating new water bodies. These are significant changes to the natural stream flow and create potential conflicts with other interest groups.

Hydro pumped storage is a further variant used widely with 290 operating units world wide, having a capacity of 83,000 MW.

The advantages of hydro power can be summarized as:

- - It is a renewable energy source
- Once built it is very economic to run, with low operating and maintenance charges and no fuel cost. The machinery is rugged with few moving parts to repair
- The units offer flexibility in meeting load demand with ramp rates of between 5 and 30 MW/min, depending on the unit in question, [as compared to thermal units at 1-3 MW/min and CT's at 10 MW/min].
- Plants can enhance environmental and recreational aspects of a river. Fishing, boating and swimming can develop on upstream impoundments, while controlled water discharge can provide stable year round stream flows downstream of the plant
- Dams may offer advantages such as flood control
- No combustion gases or solid wastes are produced

The disadvantages include:

- - Generally higher cost per kW than fossil plants
- Without proper fish passes migrating fish will be blocked from proceeding upstream
- Impounding water in reservoirs without proper maintenance flows will disrupt downstream aquatic life and result in lost plant and fish habitat.
- Water in reservoirs may become relatively anaerobic and nutrient rich, causing an imbalance in the stream when it is discharged.
- Methane is generated in the anaerobic environment.
- Reservoir storage may also cause summer discharges to be colder and winter discharges warmer than natural flows. This may harm downstream aquatic life.

- Some fish species rely on large water flows (freshets) to signal and assist their upstream migration. Water diversion, combined with inadequate or improperly timed maintenance flows, may cause significant disruption to these migrations.
- Possible negative impacts on recreational use of upstream waterways.
- Possible impacts on river/ocean interaction and nutrient availability for fish stocks.
- Lengthy construction period and hence impact on local environment and social structure.
- Loss of land resource through inundation, possibly leading to massive resettlement of population.
- Large reservoirs may influence climate.
- Sedimentation build-up behind dams may severely impact generation through time and also effect downstream systems.
- Seepage and evaporation losses can be significant.
- Flora and fauna may be severely impacted by habitat changes (both terrestrial and aquatic).
- Catastrophic failure ramifications.

HYDROGEN

Summary

Hydrogen is considered by many to be the ultimate multipurpose fuel of the future - "The Hydrogen Economy." At present, hydrogen enjoys many uses (e.g. for heavy fuel upgrading in the petroleum industry, in the chemical industry, etc.) as illustrated in Figure H1. Global hydrogen production is estimated at 19 x 109 scf/d, with the US producing over 60% of this, primarily for refinery use (55%) and ammonia production (30%). Hydrogen production needs will likely increase by a further 50% in the near term because of the need to process heavier crudes etc., and also for MTBE gasoline additive production. Production of hydrogen is as yet a relatively expensive operation, the cheapest source at present being from the steam reforming of natural gas, the price being heavily influenced by feed stock (natural gas) cost. If a non-catalytic partial oxidation route were taken, heavy fuel oil, residual, bitumen, coke or coal could be used as alternative feedstocks. These processes and all of the potential fossil fuels would also produce CO2, and possibly SO2, as well as hydrogen. In the longer term, if hydrogen becomes the major "currency fuel," clean production via the electrolysis of water is considered the likely avenue, provided low cost electricity is available from non-fossil sources. This, by today's standards, is even more expensive as NRCan cite a production cost of $13/GJ if based on electrolysis using hydro-derived electricity at 2.6 ¢/kWh.

Hydrogen is regarded as a super clean fuel, (provided the deriving energy source is "clean") as it burns to produce water. It has been estimated that, if all present fossil fuels were replaced by H2, the water generated during combustion would equate to 0.003% of total global evaporation. Nitrogen oxides are also produced from the combustion air. A hydrogen cycle derived from nuclear, solar or hydro power would not result in the generation of carbon dioxide, and this in the nearer term may be the major driving force behind the "hydrogen economy". Inevitable depletion of the world's fossil fuels may also force the world to move to a hydrogen economy. To put things in perspective if hydrogen fuelled vehicles were to capture 5% of the US transportation mandate the volume of hydrogen required would represent half of the current US hydrogen production capacity.

