A Study on the Efficiency of

Alberta's Electrical Supply System

Project # CASA-EEEC-02-04

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Prepared by

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I. Executive Summary

JEM Energy and its associates were retained by the Clean Air Strategic Alliance (CASA) to provide a report on the efficiency of Alberta's electric supply system. The objectives were to determine the efficiency of Alberta's electricity supply system and identify where there could be room for improvement. This involved two main elements:

- establishing a baseline for the losses at the various parts of the supply chain by providing a baseline assessment for generation, transmission, distribution and related equipment losses and
- determining whether improvements could be made, based on "best practices" in comparable jurisdictions.

For this project, JEM Energy examined the efficiency of Alberta's electricity supply chain at each step from the energy source to the meter. This included the various types of generation, transmission and distribution lines, and transformers. A short survey was designed and sent by email to all major Canadian utilities and a cross section of international organizations, to gather information on generation, transmission, distribution and transformer efficiencies. The raw numbers for Alberta were compared to established best practices or experience in other jurisdictions. This information was used to examine how the Alberta system was performing and what targets for improvement might be possible.

There are many types of generating plants currently in use in Alberta. They consist of hydro, fossil fuel thermal (coal & gas), simple cycle gas, combined cycle gas, cogeneration gas, hydro, biomass and wind. Each type employs a different technology and yields a different conversion efficiency. For example, efficiencies range from over 95% for hydro generation to under 30% for some fossil thermal plants. Generation from coal and gas comprises about 90% of Alberta's total. Efficiencies for large coal and gas generation range from 23% to 38% in Alberta. In Canada, the comparative efficiencies range from 13.1% to 35.9% with an overall average of 33.6%. Much of the new generation installed since 1996 has been smaller gas turbine generating units, either simple cycle, combined cycle or cogeneration. Cogeneration has the highest overall efficiency of over 80%.

On the Alberta transmission system, power flows have increased significantly over the past decade. The load on the system has continued to grow due to increasing economic activity while very little new transmission has been built. In 2002, total annual system losses were 2,765 GWh, or 4.45% of total energy transmitted – very close to the Canadian average - and reflect mainly conductor and transformer losses.

Compared to other jurisdictions, Alberta's distribution systems have lower losses and all but one is less than the Canadian average of 4.2%. One contributing factor is the age of the system. Distribution systems are relatively newer in Alberta compared to other systems in Canada.

Overall, the Alberta system efficiency is calculated to be 37.32%, based on the assumptions cited in the generation section of the report. Table 7 compares efficiencies of the various generation types in Alberta with those in other jurisdictions. The transmission and distribution system efficiency in Alberta was calculated to be 92.49 %, which is higher than all of the Canadian utilities that responded to the research. They ranged from 89.3% to 91.9%. There are a few countries that reported higher efficiencies for combined transmission and distribution, but further study is needed to determine the methodologies and protocols used.

The research indicates that there is some potential to improve efficiencies at each stage of Alberta's electricity supply system as follows.

To improve generation efficiency, a balanced approach to all generation sources and supply system in general would result in overall system efficiencies. For example, cogeneration can provide efficiency in excess of 80%. Though these forms of generation are not suitable for all situations, they can be used very effectively and efficiently in some cases.

The two major areas with potential for improving efficiency in transmission and distribution are conductors and transformers. In the short term, there is not much available for improving conductor efficiency. In the longer term, current research into future power lines, that are lighter and can transmit far more electricity than the materials used in conventional lines, indicates great improvement in efficiencies.

Transformers offer an area for increased efficiency. Though small efficiencies are gained per transformer, the estimate of over 281,000 distribution transformers on the Alberta grid would mean substantial savings.

Future research and study aimed at improving efficiency for Alberta's electricity supply system should consider:

- potential of incentives for combined cycle and cogeneration gas turbines
- potential for high efficient station power drives at generating plants
- economics of generation efficiency improvements, such as those in other Canadian jurisdictions like Nova Scotia and Ontario
- potential for distributed generation in Alberta
- processes for standard protocols for assessing distribution losses in Alberta and other jurisdictions
- potential for voluntary Energy Star distribution transformer initiative
- barriers, drivers, economics and emissions impacts of investing in Energy Star transformers versus other generation resource options

II. Introduction

JEM Energy and its associates were retained by the Clean Air Strategic Alliance (CASA) to provide a report on the efficiency of Alberta's electric supply system by conducting market and literature research and interviewing key players in the Alberta electric system supply chain.

The objectives were to determine the efficiency of Alberta's electricity supply system and identify where there may be room for improvement. This involved two main elements:

- establishing a baseline for the losses at the various parts of the supply chain by providing a baseline assessment for generation, transmission, distribution and related equipment losses and
- determining whether improvements could be made, based on "best practices" in comparable jurisdictions.

When considering the efficiency of any element of the electricity value chain, efficiency really means a measurement of the energy losses that are incurred in the generation, transmission or distribution of the energy eventually consumed. Every joule of energy saved by reducing the losses, wherever they occur, is a joule of energy saved at the very start of the chain. This is true of most methods of generating electric energy, except energy generated by wind or solar. Stated another way, every joule of energy saved through loss reduction means more energy can be delivered to the consumer for a constant energy input at the start of the chain.

Consequently, this report deals with each link of the electricity value chain - generation, transmission and distribution - and will speak to the many factors affecting the losses in each link. There exists, in the more remote regions of the province, a number of isolated small power plants serving the local communities or industrial loads, none of which have heat recovery systems. These are not connected to the provincial grid. Since this study concentrated only on those facilities within the provincial grid, these isolated facilities were not investigated or analyzed but are listed in the appendix for information.

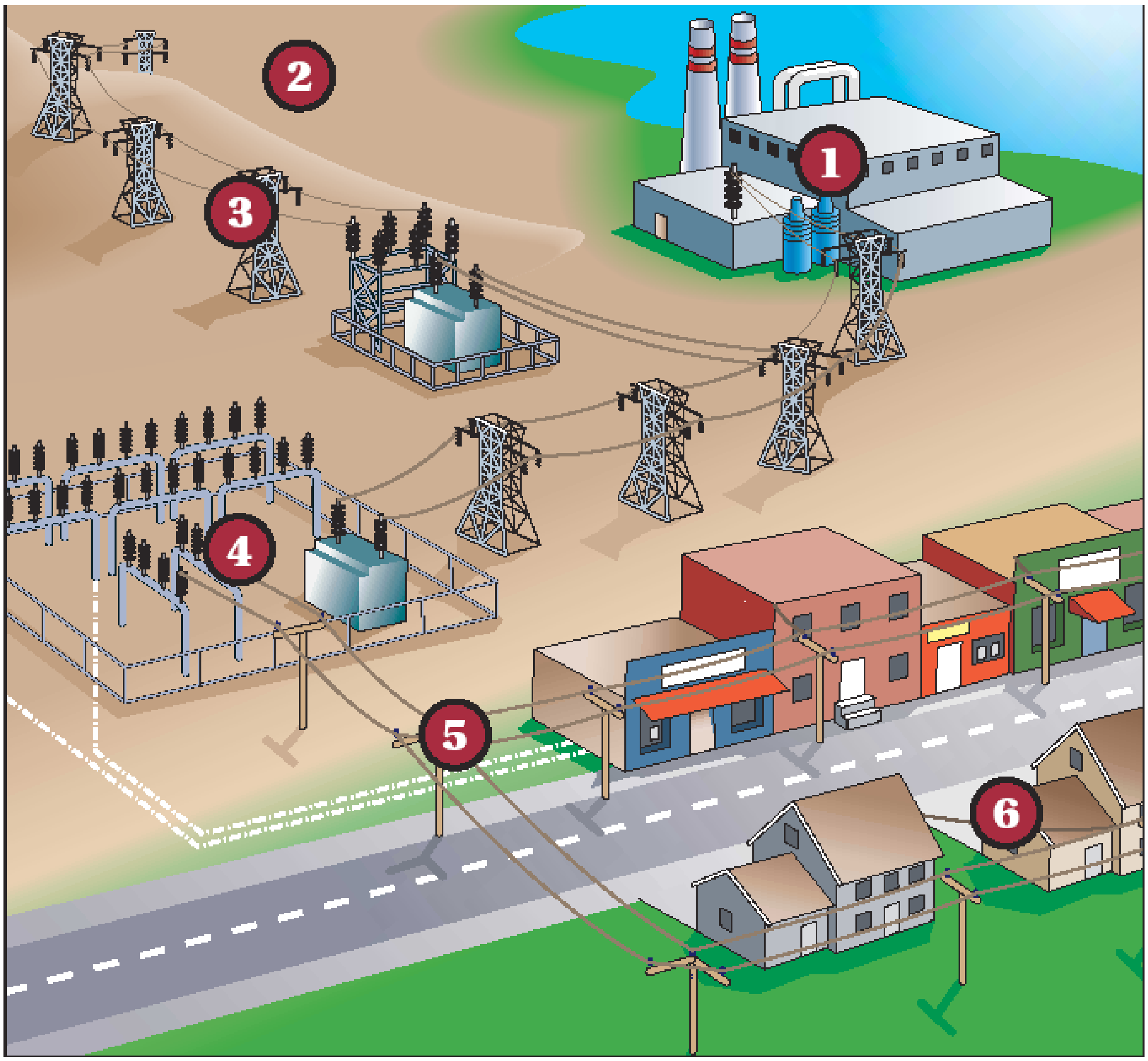
Based on this report, the CASA Electrical Efficiency and Conservation Project Team may determine if additional research is required.

How does an electricity system work?
An electricity system is a complex interconnection of generators, transmission lines, distribution lines and customers all operating in a dynamic environment where continuity and reliability of supply is generally assured.

It is a system where the energy suppliers can connect to the system at any location on, or within an economic distance from, the transmission system (the grid). The grid comprises power lines, cables, transformers, switchgear and other equipment to facilitate the transfer of electricity from generators and the transmission system directly to the distribution system.

Figure 1a illustrates a typical electricity supply system and the efficiencies of each link in the Alberta electricity chain are referenced in the legend. The overall Alberta system efficiency is **37.32%.**

Figure 1a.
Typical Electricity Supply System



Source: Aquila Networks

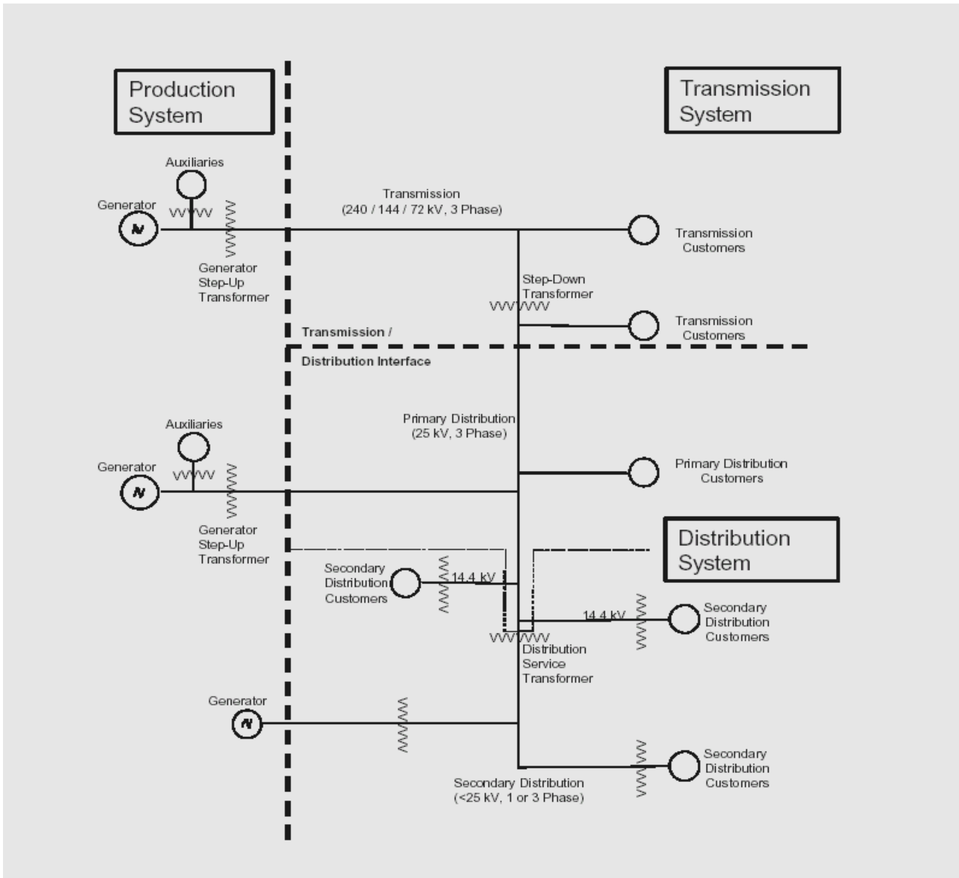
Legend:
1. Generation, efficiency = 40.35%
2/3. Transmission system, efficiency = 95.90%
4. Substation transforming voltage from transmission to distribution
5. Distribution efficiency = 96.45% (average of the four Alberta distribution system efficiencies).
6. Customers

The following assumptions were made to calculate the overall system efficiency:

1) Each coal thermal unit produces its proportionate share of coal energy (66.43% of total energy) using capacity ratings from Table 5.
2) Each gas generating plant produces its proportionate share of gas energy (29% of total energy).
3) All gas plants assumed to feed all electricity produced into the Alberta system.
4) Each Hydro unit assumed to produce its proportionate share of hydro energy (2.73% of total energy).
5) Each wind plant produces its proportionate share of wind energy (0.59% of total energy).
6) Each biomass plant produces its proportionate share of biomass energy (1.23% of total energy).
7) For wind and biomass, efficiencies of 35% and 25% respectively were used. (Efficiency in Electricity Generation-EURELECTRIC Preservation of Resources Working Group, July 2003).

The grid transports the energy from the generators to the distributors and also directly to some large industrial customers. The distribution system takes the energy delivered from the grid and delivers it to all other customers, i.e. farm, residential, commercial and street light customers. Figure 1b shows the basic operating schematic of an electricity supply system.

