AECOM

City of Regina

Alternative Energy Study Regina Wastewater Treatment Plant

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Project Number:
60143020

Date:
March 5, 2010

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March 5, 2010

Ms. Sheri Florizone
Emissions Reduction Coordinator
City of Regina
Planning and Development
P.O. Box 1790
2476 Victoria Avenue
Regina, SK S4P 3C8

Dear Ms. Florizone:

Project No: **60143020**

Regarding: **Alternative Energy Study**
Regina Wastewater Treatment Plant
Final Version

AECOM is pleased to submit the report entitled: *"Alternative Energy Study – Regina Wastewater Treatment Plant"*. We have enjoyed working on this interesting project and look forward to receiving your feedback.

Sincerely,
AECOM Canada Ltd.

Neil Klassen, C.E.T.
Manager, Program Management, Design
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NHK:am
Encl.

Distribution List

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0	A. Aftanas	January 4, 2010	Draft Issued for Client Review
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Executive Summary

Introduction

A business case analysis has been completed by AECOM on five alternative energy sources to assist the City of Regina in determining which alternative energy source will meet their objective of reducing their dependency on utility-supplied electricity and reduce greenhouse gas (GHG) emissions at their wastewater treatment plant (WWTP).

The scope of work involved a desk-top review using *RETScreen Energy Assessment* software to evaluate the following five alternative energy sources:

1. Solar
2. Wind
3. Biogas – Combined Heat and Power (CHP)
4. Wastewater Heat Recovery (heating)
5. Deep Well Geothermal

Analysis

Concept designs and costs were developed for each alternative based on the electrical baseline load requirements of the plant. The concept designs were developed to a schematic level adequate to establish approximate capital costs, and to identify operating and maintenance (O&M) parameters and costs.

The capital cost estimates are based on manufacturer's quotes, information from previous similar projects and from the manufacturer's databank in *RETScreen*. The estimates also include: a 15% allowance for engineering, 10% for contractor's overhead/profit and a 20% contingency.

The business case analysis utilizes the parameters provided by the City as presented in the following Table ES.1.

Table ES.1: Alternative Energy Analysis Parameters

Description	Value	Remark
Interest Rate	4%	
Inflation Rate	3.8%	Not including fuel
Inflation (fuel)	8%	Natural Gas and Electricity
Discount Rate	4%	
Debt Terms	20 years	100% debt
GHG Credits	$15/tonne	Increased annually for inflation at 3.8% and $20,000/yr verification
Natural Gas	$0.35/m^3	
Electricity Rate	$0.072/kWhr	

A summary of the comparative analysis for each alternative energy source is presented in Table ES.2.

Table ES.2: Summary of Alternative Energy Options

	1a Solar Photovoltaic (1.9 MW)	1b Solar Photovoltaic (7 MW)	2a Wind Turbine (1.8 MW)	2b Wind Turbine (7 MW)	3 Biogas CHP (360 kW)	4 EFE (1.9 MW)	5a Deep Well Geothermal (1.9 MW)
Electrical Capacity (kW)	1,890	7,000	1,750	7,000	360	0	0
Heating Capacity (kW)	0	0	0	0	560	1935	1935
Capital Cost	$ 25,000,000	$ 90,700,000	$ 5,700,000	$21,400,000	$ 3,300,000	$ 4,500,000	$ 9,700,000
Annual Energy Saving	$ 221,000	$ 813,000	$ 258,000	$ 1,031,000	$ 223,000	$ 138,000	$ 155,000
Annual O&M Cost	$ 70,000	$ 212,500	$ 102,000	$ 351,000	$ 108,000	$ 51,500	$ 105,000
GHG Reduction (tonnes/yr)	2,550	9,395	2,976	11,904	2,466	-346	-148
GHG credit ($/yr)	$ 38,250	$ 140,925	$ 44,640	$ 178,560	$ 37,000	-$ 5,184	-$ 2,214
Simple Payback (years)	132	122	28.3	25	22	55	199
NPV	-$ 22,600,000	-$ 80,700,000	$ 1,050,000	$ 6,600,000	$ 2,100,000	-$ 4,400,000	-$ 7,000,000
IRR (%)	Negative	Negative	10.8	15.6	29.0	Negative	Negative

All of the options do not achieve the City's criteria for simple payback of 7 to 20 years. However, several of the options are very good long-term investments based on NPV and IRR indicators; in other words they make good business sense.

The Biogas CHP Option 3 analysis presents a very good investment opportunity with a NPV of $2,100,000 and an IRR of 29.0% over a 20 year lifecycle. Both wind turbine options do present a positive long-term business opportunity when considered over the 20 year lifecycle. Wind Turbine Option 2b analysis results in the most favourable of the two with a NPV of $6,600,000 and an IRR of 15.6%. The significant initial capital investment and potential regulatory issues make this a less desirable option for the City without a more detailed review. Option 2b also provides the City with the largest reduction in GHG emissions. The Biogas option also provides a significant reduction in GHG's.

Recommendations

Our review of the base case concludes that the "do nothing" alternative is not acceptable given the potential for future electricity rate increases. Based on our analysis of the alternatives and our review of the City's WWTP operations the best value for capital investment that reduces dependence on utility-supplied electricity and reduces greenhouse gases includes the following:

1) **Biogas CHP (Option 3)** – Proceed with feasibility and preliminary engineering to implement this option. The feasibility study should include a review of possible synergies between biogas and the proposed new WWTP development.

2) **7 MW Wind Turbine (Option 2b)** – The 7 MW wind turbine provided the best long-term investment with significant payback and should be studied further.

3) **1.8 MW Wind Turbine (Option 2a)** – Although this option is not as attractive as the 7 MW option it is still a favourable long-term investment at a reduced capital cost.

Other Considerations

In preparing this report, additional considerations or recommendations were identified as follows:

1) **Reduce Electrical Load in the Future Plant Upgrade** – The City's WWTP is a high consumer of electricity per ML treated when compared to other WWTP's. This is primarily due to the type of treatment processes currently used (e.g. aerated lagoons, plant hydraulics). The City should reduce electrical base load where possible. The best opportunity is in the future WWTP expansion. This should include consideration of more efficient wastewater treatment processes and efficiency improvements to reduce electrical and natural gas loads.

2) **Integration of Alternative Energies in the Future Plant Upgrades** – With the planned expansion at the WWTP consideration should be given to study synergies between alterative energy sources and the new WWTP development including:
   - Examine the potential use of thermal energy from deep geothermal or energy from effluent (EFE) to:
     - Reduce capital costs of future expansion through pre-heat of influent stream to improve plant performance.
     - Utilize excess thermal heat as revenue potential to other business developments (i.e. warehouse development to the south).
   - Examine co-generation in combination with EFE.
   - Examine the use of biosolids as a fuel.

3) **Conduct an Energy Audit of Existing Plant** – Carry out an energy audit at the WWTP to identify areas for potential electrical load reduction. For example, opportunities to retrofit variable frequency drives (VFDs) on process pumps, peak load shaving and adjustment of power factor could further reduce the electrical base load. Installation of Heat Recovery Ventilation Systems in areas with high outdoor air ventilation loads (as required by NFPA 820) could reduce natural gas loads.

4) **Fully Utilize Biogas** – Currently biogas from the digesters is utilized as fuel in the boilers. We recommend modifications to the instrumentation and controls on the biogas system to fully utilize the available biogas in the existing boilers. The potential cost for this upgrade is estimated at about $80,000. This would be coupled with a modification of the plant operations (i.e. sequential scraping of sedimentation tanks) to allow a uniform production of biogas.