Critical Development Needs

- - More efficient H2 separation (e.g. membrane separation/PSA, electrolytic cells, under oxidized burning and, electrocatalysts).
- Safe storage mechanisms (e.g. metal hydrides).
- High efficient H2 utilization technologies (e.g. fuel cells, oxidation using wetproofed catalysts).
- Metallurgical interaction improvement (zirconium, etc.).
- Significant reduction in cost of hydrogen production, particularly non-fossil based systems.

NUCLEAR POWER - FISSION

Summary of Technology Concept

In nuclear power plants, the heat produced in fission reactions is used to produce steam for process use. Fission reactions involve the splitting of the nucleus of large atoms in a reactor yielding an energy release about one million times greater than a chemical reaction such as burning. Successful control of the fission reactions and the availability of ample supplies of fuel (uranium) have led to the development of the commercial nuclear power industry.

The global nuclear generation capacity, as of 1996, of 443 units, generated 2300 TWh (17% of total generation). At that time a further 36 units were under construction. Nationally Canada has 22 units, the US has 110 units, while Lithuania has the highest penetration of 83.4%.

Worldwide, the two most widely used reactors are the Pressurized Water Reactor (PWR) and the Boiling Water Reactor (BWR). In Canada, the Canadian designed CANDU reactor is used exclusively. International marketing efforts continue with recent CANDU sales to China .

As of 1996 all conventional u/g and open pit uranium mining shut down (low demand). The source is now in-situ leaching and byproduct from phosphate mining. There is also strong interest in using weapons grade uranium.

Pressurized Water Reactor (PWR)

The PWR is the most widely used reactor worldwide. In the U.S.A., two thirds of the commercial nuclear power plants use PWRs.

The basic elements incorporated in the PWR design include a reactor vessel, primary coolant circulating loop consisting of pumps, steam generator and pressurizer and a secondary steam generating circuit with steam turbine, condenser pumps and heaters.

In the reactor core, the primary coolant is heated to about 325C. The coolant transfers this heat to a steam generator (a particularly troublesome component in the US). The primary coolant circuit is maintained at about 15.5 MPa.

In the steam generator, water is boiled and steam at 6.9 MPa and 285C is produced. The steam drives a steam turbine and then goes to a condenser through a circuit similar to that used in a fossil fuel plant.

The net efficiency of a PWR is about 32%.

Boiling Water Reactor

The BWR differs from the PWR in that it has only one loop for reactor cooling and electrical energy production. In the core, the primary coolant is heated to about 290C at 7 MPa. As it leaves the reactor core, the coolant is about 15% steam by weight. This steam is dried and separated before it enters the steam lines. The remaining water is recirculated back to the core.

The net efficiency of a BWR is about 33%.

CANDU Heavy Water Reactor

The CANDU reactor is a PWR and, like all PWRs, it has a primary coolant loop and secondary steam cycle loops. Instead of ordinary water, however, it uses heavy water as a moderator and has a separate moderator circuit. Use of heavy water means that the CANDU can use natural uranium as a fuel.

In a CANDU system, the pressurized coolant, deuterium (10 MPa) removes the heat from the reactor core and transfers it to a steam generator where the secondary steam circuit water is boiled. The steam produced drives the turbine. While the reactor is operating, the heavy water moderator absorbs some heat. It is cooled via a separate circulating system.

Because it operates at a lower steam temperature, the typical efficiency of a CANDU plant is 28%.

Canadian nuclear waste disposal is a major issue. At present there are 5,000 m3 of waste fuel (18,000 m3 by 2030) stored in water pools or dry concrete canisters. Hearings are continuing into permanent storage options in the Canadian shield.

By 2065 there may be 500,000 m3 of low level waste which may be housed at a future low level waste disposal facility at Deep River, Ontario. Uranium tailings wastes total 225 x 106t.

Development Needs

- The following are some development needs:
- A procedure for the safe long-term disposal of nuclear waste
- A smaller inherently safe unit which would be less capital intensive
- A shorter construction schedule/modular construction (eg, Yonggwang, 8 yr. schedule (64 mo. construction))
- Reduced capital and O&M costs
- Standardization of regulatory approval procedures
- Development and fostering of public confidence
- Improvement in cycle efficiency (such as by hybrid fossil/nuclear plant with superheat and reheat capability)
- Recycling of nuclear warhead enriched uranium for peaceful purposes.