Figure 1b.
Basic Operating Schematic



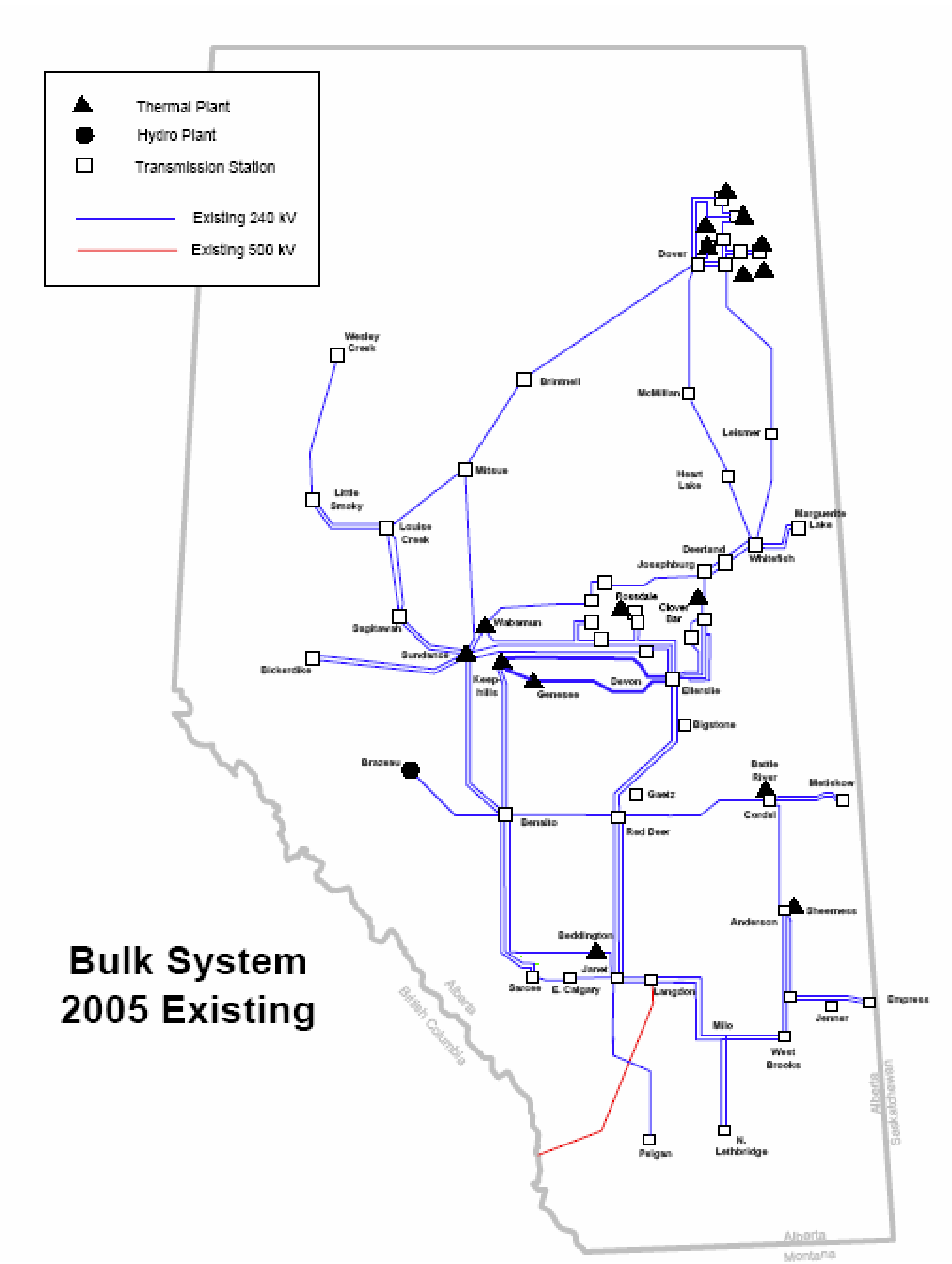
Source: ATCO Electric Ltd. 2004 distribution Tariff Application – May 2004; AEUB Application # 1347048

The grid consists of all transmission lines that operate at a voltage above 60,000 volts, the distribution lines that operate at 60,000 volts and below, and transformers, which lower the voltage from transmission to distribution voltage levels. Although generation is usually connected to the transmission system, a generator could also be tied into the high voltage lines of the distribution system, as is the case with a number of wind generators.

Alberta's electricity supply is similarly complex as shown in Figure 2. Various types of generation in concentrated geographic areas of the province supply electric energy to a transmission grid that delivers that energy to distribution networks to Alberta consumers.

While Alberta imports and exports electricity from time to time, these activities are outside the scope of this study, with the exception of noting them as part of the supply system.

Figure 2. Alberta's Electricity Supply



Source: Edmonton-Calgary 500kV Transmission Development Need
Application to the EUB # 1346298, May 7, 2004

III. Methodology

For this project, JEM Energy examined the efficiency of Alberta's electricity supply chain at each step from the energy source to the meter. This included the various types of generation, transmission and distribution lines, and transformers.

The first stage of the project plan identified key players in the Alberta electricity supply chain and determined what relevant data were available. Working through the supply chain, contacts were made with individuals in each major distribution and transmission company, the Alberta Electric System Operator (AESO), the Alberta Energy & Utilities Board (AEUB) and some of the generating plant owners. Some generation owners were unwilling to share information because of the highly competitive nature of that part of the industry. However, the transmission and distribution businesses remain regulated monopolies and so information was more easily obtained. For example the generation data on all plants in service prior to the restructuring legislation of 1995 is public information and therefore available. However, much of the information from generation plants commissioned since then (approximately 1996), is held proprietary by the owners. Consequently, the principal source for information on all generating plants was the information library of the AEUB, and data published by the individual generation owners.

A short survey was designed and sent by email to all major Canadian utilities and a cross section of international organizations, to gather information on generation, transmission, distribution, and transformer efficiencies. The raw numbers for Alberta were compared to established best practices or experience in other jurisdictions. This information was used to examine how the Alberta system was performing and what targets for improvement might be possible.

The following sections deal with the current efficiency of Alberta's generation, transmission and distribution, how this compares with other jurisdictions and where further study could be warranted.

IV. Generation

Electrical generation efficiency has two components. One component is a measure of the conversion efficiency of the fuel source and the other is the ratio of the net electricity available to the grid to the gross electricity generated. The difference between gross less net electricity is generally referred to as station power.

In thermal plants, the conversion efficiency is measured by its heat rate, which is the thermal energy (BTUs or GJs) from the fuel required to produce one kWh of electricity. A plant's heat rate is determined by the plant's design, location, quality of the fuel and the patterns and levels of operation. Typically, plants operating near capacity will experience their most efficient heat rates. Plant cycling and/or operating below capacity will produce higher heat rates. Under competitive markets, it is expected that most plants are operating at their most efficient levels. In addition to how a plant is operated, some plant design modifications can be undertaken to improve heat rates.

Station power is the power required to operate all the auxiliary systems needed for the power plant. This power is taken from the gross output of the plant, supplies all loads in the plant and includes the losses of the step-up transformers supplying the transmission system.

What is Alberta's current situation?

Figure 3 provides a snapshot of the Alberta electrical generation capacity by source. Figures 4 and 5 show the energy produced in 1993 and 2003 respectively, by source. Most significant is the reduction in coal from over 80% in 1993 to just over 66% in 2003, while gas increased from under 16% in 1993 to 29% in 2003.

Energy produced by each source will vary and is dependent on such factors as individual unit availability, system demand and dispatching. This increase in gas generation has been mostly in smaller plant capacity units and cogeneration installations that result in improved system efficiencies. For example, recently commissioned combined cycle plants have electricity conversion efficiencies in the 46% to 49% range, and overall cogeneration conversion efficiencies up to 83%.

Figure 3. Alberta's Generation Capacity 2003

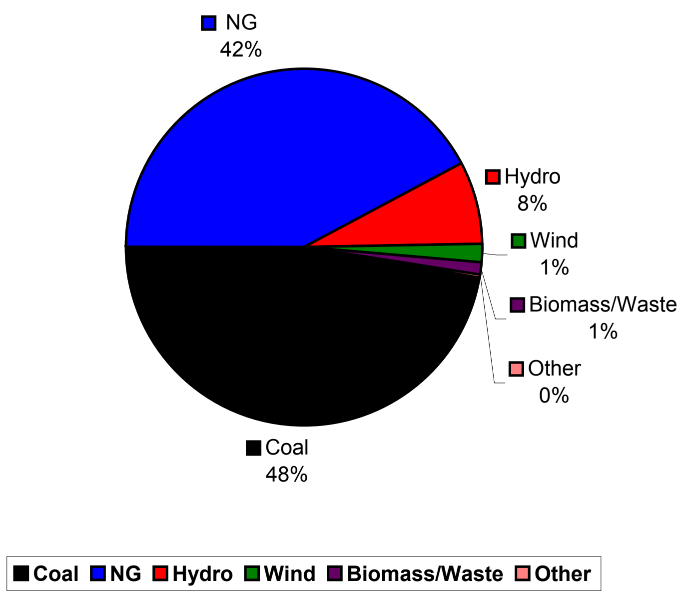


Figure 4. Alberta's Generation by Energy 1993

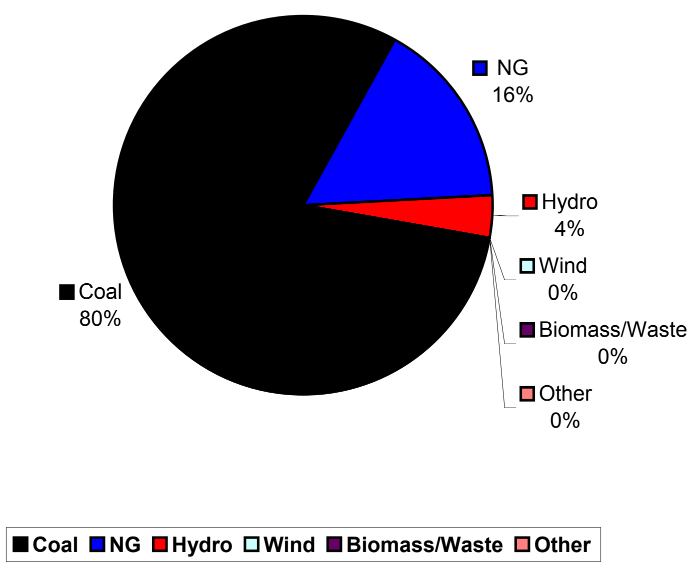
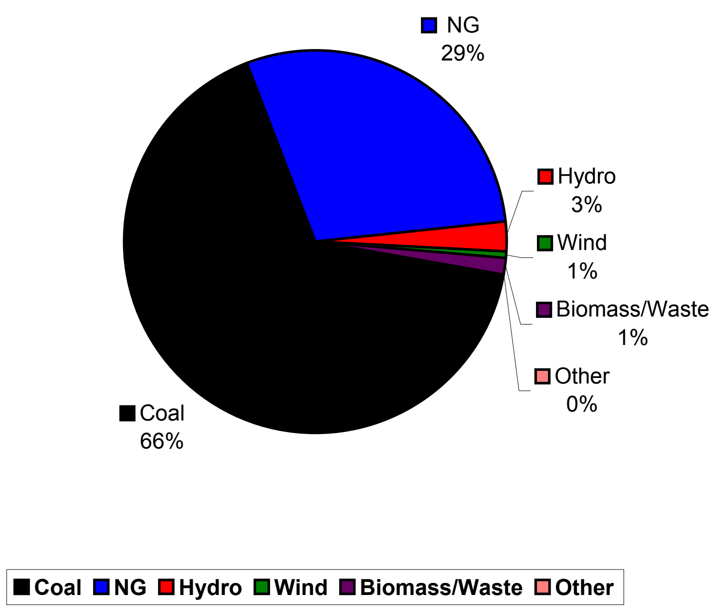


Figure 5. Alberta's Generation by Energy 2003



The generating plants currently in use in Alberta represent several very different technologies. They consist of hydro, fossil fuel thermal (coal & gas), simple cycle gas, combined cycle gas, cogeneration gas, biomass and wind. Tables 1a and 1b list all Alberta generating plants segmented by the non-renewables such as coal thermal, gas thermal, simple cycle gas turbine, combined cycle gas plant, and the renewables such as hydro, wind and biomass.

Each type will generally employ a different technology and yield a different fuel conversion efficiency. For these reasons, this report will discuss each type separately.

Heat rates or energy conversion efficiencies for all generating units or stations in the supply chain are not available, but there is sufficient information to determine the levels of efficiency for coal and gas generation. For the hydro, wind and biomass units or plants it has been possible, for most plants, to obtain information on average annual consumption in order to calculate plant capacity factors.

Table 1a. All Generation Plants by Source: Coal & Gas

COAL 5475 MW: 48% of system				NATURAL GAS 4786 MW: 42% of system							
Owner	**Unit**	**MCR***	**ISD***	**Owner**	**Unit**	**MCR**	**ISD**	**Owner**	**Unit**	**MCR**	**ISD**
ATCO	Battle River #3	147	1969	ATCO	ATCO Scotford Upgrader	184	2003	Maxim Power	Maxim #4	6	
ATCO	Battle River #4	147	1975	Air Liquide	Air Liquide Scotford #1	80	2000	City of Medicine Hat	Medicine Hat #1	205	Various, 7 units
ATCO	Battle River #5	368	1981	Trans Canada Power	Bear Creek	80	2003	ATCO	Muskeg River	200	2002
EPGI	Genesee #1	381	1994		BuckLake	6		Nexen & EnCana	Nexen Inc #1	120	2001
EPGI	Genesee #2	381	1989	Calpine Canada	Calpine Calgary Energy Centre	250	2003	ATCO	Poplar Hill #1	47	1998
Milner Power	H.R. Milner	144	1972	Trans Canada Power	Carseland Cogen	80	2002	ATCO	Primrose #1	85	1998
TransAlta	Keephills #1	383	1982		Celanese	20		ATCO	Rainbow #1	26	1961
TransAlta	Keephills #2	383	1983	EPGI	Clover Bar #1	158	1970	ATCO	Rainbow #2	40	1970
ATCO & TransAlta	Sheerness #1	378	1986	EPGI	Clover Bar #2	158	1973	ATCO	Rainbow #3	21	1966
ATCO & TransAlta	Sheerness #2	378	1990	EPGI	Clover Bar #3	158	1977	ATCO	Rainbow #5	47	1999
TransAlta	Sundance #1	280	1970	EPGI	Clover Bar #4	158	1979	ATCO	Rainbow Lake #1	47	2001
TransAlta	Sundance #2	280	1973	Dow Chemical	Dow Hydrocarbon	310	1999	Trans Canada Power	Redwater Cogen	40	2001
TransAlta	Sundance #3	353	1976	Canadian Hydro	Drywood	6		EPCOR	Rossdale #10	69	1966
TransAlta	Sundance #4	353	1977	Northstone Power	Elmworth	9		EPCOR	Rossdale #8	65	1960
TransAlta	Sundance #5	353	1978	EnCana	Cavalier	120	2001	EPCOR	Rossdale #9	69	1963
TransAlta	Sundance #6	357	1980	EnCana	Foster Creek	80	2003	SAIT	SAIT	6	
TransAlta	Wabamun #1	65	1958		Fort Nelson	47		ATCO	Sturgeon #1	10	1957
TransAlta	Wabamun #2	65	1956	Maxim Power	Gold Creek Facility	7	1999	ATCO	Sturgeon #2	8	1954
TransAlta	Wabamun #4	279	1968	ATCO & EPCOR	Joffre #1	474	2000	Suncor & TransAlta	Suncor	445	Various, 6 Units
				Trans Canada Power	MacKay River	165	2004	Syncrude	Syncrude #1	345	Various, 7 Units
				Imperial Oil	Mahkeses	180	2002		University of Alberta	39	
				Maxim Power	Maxim #2	8		ATCO	Valley View 1	45	2001
				Maxim Power	Maxim #3	7			Weldwood	50	

Table 1b. All Generation Plants by Source: Hydro, Wind, Biomass

HYDRO 869 MW/8%				WIND/BIOMASS 306 MW/3%			
Owner	**Unit**	**MCR**	**ISD**	**Owner**	**Unit**	**MCR**	**ISD**
TransAlta	Bighorn Hydro	120	1972	Alberta Pacific Forest	APF Athabasca (Biomass)	99	
TransAlta	Bow River Hydro	319	1911 to 1957	Vision Quest	Castle River #1 (Wind)	40	1997 to 2001 (67 units)
TransAlta	Brazeau Hydro	350	1965	Canadian Hydro	Cowley Ridge (Wind)	47	1993 to 2001 (77 units)
ATCO Power	CUPC Oldman River	32	2003	Alqonquin Power	Drayton Valley (Biomass)	11	1987
Irrican Power	Chin Chute	11	1994	Vision Quest	McBride Lake (Wind)	75	2002 to 2003 (114 units)
Irrican Power	Irrican Hydro	7		Drayton Valley Power	Westlock (Biomass)	17.5	1998
Irrican Power	Raymond Reservoir	18		Clean Power Income Fund	Whitecourt Power (Biomass)	25	
EPCOR & Canadian Hydro	Taylor Hydro	12	2000				
Canadian Hydro	St. Mary	2.3	1992				
Canadian Hydro	Waterton Dam	2.8	1992				

Tables 1a & 1b Source: AESO Edmonton-Calgary 500 kV Transmission Development Need Application & EUB library
*MCR: Maximum Capacity Rating in megawatts
*ISD: In Service Date

Hydro
For hydro units, efficiency is a function of the net KWh generated in proportion to the flow volume, turbine design and the head of water used to generate electricity. Therefore efficiency numbers will fluctuate as reservoir levels vary.