   The instrumentation and control upgrades could potentially reduce the amount of biogas being flared from the current 47% to an estimated 14% of total. This represents an annual reduction in natural gas consumption at the WWTP of 636,000 m^3 or an equivalent of $126,200/year based on biogas containing 62% methane (CH_4). The simple payback in this scenario is less than one year.

   The potential upgrades required for this scenario require further investigation but could include:
   - Pressure controller/instrumentation to allow automatic switchover from raw gas to natural gas on the boilers.
   - Upgraded instrumentation/control from improved control of air/fuel ratios on the boilers.

5) **Biogas Treatment** – Evaluate a gas treatment system for the existing boilers. This investment could reduce or eliminate the current boiler maintenance of $55,000 per year, which is currently the result of corrosion damage caused by running untreated biogas in the boilers (e.g. high hydrogen sulfide (H_2S), siloxanes, and moisture content). Based on a gas treatment system roughly estimated at $1M,

the simple payback would be 18 years. However, the biogas treatment system would require additional maintenance (such as media replacement) which would offset the savings in maintenance. This concept would require additional review.

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1. Introduction

1.1 Purpose

AECOM was retained by the City of Regina in November 2009 to conduct a study of alternative energy sources at the City's Wastewater Treatment Plant (WWTP). The objective of the study is to enable the City to identify a feasible alternative energy source at the WWTP to reduce dependence on utility supplied energy and to reduce greenhouse gas (GHG) emissions. The study examines five possible energy sources identified by the City including:

1. Solar
2. Wind Turbine
3. Biogas – Combined Heat and Power (CHP)
4. Wastewater Heat Recovery (heating)
5. Deep Well Geothermal

In addition, this report comments on the use of the plant's digested sludge solids as a potential fuel source.

The City owns and its WWTP consisting of a pumping station, primary treatment plant, secondary aeration lagoons, a tertiary phosphorus removal treatment plant and UV disinfection system. The WWTP treats an average of about 69 ML/d. The McCarthy Boulevard Pumping Station was not evaluated as part of this study, due to the physical separation from the WWTP.

The City's WWTP generates anaerobic digester gas (ADG) as part of the treatment process. Approximately half of the CH_4 is utilized in the plant to power boilers and the remainder is flared off.

The City's WWTP is a large consumer of electrical energy with annual electrical bills that exceeds $1M (based on 2008 bills). The City wishes to reduce their vulnerability to escalation in electrical costs which have been speculated to double in the next 10 years. Saskatchewan's electrical supply has a high GHG grid factor (671 tonnes CO_{2e} per kWh) due to its heavy reliance on coal generated electricity.

Regina's City Council has set a goal to reduce GHG emissions 15% below 1990 levels by 2012. The WWTP is an important target for the City's GHG reduction plan, based on both the large electrical consumption and the generation of methane (CH_4) through the anaerobic digestion process.

A previous study for the City of Regina prepared in July 2005, *Detailed Feasibility Study for Utilization of Raw Methane Gas* (hereinafter called the Methane Report) recommended that the City proceed with utilizing the ADG in a 250 kW internal combustion (IC) engine throughout the year to generate CHP with the balance of the ADG used to run the existing boilers. This study re-evaluates this biogas option.

All five alternative energy sources examined were modelled and analysed using *RETScreen Clean Energy Project Analysis Software* which evaluates each alternative on a common platform and will enable the City to make decisions related to potential energy production, energy savings, capital costs, emission reductions, as well as financial viability.

2. Scope of Work

This study consists of a desktop review of the following five alternative energy options:

1. Solar
2. Wind
3. Biogas – Combined Heat and Power (CHP)
4. Wastewater Heat Recovery (heating)
5. Deep Well Geothermal

2.1 Methodology

The scope of work for this study included the following:

Information Assembly – The following information was gathered pertaining to the Regina WWTP:

- site plan and aerial photographs
- a summary of process and heating ventilation and air conditioning (HVAC) equipment
- single line electrical drawings
- 2008 utility bills
- electricity demand trend data for the main electrical meter through the plant process control system (i.e. SCADA system)
- effluent temperature and flow rate profiles for peak wet flow and minimum dry flow conditions
- biogas flow rate and composition data
- previous related studies

Review Data – Baseline energy load and consumption patterns were reviewed and validated in order to determine a practical size for on-site generation using alternative sources. Existing natural gas and electricity rate structures, current energy costs, and financial parameters were also researched and extracted from utilities and City sources. The Methane Study was reviewed and provided valuable information regarding the co-generation option. The report titled *"2009 Saskatchewan's Deep Geothermal Energy Potential: Its Application and Feasibility"* prepared for Saskatchewan Ministry of the Environment under the Go Green Fund, provided valuable information regarding the deep geothermal option. Additional discussions and input from Mr. Brian Brunskill from Helix Geological Consultants Ltd., who was one of the primary authors of the report, were also conducted to obtain information regarding the application of this technology at the WWTP.

Develop Conceptual Designs and Costs – A concept design for each of the five alternative energy options were developed based on the electrical baseline load requirements of the plant, and the energy available (e.g. wind, solar, biogas, effluent heat). The concept design was developed to a schematic level to establish capital costs and operating and maintenance (O&M) parameters and costs. The probable cost for each concept was developed based on cost data automatically generated in *RETScreen Clean Energy Analysis Software*. Equipment suppliers were also contacted regarding major equipment components. AECOM's experience on similar previous projects and costs provided in previous reports were also used to augment and verify capital costs of some concepts.

Site Visit and Meeting – A. Aftanas and N. Klassen of AECOM visited the City's WWTP on the morning of December 2, 2009. The site tour was led by Mr. Jeff Shilling, the City's Control System Support Technologist. The purpose of the tour was to identify preferred locations for integrating the various alternative energy concepts into the WWTP site. The tour also involved an overview of the treatment systems and review of the existing equipment that might require replacement under several of the alternative concept options. A meeting was held on December 2nd, 2009 at the Regina City Hall to review and confirm the study objectives. The meeting agenda covered an overview of AECOM study objectives, a review of the proposed study concepts, and a discussion on present and future energy costs, and financial parameters to be used in the study. The meeting was attended by the following City personnel:

1. Mr. Gary Nieminen, M.Sc., P.Eng., Manager, Environmental Engineering Branch
2. Ms. Sheri Florizone, Emissions Reduction Coordinator
3. Mr. Peter Hagar, Senior Engineer, Environmental Engineering Branch
4. Mr. Kurtis Doney, M.Sc. EIT, Project Engineer, Environmental Engineering Branch
5. Mr. Cyrus Crook

Several important clarifications were made at this meeting including:

- The study is to be based on alternative energy sources for the existing WWTP only, with no consideration for the application of these technologies to the proposed WWTP upgrade.
- Mr. Gary Nieminen also requested that the study provide some comment on the potential for using digested sludge from the WWTP as an alternative fuel source to help reduce dependence on utility supplied energy.

Alternative Energy Sources Analysis – The concept system for each alternative energy source was pre-screened for available energy potential of that source and for the feasibility of integrating the energy source into the existing WWTP system. Each alternative system was then analyzed using *RETScreen Clean Energy Project Analysis Software*. *RETScreen* was used to analyze each alternative concept based on a variety of relevant parameters including:

- Capital and O&M costs
- Energy production potential
- GHG emissions avoided

The analysis of each alternative was then compared against each other to determine the most cost effective option based on a simple pay back and NPV. The financial, GHG and sensitivity analysis' are presented and evaluated in Section 7 of this report.