NUCLEAR POWER - FUSION

Summary of Technology Concept

Fusion (hot) is an attempt to mimic the reactions occurring in the sun, ie., the solar fusion of hydrogen which releases enormous amounts of energy. Fusion research has continued for more than 40 years because: there exists an almost inexhaustible supply of fuel; there is a low perceived environmental impact (no SO2, NOx or CO2 is produced, and compared to fission, no very long-life radioactive waste is formed, the reactor radioactive inventory is relatively small, and the reaction is inherently safe because malfunctions will cause a rapid shutdown); and there is a potentially high technical and economic efficiency.

Fusion involves the release of energy when light elements such as hydrogen isotopes are fused together to form larger nuclei. For example:

2H + 3H 4He + n + 17.6 MeV

Where 2H is deuterium, 3H is tritium, 4He is an isotope of helium and n is a neutron. The energy produced appears as kinetic energy of the product particles, with 20% in the 4He and 80% in n. To induce deuterium-tritium reactions on the scale needed to produce commercial quantities of energy, temperatures in the range 100-200 million C are required. At these temperatures atoms are completely ionized and the fuel becomes a plasma. For the reaction to become self-sustaining, the plasma must be confined at these temperatures for 1-2 seconds at a minimum ion density of 2.5 x 1020/m3. These criteria being fulfilled, 37 kg of deuterium and 56 kg of tritium can generate IGWy of thermal energy. Canada possesses the largest quantity of civilian tritium in the world (ex-CANDU).

Containment of the plasma can be achieved through strong magnetic fields in a tokamak or a Stellarator. Since the ions in a plasma are electrically charged, they can be influenced by a magnetic field. In particular, an ion in motion will follow a helical path around and along a line of magnetic flux. Both the tokamak and the Stellarator include a toroidal plasma vessel with magnetic field coils wound circumferentially around the vessel. The tokamak employs a plasma current which ohmically heats the plasma, while the Stellarator does not use such a current.

Since tritium is not very abundant on earth, the reactor is surrounded by a breeder blanket containing lithium 6 (relatively abundant). In the breeder, the following reaction takes place:

6Li + n 3H + 4He + 4.6 MeV

Capture of the neutron during generation of tritium produces heat in the blanket, from which it can be extracted to produce steam and hence electricity. To put this in perspective, a tokamak reactor of 20-30m diameter with 2-3m of reactor shielding would have a thermal rating of several GW.

Several years ago, two American scientists claimed to have achieved cold fusion while electrolyzing heavywater with a palladium cathode. Due to the skepticism with which this discovery was greeted, the scientists are continuing their research, with Japanese backers, under tight security in France.

Critical Development Needs

- **-** Reduce temperature requirements of the hot fusion plasma such that more of the produced energy is available for use.
- Achieve breakeven energy balance.
- Commitment to a demonstration hot fusion reactor (global cooperative effort).
- Pursue the cold fusion concept so that a comprehensive understanding is obtained.

SOLAR ENERGY

Summary of Technology Concept

It is estimated that the amount of solar power reaching the earth's surface is 174,000 TW. This compares to global power generation capacity of 10 TW. Consequently there is optimism that in time a significant portion of human energy needs can be harvested from solar energy. The average intensity of the sun's radiation along the earth's orbit is 1.368 kW/m2, while the irradiance at a latitude of 45N is 0.139 kW/m2 (a function of latitude, cloudiness, diffusion irradiance) which results in an annual insolation at our latitude of 1,200 kWh/m2 year. If PV conversion efficiency is assumed at 15% then the resultant generated energy 180 kWh pa/m2 of collector. Hence if a household desired 3 kW of solar PV then an array of 12m x 12m () would be required, whereas for a 100 MW facility a power plant area of 10 km2 would be required ().

Solar energy can be converted to electricity either through photovoltaic (pv) cells or through solar thermal energy devices, the latter being the most developed option at this time.