A test, called the Gibson Test, can be performed to measure the efficiency at a particular point in time but that efficiency will be related directly to the water level in the reservoir at that instant. A rise in water level after a heavy rainfall or in the spring, or a drop in water level towards the end of the summer season will result in different numbers.

Alberta's hydro plants are mainly in two categories. There are TransAlta's plants, which are currently used to supply ancillary services to the Alberta integrated electric system. These units are not operated at the discretion of the owners but rather at the direction of the System Operator to satisfy the ancillary needs of the system, typically various types of generation reserve. Table 2 shows details on these units including the MCR capacity, average annual energy production and corresponding average annual capacity factor for each plant. The capacity factors vary widely, from 12.25% to the high of 55.94%. It is important to understand that the operation of these plants in the current market may be very different from the conditions and needs at the time the plants were designed and built.

Table 2. Hydro Plants

Plant Name	Unit #	Owner	ISD	MCR Capacity (MW)	Annual Energy (GWh)	Average Annual Capacity Factor (%)
Barrier	1	TAU	1947	11.3	39.5	39.90
Bearspaw	1	TAU	1954	16	69.7	49.73
Bighorn	1	TAU	1972	60	405.5	38.57
	2	TAU	1972	60		
Brazeau	1	TAU	1965	160	394.8	12.25
	2	TAU	1965	190		
	Outlet 1	TAU		9		
	Outlet 2	TAU		9		
Three Sisters	1	TAU	1951	2.7	4.2	17.76
Cascade	1	TAU	1942	17	51.7	16.86
	2	TAU	1957	18		
Ghost	1	TAU	1929	1	171	30.98
	2	TAU	1929	17		
	3	TAU	1929	17		
	4	TAU	1954	28		
Horseshoe	1	TAU	1911	5	83.3	55.94
	2	TAU	1911	3.5		
	3	TAU	1911	3.5		
	4	TAU	1911	5		
Interlakes	1	TAU	1955	5	8.5	19.41
Kananaskis	1	TAU	1913	4.5	92.5	55.58
	2	TAU	1913	4.5		
	3	TAU	1951	10		
Pocaterra	1	TAU	1955	12.5	29	26.48
Rundle	1	TAU	1951	17	72.9	17.71
	2	TAU	1951	30		
Spray	1	TAU	1951	47.5	208.1	25.01
	2	TAU	1951	47.5		

Source: TransAlta's published Facts and Figures
Annual energy is the 1972 to 2002 average annual generation; Source: TransAlta data records
MCR capacity ratings: Table E-1: AEIS Generation Capacity; AESO Application 1346298 to EUB

As well, there are other hydro plants that have been installed as merchant plants specifically to provide electric energy into the commercial electricity market. Details on these units can be seen in Table 3. These plants were installed purely for investment purposes, i.e. to obtain a return on investment capital. Accordingly, it is expected that the plants were designed to maximize energy output for minimum capital outlay, thus ensuring the highest economically efficient turbine generators.

Table 3. Merchant Hydro Plants

Plant Name	Unit #	Owner	ISD	Capacity (MW)	Avg. Annual Energy (GWh)	Ang. Annual Capacity Factor (%)
Belly River		Can. Hydro	1991	2.7	11.5	48.62
Chin Chute		Irrican Power	1994	11	93 [2]	71.24
Raymond		Irrican Power		18.5		
Dickson Dam	1	Algonquin	1992	5.6	N/a	
	2	Algonquin	1992	5.6		
	3	Algonquin	1992	5.6		
Oldman River	1	ATCO Power	2003	16.1	114	40.67 [1]
	2	ATCO Power	2003	16.1		
St.Marys		Can. Hydro	1992	2.3	13	64.52
Taylor Chute		EPGI/Can. Hydro	2000	12.6	42	36.24
Waterton Dam		Can. Hydro	1992	2.8	12.5	50.96

Source: Owners published facts & figures or Information supplied on request
Notes: 1. Owner's forecast numbers
2. One year's data April 1 to Sept. 30 irrigation season water flow

Wind

Currently, Alberta has an installed capacity of approximately 173 megawatts of wind generation, representing about 2% of Alberta's electrical generation capacity. Although wind generation is a key component in the emissions reduction equation, efficiency is not as relevant as in other forms of generation, due to the fact of the "fuel supply" being cost-free for wind turbines. Discussions with Alberta wind industry personnel as well as CANWEA indicated no knowledge of wind generation efficiency studies.

The efficiency of wind turbines can be calculated as the ratio of the power generated to the theoretical power of the wind, which has a theoretical limit of 59.3%.[1] When evaluating the electricity supply chain, capacity factor is one measure of comparing wind power to conventional generating sources. It is defined as the ratio of the energy generated during a given period to the energy that would have been generated had the wind turbine been running continually at maximum output. In southern Alberta, the average capacity factor for wind turbines over the past four years was 30%.[2] Table 4 details wind farm generation data. The average energy and capacity factors are owner's projections.

Table 4. Wind Generating Plants

Plant Name	# of units	Owner	In-service date	Capacity (MW)	Avg. Annual Energy (GWh)	Avg. Annual Capacity Factor (%)
Castle River	67	Vision Quest	1997 - 2001	39.5	105	36.09
Cowley Ridge	57	Can. Hydro	1993	21.4	60	32.01
Cowley North & Sinnot	20	Can. Hydro	2001	26	70	30.73
Magrath	20	Suncor	2004*2	30	See Note 1	See Note 1
McBride Lake	114	Vision Quest	2002 - 2003	76	220	33.04
Summerview	n/a	Vision Quest	2004*1	70	See Note 2	See Note 2
Waterton	6	Vision Quest	1997 - 2001	3.8	n/a	n/a

Source: Owner's published Facts and Figures
Average annual energy and capacity factors are owners projections
Notes:
1) The wind farm was placed in service only in July 2004
2) Summerview in-service scheduled for Q3, 2004

[1] Wind Energy Fact Sheet 14, U.S. DOE
[2] AESO 500 kV Transmission Development Application, pp E13/E14, May 2004

Fossil Fuel Thermal
All thermal generating plants and owners supplying the Alberta market are detailed in Table 5 by identifying the:

- Unit name, owner and in-service date
- Unit capacity and fuel type
- Unit heat rate
- Unit conversion efficiency
- Amount of station power consumed at each unit (if available)

Table 5
Coal & Gas Thermal Generating Units
Capacities, Heat Rates & Efficiencies

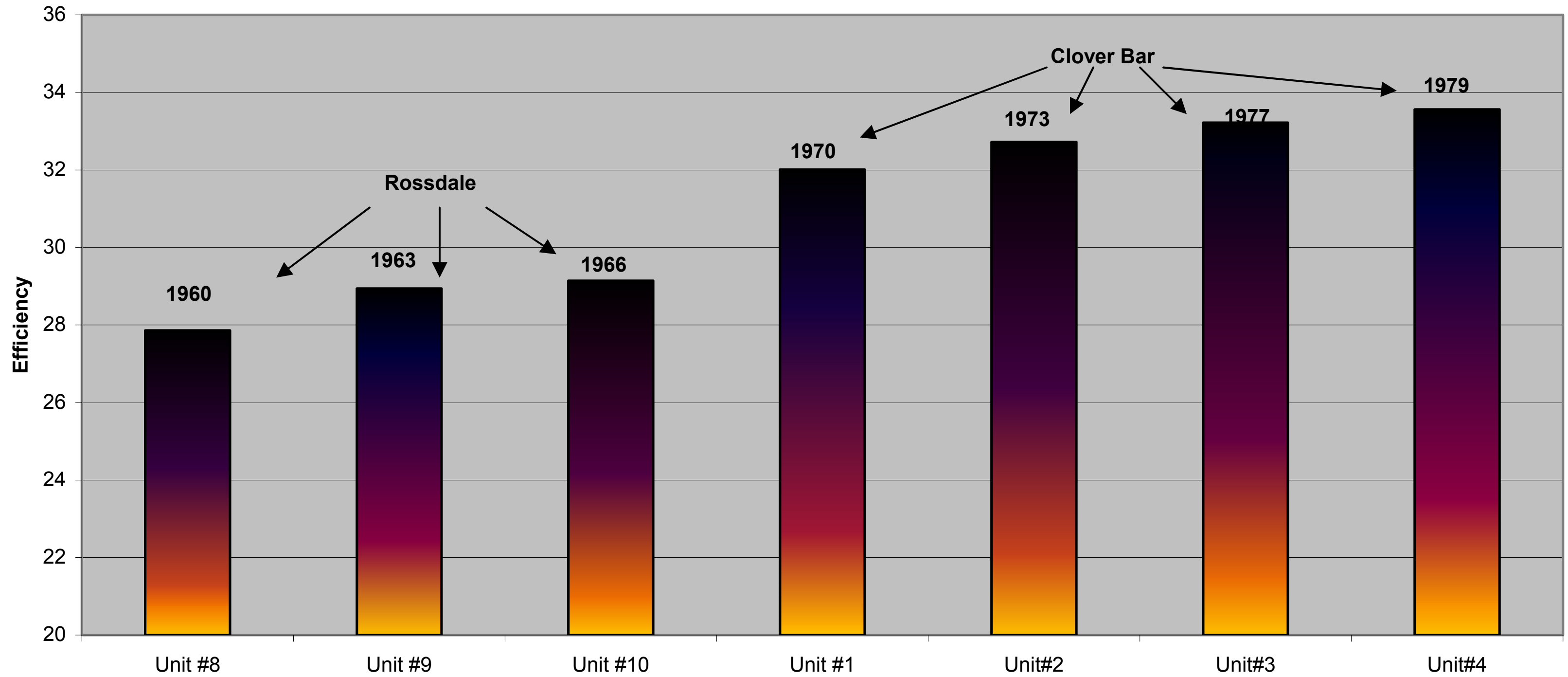
Plant	Owner	ISD	Retirement[1]	Capacity (MW)[2]	ECR (MW)[3]	Fuel Type	Heat Rate (GJ/GWH)	Conversion Eff. %	Station Service %[5]
Battle River 3	ATCO	1969	2013	147	156	Coal	11,630	**30.95**	n/a
Battle River 4	ATCO	1975	2013	147	156	Coal	11,380	**31.63**	4.85
Battle River 5	ATCO	1981	2020	368	390	Coal	9,980	**36.07**	6.02
Clover Bar 1	EPGI	1970	2010	157	171	NG	11,246	**32.01**	n/a
Clover Bar 2	EPGI	1973	2010	157	171	NG	11,003	**32.72**	n/a
Clover Bar 3	EPGI	1977	2010	157	176	NG	10,838	**33.22**	4.80
Clover Bar 4	EPGI	1979	2010	157	176	NG	10,726	**33.56**	4.80
Genessee 1	EPGI	1994	2029	381	407	Coal	10,136	**34.68**	6.12
Genessee 2	EPGI	1989	2029	381	407	Coal	10,136	**34.68**	6.12
Genessee 3	EPGI	2005	TBD	450	n/a	Coal	9368*[4]	**38.43*[4]**	n/a
H.R. Milner	Milner Power	1972	2012	144	153	Coal	15,590	**23.09**	n/a
Keephils 1	TAU	1982	2023	383	404	Coal	10,222	**35.22**	6.20
Keephills 2	TAU	1983	2023	383	404	Coal	10,222	**35.22**	6.20
Rossdale 8	EPGI	1960	2003|*[6]	65	71	NG	12,920	**27.86**	n/a
Rossdale 9	EPGI	1963	2003|*[6]	69	73	NG	12,439	**28.94**	n/a
Rossdale 10	EPGI	1966	2003|*[6]	69	72	NG	12,353	**29.14**	n/a
Sheerness1	ATCO	1986	2026	378	400	Coal	10,220	**35.23**	6.02
Sheerness 2	ATCO	1990	2026	378	386	Coal	10,220	**35.23**	6.02
Sundance 1	TAU	1970	2017	280	295	Coal	10,726	**33.56**	n/a
Sundance 2	TAU	1973	2017	280	295	Coal	10,726	**33.56**	n/a
Sundance 3	TAU	1976	2020	353	374	Coal	10,892	**33.05**	n/a
Sundance 4	TAU	1977	2020	353	374	Coal	10,892	**33.05**	n/a
Sundance 5	TAU	1978	2020	353	374	Coal	10,221	**33.45**	6.67
Sundance 6	TAU	1980	2020	357	385	Coal	9,978	**35.11**	6.37
Wabamun 1	TAU	1958	2004	65	67	Coal	14,284	**25.2**	n/a
Wabamun 2	TAU	1956	2004	65	67	Coal	14,936	**24.1**	n/a
Wabamun 4	TAU	1968	2010	279	295	Coal	11,668	**30.85**	n/a

Notes:
1. Unit retirement dates as per AEUB Decision U97065 adjusted as per PPA determination
2. Unit capacities as per PPA determination regulation 2000
3. ECR (Emergency Capacity Rating) from the 1999/2000 AEUB GTA decision
4. Preliminary values as per EPGI –Genessee Unit 3 application to AEUB
5. Station service expressed as % of gross electrical output
6. Rossdale Units 8, 9 & 10 retirement dates not yet confirmed. Dates shown are original PPA expiry dates

Source: CERI Study No. 98, June 2000-ISBN 1-896091-64-4, The Alberta Electricity Market, An Analysis and Price Forecast; Original source, Independent Assessment Team, August 27, 1999 Final Report, EUB Decision U99099

Fossil fuel thermal plant conversion efficiencies in the Alberta system range from a low of 23% for the Milner coal plant built in 1972 to over 36%. The exception to this is the Genesee 3 coal plant with a projected efficiency of 38%. (See Table 5). This range is the result of improvements in turbine and boiler technologies over that 30-year period. During this period, experience and further research in the combustion of coal and steam turbine design gradually improved the efficiency of essentially the same type of technology. For example, the efficiency of the Alberta gas thermal units in the Rossdale and Clover Bar Plants improved in each subsequent unit installed. The first of these units, installed in 1960, had an efficiency of 27.86%. The last of these, installed in 1979, had an efficiency of 33.56%. (See Figure 6)

Figure 6. Efficiency Improvements – Gas Thermal Units



	Rossdale			Clover Bar			
	Unit #8	Unit #9	Unit #10	Unit #1	Unit #2	Unit #3	Unit #4
Year Installed	1960	1963	1966	1970	1973	1977	1979
Efficiency %	27.86	28.94	29.14	32.01	32.72	33.22	33.56

The larger and more recently built units generally show a better fuel conversion efficiency. Gas thermal plant efficiencies have improved as each subsequent plant has been designed. The Genesee 3 improvement in efficiency to almost 38.5% results from the adoption of a different and improved boiler technology not previously used in Alberta.