3. Background Information

The following section provides background information and context for understanding this report.

3.1 Dependence on Utility Supplied Power

The City's WWTP is a large consumer of electrical energy with annual electrical bills that exceed $1M. The City wishes to reduce their vulnerability to future escalation in electrical costs which have been speculated to double in the next 10 years (refer to articles in Appendix 9.5). Table 3.1 below summarizes annual energy consumption and costs, for both electricity and natural gas, based on the WWTP's 2008 utility bills.

Table 3.1: 2008 Energy Consumption at the Regina WWTP

Energy Source	2008 Annual Consumption	2008 Annual Cost	
Electricity	17,360,000 kWh	$	1,131,000
Natural Gas	622,400 m^3	$	204,500
TOTAL		$	1,335,500

3.2 Greenhouse Gas (GHG) Emissions

3.2.1 Introduction

Although certain aspects of global climate change are contested, most researchers now agree that anthropogenic emissions (i.e. those caused by human activities) of carbon dioxide (CO_2), CH_4, nitrous oxide (N_2O) and other compounds that have similar and more pronounced GHG effects are the main cause of increasing global temperatures. Biogenic GHG emissions are caused by natural activities such as forest fires or the aerobic decomposition of organic matter in swamps and marshes, and are not included in inventory calculations.

The main compounds that are attributed to global climate change and their associated carbon dioxide equivalent (CO_2e) global warming potential (GWP) factor as indicated below:

Figure 3.1: GHG Compounds

Greenhouse Gas	Global Warming Potential
Carbon dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous oxide (N_2O)	310

Source: IPCC

Carbon footprinting and GHG accounting employ many different and evolving standards and protocols that vary from jurisdiction to jurisdiction. A "Carbon Footprint" is understood as a complete accounting of GHG emissions, whereas an "Inventory" is based on and limited to the reporting requirements of a specific GHG reporting protocol.

The pre-eminent scientific body in the GHG reporting area is the Intergovernmental Panel on Climate Change (IPCC) which has published a "top down" protocol for the preparation of national inventory reports. Environment Canada follows the IPCC protocol and applies country-specific data where it is available for estimating GHG emissions from wastewater handling and treatment.

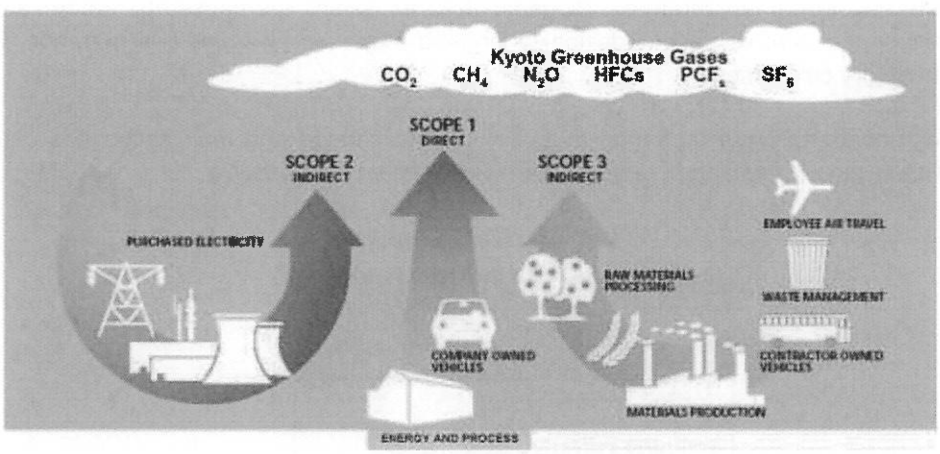
In the field of GHG accounting there are several protocols emerging in the water industry and municipal sector to achieve better accuracy by using "bottom up" accounting methods. For example, the United Kingdom (UK) Water Industry Research (WIR) accounting protocol appears to be gaining acceptance in the industry as a standard; however, in the State of California the Local Government Operational Protocol (LGOP) has been put forward to the industry and is also gaining acceptance.

The challenge in preparing a bottom up protocol is setting the boundaries of the accounting inventory and identifying the scope of the emissions. The *Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard*, by the World Resource Institute and World Business Council for Sustainable Development (WRI/WBCSD) developed the concept of scoping emissions this was subsequently adopted by the LGOP. This approach groups emissions into one of three categories:

- Scope 1 – Direct Emissions (associated with combustion of fossil fuels on site and other process emissions).
- Scope 2 – Indirect Emissions (associated with imported power and heat used on site).
- Scope 3 – Indirect Emissions (associated with other activities related to the primary activity such as chemical use for wastewater treatment and includes biogenic CO_2).

These three categories are illustrated in Figure 3.2.

Figure 3.2: Categories of GHG Emissions



The preceding discussion is intended to illustrate that GHG emissions are a significant issue for the City's WWTP. Accounting protocols are evolving both in Canada and worldwide for the water industry; however, there is currently no universally accepted standard in the industry.

3.2.2 Regina WWTP GHG's

Regina's City Council has set targets to reduce GHG emissions 15% below 1990 levels by 2012. The WWTP is an important target for City's GHG reduction, due to the high electrical consumption and the generation of CH_4 and CO_2 through the anaerobic digestion process.

Saskatchewan currently has some of the highest GHG and CO_2 emitting power generation in Canada resulting in a high power grid factor GHG factor due to the large percentage of fossil fuels such as coal and natural gas used for power generation. This also represents a greater opportunity to the WWTP for making a significant contribution to the reduction of GHG and CO_2 emissions. The City's WWTP is currently reducing GHG emissions by partly utilizing biogas in boilers that would be flared or otherwise discharged to the atmosphere. Generating power using renewable fuel such as digester biogas in a co-generation unit will further reduce GHG emissions by off-setting power use from the grid.

The approximate GHG emissions at the WWTP are summarized in Table 3.2 below.

Table 3.2: Approximate GHG Emissions at the Regina WWTP

Contributor	Annual Quantity	GHG Factor Applied	Associated Annual GHG Footprint
Electricity	17,360,000 kWh	809 kg/MWh	14,044 tonnes/yr
Natural Gas	622,400 m^3	1.80 kg/m^3	1,120 tonnes/yr
Anaerobic Digester Gas	1,987,700 m^3	54.6 kg/TJ	2,506 tonnes/yr
		TOTAL	**15,274 tonnes/yr**

Notes: 1. Electric and NG consumption based on 2008 utility bills. According to Regina's WWTP 2006 Annual Report, electric consumption = 18,165,000 kWhr.

2. Anaerobic Digester Gas quantities based on the City's WWTP 2006 Annual report, with an average of 62% CH_4 and 38% CO_2.

3. GHG factor for electricity based on CO_{2e} Power Grid Factor for Saskatchewan generated power provided by RETScreen.

4. CO_2 emission factors based on 98 to 99% combustion of anaerobic digester gas (i.e. burned in boilers or flare stack with 0% released directly to atmosphere).

5. GHG emission factors are approximate.

3.3 Previous Reports

Two previous reports evaluated alternative energy sources for the Regina WWTP as follows:

1. *Methane Gas Utilization, Detailed Feasibility Study, Wastewater Treatment Plant, prepared by 2020 Environmental Solutions, July 2005.*
2. *Small Hydro Power Generation Study, City of Regina Sanitary Sewer Outfall prepared by AECOM (formerly UMA Engineering Ltd.), November 2004.*

These reports provided a valuable resource for the development of this report.