Photovoltaic development enjoys the broadest world wide support of all emerging renewable energy options. In semiconducting (p type, doped with boron to create an excess of holes; n type, doped with phosphorous to create excess electrons) material there is an energy gap between fixed electrons in the valence band and electrons in the conduction band (0.66 to 2.4 ev). In some semiconductors these energy gaps correspond to the energy in visible light (1.59 and 3.26 ev). When light with energy greater than the energy band gap is absorbed, electricity is produced. The combination of support substrate, absorbing layer and semiconductor is called a solar cell. Single crystal silicon technology has gained the largest share of the global market to date. However R&D continues to bring to the market more cost effective PV options. Cells can be classified in the following categories:

Non Thin Film:

- Wafered crystalline silicon - All products derived from bulk silicon, whether single crystal or polycrystalline, including ribbon silicon.

- Grown crystalline silicon sheet - All relatively thick non-sliced cells, such as dendritic web.

- Deposited silicon sheet - Single-crystal or polycrystalline sheet less than 50 microns thick and supported on a low cost substrate.

- Gallium arsenide is the foremost III-V material, however it is 30 times more costly than Si.

- Concentrator - Both silicon and periodic table group III-V compound cells for any level of concentration.

- Spheral silicon - silicon beads on flexible aluminum foil.

Thin Film (1):

- Multijunction amorphous silicon (a-si) - Stacked, two-terminal tandem devices using alloys based on amorphous silicon. Tandem cells with wide ranging gaps (1.85 - 1.30eV) will increase max efficiency.

- Single-junction amorphous silicon (a-si) - All amorphous silicon-based devices without multiple junctions.

Thin film silicon.

- Copper indium diselenide ($CuInSe_2$) - Single-junction thin-film devices undergoing R&D.

- Cadmium telluride (CdTe) - Single-junction thin-film devices in early stage of commercialization.

These categories can also be subdivided further. Concentrator cells can be relatively simple, comparable with flat-plate wafer construction, or they can be of the point-contact type (highest efficiency single junction Si cell). Wafered silicon cells can be made from Czochralski crystals or from cast polycrystalline silicon.

Additionally, modules can be of the flat plate (static or tracking), concentrator single or two axis tracking, fresnel lenses (most popular), parabolic reflectors/focus receiver, and heliostats (no PV application to date).

Growing attention is focusing on pv integrated building materials such as roofing tiles and curtain walls.

PV R&D is primarily conducted in the U.S., however Japan and Germany are significant funders of the global effort. World production and marketing at this time is dominated by single crystal, polycrystal and amorphous silicon cells. The US is the world leader in production capacity.

Whereas many of the cells developed in the 80's exhibited major stability problems and degradation, solutions have been implemented. R&D is focusing on thin films to reduce manufacturing costs. The most reliable and low risk PV is crystalline silicon (single or poly-si) which have the highest commercial conversion efficiencies and a stable outdoor lifetime. Poly crystalline Si will dominate PV in the near term. Of the thin film technology amorphous silicon is the most commercial today. However efficiencies are low and material stability outdoors has been poor. CdTe and CIS thin film multi junction cells are anticipated to offer significant longer term benefits. Concentrator PV is not at this time cost effective. The cost of PV electricity is of the order of 60 ¢/kWh in 1998. Consequently major capital cost reduction and efficiency improvements are required before grid connected systems are competitive. EPRI have identified over 60 separate types of cost effective PV applications for utilities and their customers. Current (1997) global production is cited at 127 MW p.a., while the global installed base is over 800 MW. In the US President Clinton/USDOE have proposed a plan to have a million solar powered homes by 2010.

It is interesting to note that certain US states are beginning to require that utilities include a percentage of solar energy in their mix (1999, Arizona, 0.5%).

Solar energy can be concentrated by factors of 10,000 or more by the use of mirrors, creating temperatures as high as 3800C. Hence use in conjunction with a thermodynamic cycle to generate electricity is possible. Three systems are presently in use: parabolic trough collectors (= 15%), solar towers (= 15-20%), and parabolic dish systems (= 25% with stirling engine). Solar thermal systems rely on direct solar radiation and hence cannot be used under cloudy sky conditions which diffuses radiation completely. There is currently 380 MW of solar thermal operational world wide (mostly in California).