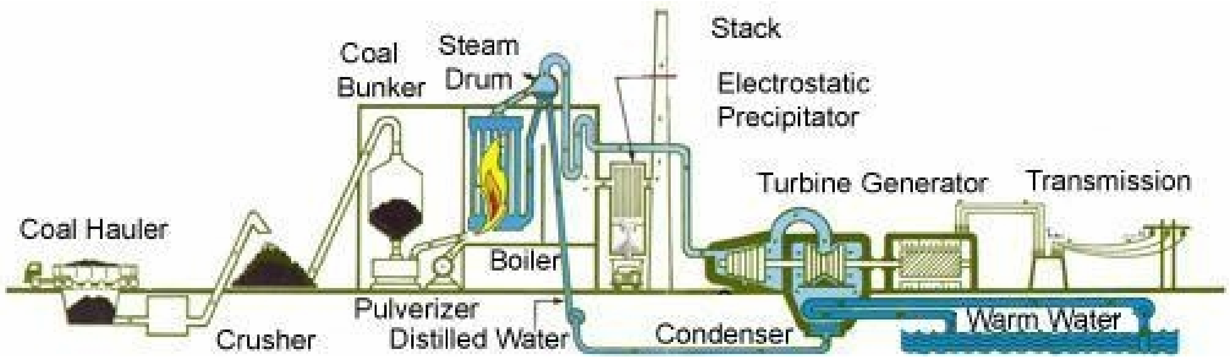
All previous thermal plants in Alberta employed the sub-critical boiler plant technology whereas Genesee will employ the super-critical boiler plant technology. The super-critical boiler system captures a greater percentage of the combustion heat. For example, the sub-critical units experience, on average, about 15% to 15.5% boiler heat loss. The projected loss from the Genesee 3 super-critical unit is projected at about 11%.

Generation station power consumes between 6% and 8% of the generated energy. Unit step up transformers are included as part of the generation efficiency equation. The Canadian Electricity Association's (CEA) 2002 Environmental Commitment and Responsibility (ECR) Annual Report indicates a station power Canadian average of 6.09% for all fossil-based generation. This compares well with the Alberta data in Table 5, which is for thermal generation only.

The efficiencies of thermal plants vary dependent on the specific boiler and turbine design at the time of purchase. The amount of station power needed for each unit, however, varies from plant to plant because it is dependent on many factors such as fuel quality, stack height and distance from cooling water source. Thus, a direct comparison cannot be made necessarily between two plants or units.

Gas thermal plants experience a lower station power need than coal plants due to coal handling power requirements. In table 5, the source information for Battle River #4 of 4.85% station power does not provide sufficient detail to explain this level of efficiency. Figure 7 illustrates the stages of a coal fired thermal plant and the various components requiring station power to operate the plant. The supplied coal is put through a crusher and pulverizer. It is then burned in a boiler to heat water and convert it to high-pressure steam. The steam is directed to a steam turbine that is connected to an electrical generator to produce electricity supplying the transmission grid. A condenser converts the steam exhausting from the turbine back into water that is reused in the boiler. Water from a reservoir supplies the condenser that cools the steam. The condensing process increases the efficiency of the electricity generation.

Figure 7. Stages of a Coal Fired Thermal Plant



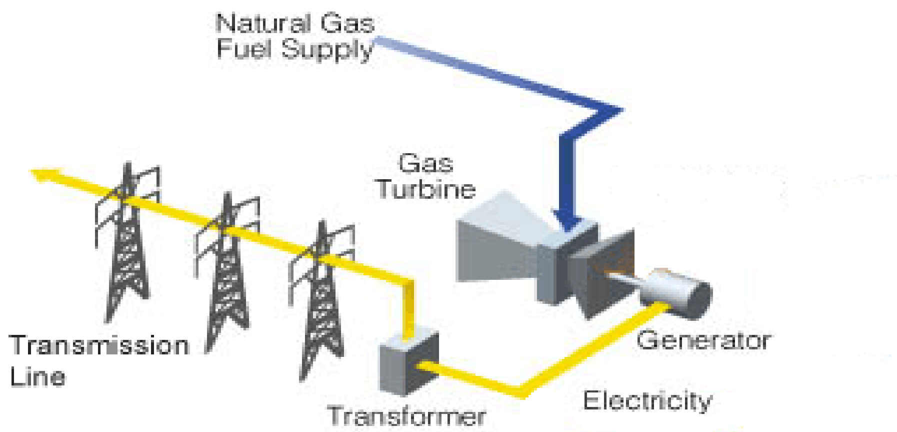
Source: ATCO Power

Gas Turbines (Simple Cycle, Combined Cycle & Cogeneration)

With the establishment of a power market and deregulation in Alberta, much of the new generation installed since 1996 has been smaller gas turbine generating units. A few have been simple cycle design but most have been either combined cycle or cogeneration.

Figure 8 illustrates the simple cycle gas turbine, where natural gas supplies the turbine that drives the electric generator connected to a step up transformer that supplies power to the transmission grid. Because these units can be brought up to speed within minutes, it makes them ideal for meeting peak loads to provide additional system reliability or support.

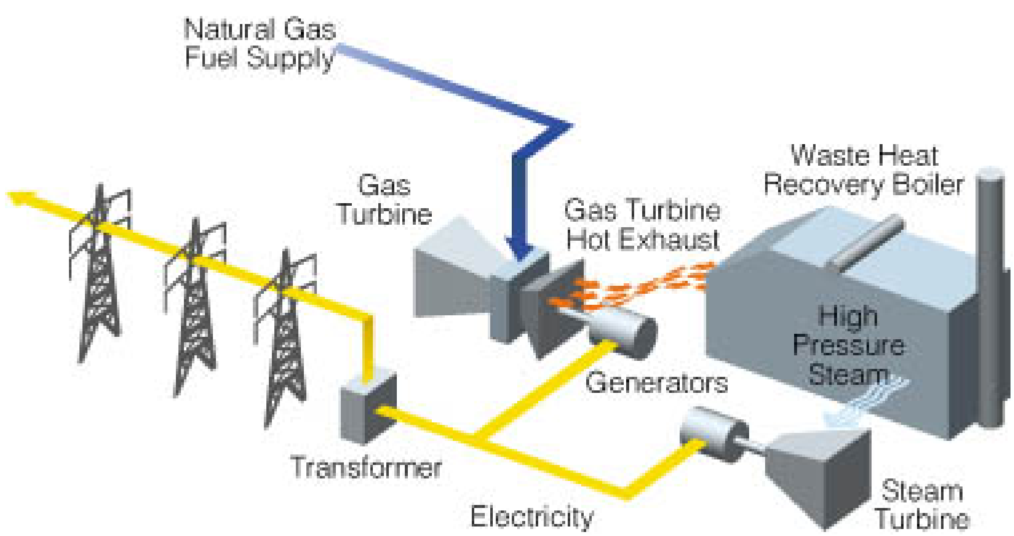
Figure 8. Simple Cycle Gas Turbine



Source: Atco Power

The combined cycle gas generator shown in Figure 9 combines a gas turbine with a steam turbine to produce electricity from one fuel input. A gas turbine turns an electrical generator. The hot exhaust off the turbine is captured and utilized in a heat recovery boiler to generate additional electricity through a steam turbine. Depending on the amount of energy required from the steam turbine, this technology may require supplementary fuel supply to the heat recovery boiler. This technology can result in a fuel conversion efficiency of up to 50% and contributes fewer emissions to the environment than traditional coal fired thermal generation.

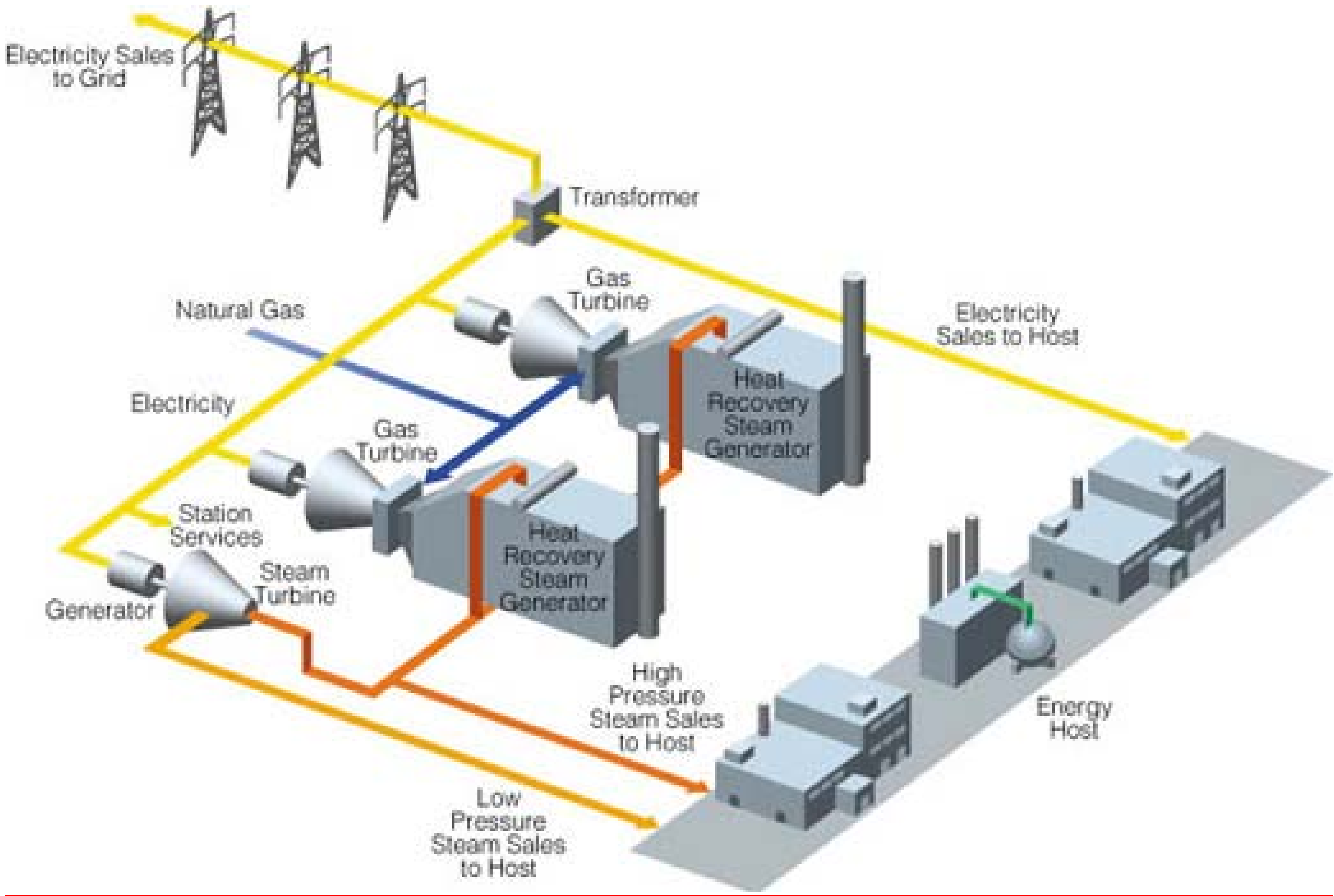
Figure 9. Combined Cycle Gas Generation



Source: Atco Power

Figure 10 illustrates a gas cogeneration plant where, in addition to the gas turbine electricity generation, the hot exhaust from the gas turbine is utilized to supply steam to the on-site industrial process. The co-generation process could also provide steam to a steam turbine thereby providing a triple process, i.e. an initial gas turbine with waste heat recovery to produce and supply steam to both a steam turbine and process steam or heat to an industrial host. Cogeneration systems are over 80% efficient, lowering environmental emissions by capturing and recycling waste heat. The greatest amount of new generation installed since 1996 has been co-generation.

Figure 10. Cogeneration



Source: Atco Power

Gas turbine versus overall efficiency, as shown in table 6, refers to the efficiency achieved by the various gas plant configurations as illustrated in Figures 8, 9 & 10. For example, the simple cycle gas turbine plants at Valleyview and Poplar Hill, which are configured as in Figure 8 in which all turbine exhaust heat is vented to the atmosphere, have efficiencies in the order of 40%. In the case of cogeneration however, as per the Carseland plant, the efficiency of the gas turbine alone is 41% but with the capture of the turbine exhaust heat to generate more electricity the overall plant efficiency reaches 75%. Table 6 lists the various gas turbines in Alberta and data that was available for each.

Table 6. Various Gas Turbines in Alberta

Plant Name	Owner	Type of Plant	ISD	Capacity (MW)	Heat Rate (GJ/GWh)	Gas Turbine Eff.(%)	Overall Eff.(%)	Station Service (%losses)
Valleyview	ATCO	Simple Cycle	2001	45	9,100	39.6	n/a	2.08
Poplar Hill	ATCO	Simple	1998	45	8,517	42.2	n/a	n/a
Cavalier	Encana	Combined Cycle	2001	107	7,845	n/a	46.0	2.67
Calgary EnergyCentre	Calpine	Combined Cycle	2003	283	7,386	n/a	48.7	n/a
Foster Creek	Encana	Co-Gen	2003	83.4	11,158	32.7	83.3	
Muskeg River	ATCO/ SaskPower	Co-Gen	2002	160	10,792	33.3		7.07
Mahkeses/Cold Lake	Imperial Oil	Co-Gen	2002	170	n/a	31.7	84.0	n/a
Redwater	TransCanada	Co-Gen	2001	40.8	n/a	n/a	75.0	n/a
BearCreek	TransCanada	Co-Gen	2002	80	n/a	n/a	60.0	n/a
Carseland	TransCanada	Co-Gen	2002	80	n/a	41.1	75.0	n/a
Mackay River	TransCanada	Co-Gen	2004	165	n/a	n/a	75.0	n/a
Scottford	Air Liquide	Co-Gen	2000	89	n/a	n/a	78.0	n/a
Dow-Ft Sask	TransAlta/ Air Liquide	Co-Gen	1999	130	n/a	38.0	63.9	n/a
Primrose	Atco/CNRL	Co-Gen	1998	83	n/a	n/a	78.0	n/a

n/a: not available

What's happening in other jurisdictions?

The Canadian Electricity Association (CEA) produces an annual Environmental Commitment and Responsibility (ECR) report. The ECR program was launched in 1997 as an industry wide approach to environmental performance reporting for the corporate utility members of CEA. One section of the 2002 report reviews all generation, transmission and distribution activities as they relate to their impact on the environment. However, the information is only reported in aggregate nationally for plant conversions by fuel type and efficiencies in generation, transmission and distribution. The ECR indicates the conversion efficiency for fossil fuel generation ranges from 13.1% to 35.9% with the average being 33.6%.