3.4 *RETScreen* Analysis

3.4.1 Introduction

RETScreen software is used worldwide to evaluate the energy production, savings, costs, emission reductions, financial viability and risk for various types of renewable-energy and energy-efficient technologies (RETs). *RETScreen* was developed and is managed under the CanmetENERGY research centre of Natural Resources Canada (NRCan), and is supported by an international network of experts from industry, government and academia.

In spite of concern with the global climate changes, financial indicators are an important concern in the City's investment decisions. *RETScreen* analysis provides financial data that can be used to compare alternatives, based on costs and benefits of each alterative analyzed. These costs, benefits and environmental information are provided in the results section of the report.

3.4.2 Environmental Indicators

The analysis and results include estimated reductions in GHG emissions. The amount of GHG reduction for each option is indicated in Section 5 of this report.

We have included an estimated cost per tonne of GHG emission reduction on an annual basis to reflect the relative benefit of each of the alternatives. The *RETScreen* analysis accounts for factors such as actual sunlight hours (for Solar-Photovoltaic options) and meteorological conditions such as wind conditions and variations. The analysis software also takes into consideration the ability of the plant to use the energy generated.

3.5 Parameters for Financial Analysis

The financial criteria used for the analysis has a significant effect on the results provided by the analysis. After consultation with officials from the City of Regina a 20 year lifecycle cost analysis was selected along with the following financial parameters for the analysis of each alternative.

Debt Ratio:	100.0%	
Debt Interest Rate	3.5% to 6.0%	
Debt Period	20 yrs.	
Inflation Rate	3.8%	
Project Discount Rate:	4.0%	
Energy Inflation Rate (Electricity and Natural Gas):	8.0%	
Project Life Expectancy:	20 yrs.	
Value of GHG Credits:	$15/tonne	CO_{2e} avoided

The City provided a range of values for "Debt Interest Rate" of 3.5 to 4.0% for current financing rates with predictions for rates in the range of 5 to 6% on future projects. This study evaluated the alternative energy sources at 4% debt interest rate.

The inflation on electricity and natural gas is estimated at 8% per year. Refer to Section 4 for additional discussion on projected future energy rates. The 8% per year escalation equates to more than a doubling of electrical/gas rates in 10 years.

Credits for GHG reductions have been applied to the financial evaluations. These values are assumed and would only apply if cap and trade legislation is implemented or on a voluntary basis. An estimated value of $15/tonne is used.

Capital costs used in the analysis are based on estimates provided by manufacturers and *RETScreen's* databank of manufactured costs. Deep well geothermal costs were provided by B. Brunskill. Component estimates of probable cost are included in the Appendix with each *RETScreen* report.

3.5.1 Financial Indicators – Glossary of Terms

3.5.1.1 RETScreen Glossary of Terms (complete definitions available in the Appendix):

GHG Reduction Income
The annual GHG reduction income represents the income generated by the sale or exchange of the GHG reductions.

Discount Rate
The discount rate (%) is the rate used to discount future cash flows in order to obtain their present value.

Debt Interest Rate
The debt interest rate (%) is the annual rate of interest paid to the debt holder at the end of each year of the term of the debt.

Net Present Value (NPV)
The NPV of the project is the value of all future cash flows, discounted at the discount rate, in today's currency.

Internal Rate of Return (IRR)
The measure of profitability of investments.

IRR (Pre-tax IRR – Equity)
The pre-tax IRR on equity (%) represents the true interest yield provided by the project equity over its life before income tax.

IRR (Pre-tax IRR – Assets)
The pre-tax IRR on assets (%) represents the true interest yield provided by the project assets over its life before income tax.

Simple Payback
The simple payback (year) represents the length of time that it takes for a proposed project to recoup its own initial cost, out of the income or savings it generates.

Debt Ratio
The debt ratio (%) is the ratio of debt over the sum of the debt and the equity of a project.

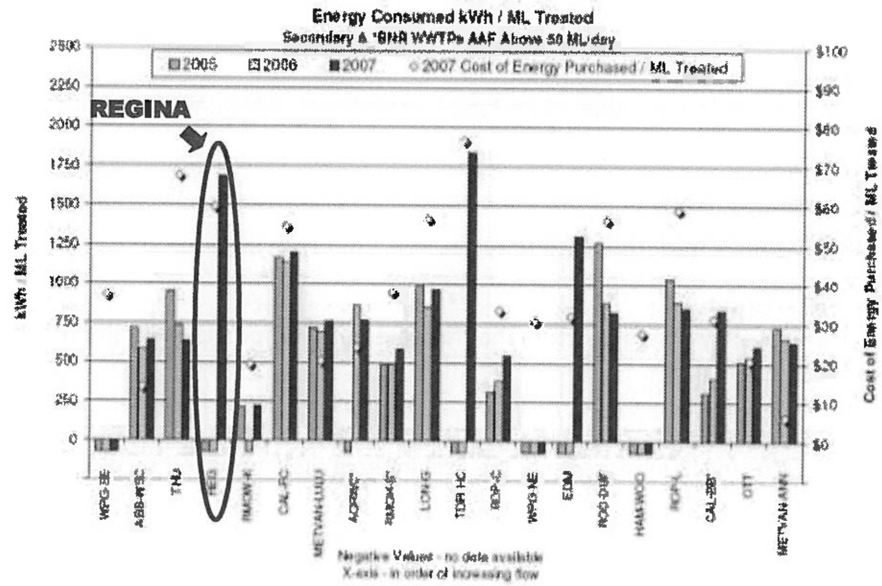
Project Life
The project life (year) is the duration over which the financial viability of the project is evaluated.

3.6 Future Plant Expansion

This study focuses on the analysis of alternative energy systems and based on the energy needs and configuration of the current WWTP.

The City's WWTP is a high energy consumer per megalitre (ML) treated compared to other WWTP facilities across Canada (refer to Figure 3.3).

Figure 3.3: Energy Consumed – Regina WWTP vs Other Canadian WWTP's



Source: National Water & Wastewater Benchmarking Initiative

The high electrical consumption at the City's WWTP is a result of the treatment process and the significant electrical demands for pumping and blowers. The City is considering more efficient processes with specific consideration to reduce the hydraulic pumping and aeration power requirements at the WWTP as a part of the proposed expansion. Based on our knowledge of the proposed project (which has not yet been designed), we are anticipating significant reductions to electrical demand as follows:

- An approximate 75% reduction of current blower capacity.
- A 50% reduction in the primary treatment, elimination of pumping for dry weather flows, plus the additional electrical requirements of a new mechanical secondary plant (such as return activated sludge and waste activated sludge pumps).

This represents a major portion of the current electrical demand and would be the single most effective method of reducing the WWTP's consumption of electrical power.

During our study and analysis we have also identified opportunities to reduce energy consumption for the proposed future expansion. The foremost of these is the opportunity to utilize one of the energy systems studied here to increase the WWTP influent temperature to effect more efficient treatment and in turn result in a smaller plant expansion. Initial exploration into this concept reveals that a modest increase in influent temperature could have a significant impact on the proposed BNR tank sizes and in turn the plant capital costs.

If the plant upgrades proceed, we recommend that the results of this report be re-evaluated and adjusted for the new plant conditions, and that the concept of increasing influent temperatures to reduce plant expansion size (and capital cost) be evaluated in some detail.