Critical Development Needs

- - Component cost reduction (large scale production; BOP cost optimization; improved efficiency; battery cost).
- Reduction of Silicon cell output degradation with time, particularly thin film a-Si (Staebler Wronski effect).
- Use of lower grade and thinner materials to minimize cost.
- Maximize benefits of concentrator development, and heat extraction.
- Development of CIS based systems (high efficiency/low cost).
- Improved reliability, efficiency and reduced production costs of all solar components, particularly B.O.P. (power conditioners, battery storage).
- Scale up of most advanced material systems.
- Market development for pv technology.
- Design to maximize cleanliness and minimize breakage.
- Development of hybrid solar-fossil fuel generating - integrating gas combined cycle and solar collectors.
- Demonstration of acceptable utility plant life.
- Impacts on utility systems reliability, penetration, security, reserve margin, voltage control, line loading, operation, forecasting, unit commitment, harmonics and power quality, protection and planning.
- Development of Codes & Standards to permit safe and economic operation and interconnection.
- Development of DC systems to negate need for inversion.
- Development of photochemical systems for the direct use of sunlight in chemical process, such as detoxification, catalytic carbon dioxide reforming of methane, methanol, etc.

SUPERCONDUCTIVITY

Summary of Technology Concept

The phenomenon of superconductivity was discovered in 1911 by H.K. Onnes, a Dutch physicist, who witnessed superconducting mercury. Essentially, superconductivity is the property of many materials whereby as their temperature drops close to absolute zero (-273C; -460F; 0K) their electrical resistance disappears, thereby permitting the conduction of currents without any loss of energy (I2R drop). A second critical property of superconductivity is that when a superconductor is placed in a magnetic field, and then cooled to the point where it becomes superconductive, the magnetic field will be excluded from the superconductor. This is known as the Meissner effect. Strong magnetic fields can cause certain HTSC's to loose superconducting state hence selection is critical.

Until recently the degree of cooling required necessitated the use of liquid Helium (at -452F, 4ak) to facilitate superconductive temperatures. However, recently ceramics have been developed which exhibit superconductivity at much higher temperatures (135k, EPRI) permitting the use of liquid Nitrogen (boiling point 77 K) as a coolant, which is orders of magnitude cheaper than Helium. There have also recently been claims from Japan that room temperature (350 K) superconductivity using a yttrium compound has been achieved. Over 100 compounds are considered as HTSC's achieving up to 100 times the current carrying capability of copper. Superconduction theory development lags behind laboratory experimentation, however, it is thought that what is occurring is a new electron state whereby electrons form into pairs (as opposed to random singular movement) and a group discipline occurs which results in the avoidance of collisions and hence energy loss. Superconductors also exhibit strong magnetic properties. It is these two properties which may herald great technological strides in the future commercialization of superconducting technology. It must be appreciated that the ceramics in question only function as lossless superconductors under DC current, not AC current.

Specific applications include:

- - Superconducting cables.
- Electromagnet development in conjunction with Nuclear-Fusion & MHD.
- Computer miniaturization and speed increase.
- Generators, transformers, & large motors (size reduction; improved response).
- Superconducting coil magnetic energy storage (i.e. storage of mag field generated by DC current in a coil. AC/DC power conditioner req.)
- Magnetically levitated trains.
- Magnetically propelled ships (i.e. Yamato - 280 tons, 4 tesla, 6.5 kts).
- Medical uses (MRI).
- High energy physics (supercollider).
- Magnetic heat pumps.
- Magnetic separators.
- Magnetic bearings.
- Magnetic pumps.
- Shielding systems.

Critical Development Needs

- - Maximize current density over long lengths of conductor.
- Compound stability & deterioration prevention.- Overcome brittleness problems.
- Development of high performance, multifilament stranded flexible conductors, in particular for magnetic device usage.
- Further temperature increases, approaching room temp.
- Basic material science.
- Increasing the temp/mag field strength current density windows.
- Assessment of potential benefits to utility industry.
- Transmission cables (> 10,000 A/cm2; > 0.1 T)
- Generators (> 100,000 A/cm2; 5-6 T) 0.5% efficiency improvement.
- Magstorage (> 300,000 A/cm2; 2-6 T) 90% efficient.
- Development of ceramics based on less rare elements as reserves of yttrium and thallium are small.
- Minimizing ac losses.
- Contact methods for joining superconducting and non-superconducting materials.
- Assessment of health effects of dc magnetic fields.