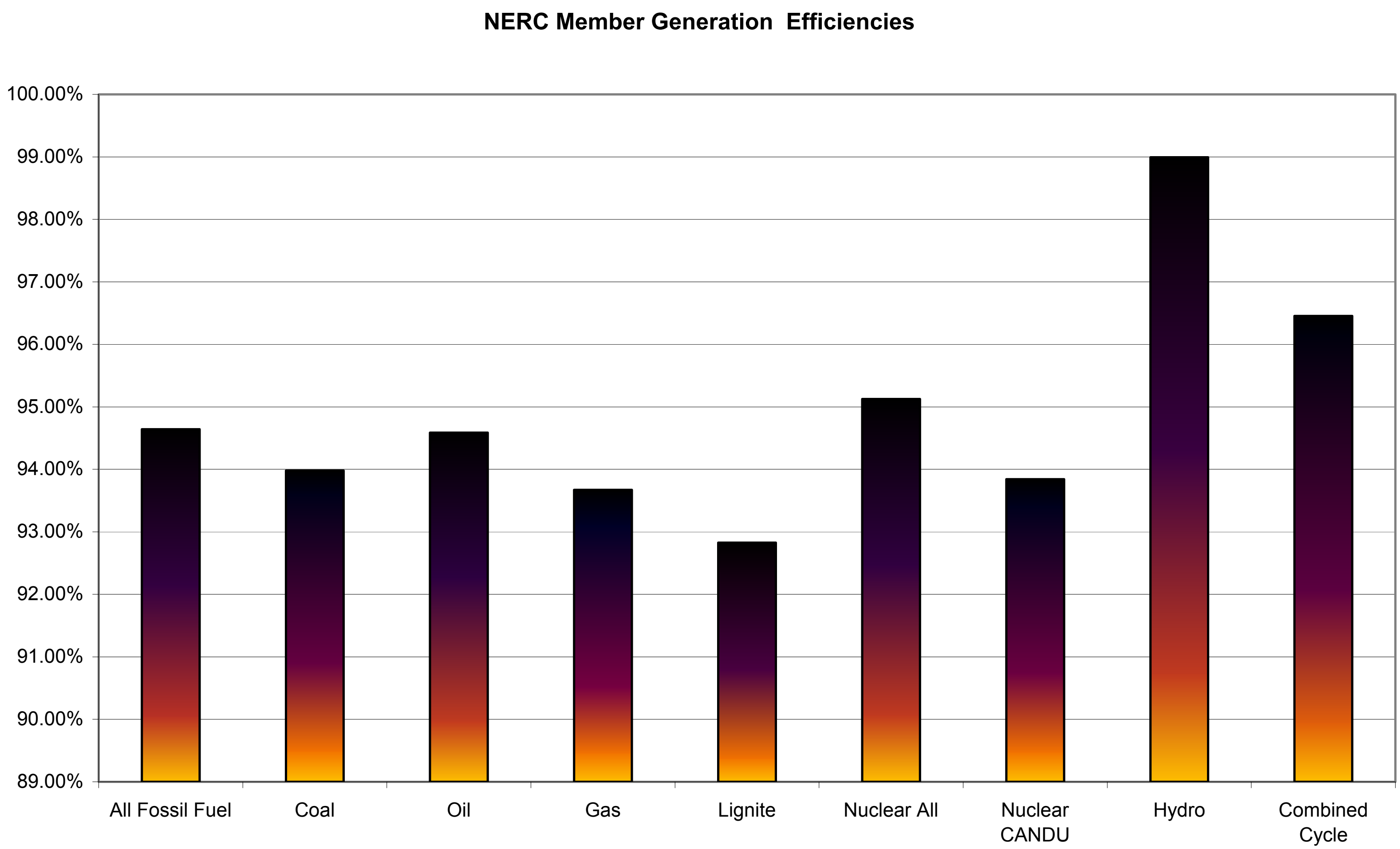
Table 7 compares thermal fuel conversion efficiencies of Alberta's coal and gas plants to those in other jurisdictions. The new boiler technology of Genesee 3 provides the highest rating of all plants at over 38%.

Table 7. Generation Fuel Conversion Efficiencies

Fuel	Alberta	BC Hydro	Sask Power	MB Hydro	Hydro One	NS Power	Maritime Electric	NSW Australia
Coal	23.1% (Lowest: Milner) 38.4% (Highest: Genessee3)	N/a	30.7%	27.8%	N/a	34.1%	N/a	37.1%
Gas	27.9% (Lowest: Rossdale 8) 33.7% (Highest: Cloverbar 2)	36.5 %	N/a	27.1% to 28.5%	N/a	32.7%	N/a	42.0%
Oil	N/a	N/a	N/a	29.6%	33.2 %	32.2%	18.9%	N/a

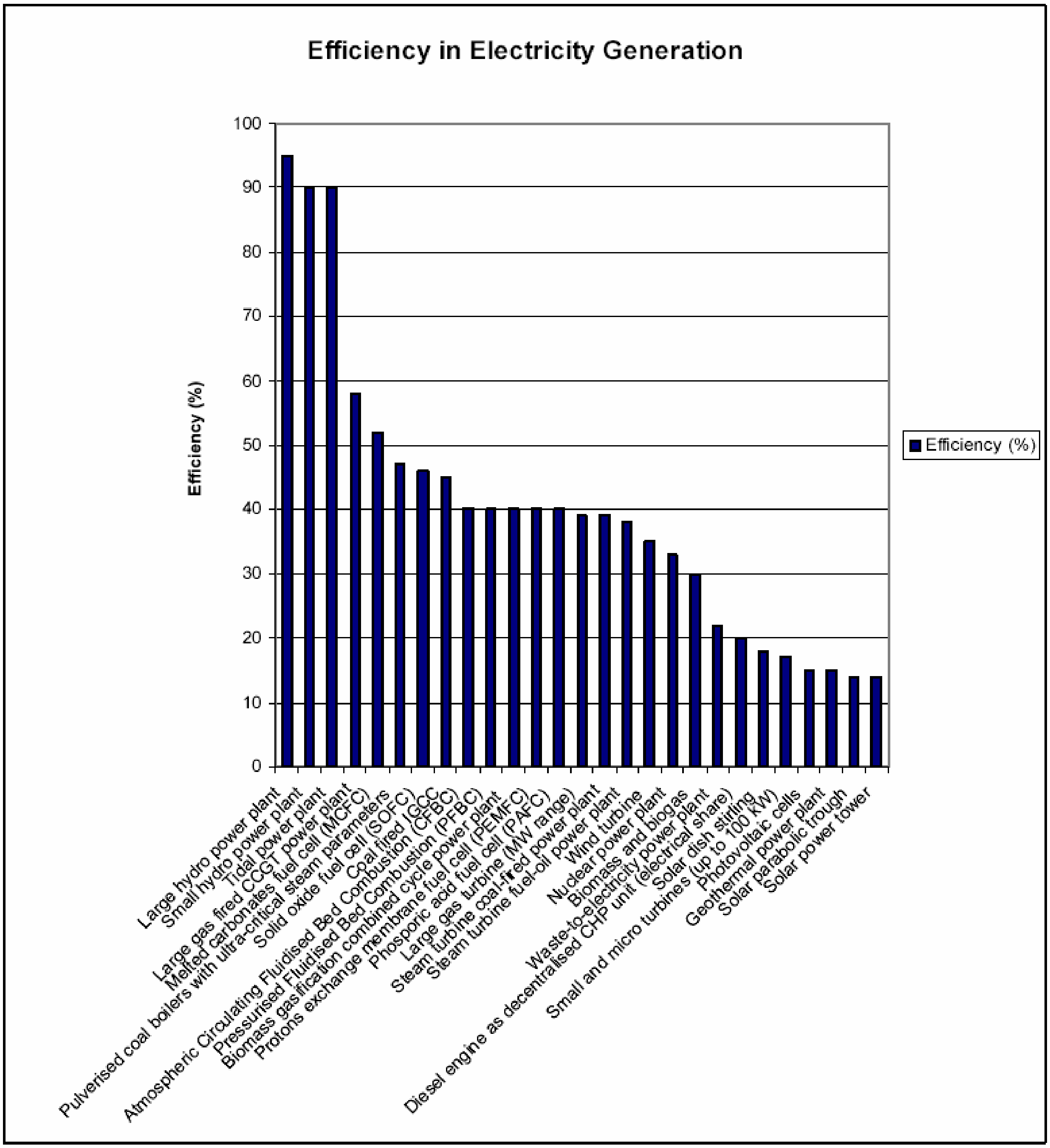
The ECR report also indicates the average efficiency, ratio of net electricity to gross electricity generated, is 93.9% for all fossil thermal plants and 99.8% for all hydro plants. The North American Reliability Council (NERC) Generating Availability Data System (GADS) provides averages for all contributing members, which represents 530 utilities across North America. Appendix 3 lists all contributing members. Figure 11 illustrates those generation efficiencies by type, averaged for all contributing members. Compared to Canada, the GADS report indicates all fossil fuel plants are slightly higher at 94.6% and all hydro plants are slightly lower at 98.9%.

Figure 11. NERC Member Generation Efficiencies



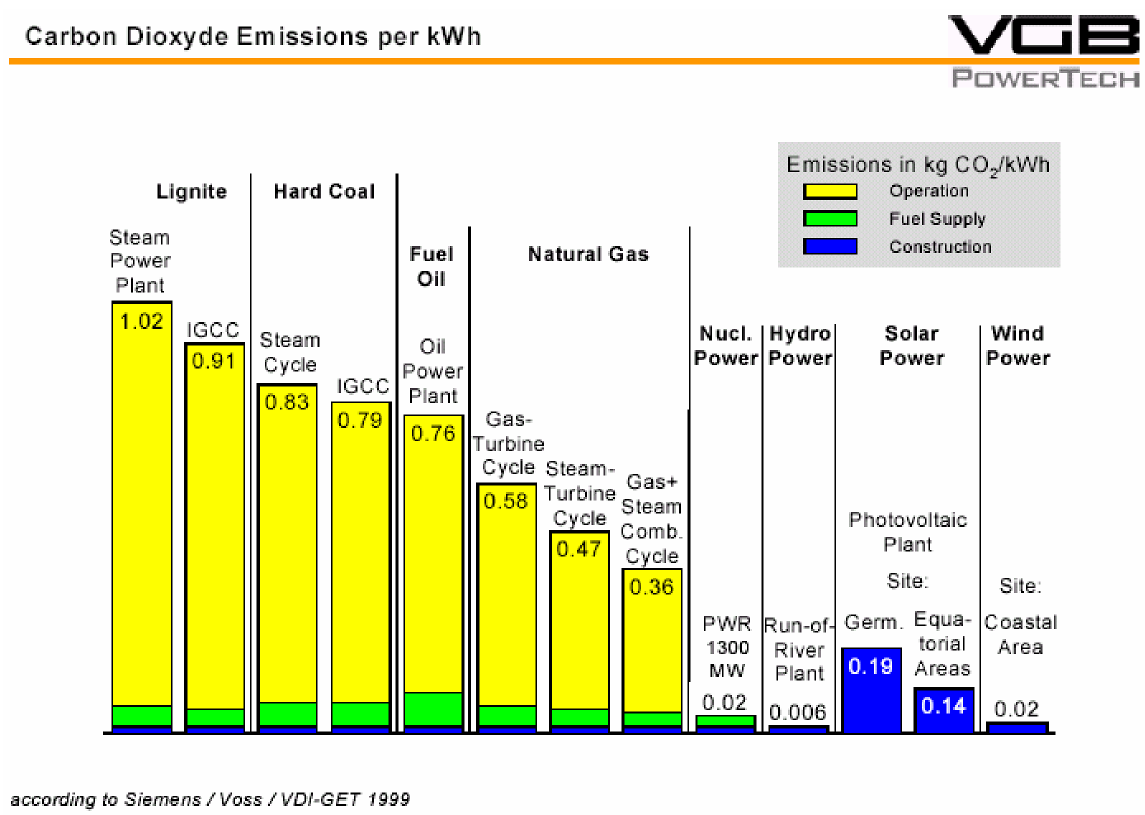
An overall comparison of generation technology efficiencies was done by EURELECTRIC of Brussels, Belgium and is illustrated in Figure 12. EURELECTRIC is the sector association of the European electricity industry. It shows efficiencies at 95% for hydro plants, 39% for coal-fired thermal and 35% for wind plants. This graphic is strictly an efficiency comparison and does not take into account any impact these technologies have on GHG emissions, which are illustrated in Figure 13.

Figure 12. Efficiency in Electricity Generation



The same study by EURELECTRIC provided Figure 13 below, an overall comparison of specific CO_2 emissions per kWh by generating source. This represents a full "life-cycle balance" comparison, which includes site erection and fuel supply.

Figure 13. Comparison of CO_2 emissions by generating source



Can improvements be made to Alberta's generation?
Efficiency gains can be realized in generation plants by using high efficiency motors and pumps that supply services to the plants, generally referred to as station power.

Some Canadian utilities are implementing improvements in their generation system efficiencies. Nova Scotia Power is improving plant efficiencies through improved understanding of boiler operations and the best fuel blends to use with each. They estimate gains of up to 10% in some thermal plants. Ontario Power Generation (OPG) undertook energy saving initiatives between 1994 and 2002, resulting in savings of 2,441 GWh, cutting emissions by 2.3 million tonnes CO_2, NOX and SO_2.[3]

Given the abundance of inexpensive coal in Alberta, coupled with the competitive nature of the industry, use of new coal combustion technologies can contribute to improved coal plant generation efficiencies in the province. Continued development of on-site cogeneration will also contribute to overall electrical generation efficiencies, as older less efficient coal fired thermal plants are retired.

Many of the coal and gas thermal generating units are approaching retirement so it is unlikely that owners will consider investing in efficiency improvements. Similarly, for those units that have longer remaining lives (more than 10 years to retirement), today's competitive electricity market will greatly influence whether small efficiency gains are worthwhile economically or to achieve small reductions in GHG emissions.

Distributed generation is not common in Alberta. Distributed generation is normally defined as small generation plants installed within the distribution system. Its advantage is that it can contribute to loss reduction in both the transmission and distribution systems. Unlike generation currently existing at places such as hospitals, universities, etc., which strictly provides emergency standby power, distributed generation can operate on a continuous energy supply basis and the supply chain itself is used as standby. Isolated plants as listed in Appendix 4, are utilized because the loads they serve are too remote from the electrical interconnected system and thus it is not economically practical to service those loads from the Alberta electricity system. This differs from distributed generation in that distributed generation is installed within an electrical distribution system to either supplement or replace the energy supply from the distributing company. Any energy provided by a distributed generator replaces energy that would have otherwise been supplied by a centrally located generator on the transmission system. This is a major area of study and may warrant further examination.

[3] CEA/ECR Annual Report 2002

V. Transmission and Distribution

The transmission system (grid) is an interconnected network of wires (transmission lines) that facilitate the transfer of electricity from points of supply (generators) to points of delivery (distributors or loads). Losses occur in exactly the same manner on the transmission and distribution systems and in various pieces of equipment, such as transformers, used in the delivery of electricity to customers.

Electricity is pushed through the grid by the voltage and flows along the grid in the form of current. This current experiences resistance in the transmission lines. The magnitude of the current is a function of how much load is flowing along the transmission line and the operating voltage of the transmission line. For a given fixed load, the current along the transmission line will vary in direct proportion to the operating voltage of the transmission line.

Once a transmission line has been designed and built, the operating voltage and the conductor size are fixed. The only variable left is the amount of current flowing in the line. The higher the power flow, the higher are the losses. The only possibility for a reduction in losses is a decrease in load. Electric load on a transmission line tends to increase over time due to increasing customer demands driven by economic forces. Transmission losses increase as well. There is a load-carrying limit for a transmission line, which is established by system stability and voltage drop considerations.

JEM Energy's project team attempted to answer two main questions:

1. What are the components of conductor line losses? For example, are these losses due to the conductor size and/or number of conductors per phase or by the distance of generation to load centers?
2. Could greater efficiencies be achieved with modern equipment? If we separate transformers' significant losses from conductor losses and apply data on the improved transformer design efficiency over time, can we provide estimated improvements?

Through the AEUB, AESO and other sources, the project team examined the total annual system losses, as determined by the metered energy entering the transmission system less the metered energy leaving the system. Unaccounted for energy (UFE) was also addressed, since the delivery of electricity over an electricity transmission and distribution system results in a portion of the electricity being consumed or lost before it reaches the customer. However, unaccounted for energy is not a consideration in transmission. This is an issue more prominent in the distribution system.

What is Alberta's current situation?

On the Alberta transmission system, power flows have increased significantly over the past decade. The load on the system has continued to grow due to increasing economic activity while very little new transmission has been built. This is particularly true in the main transmission corridor between Edmonton and Calgary.

Over the past few years, the transmission administrator (AESO) has managed the transmission flows in this heavily loaded corridor through the introduction of locational-based pricing incentives for generators located around Calgary. Although the main driver for these generators was to solve voltage collapse problems in the Calgary area, a resulting benefit has been reduced line losses on this corridor.

Six 240 kV transmission lines connect Edmonton to Calgary regions. (See Figure 2). These transmission lines average about 300 km in length. They represent about 10% of the total transmission lines in Alberta but account for approximately 25% of the transmission line losses This occurs for two reasons: the Calgary load, which represents one of the two major load centres in Alberta, and the 500 kV tie line to B.C. In 2001, exports to B.C. increased significantly. The load in Calgary has grown faster than the rest of the province.