4. Baseline Energy Loads

4.1 Electricity

The existing connected load and electrical consumption patterns at the Regina WWTP were evaluated in order to determine a practical size for the on-site electrical generation options, and to compare and evaluate the potential benefit of on-site electrical generation against the present utility-based electrical supply. The following information was evaluated:

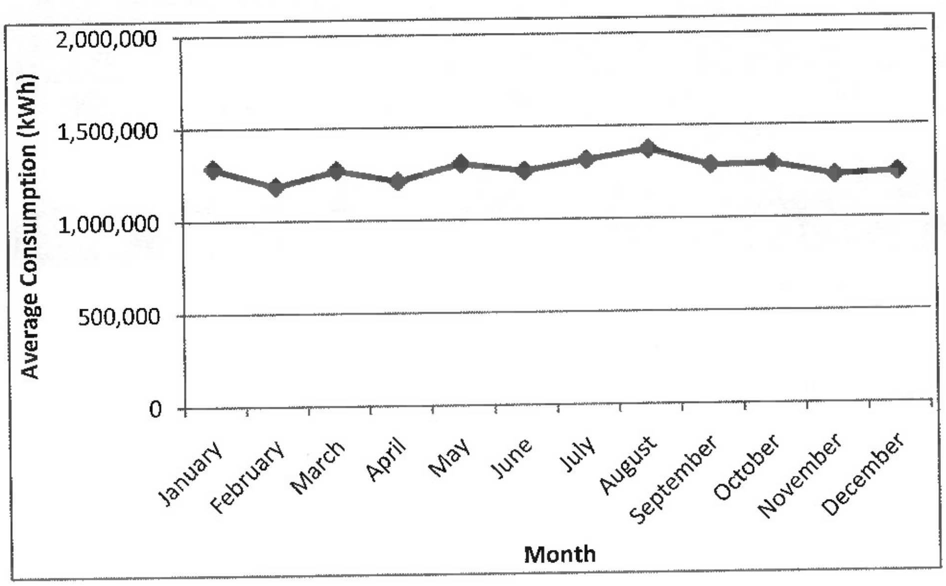
1. Data extracted from SCADA system for main electrical meters.
2. Monthly electrical bills for 2008.
3. Electrical information presented in the 2006 WWTP Annual Report.

The largest consumption of electrical power at the WWTP comes from running the process pumps and blowers. Electrical consumption at the WWTP is relatively steady due to the requirement to run the process pumps and blowers 24 hours a day. There are small fluctuations as equipment is switched on and off, and relatively minor increases in electrical consumption during occupied hours due to increased lighting, heating and air conditioning requirements.

4.1.1 Seasonal Variations

The average consumption of electrical power varies month to month, and the variances exceed the effect that the number of days per month could create. The higher electrical consumption in summer reflects wet weather flows and subsequent increased influent volumes. In general the variations between seasons are small, as illustrated in Figure 4.1 below:

Figure 4.1: WWTP Electrical Consumption – Average Monthly

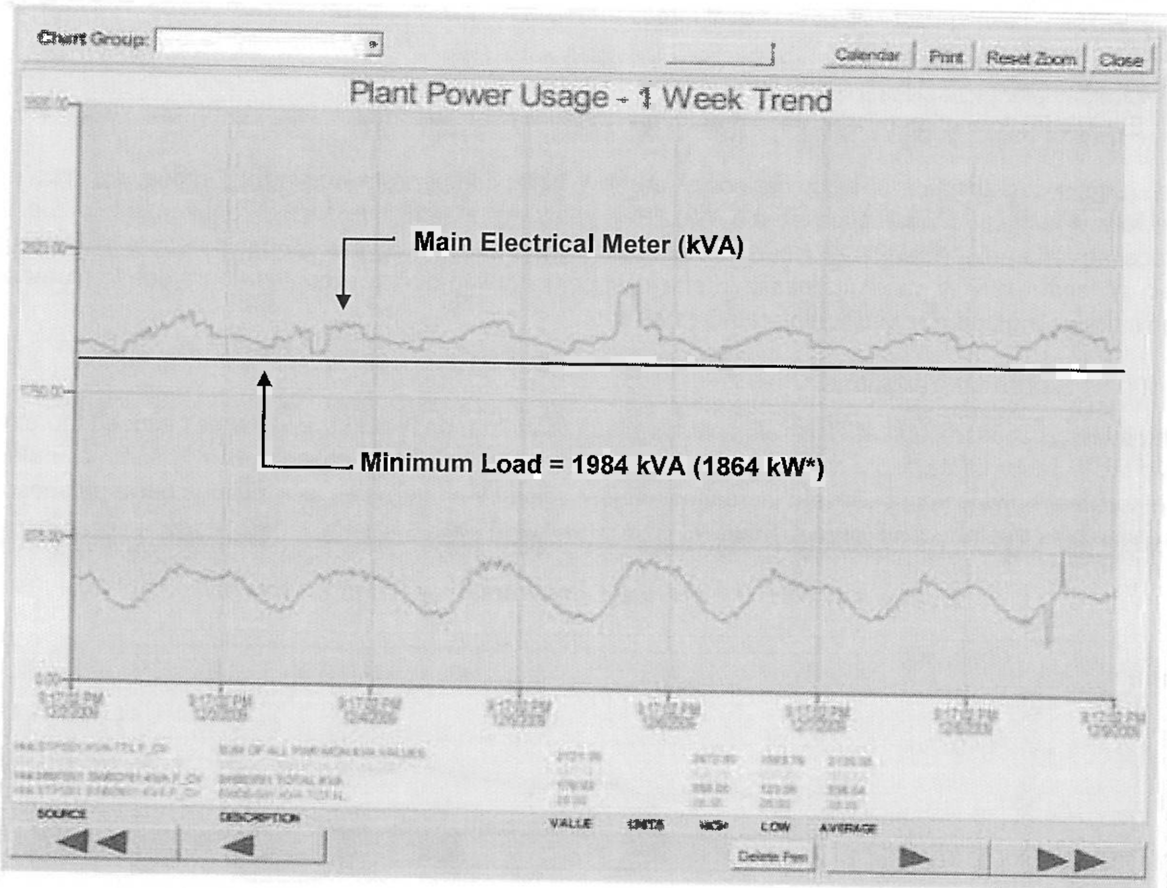


Based on electrical data from Methane Report and from 2008 electricity bills.

4.1.2 Daily Variations

The instantaneous electrical demand is shown in Figure 4.2 and Figure 4.3 below for both winter and summer conditions. Figure 4.2 shows representative electrical loads from the main electrical meter over a one week period during the winter (December 2, 2009 to December 9, 2009), and Figure 4.3 shows representative electrical loads over a one week period in summer (July 6 to July 13, 2009). The minimum electrical load is superimposed as a red line for each weekly trend. The readings indicate relatively steady electrical consumption with a minimum load of 2,034 kW for a typical week in winter and a minimum load of 1,864 kW for a typical week in summer.