TIDAL POWER

Summary of Technology Concept

Tidal Power Generation utilizes the ocean's tidal phenomenon caused by the gravitational forces of the moon and the sun and the rotational forces of the earth. The moon, being much closer to earth than the sun, exerts twice the gravitational force, and as a result, the tides basically follow the lunar rhythm causing a regular, predictable rise and fall of the water surface levels sweeping westward with a period of 12 hours, 25 minutes. The influence of the sun's gravity is to modulate the tides, resulting in the phenomena of spring and neap tides. In simplest terms, the tidal power concept involves construction of a dam or barrage across the entrance of a tidal influenced bay or inlet, to create a holding basin, wherein rising tidewater is sluiced in and contained. The stored water is held until the tide recedes sufficiently to allow the basin water to be released through power generation turbines built into the dam structure.

Centuries old harnessing of tidal power utilized the traditional water wheel set in an open flume and was used to power various types of mills. In modern times, for tidal power electrical generation, technology has been concentrated on low head reaction turbines, because of the relatively low heads obtainable from tidal regimes. The horizontal flow, propeller type, in two versions: 1) bulb type and 2) straight-flow type have emerged as front runners. This type has the inherent advantage that there is no change in the direction of flow and does not need as deep a setting as vertical axis machines. The bulb type of turbine has a conventional shaft driven generator housed in a steel bulb or chamber situated in the upstream water passage. The straight-flow (Straflo) type has the generator arranged around the turbine runner and has only a relatively small upstream bearing assembly housed in the upstream water passage. Because of its unique arrangement, the straflo turbine has cost and operational advantages over the bulb type and appears to be favoured for tidal applications.

Inherently, tidal power production is cyclic being tied to the lunar cycle. This problem of continuity of supply of large amounts of energy is one of the main disadvantages of tidal power, and as a consequence retiming of power output (wholly or partially) in order to make it available when most required, is an important and costly consideration. Retiming and/or extending periods of generation can be achieved in several ways such as generating while filling the holding basin, multiple level basins, pumping to increase generation head and coordinated operation with other energy sources, such as pumped storage, and compressed air energy storage.

There are several areas in the world where the tidal regime is such to justify consideration of a tidal power plant. Attractive sites have been defined in England, France, Spain, Alaska, Gulf of California, Argentina, India, Korea, Australia, USSR and Canada's Bay of Fundy.

To date only four tidal power plants have been constructed. The French 240 MW plant at La Rance, completed in 1966 was the world's first. Russia completed a plant (0.4 MW) in 1969. China completed its 3 MW Jiang Xia Tidal Plant in 1981. In 1984 Nova Scotia completed the 20 MW Annapolis Tidal Power Plant, the first tidal plant in North America.

Tidal Power technology has advanced to the state where large scale power developments are technically feasible compared to other utility alternatives; however, it is not presently an economic choice. Tidal power does provide a virtually inflation free, renewable source of energy and at some time in the future, may well become economically attractive. There are environmental issues relating to impacts on water levels in the far field, sediment transport, and possibly fish impacts which need addressing.

Critical Development Needs

For Tidal power to proceed in the foreseeable future, it is likely that a cost-effective means would have to be found to economically retime the energy output (i.e. converting it from intermittent pulses into firm capacity and energy).

Greenhouse gas abatement requirements may accelerate consideration of this technology.

The economics of tidal power are sensitive to the fuel costs of alternate energy sources hence the assessment of Tidal Power should be periodically updated in light of this.

Contact should be maintained with other countries as their tidal technology advances and incorporate any improvements into study updates. Means of reducing capital costs substantially need to be identified (e.g. diaphragm walls, etc.).

Environmental aspects relating to the fishery, aquatic species and bird habitat, and changes in tidal amplitude are areas of particular concern and will need to be addressed. A continuing examination and compilation of a comprehensive database on environmentally sensitive issues for the Fundy Region is essential to the implementation of a tidal project.

WAVE POWER

Summary of Technology Concept

Waves are caused by the transfer of energy from wind to sea. The rate of transfer depends on wind speed and the distance over which it interacts with the water (the fetch). Potential energy is carried in waves by the mass of water displaced from mean sea level and kinetic energy by the velocity of water particles. Waves can be characterized by their height, wavelength (distance between successive crests), and period (time between successive crests). Power is usually stated in kilowatts per meter, representing the rate at which energy is transferred across a line of 1 m length parallel to the wave front. The strongest winds blow between 40 and 60 degrees latitude in both northern and southern hemispheres. Coasts with exposure to the prevailing wind and long fetches are likely to have the greatest wave energy density. Nova Scotia possesses a very favourable wave energy density, nonetheless, the winter's climate may impose conditions not conducive to waver energy extraction.