While there are many similarities in the networks of different transmission and distribution companies there are also important and significant differences, including:

- geographical size of the area where the network is located
- number of customers connected to the network
- quantity of electricity distributed
- degree of dispersion of customers across the network
- proportion of different types of customers connected to the network, and
- amount of underground cables compared to overhead lines.

In addition to these differences, individual companies have historically adopted different designs, operating and investment principles, all of which have led to very different network configurations.

In Alberta, all transmission efficiency related data required for this study resides with the Alberta Electricity System Operator (AESO). The transmission owners are strictly operators and maintainers of their respective systems.

All transmission line owners, transmission capacity (total km of lines) and system voltages are listed in Table 14.

In 2003, total annual system losses were 2,765 GWh, or 4.45% of total energy transmitted – 62,089 GWh. This was determined by the metered energy entering the system plus scheduled imports (point of supply/POS) less the sum of the metered energy leaving the system plus the scheduled exports (point of delivery/POD). These losses reflect both conductor and transformer losses on the grid. AESO does not delineate between conductor and transformer losses.

Table 14.Total Circuit Kilometres of Alberta Transmission and Distribution Lines

Utility	Transmission Lines (>60 kV)	Distribution Lines (60 kv or less)	Total lines (in kilometers)
ATCO Electric	8,911	58,240	67,151
ENMAX	279	6,185	6,464
EPCOR	188	4,315	4,503
ALTALINK	11,246	10	11,256
FORTIS	0	94,231	94,231
CITY OF LETHBRIDGE	35	700	735
CITY OF MEDICINE HAT	54	606	660
CITY OF RED DEER	0	672	672
OTHER TOWNS	0	376	376
TOTALS	20,714	165,334	186,048

Ref: EUB 2002 Annual Electricity Statistics

What's happening in other jurisdictions?
The ECR report indicated an overall efficiency of 96.01% in 2002 for transmission in Canada. This compares very closely to the 95.55% efficiency experienced by the Alberta system. These efficiencies are the ratio of kilowatt-hours out to kilowatt-hours in. JEM Energy initiated research by contacting individual contributing ECR members. Their responses are illustrated in Table 15. The Department of Energy, Utilities and Sustainability in New South Wales, Australia also responded to a similar request and their response is included in Table 15.

Distribution
Total distribution system losses were collected from reliable sources such as the Alberta Energy Utilities Board (EUB) and distribution companies. A comparison of distribution losses similar to the comparisons done for transmission was conducted.

Utilities estimate distribution wire losses based on distribution voltage levels and conductor sizes and are determined by the total metered energy entering the distribution system less the total metered energy consumed by the customers.

Electricity losses occur in the operation of the following components of an electrical distribution system:

- distribution feeder conductors
- distribution service transformers, and
- secondary wires to individual customers.

Alberta distribution system losses shown in Table 15 were obtained from:

- Fortis distribution loss study to EUB, March 24, 2003
- EPCOR distribution loss study to EUB, September 30, 2003
- ENMAX distribution losses to EUB, October 10, 2003
- ATCO Electric distribution losses to EUB, 2004
- City of Red Deer, direct response to research team.

It is only recently that the EUB has been collecting losses studies and calculations as part of distribution tariff applications. Some companies indicated to JEM Energy that there is no standard protocol for the conduct of distribution losses studies so it is premature to draw conclusions by direct comparison of one study result to another.

Unaccounted for energy (UFE) or non-technical losses are those losses that cannot be determined analytically. These losses include a large list of items and are determined by subtracting the energy delivered from the energy accepted. They include physical losses from the distribution system such as contact with vegetation, contact with the ground resulting from vehicular or storm damage, lightning and corona. These non-technical losses also include administrative losses such as non-billed service, error in the estimation of un-metered delivery and meter/meter data management error. Non-technical losses also include losses that result from fraud and theft. Only one distribution utility addressed UFE as a percentage of total losses. It indicated UFE represented 0.46% of total losses, of which theft and fraud accounted for 0.32%.

What's happening in other jurisdictions?

The ECR report indicates an overall efficiency of 95.8% for Canadian distribution systems. The report also documents distribution transformer efficiencies at 98.91% for single phase up to 25 KVA to 99.5% for those in the range of 3-phase 1000 KVA to 3000 KVA. Table 15 also illustrates Alberta's distribution system efficiencies with those in other jurisdictions.

Table 15. Transmission & Distribution System Efficiencies

Utility or Jurisdiction	Transmission System Efficiencies	Distribution System Efficiencies	Distribution Transformer Efficiencies (at 50% load)
Alberta	95.55%	ATCO 95.0%	99.2% (2003 purchases only)
		ENMAX 97.0%	99.3% (lg. 3 Ø) to 98.8% (sm.1Ø)
		EPCOR 97.6%	98.99% (500 kVa/10% to 100% load range) to 98.3% (<150 kVA)
		FORTIS 96.2%	99.44%
Sask Power	95.8%	95.3%	98.8%
Hydro One/Ontario	97.2%	92.7%	99.3% (11,158 Transformers)
Maritime Electric/PEI	96.3%	94.9%	99.2%
NS Power	97.1%	94.7%	98.8%
Manitoba Hydro	93.4%	95.6%	N/a
New South Wales/Australia	96.9%	93.8%	98.0%
Canadian Average (CEA/ECR)	96.0%	95.8%	98.9% (1Ø) to 99.5% (3Ø)

1Ø to 3Ø= single phase to three phase

Table 16 lists transmission and distribution losses by percentage for electricity supply systems for Western Europe, Australia and New Zealand compared to North America.

Table 16. Transmission and Distribution Losses (by percentage of total system) Europe, Australia, New Zealand and North America 1980 to 2000

Country	% losses 1980	% losses 1990	% losses 1999	% losses 2000
Finland	6.2	4.8	3.6	3.7
Netherlands	4.7	4.2	4.2	4.2
Belgium	6.5	6.0	5.5	4.8
Germany	5.3	5.2	5.0	5.1
Italy	10.4	7.5	7.1	7.0
Denmark	9.3	8.8	5.9	7.1
United States	10.5	10.5	7.1	7.1
Switzerland	9.1	7.0	7.5	7.4
France	6.9	9.0	8.0	7.8
Austria	7.9	6.9	7.9	7.8
Alberta	**N/a**	**N/a**	**N/a**	**8.0***
Sweden	9.8	7.6	8.4	9.1
Australia	11.6	8.4	9.2	9.1
United Kingdom	9.2	8.9	9.2	9.4
Portugal	13.3	9.8	10.0	9.4
Norway	9.5	7.1	8.2	9.8
Ireland	12.8	10.9	9.6	9.9
Canada	**10.6**	**8.2**	**9.2**	**9.9**
Spain	11.1	11.1	11.2	10.6
New Zealand	14.4	13.3	13.1	11.5
European Union	7.9	7.3	7.3	7.3
Average	**9.4**	**8.1**	**7.9**	**7.9**

(Ref: International Energy Agency through U.K. Office of Gas & Electricity Markets)

* Distribution component is average of 4 utilities from table 15

Can improvements be made to Alberta's transmission and distribution?

Transmission

Table 15 illustrates that transmission system efficiencies are relatively consistent in most Canadian jurisdictions. Alberta's system is very close to the national average of 96%.

However, there could be some efficiencies attainable. One of the areas for potential improvement is reducing the load on the transmission system by building generation closer to the markets they serve. This model was tried in the past with locational-based pricing incentives, such as the Invitation to Bid on Credits (IBOC), which incented new generators starting in 2001 and resulted in 281 megawatts of generation. The second was the Locational Based Credit Standing Offer (LBCSO), which resulted in 215 megawatts.

Two major initiatives are currently being studied to supply additional transmission capacity in Alberta and could provide opportunities to incorporate efficiencies:

- AESO application for 500 kV north/south line
- DC line Fort McMurray to the U.S. with major Alberta points of access (Northern Lights project)

In the U.S., the Oak Ridge National Transmission Technology Research Centre in Oak Ridge, Tennessee is conducting research into next-generation power lines that are lighter and can transmit far more electricity than the materials used in conventional lines. Though in a very preliminary stage, the claim is that "3M's new conductors can increase current-carrying capacity by three fold for the same size cable at minimal cost and environmental impact."[4]

There may also be scope for improvements in transmission transformer efficiencies. For example, AltaLink has a total of 445 transformers on the Alberta system, of which 292 are operating at 138 kilovolts (kV), and up to 83 MVA. The balance operates at 500 kV, 245 kV, 69 kV, 34.5 kV, 25 kV or 13.8 kV and range from 10 MVA to 400 MVA. The cost of these large transformers prohibits any economical replacements. However, Energy Star rated transformers would provide improved efficiencies, when replacements are required due to failures or upgrades.

Distribution

Compared to other jurisdictions, Alberta's distribution systems have lower losses and all but one is less than the Canadian average of 4.2%, as was illustrated in Table 15. One contributing factor is the age of the system. Distribution systems, including transformers are relatively newer in Alberta compared to other systems in Canada.

The CEA's ECR report shows the national average for transmission and distribution combined losses were 8.2% in 2002. Overall, transmission and distribution losses in Alberta averaged 7.68% during that same period.

Table 16 reports Canada's transmission and distribution losses at 9.9% for 2000. The most efficient is Finland with 3.7%, which represents a 40% reduction in losses since 1980. Non-technical reasons for the variances in losses can also be attributed to a country's geography, customer density, urban versus rural ratios, or loss calculation protocols. One reason Canada has higher transmission and distribution losses than other countries is due to the long distances of the transmission and distribution systems. However, the losses trend increased for Canada in 1999 and 2000 compared to a flat or downward trend in many other countries. There are also other variances, which could be further explored. For example why is Finland's loss rate is at 3.7% and New Zealand's at 11.5%, or what caused the U.S. to go from 10.5% for 10 years to 7.1% in 1999 and 2000? It is possible that some of these significant loss reductions may be attributed to increases in costs associated with losses in recent years. Therefore, greater attention and time is now paid to the accuracy of loss calculations. The source document for Table 16 does not

[4] Stovall, ORNL Engineering Science & Technology Division, 2002

indicate the protocols used by the various jurisdictions for the determination of their system losses. Further study into the protocols used would provide for better comparisons between Alberta and other jurisdictions.

In Alberta, the losses vary by distribution wires companies, due in part to rural vs. urban systems. Urban utilities such as ENMAX and EPCOR experience lower losses (up to 3%) due to shorter distances between substations and loads, and a higher concentration of customers, compared to ATCO Electric and Fortis with their many kilometers of rural distribution lines. Table 17 below illustrates the comparisons of Alberta's distribution system losses and customers per kilometer with those in Saskatchewan, Nova Scotia and PEI.[5] Although customers/km is a factor in distribution losses, utilities faced with low customers/km ratios have addressed this issue to a large degree with technological solutions, such as voltage regulators and capacitor banks.

Table 17. Customers/ KM to Distribution Losses Comparisons

Utility	KM of Distribution Lines	# of Distribution Customers	Cust/KM	Distribution Losses %age
ENMAX	6,185	359,942	58.2	3.0
EPCOR	4,315	287,732	66.7	2.4
Fortis	94,231	359,917	3.8	3.8
ATCO Electric	58,240	162,133	2.8	5.0
SaskPower	139,460	425,209	3.0	4.7
NS Power/Halifax Metro	2,677	165,217	61.7	5.3
NS Power/non-urban	22,047	284,265	12.9	
Maritime Electric	4,500	69,480	15.4	5.1

Variations may also be attributed to different protocols for calculating losses. Consequently, consistent protocols should be in place to accurately compare distribution system losses.

Unaccounted for energy is a prominent issue in the distribution system. Although included as losses, they are outside the scope of an efficiency study because they are non-technical losses and need to be addressed by specialists in those areas.

Transformers are an integral component of the transmission and distribution systems and have been considered a relatively high efficiency component. However, recent advances in technology have produced improvements and high efficiency Energy Star transformers are now available. The U.S. Energy Star transformer program is a voluntary program that recognizes utilities that make a commitment to purchase high efficiency distribution transformers. Partners agree to perform an economic analysis of total transformer-owning costs and to buy transformers that meet Energy Star guidelines only when they are cost

[5] EUB Electric Industry Annual Statistics 2002; SaskPower 2003 Annual Report; NS Power/J.Fraser email response Sept/04; Maritime Electric/N.Warren email response Sept/04

effective. Five Canadian firms are members of this initiative. Canada has not developed an Energy Star transformer program as yet. The U.S. Energy Star's website includes a transformer efficiency calculator that allows engineers and building personnel to evaluate options by comparing efficiencies and operating costs of Energy Star transformers with other models. The link to this site is listed in Appendix 2 of this report.

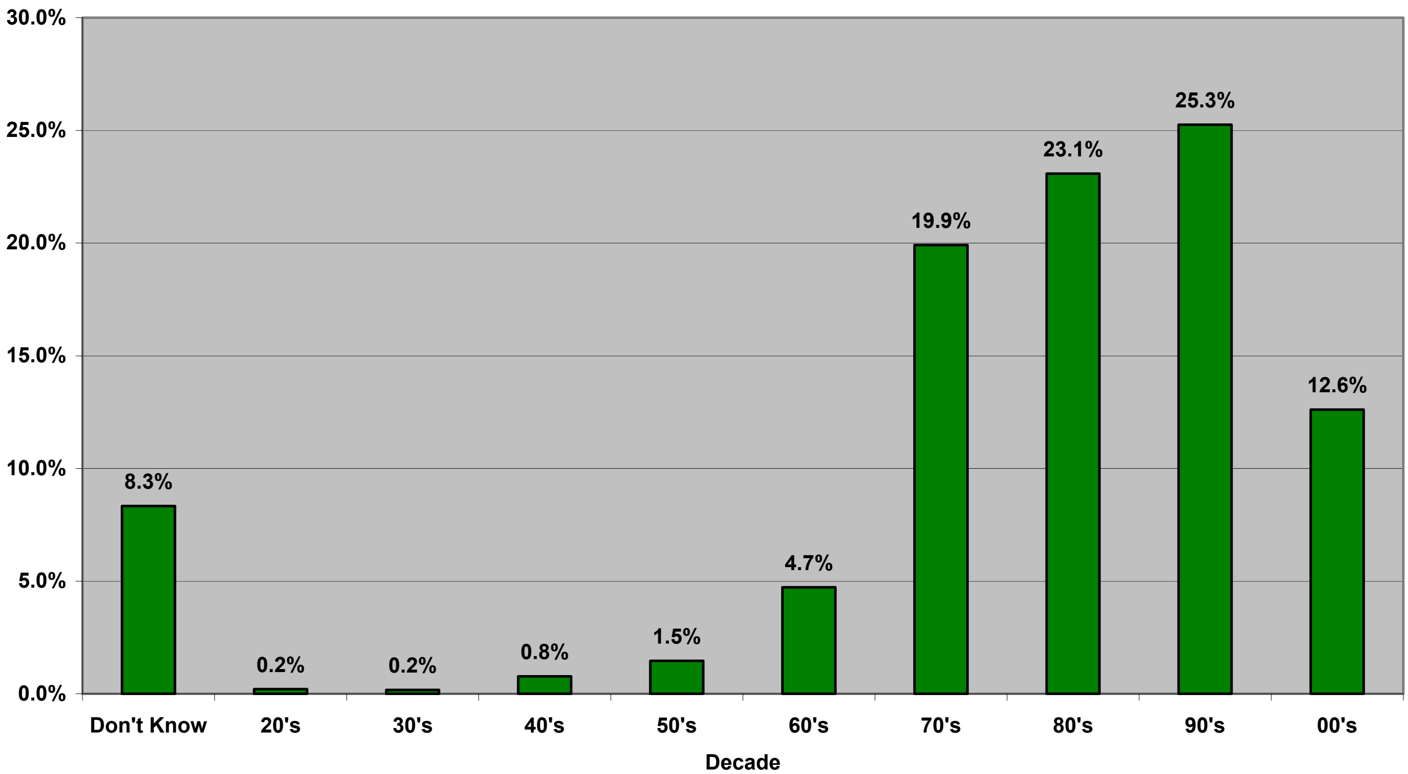
A U. S. Environmental Protection Agency (EPA) study on high efficiency distribution transformers estimated potential savings to be just under 100 kWh per transformer per year. (At 25% average load and expected life of 30 years, savings would be 2.9 billion kWh equating to 1,780,000 MT of CO_2 emission reductions). This is based on an average efficiency improvement of $1/10^{th}$ of 1 percent for all transformers sold to U.S. utilities in one year.[6] A link to the complete study is in Appendix 2. Other studies have indicated even greater savings, depending on loading assumptions and current transformer inventories.