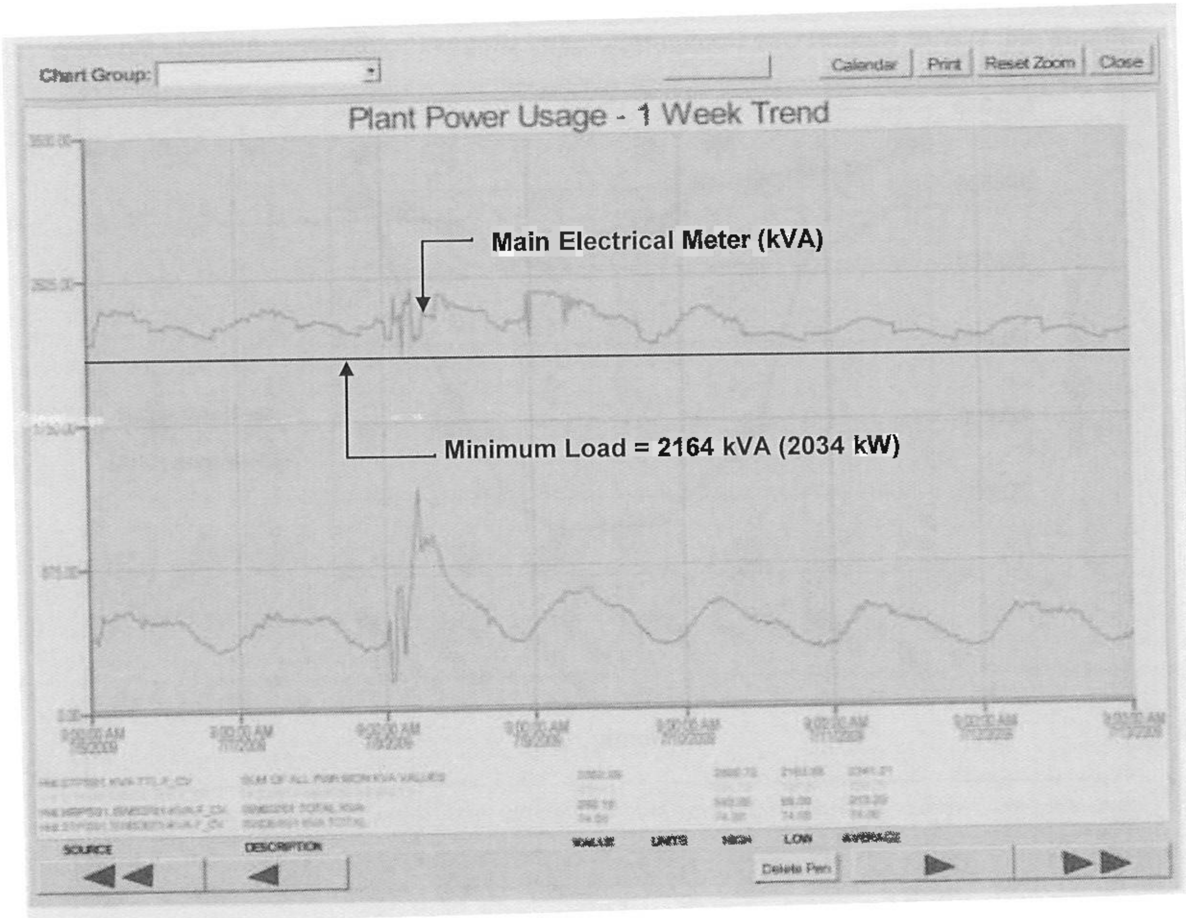
Figure 4.2: Winter – WWTP Electrical Consumption – 1 Week Trend (December 2 to 9, 2009)



Notes: *Taken from City of Regina WWTP SCADA system*

** Corrected for WWTP power Factor = 94%*

Figure 4.3: Summer – WWTP Electrical Consumption – 1 Week Trend (July 6 to 13, 2009)



Taken from City of Regina WWTP SCADA system

Corrected for WWTP power Factor = 94%

The study selected 1,500 kW (below daily minimums), as the target energy production level as the basis for all of the on-site generation options.

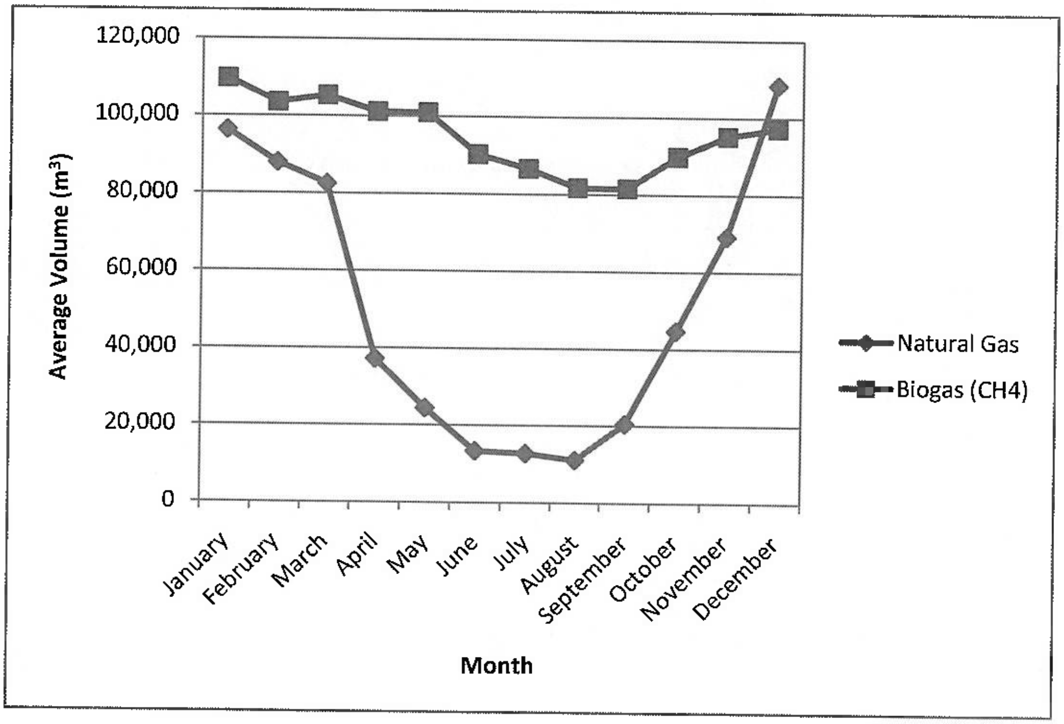
4.2 Natural Gas

SaskEnergy Inc. provides the natural gas service to the WWTP, which is delivered under contract with TransGas. The natural gas consumption used in this report is based on monthly averages over a six year period from data contained in reports provided by the City and from 2008 natural gas bills for the WWTP.

The natural gas is used for WWTP heating and for process heating of digesters and scum. Natural gas consumption is highest in winter (over 80,000 m^3/month) and lowest in summer (approximately 10,000 m^3/month). The summer process heating requirement (approximate heating input of 550 kW) is lower in the summer due to the higher temperatures of the influent. The plant heating boilers provide heat for both the plant heating and the process heating. The boilers can operate on both natural gas and biogas. Approximately 53% of the biogas produced is currently used in the boilers and 47% is flared off.

The average monthly gas consumption and biogas production is shown in Figure 4.4.

Figure 4.4: WWTP Natural Gas Consumption and Biogas Production – Average Monthly



Natural gas consumption based on monthly data from Methane Report for years 2000 to 2004 and 2008 WWTP gas bills. Biogas production taken from City of Regina 2006 Annual Report and monthly data from Methane Report for years 2000 to 2004.

4.3 Baseline WWTP Energy Needs

Based on the data in the previous sections, baseline performance criteria were established for alternative energy source systems as summarized in **Table 4.1**.