Globally, the wave power dissipated on coastlines with favourable exposure is in excess of 2 TW.

Concentrated effort to establish effective wave energy extraction technologies dates from the mid 1970s. Research has focused on devices, based on the following activating motion: heaving, heaving and pitching, pitching, oscillating water column and surge. In many cases, the devices generate a pressurized fluid (e.g. water) which may be used to generate electricity and/or be used for desalination purposes.

Critical Development Needs

- - Establish comprehensive wave climate and winter/storm data to facilitate identification of optimum sites.
- - Proving of materials/designs capable of withstanding severe location conditions (e.g. corrosion, biological fouling, storms, etc.).
- - Maximizing energy extracting efficiency and hence minimize capital cost of modular facilities.
- - Inventive R & D needs to be focused on design categories which are most likely to result in success.
- - Long term demonstration of promising devices to prove materials' life expectancy and generate confidence in costs, operation, and maintenance.
- - Establish environmental impacts (e.g. sediment transport, aesthetics, hazards, etc.).

WIND GENERATION

Summary of Technology Concept

Wind energy is one of man's oldest sources of power, although contemporary wind turbines bear little resemblance to earlier windmills. Modern wind turbine development has concentrated on two basic turbine forms, the Vertical Axis (Darrieus) configuration and the elevated Horizontal Axis unit. Horizontal Axis Wind Turbines, HAWT, are further developed than Vertical Axis Wind Turbines, VAWT, and dominate current installations as a significant technology base is available from the aircraft industry. VAWTs have several inherent advantages over HAWTs including no yaw control requirement, potentially higher output power, less fluctuations, and easy ground accommodation of electric power equipment. The main detrimental features of VAWTs are that they are not inherently self-starting and operation at low wind speed is less effective than HAWTs. Additional options exist for synchronous and non-synchronous generation with both configurations.

HAWTs' blades rotate too slowly to produce electricity efficiently and a gearbox is used to increase the generator's speed to an acceptable level. HAWTs are also equipped with yaw control systems to rotate the turbine to constantly face the wind, and blade pitch control systems that ensure constant generator speeds under a wide variety of wind speeds. Use of asynchronous generators and solid state inverter technology have also expanded the operability of HAWTs.

The levelized cost of electricity from wind turbines has dropped dramatically over the past 10 years with technology improvements, equipment standardization, and operating/maintenance experience. Some of the more important advances include:

- - Advanced air foils, often made of steel alloys and composites, developed with a better understanding of wind loads. The air foils produce more power in low winds and reduce blade soiling.
- Advanced operating strategies, such as the electronically controlled variable speed generator. This system allows a constant 60 hertz electricity output, even when winds are outside of the ideal range, and eliminates the heavy gearing normally required to act as a brake during high winds. The advantages include lower manufacturing costs, increased energy gathering efficiency, reduction in harmonics, and production of a unity power factor.
- Increasingly tall towers allow substantially greater energy capture (from higher wind loads) for relatively small increases in tower and foundation cost.
- Planetary gearboxes.
- Electrodynamic brakes.

Generating electricity by harnessing wind has undergone considerable application in the last decade. Whereas in 1982 there were 25 installations worldwide with a rating of 50 kW or greater, today there are hundreds of thousands of such installations, 16,000 for a total of 1500 MW in California alone. The average size of units presently being installed is 600 kW, while 1-1.5 MW size units are under development. Total global penetration is of the order of 7,630 MW as of 1998, and that projected by 2010, 25000 MW. The vast majority of WTG manufacturing capability is located in Europe. The practicality of application is particularly site specific & it must be appreciated that capacity factors of 30% are at the high end of user experience. The issue of firming of wind energy supply is also important ,thereby dictating an appropriate generation system mix. Other attractive options are wind/diesel combinations in remote regions; and also wind/hydro combinations to maximize utilization of wind derived energy. CANMET has predicted that over the next 10 years, there is a market potential of 985 MW of wind capacity, chiefly in Quebec (725 MW), Newfoundland (122 MW), Ontario (61 MW) and Nova Scotia (42 MW). In the US the possibility of supplying 10% of the nations electrical energy is being seriously contemplated, in fact it is claimed that N&S Dakota and Texas could supply 20% of the nations power requirements. It is noteworthy that in regions/countries where the largest WTG penetrations are experienced significant subsidies have been available to promote adoption (i.e. California, and most European countries).