It is estimated there are 340,000 in-service distribution transformers in Alberta. This is based on Fortis' in-service inventory of 179,902 [147,420 Fortis owned, balance customer owned], Enmax in-service inventory of 43,316, plus EPCOR's design criteria of 12 distribution transformers per customer. ATCO Electric was assumed to have same transformer per customer ratio as Fortis; Red Deer, Lethbridge, Medicine Hat & other towns assumed to have same transformer per customer ratio as EPCOR.[7]
Assuming a saving of 100-kWh/ transformer/year for all transformers currently in use in Alberta, estimated savings of 1,020 million kWh would result over an expected life of 30 years.

Future work could investigate barriers and financial challenges, such as mechanisms that provide balanced incentives between cost-effective investments in high-efficiency transformers and other resource options, or the potential for a Canadian Energy Star Transformer Program. Further study is required in this area to determine the potential savings, emission reductions, costs and economics. Figure 14 illustrates the Fortis in-service transformers age range by decade. This inventory represents just over half of the total in-service transformers in Alberta and of these over 25% are at least 25 years old. This data could form the basis for further study into the savings potential for an Energy Star initiative for Alberta.

[6] The Economic & Environmental Benefits of High-Efficiency Distribution Transformers/US EPA
[7] email from J.Holmes/Fortis Aug. 2004; email from K.Hawrelko/Enmax Sept. 2004; EPCOR distribution loss study to EUB, September 30, 2003

Figure 14
Fortis In-Service Transformer's Age by Decade



VI. Conclusions

Overall, the Alberta system is above average for system efficiency compared to other jurisdictions. However, a few other jurisdictions, such as Finland's transmission and distribution, do indicate higher efficiencies of up to 96.3%, compared to Alberta at 92.49%. Further study could determine what practices or methods resulted in the higher efficiencies.

To improve generation efficiency, a balanced approach to all generation sources and the supply system in general will result in overall system efficiencies. For example, cogeneration provides efficiencies in excess of 80%. However, these forms of generation are not suitable for all situations. Efficiency gains could also be realized in generation plants by using high efficiency motors and pumps that supply services to the plants, generally referred to as station power.

The two major areas with potential for improving efficiency in transmission and distribution are conductors and transformers. In the short term, there is not much available for improving conductor efficiency. In the longer term, current research into future power lines that are lighter and can transmit far more electricity than the materials used in conventional lines may provide some future efficiency.

Transformers offer an area for increased efficiency. Though small efficiencies are gained per transformer, the fact that there are over 300,000 estimated on the Alberta grid would mean substantial savings, depending on the quantities upgraded.

Future research and study aimed at improving efficiency for Alberta's electricity supply system is itemized as follows:

- potential of incentives for combined cycle and cogeneration gas turbines
- potential for high efficient station power drives at generating plants
- economics of generation improvements in other Canadian jurisdictions such as Nova Scotia and Ontario
- potential for distributed generation in Alberta
- processes for standard protocols for assessing distribution losses in Alberta and other jurisdictions
- potential for voluntary Energy Star distribution transformer initiative
- barriers, drivers, economics and emissions impacts of investing in Energy Star transformers versus other generation resource options
- potential of incentives to increase distributed generation
- potential of incentives for locational based pricing for generation

VII. Appendices

Appendix 1: Glossary and Acronyms

AESO: Alberta Electric System Operator

Alternating Current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America, the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used in power systems because it can be transmitted and distributed more economically than direct current.

Base Load: The minimum continuous load over a given period of time. Base load generating stations operate essentially at full output whenever possible.

British Thermal Unit (Btu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Bulk Electricity: Large amounts of electric power at transmission voltages, generally to run industrial plants and operations.

Bundling Electricity: Combining the costs of generation, transmission and distribution and other services into a single rate charged to the retail customer.

Capacity: In the electric power industry, capacity has two meanings:
1. System Capacity: The maximum power capability of a system.
For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity.
2. Equipment Capacity: The maximum power capability of piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.
:
Capacity Factor: The ratio of the total energy generated by a generating unit for as specified period to the maximum possible energy it could have generated if operated at the maximum continuous rating (MCR) for the same specified period, expressed as a percent.

Circuit: A conductor or a system of conductors through which electric system flows.

Combined Cycle Generation: An electric generating technology in which electricity and process steam is produced from waste heat exiting from one or more combustion turbines. The combined-cycle process combines the gas turbine generator with the steam turbine generator by using heat recovery boilers to capture the energy in the gas turbine exhaust gases for steam production to supply a steam turbine generator.

Cogeneration: The simultaneous production of power and thermal energy. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumption: Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g., $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Demand Sales: A producer agrees to make generating capacity available to a buyer when it is called upon or 'demanded'.

Direct Current (DC): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economic Dispatch: A process allowing members of a power pool to buy and sell excess energy amongst themselves to maximize the efficiency of generation and transmission facilities.

Efficiency – Operational: A measure of how efficiently a plant's capacity to produce electricity is utilized Operational efficiency is measured using a measure called capacity factor. Capacity factor is the ratio of the total electricity that a plant produced during a year compared to the total potential electricity that would have been produced if the plant operated 100% of the time in the year.

Efficiency – Electrical Generation: Measures the amount of energy in the raw fuel needed to produce a specified amount of electricity. Energy Efficiency is measured using a measure called the *heat rate.* The heat rate is the amount of energy (Btu or GJ) in the fuel needed to produce one kilowatt-hour of electricity

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kWh).

Electric Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g., 20 mills per kWh). The other component of the price is the demand charge.

Energy Sales: An agreement by a selling utility to provide a buyer with a designated amount of electricity over a definite period of time.

Energy Source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Exchange: The transfer and return of electricity from one utility to another at different time periods or seasons to achieve a more economic or efficient overall system operation. Such transfers are possible because of differences in electricity demand, generation resource capability or system operating characteristics.

Extra High Voltage (EHV): Any transmission voltage higher than 345 kV.

Firm Energy or Power: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt (GW): One billion watts. (see Watt)

Gigawatt hour (GWh): A unit of bulk energy. One million kilowatt hours. One billion watt hours.

Generation: The process of converting thermal, mechanical, chemical or nuclear energy into electric energy.

Grid: A network of electric power lines and connections.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity: The capacity measured at the output terminals of all the gene-rating units in a station, without deducting station service requirements.

Interconnected System: A system consisting of two or more individual power systems connected together by tie lines.

Interruptible Energy or Power: Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Intertie (Interutility Tieline): Transmission circuit used to tie or inter-connect two load areas of two utility systems.

Independent Power Producer (IPP): A privately owned power generating facility which may be connected to a utility system to supply electricity for domestic or export markets.

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts

Kilowatt (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100 watt light bulbs.

Kilowatt hour (kWh): The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load: The total amount of electricity required to meet customer demand at any moment. The load equation fluctuates deepen-ding on electricity use throughout any given day.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. Usually expressed in per cent.

Load Forecast: The anticipated amount of electricity required by customers in the future.

Electricity Losses: The energy that is lost through the process of transmitting electric energy.

Mcf: One thousand cubic feet.

MMcf: One million cubic feet.

Megawatt (MW): A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h): A unit of bulk energy; 1000 kilowatt hours

Non-utility Generator (NUG): An electricity producer which does not have a mandate or obligation to supply electricity to the public.

Nuclear Power: Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatt or megawatts.

Power Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power: The rate of doing work. Electric power is measured in watts.

Power Factor: The ratio of real power to apparent power.

Power Purchase Arrangements: An auction process for owners of Alberta's generators to sell individual units to interested parties.

Power System: The interconnected facilities of an electrical utility. A power system includes the generation, transmission, distribution, transformation, and protective components necessary to provide service.

Primary Distribution: Electric distribution less than 69 kilovolts (kV) and equal to or greater than 25 kV.

Reactive Power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment, usually expressed in kiloVArs (kVAr) or megaVArs (MVAr).

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

Secondary Distribution: Electricity distribution less than 25 kilovolts (25kV)

Secondary Energy Consumption: The amount of energy available to, and used by, the consumer in its final form.

Self-Generation: Generation of electricity by a customer for their own use.

Stranded costs/investment: Utility assets that would lose value in a competitive market.

Substation: A facility for switching electrical elements, transforming voltage, regulating power, or metering.

Terawatt Hours (TW.h): One billion kilowatt hours.

Thermal Rating: The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

Transformer: An electrical device for changing the voltage of alternating electricity.

Transmission: The process of transporting electric energy in bulk on high voltage lines from the generating facility to the local distribution company for delivery to retail customers.

VArs: Volt-amp reactive, a measure of reactive power.

Vertical Dissaggregation: Separating electric generation, transmission and distribution functions of a utility into separate companies.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts. A horse power is 746 watts.

Appendix 2: Reference Documents and Websites

1. AESO Transmission Development Need application Edmonton – Calgary 500 KV
2. Annual Report of the Environmental Commitment and Responsibility Program (ECR)/Canadian Electricity Association.
3. Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the U.S. – 2000 (Natural Resources Defense Council/ Pubic Service Enterprise Group/Corporate Climate Accountability Project of the Coalition for Environmentally Responsible Economies)
4. Domestic Energy Use in the UK Power Conversion, Transport and Use – An A-level R & A project, Graham Philips, spring 2002.
5. Edmonton – Calgary 500 kV Transmission Development Need Application to the AEUB # 1346298, May 7, 2000.
6. Independent Assessment Team Reports – Power Purchase Arrangements Final Version – April 24, 2000.
7. Alberta Electric System Operator – 2004 Phase 1 Revenue Requirement Application to the AEUB # _____, April 20, 2004-07-12
8. Electricity Distribution Losses – A Consultation Document to The Office of Gas and Electricity Market, January 2003.
9. ESBI Alberta Ltd. 2002 Tariff Application & Negotiated Settlement – EUB Decision 2002-064, July 16, 2002.
10. A Review of the Efficiency of the Management of System Support Services, Transmission Losses and Inadvertent energy on the Alberta Interconnected System in 1999, by ESBI Alberta td., Transmission Administrator, December 31, 1999.
11. EUB Decision U99099, 25 November, 1999 in respect of applications by Atco Electric Ltd., EPCOR Generation Inc., EPCOR Transmission Inc., and TransAlta Utilities Corporation respecting tariff applications for the 1999 and 2000 test years.
12. EPCOR Distribution Inc., Distribution Loss Study, September 30, 2003
13. Aquila Networks Canada, Distribution Loss Study, March 24, 2003
14. EUB Statistical Series 2003-28: Alberta Electric Industry – Annual Statistics for 2002
15. U.S. Energy Star Transformer Brochure: http://www.energystar.gov/ia/partners/manuf_res/brochure.pdf
16. U.S. Energy Star Transformer Calculator: http://www.energystar.gov/index.cfm?c=manuf_res.pt_commercial#trans
17. EPA Study on High Efficiency Distribution Transformers: http://www.ece.umr.edu/links/power/Energy_Course/energy/Energy_eff/Energy_efficiency/dolsens.pdf
    EURELECTRIC, Union of the Electricity Industry of Europe in Brussels, Belgium: www.eurelectric.org

Appendix 3: NERC Member GADS reporting utilities

1998-2002 GENERATING AVAILABILITY REPORT (GADS)
Utilities by Region, October 2003, North American Electric Reliability Council
Princeton Forrestal Village,116-390 Village Boulevard, Princeton, New Jersey 08540-5731, Phone: 609-452-8060, Fax: 609-452-9550, Internet: http://www.nerc.com, e-mail: gads@nerc.com

Utilities Reporting to GADS

UTILITY IDENTIFICATION CODE
NERC assigns each utility participating in the Generating Availability Data System (GADS) a unique identification code. This three-digit code allows each system's data to be uniquely catalogued and filed in the database. This Appendix contains a list of the codes for each utility system presently participating in NERC GADS.
Note that NERC assigns identification codes for each utility based on the following criteria:
Region Coding Series
Canadian and Outside

Continental USA	000 - 099
NPCC	100 - 199
MAAC	200 - 299
SERC	300 - 399
ECAR	400 – 499
MAIN	500 – 599
MAPP	600 - 699
SPP	700 - 799
ERCOT	800 - 899
WSCC	900 – 999

UNIT IDENTIFICATION CODE
Each utility participating in GADS assigns unique identification codes to its units. This three-digit code allows each unit's data to be uniquely catalogued and filed in the database. Note that each utility must assign identification codes for individual units based on the following criteria:

UNIT TYPE	CODING SERIES
Fossil (Steam)	100 - 199
(Use 600-649 if additional numbers are needed)	
Nuclear	200 - 299
Combustion Turbines (Gas Turbines or Jet Engines)	300 - 399
(Use 700-799 if additional numbers are needed)	
Diesel Engines	400 - 499
Hydro/Pumped Storage Units	500 - 599
(Use 900-999 if additional numbers are needed)	
Fluidized Bed Combustion Units	650 - 699
Miscellaneous Units (Multi-Boiler/Multi-Turbine,	

Geothermal, Combined Cycle, etc.) 800 - 899

UTILITY LIST BY REGION
Non-Regional Member Utility

Utility Code Utility Name

010 Hawaiian Electric Company, Inc.
022 Ecoelectrica L.P.

REPORTING UTILITIES BY NERC REGION

NORTHEAST POWER COORDINATING COUNCIL (NPCC)
Utility Code Utility Name

003 Ontario Power Generation
004 New Brunswick Electric Power Commission
100 Great Lake Hydro America
101 Boston Edison Co.
102 Constellation Energy (NPCC)
103 Bangor Hydro (USA)
104 Dynegy-Northeast Generation (Central Hudson Gas & Electric Corp.)
105 Central Maine Power Co.
107 Connecticut Light & Power Co.
108 Consolidated Edison Co. of New York, Inc.
109 Glenwood Energy Center (Keyspan Energy-Parent)
110 Fort Jefferson Energy Center (Keyspan Energy-Parent)
111 Connecticut Light & Power Co.
112 Holyoke Water Power Co.
113 Keyspan Energy (Lilco)
115 PG&E National Energy Group - NPCC
116 Commonwealth Energy System
117 New York State Electric & Gas Corp.
118 NRG Energy (Niagara Mohawk Power Corp.)
119 Mirant - New York (Orange and Rockland Utilities, Inc.)
120 New York Power Authority
121 Public Service of New Hampshire
122 Rochester Gas and Electric Corp.
123 Wisvest - CT, LLC
124 Western Massachusetts Electric Co.
125 Yankee Atomic Electric Company
126 Mass. Municipal Wholesale Elec. Co.
127 Dominion Nuclear Connecticut
128 Connecticut Yankee Atomic Power Co.
129 Montaup Electric Co.
130 ARC-Semass

131 Sithe Energies, LLC New England
133 FPL Energy-Wyman LLC
134 Nantucket Electric
135 Lowell Cogeneration Company LP
136 Mirant - New England
137 Ocean State Power
138 American National Power
139 Penobscot Hydro LLC
140 KeySpan Energy-Ravenswood
141 NRG Energy-New England
143 VAE Lowell Power
144 Entergy Nuclear Northeast
145 El Paso Merchant Energy, LLP
146 Massachusetts Bay Transportation Authority
147 Brainstree Electric Light Department
148 Indeck Pepperell Power
150 Connecticut Municipal Electric Energy Coop.
151 Orion Power New York
152 NRG Energy-New York
153 Ogden Martin Babylon
154 Yesco Power
155 TBG Cogen Partners (Calpine Corporation [NPCC])
156 Columbia/Zapco
157 Montenay Power
158 American Ref-fuel Co.
159 Nissequogue Cogen
161 PPL Generation Co. (New England)
162 Aquila-NPCC
163 Wyeth-Ayerst Pharmaceuticals
164 Conedison Energy
165 Energy Systems North East (ESNE)
166 AES New Energy
167 Taunton Municipal Light
169 AES Londonderry LLC (Granite Ridge)
170 Masspower
171 Unitil Power Corp.
172 Fitchburg Gas and Electric Light Co.
173 North Atlantic Service Corp.
174 Coventa Haverhill, Inc.
175 Wheelabrator Millbury, Inc.
176 Whellabrator Technologies, Inc.
177 Barre Energy Partners, L.P./Zahren Alternative Power Company
178 Ridgewood Providence Power Partners, L.P.
179 Waste Management of New Hampshire, Inc.
180 Suncook Energy LLC
181 Massachusetts Water Resources Authority

182 Vermont Electric Power Co.
183 Chi Energy
184 Hafslund U.S.A., Inc.
185 American Paper Mills of Vermont
186 Hudson Light & Power
187 Sterling Municipal Electric Light Department
188 Chicopee Hydro Electric Limited Partnership
189 Swift River Co.
190 Northeast Generation Company
191 PS&H IPPS
193 Pioneer Electric Hydor Co., Inc.
194 Connecticut Resources Recovery Authority
195 Springfield Water And Sewer Commission
196 Duke Energy Trading (NPCC)
197 Peabody Municipal Light
198 New Hampshire Electric Cooperative, Inc.
199 Indeck Pepperill Power Associates.