Table 4.1: WWTP Baseline Energy Summary

	Demand	Annual Average Consumption
Electrical Demand – Minimum *	1,864 kW	-
Electrical Demand – Peak **	2,692 kW	-
Electrical – Average ***	1,678 kW	15,000 MWh
Heating – Average		12,500 MWh
Heating – Process	550 kW	7,700 MWh
Heating – Building	2,000 kW	4,800 MWh

**Taken from SCADA readings in Fig. 4.2 and 4.3*

***Taken from August 2008 SaskPower electrical bill*

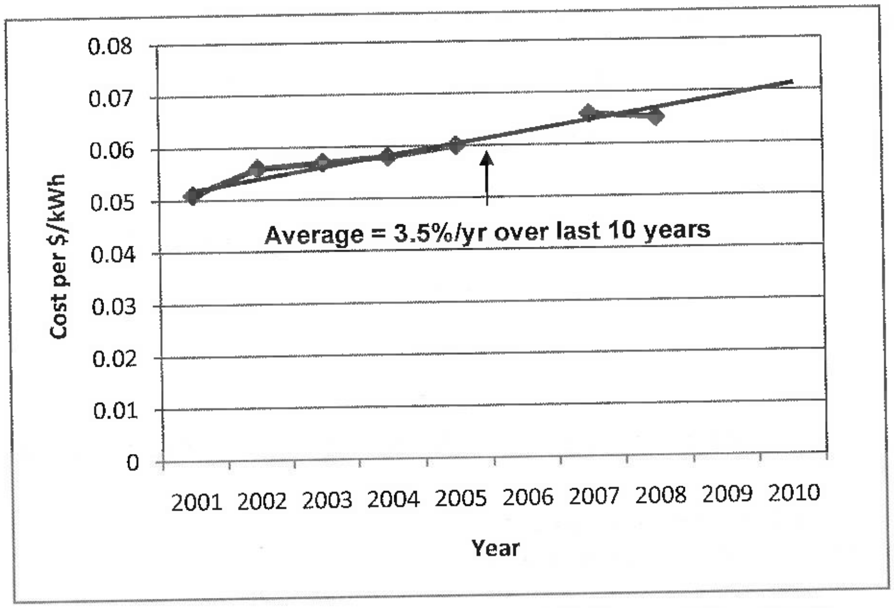
**** Average data includes WWTP outages*

4.4 Energy Rates

4.4.1 Historical and Projected Future Rates

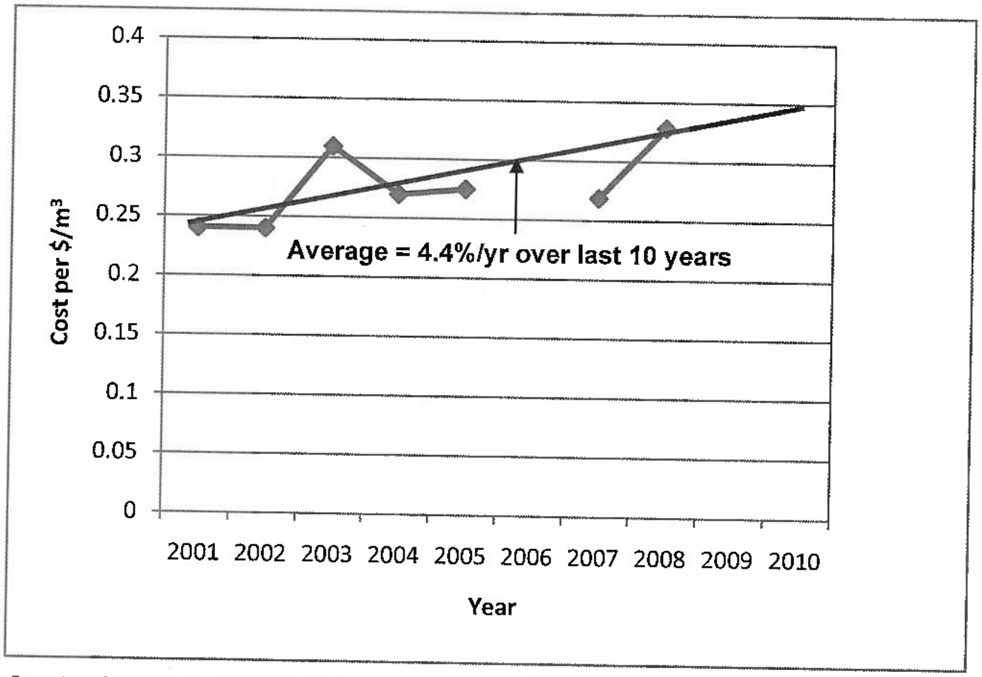
There is significant debate about the rate at which electrical and natural gas costs will increase over the next decade or two. Recently there has been significant speculation that electrical rates in Saskatchewan could increase at 8% per year for the next decade (refer to articles in the Appendix 9.5) which equates to more than a doubling of the current rate over that time period. Figure 4.5 and Figure 4.6 show the historical rates for electricity and natural gas at the WWTP for the last 10 years. In this study we have based our analysis on 8% annual escalation on both electricity and natural gas rates.

Figure 4.5: WWTP Historical Electrical Rates



Based on City of Regina WWTP actual annual electrical bill divided by annual kWhr consumed.

Figure 4.6: WWTP Historical Natural Gas Rates



Based on City of Regina WWTP actual annual natural gas bill divided by annual cubic metres consumed.

Based on the historical information and projections of future energy costs, the following energy rates were used in this study:

- Electricity Rate = \$0.072/kWhr – escalated at 8%/yr
- Natural Gas Rate = \$0.35/m^3 – escalated at 8%/yr

5. Alternative Energy Sources

5.1 Introduction

This section provides a basic discussion of the five renewable energy sources considered to provide alternate sources of energy for the Regina WWTP.

- Solar-Photovoltaic (electrical generation)
- Wind (electrical generation)
- Biogas – Combined Heat and Power (CHP)
- Wastewater Heat Recovery (heating)
- Geothermal Energy (heating)

The study provides a basic description of five energy sources and a total of eight system concepts and how they may be configured at the WWTP to collect and transform these energy sources into electrical power and/or heating for processes or building spaces.

The study methodology includes a business case comparative analysis conducted to quantify the costs and benefits of each alternative. The financial analysis considered a variety of fiscal parameters including project costs, operating/maintenance costs, savings/income, financial viability, yearly cash flows and cumulative cash flows, and provides simple paybacks as well as NPV and IRR results. The sensitivity analysis provides estimates for the sensitivity of financial parameters which have the greatest impact on financial indicators.

The results of our analyses are presented in another section and include both the environmental effect and financial benefits for these five alternatives.

5.2 Basis of Analysis

A common energy production level was identified to provide an equitable comparison of the energy sources and technologies in our analysis. The following target production levels for both the electrical and heating were selected based on the WWTP energy data provided in Section 4 and the following:

5.2.1 Electrical Generation Target:

The three following alternative energy options provide electrical power generation:

- Solar-Photovoltaic
- Wind
- CHP

The solar-photovoltaic and wind options are subject to variations of the earth's climatic system (sunny, cloudy, night, no wind, too windy) unless used in conjunction with suitable storage capacity or with supplementary power sources such as main electrical grid or other power generation source. The internal combustion engine co-generation source is the only one of these three sources of electrical power generation that is considered continuous, and was therefore selected as the baseline for evaluating and comparing these three alternatives.

The solar-photovoltaic and wind systems were sized at 360 kW/hr to provide approximately the same net annual amount of power (3.15 MWh/yr.) provided by the CHP system operating approximately 98% of the time allowing 2% for maintenance. The CHP system was sized for 360 kW based on the available biogas at the WWTP for continuous generation of up to 360 kW of electrical power.