Critical Development Needs

- - Although smaller (300 kW) units are well proven and have good availability records (0.95), large multi megawatt WTG units have not proven to be so. 600 kW is the maximum commercially proven unit size at this time.
- Further reduction in installed capital cost.
- Improved power electronics to permit reliable/cost effective variable speed operation, thereby improving operational flexibility; compatibility with site parameters; compatibility with utility networks; improved dynamics and energy capture.
- Design capable of withstanding severe northern climate and storm damage (including 60m/s wind).
- Increase fatigue life of mechanical components and materials (e.g. blades).
- Designed to achieve acceptable 30 year life and appropriate reliability.
- Thorough assessment of ecological impact (noise, bird kill, visual).
- Means of minimizing impact of WTG's on avian mortality.
- Minimization of telecommunication interference.

WOOD/BIOMASS FOR POWER PRODUCTION

Summary of Technology Concept

Biomass is in effect the chemical storage of solar energy, through the process of photosynthesis. It is the only recoverable source of carbonous fuel, and hence can be GHG neutral when managed on a sustainable basis.

- Biomass is a low energy density feedstock, particularly when wet, which has limited potential for power generation because of economic restrictions imposed by transportation. None the less, there may be regional advantages in the use of biomass, in particular:
- Cofiring with coal (or oil/gas) of utility boilers, to reduce per unit life cycle CO_2 emissions.
- Cogeneration at a specific location.
- Biogasification to create gas/heat/electricity, in particular in the developing world and remote communities.
- Production of bio ethanol via pyrolysis for transportation use.
- Charcoal production.

The most important sources of biomass for power production include:

- biomass (forest industry; agriculture) residues
- natural forest trees
- managed fast growth plantations

In the developing world there is considerable potential for the use of food crop residues (typically 17.5 MJ/kg (dry)). In 1990 12% of the global primary energy was sourced from biomass, the majority being in the developing world (China, India, Africa, South America). Unfortunately most of this usage is at very low efficiency hence the need for low cost, simple processes, for the highly efficient use of biomass. There is potential resource available to supply a large portion of global energy needs. However the low energy density (high water content) make application more amenable to dispersed, rural application. Typical facilities are small by utility standards.

Renewables also offer significant potential as a transportation fuel feedstock (ethane). Large scale biomass usage also brings significant concerns associated with reduced bio diversity, conflict with food production, environmental sensitivity, aesthetics, effluents.

As of 1995 there was 9000 MW of biomass capacity operational in the US, 88% of which was fired by wood. It has been reported that there have been many plant closures of late because of poor cost competitiveness (6.5 ¢/kWh US). Utility restructuring will factor against this technology, however GHG abatement may promote it.

- Biomass can be converted to gas via:
- fermentation - small scale application
- anaerobic digestion - small scale application
- flash pyrolysis - medium scale application
- coking/charcoal prod. - medium scale application
- hydrogenation (gasif. H_2) - large scale application

- pyrolysis + hydrogenation - large scale application
- hydro thermal upgrade + hydrogenation - large scale application
- coking + gasif. + synthesis - large scale application

Fluid bed gasification plus synthesis is anticipated to be the most effective however development effort must be pursued.

Critical Development Needs

- - A more in-depth understanding of the effects of wood/coal co-firing on generation efficiency, ash slagging/fouling characteristics, etc.
- Pressurized bio-gasification needs developing. The demise of Enviropower has had a major retrograde impact on the technology prospects.
- NRcan are promoting R & D into fluid bed gasification (mild gasification) plus fluid bed combustion of char. Application in rural communities throughout the developing world could have major benefits with regard to access to electricity and heat, and also improvements in employment and energy use. Environmentally this could provide large benefits (CO_2, particulate, etc.).
- R&D is continuing into flash pyrolysis of biomass to produce char and vapour, the latter being condensed to create a bio-oil for potential use in diesel engines.
- Coking process needs developing as does solids/alkali removal at high temperature.