MID-ATLANTIC AREA COUNCIL (MAAC)
UTILITY CODE UTILITY NAME

201 Atlantic Electric Co.
202 Constellation Energy (Baltimore Gas and Electric)
203 Delaware Municipal Utilities
204 Delmarva Power & Light Co.
205 Jersey Central Power & Light Co.
206 Easton Utilities Commission
208 Metropolitan Edison Co.
209 Vineland Municipal Electric Utilities
211 Exelon Generation Co., LLC (MACC) (Pennsylvania Electric Co.)
212 Pennsylvania Power & Light Co.
213 PECO Energy (Philadelphia Electric Co.)
214 Potomac Electric Power Co.
215 Public Service Electric and Gas Co.
216 UGI Corporation
220 EME Homer City Generation L.P.
221 Cinergy Capital & Trading, Inc.
222 PEI Power Corporation
223 FPL Energy
224 Williamitte Industries Inc.
225 Crown Vantage
226 Williams Energy
227 Statoil
228 American Ref-fuel
229 First Energy
230 Schuylkill Energy Resources

231 Pedricktown Cogen
232 Amergen
233 Limited Methane LTD. (NRG Energy - Mid Atlantic)
234 Commonwealth Chesapeake
235 Mirant Potomac River
236 Reliant Energy Systems, Inc. - East
237 Reliant Energy Systems, Inc. - Central
238 Reliant Energy Systems, Inc. - West
239 Bethlehem Steel
240 El Paso Merchant Energy-MAAC
241 Sempra
242 NRG Energy-Mid Atlantic
243 Aquila-MAAC
244 Convanta Energy
245 Delaware Municipal Electric Cooperative
246 Mt. Carmel NUG
247 Duke Energy Trading (MAAC)
248 Old Dominion Electric Cooperative
250 Calpine Corporation (MAAC)

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL (SERC)
UTILITY CODE UTILITY NAME

301 Alabama Electric Coop., Inc.
302 Alabama Power Co. (Southern Company)
303 Carolina Power & Light Co.
304 Southern Power
307 Duke Energy (Duke Power Company)
311 Old Dominion Electric Cooperative
312 Georgia Power Co. (SOCO)
313 Gulf Power Co.
315 Mississippi Power Co. (SOCO)
318 Savannah Electric and Power Co. (SOCO)
319 South Carolina Electric & Gas Co.
320 So. Carolina Public Service Authority
321 So. Mississippi Electric Power Association
323 Southern Electric Gen. Co. (SOCO)
325 Alcoa Power Generating (Tapoco, Inc.)
326 Tennessee Valley Authority
328 Virginia Power-Dominion
330 Seminole Electric Coop., Inc.
331 Oglethorpe Power Coop.
332 Calpine Corporation (SERC)
333 El Paso Merchant Engergy-SERC/FRCC
334 Aquila-SERC
335 Duke Energy Trading (SERC)

336 Mirant - SERC
339 Intergen (SERC)

FLORIDA RELIABILITY COORDINATING COUNCIL (FRCC)
UTILITY CODE UTILITY NAME

305 Tallahassee Electric Department
306 Constellation Energy (FRCC)
308 Florida Power & Light Co.
309 Florida Power Corp.
310 Mirant - FRCC
314 Jacksonville Electric Authority
317 Orlando Utilities Commission
324 Tampa Electric Company

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT (ECAR)
Utility Code Utility Name

401 Appalachian Power Co. (AEP)
402 Central Operating Company (AEP)
403 Cinergy
(formerly Cincinnati Gas & Electric Co. (The) See #430)
404 Centerior Energy
(formerly Cleveland Electric Illuminating Co. (The))
405 Columbus Southern Power Co.
406 Consumers Power Co.
407 Dayton Power and Light Co. (The)
408 Detroit Edison
409 Duquesne Light
410 East Kentucky Power Coop., Inc.
411 Indiana Michigan Power Co. (AEP)
412 Indiana-Kentucky Electric Corp. (OVEC)
413 Indianapolis Power & Light Co.
414 Kentucky Power Co. (AEP)
415 Kentucky Utilities Co.
416 Louisville Gas and Electric Co.
417 Monongahela Power Co. (APS)
418 Northern Indiana Public Service Co.
419 Ohio Edison
420 Ohio Power Co. (AEP)
421 Ohio Valley Electric Corp. (OVEC)
422 Pennsylvania Power Co. (Ohio Edison)
424 Cinergy
(formerly Public Service Co. of Indiana, Inc. See #430)
425 Southern Indiana Gas and Electric Co.

426 Centerior Energy (formerly Toledo Edison Co. (The))
427 West Penn Power Co. (APS)
430 Cinergy
431 Orion Midwest
432 DTE Georgetown, LLC
433 Calpine Corporation (ECAR)
434 El Paso Merchant Energy (ECAR)
435 Constellation Energy (ECAR)
436 AEP - Lawrence
437 Duke Energy Trading (ECAR)
438 Mirnat - ECAR
439 AES - ECAR

MID-AMERICA INTERCONNECTED NETWORK (MAIN)
Utility Code Utility Name

502 Constellation Energy (MAIN)
503 Central Illinois Light Co.
504 Ameren Energy Generating Company-CIPS
506 Exelon Generation, LLC (MAIN) [Commonwealth Edison Co.]
507 Electric Energy, Inc.
508 Dynegy (Illinois Power Co.)
514 Southern Illinois Power Coop.
516 City Water, Light and Power (Springfield)
517 Ameren-UE (formerly Union Electric Co.)
521 Wisconsin Electric Power Company
522 Alliant Energy (formerly Wisconsin Power & Light Co.)
523 Wisconsin Public Service Corp.
524 Calpine Corporation (MAIN)
525 El Paso Merchant Energy-MAIN
526 Reliant Energy - MAIN
527 Duke Energy Trading (MAIN)
528 Dominion Energy
607 Alliant Energy (formerly Interstate Power)
608 Alliant Energy (formerly IES Utilities)
612 Alliant Energy (formerly IES Utilities)

MID-CONTINENT AREA POWER POOL (MAPP)
UTILITY CODE UTILITY NAME

601 Basin Electric Power Coop., Inc.
603 Great River Energy (Coop. Power)
605 Dairyland Power Coop.

606 Central Iowa Power Coop.
609 MidAmerican Energy Co.
(formerly Iowa-Illinois Gas and Electric Co.)
610 MidAmerican Energy Co.
(formerly Midwest Power and Iowa Power Inc.)
611 MidAmerican Energy Co.
(formerly Midwest Power and Iowa Public Service Co.)
614 Lincoln Electric System
615 Otter Tail Power Co.
616 Minnesota Power
617 Minnkota Power Coop., Inc.
618 Montana-Dakota Utilities Co.
619 Muscatine Power & Water
620 Nebraska Public Power District
621 XCEL (Northern States Power Co.)
622 Northwestern Public Service Co.
623 Omaha Public Power District
624 Great River Energy (formerly United Power Association)
625 Western Area Power Administration
626 Missouri Basin
627 Minnkota Power Coop., Inc.
(formerly Square Butte Electric Coop.)
628 Calpine Corporation (MAPP)
629 El Paso Merchant Energy (MAPP)

SOUTHWEST POWER POOL (SPP)
Utility Code Utility Name

703 Arkansas Power and Light Co. (Entergy)
704 Associated Electric Coop., Inc.
708 Central Louisiana Electric Co.
709 Denver City Energy Associates
715 Empire District Electric Co.
716 Grand River Dam Authority
717 Gulf States Utilities Co. (Entergy)
718 Kansas City Power & Light Co.
719 KGE, A Western Resources Company
720 KPL, A Western Resources Company
722 Louisiana Power and Light Co. (Entergy)
723 Mississippi Power and Light Co. (Entergy)
728 New Orleans Public Service, Inc. (Entergy)
729 Oklahoma Gas and Electric Co.
730 American Electric Power West (Public Service Co. of Oklahoma)
732 American Electric Power West (Southwestern Electric Power Co.)

733 Southwestern Power Administration
734 Southwestern Public Service Co.
735 Sunflower Electric Coop, Inc.
737 Western Farmers Electric Cooperative
739 System Energy Resources, Inc. (Entergy)
740 Louisiana Generating, LLC
750 Borger Energy Associates (BEA)
751 Calpine Corporation (SPP)
752 El Paso Merchant Energy-SPP
753 AES - SPP
754 Intergen Corp (SPP)

ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)
UTILITY CODE UTILITY NAME

801 Austin Energy (formerly Austin Electric Department)
802 EXTEX Laporte Limited Partnership (Exelon Generation, LLC-ERCOT)
803 Constellation Energy (ERCOT)
804 AES - ERCOT
805 Intergen Corp (ERCOT)
808 Brazos Electric Power Coop., Inc.
810 Calpine Corporation (ERCOT)
811 El Paso Merchant Energy (ERCOT)
812 American Electric Power West (Central Power and Light Co.)
819 TU Electric Generating Division
(formerly Dallas Power & Light Co.)
828 Garland Power & Light Co.
838 American National Power
839 Mirant - ERCOT
840 Reliant Energy (formerly Houston Lighting & Power)
854 Lower Colorado River Authority
868 San Antonio City Public Service
879 TU Electric Generating Division
(formerly Texas Electric Service Co.)
880 TU Electric Generating Division
(formerly Texas Power and Light Co.)
884 American Electric Power West (West Texas Utilities Co.)
887 TU Electric Generating Division
(formerly Texas Utilities Generating Co.)
888 Texas Municipal Power Agency
889 San Miguel Electric Coop., Inc.
894 TU Electric-Generating Division (Sweetwater)

WESTERN ELECTRCITY COORDINATING COUNCIL (WECC)

Utility Code	Utility Name
001	B.C. Hydro
007	TransAlta Utilities
902	Arizona Electric Power Coop., Inc.
904	Arizona Public Service Co.
905	Calpine Corporation (WECC)
906	El Paso Merchant Energy-WECC
907	Constellation Energy (WECC)
909	Tri-State G&T Association, Inc. (formerly Colorado Ute Electric Association, Inc.)
913	El Paso Electric Co.
914	Eugene Water & Electric Board
917	Idaho Power Company
920	Los Angeles Department of Water and Power
921	La Paloma Generating
922	Montana Power Co.
924	Sierra Pacific Power Co. (Nevada Power Company)
925	**Pacific Gas and Electric Co.**
926	Pacificorp (Pacific Power & Light Co.)
927	PG&E National Energy Group - WECC
928	Mirant - WECC
929	Pinnacle West Energy CO.
930	Platte River Power Authority
931	Portland General Electric Co.
932	Public Service Co. of Colorado
933	Public Service Co. of New Mexico
936	PUD No. 1 of Chelan County
938	PUD No. 1 of Douglas County
940	Reliant Energy -- WECC
942	Sacramento Municipal Utility District
944	Salt River Project
945	San Diego Gas & Electric Co.
947	Seattle City Light
948	Sierra Pacific Power Co.
949	Southern California Edison Co.
953	Tucson Electric Power Company
954	Pacificorp (Utah Power & Light Co.)
956	**Energy Northwest**
958	Tucson Electric Power Co.
959	U.S. Army Corp of Engineers - Portland District
960	U.S. Army Corp of Engineers - Walla Walla District
961	U.S. Army Corp of Engineers - Seattle District
965	Deseret Generation & Transmission Coop.
966	Imperial Irrigation District

967 AES Redondo Beach
968 U.S. Bureau of Reclamation
969 NRG Energy-Western
970 Tenaska-Washington State
971 AES-Alamitos LLC
972 NRG Energy - Western
973 Duke Energy Trading (WECC)
974 Intergen Corp. (WECC)

Appendix 4: ATCO Isolated Electric Generating Facilities – 2003*

Fossil Fuel Generating Stations		
Name of Facility	Type of Fuel	Gross Generation Capacity (MW)
Algar Microwave Tower	Diesel	0.100
Berland Microwave Tower	Diesel	0.020
Bullmoose	Natural Gas	0.320
Burnt Brazion	Natural Gas	1.300
Chevron Simonette	Diesel	0.315
Chinchaga	Natural Gas & Diesel	1.255
Chipewyan Lake	Diesel	0.305
Crow Lake Microwave Tower	Diesel	0.030
Economy Microwave Tower	Diesel	0.030
Fawcett River Microwave Tower	Diesel	0.050
Flat Top Mountain Microwave Tower	Diesel	0.020
Foggy Mountain Microwave Tower	Diesel	0.020
Fort Chipewyan	Diesel	4.720
Fox Lake	Diesel	2.390
Garden Creek	Diesel	0.800
Indian Cabins	Diesel	0.060
Karr	Natural Gas	0.142
Little Horse	Natural Gas & Diesel	0.142
Marten Hills	Natural Gas & Diesel	0.550
May Microwave Tower	Diesel	0.030
Narrows Point	Diesel	0.120
Ocelot Brazion	Natural Gas	0.678
Palisades	Natural Gas & Diesel	20.180
Peace Point	Diesel	0.070
Seal Lake	Natural Gas & Diesel	0.315
Simonette Microwave Tower	Diesel	0.030
Steen River Microwave Tower	Diesel	0.015
Steen River Town	Diesel	0.130
Stowe Creek	Natural Gas	1.450
Touchwood Microwave Tower	Diesel	0.040

Hydroelectric Generating Stations	
Name of Facility	Gross Generation Capacity (MW)
Astoria Hydro	1.400

* None of these have heat recovery systems.