The *RETScreen* program generates climate date for each source of energy (i.e. solar and wind) based on the Regina area, and determines the annual power production available. Solar and wind power generation equipment were selected from those provided in the RETScreen data base to meet the annual capacity requirement and the analysis incorporates the inefficiency of each product. The combined impacts of these climatic and system inefficiencies resulted in the following system efficiency (i.e. ratio of total annual installed system power production as compared to the system's rated capacity):

- Solar-Photovoltaic: 18.9% efficiency
- Wind Turbine: 24.0% efficiency

The systems were sized for analysis as near equivalents to a 360 kW internal combustion co-generation system:

- Solar-Photovoltaic: rated at 1,890
- Wind Turbine: rated at 1,750 kW

The analysis also considered Solar-Photovoltaic and Wind Turbine systems with higher power generation capabilities, closer to the WWTP's mean hourly power consumption of 1,700 kW/hr. This analysis is only applicable to the Wind Turbine and Solar-Photovoltaic systems. The biogas available at the WWTP is insufficient to power a co-generation system that can produce this amount of power.

Since the WWTP's power consumption is relatively stable, systems capable of producing approximately 1,500 kW/hr. continuous (13.1 MWh/yr.) were selected. This value is below any probable minimum power consumption at the WWTP.

The same analysis methods used for the 360 kW sized systems were used to establish the required continuous output of 1500 kW for the Solar-Photovoltaic and Wind Turbine systems and resulted in the following scenarios:

- Solar-Photovoltaic: rated at 7,000 kW
- Wind Turbine: rated at 7,000 kW (four 1,750 kW turbines)

These systems would generate hourly electrical overcapacity of about 4,350 kW/hr during peak solar generation or peak wind generation periods requiring either sophisticated controls to limit production or a storage medium to allow the equivalent annual capacity to be utilized. This surplus electrical power could be used in other systems such as with an electric boiler (at additional cost) to produce heat for process or space heating. An electric boiler running on the excess power generated could offset some of this demand, in varying amounts according to both the power generation and heating demand.

The wind and solar options do not eliminate dependency on SaskPower.

5.2.2 Heating Generation Target

Three sources of alternate energy for process and space heating were identified:

- Co-generation from Bio-gas
- Wastewater Heat Recovery (heating)
- Deep Well Geothermal

The alternative energy heating production targets were established using the same methodology as for the electrical power targets. In the case of heating all three sources are considered to be continuous, thus similar hourly system capacities were used for the evaluation. The target output for heating energy was established based on the effluent from energy system which recovers heat from the existing WWTP effluent.

Annual effluent flow rates from the WWTP are typically in the order of 26,500 ML, with average temperatures of 15°C. This effluent could be used to produce approximately 1,935 kW per hour of energy through a heat pump system, resulting in approximately 11,000 MWh of annual heating energy. The total annual load at the WWTP is approximately 12,500 MWh.

This hourly capacity exceeds the minimum energy requirements during the non-heating months of the year, as determined by the constant process energy demand of 550 kW. Without some form of storage, the actual recovered energy would be governed by the maximum energy demand during the time that the heat energy is produced. Thermal storage was not considered for any of these energy systems.

5.3 Base Case – "Do Nothing"

The base case is sometimes referred to the "do nothing case"; and consists of carrying on with current practice. Under this option the following will continue:

- SaskPower electrical consumption will continue at about 17,360 MWh/yr, or until the WWTP upgrade occurs. Currently the electrical bills are about $1,131,000/yr (2008 rates), and could potentially double to $2,262,000/yr if electrical rates double in the next decade.
- SaskEnergy natural gas consumption will continue at about 622,000 m^3/yr, or about $204,000/yr, plus escalation.
- Boiler maintenance will continue to be high due to the corrosive nature of burning biogas in the boilers. The "Methane Utilization Report" estimated annual maintenance costs for the boiler to be $55,000/yr (2006 dollars), with a boiler replacement required every 10 years.

5.4 Solar-Photovoltaic

5.4.1 Introduction

The sun's energy can be captured with various technologies to transfer that energy to a fluid (solar collectors) or to convert it to electricity (photovoltaic cells or heat engines). Solar energy can be used for space heating, domestic water heating, industrial processes, or to meet electricity needs. This study considered only photovoltaic technology used to generate electricity. Thermal solar technology was not in the scope of this report but could be explored further in a future study.

Since most common electrical loads require alternating current (AC), the direct current (DC) electricity from photovoltaic cells must be converted to AC at the required voltage. This is accomplished using electronic inverters to suit the particular system capacities and requirements.

When electrical power is required outside of the solar power producing hours (i.e. sunlight) or demand exceeds capacity (cloudy, night time, etc.) the City must rely on another source of power supply (SaskPower) or rely on stored excess power (batteries).

Development of storage methods for electrical power generated by photovoltaics includes: traditional lead-acid batteries, gel-type batteries, and flow batteries such as the Vanadium Redox principle battery. The Vanadium units are getting increased consideration and application for storage at facilities generating up to several mega-watts of power. They reportedly have almost unlimited storage capacity, based on increasing the reservoir size, and are quite robust, but they have a relatively lower energy storage to volume ratio.

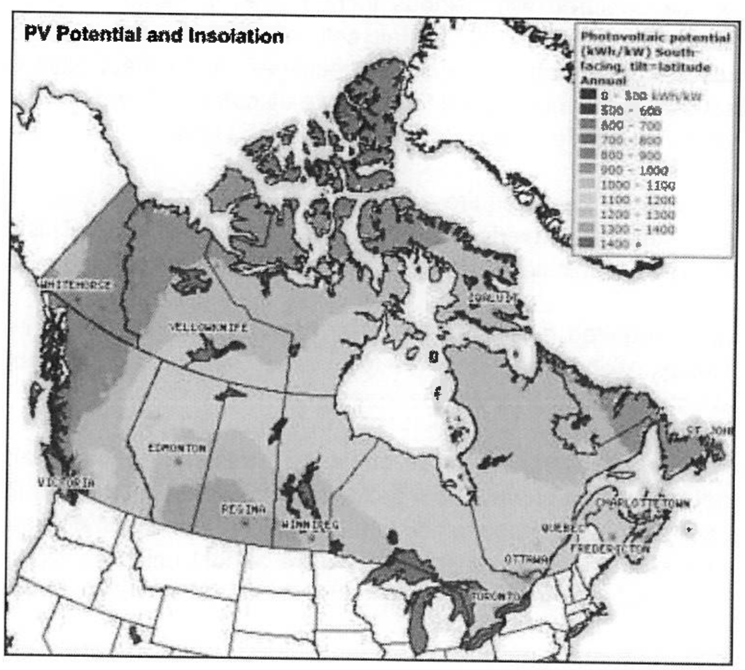
Where photovoltaic systems are connected into the main electrical power grid, the electrical utility may agree to purchase surplus power for redistribution. SaskPower offer a Net Metering program for eligible technologies including the alternatives in this study. Certain interconnection requirements must be met and are available at www.saskpower.com. Such arrangements can help to offset the requirement for power during non-solar hours by using the credits or revenue from the excess capacity sold to the utility. Funding assistance under the SaskPower Net Metering Program is also available. There are conditions on how this power is transacted back to the utility leading to increased producer system costs, but it can reduce or eliminate the need for electrical storage capacity.

Natural Resource Canada's Development of Photovoltaic Resource Maps for Canada provides insolation and photovoltaic potential data for this type of analysis (Natural Resources Canada [NRCan], 2007a). The models (and subsequent maps) are based on 1974 – 1993 (NRCan, 2009) monthly mean daily global insolation data for different surface orientations.

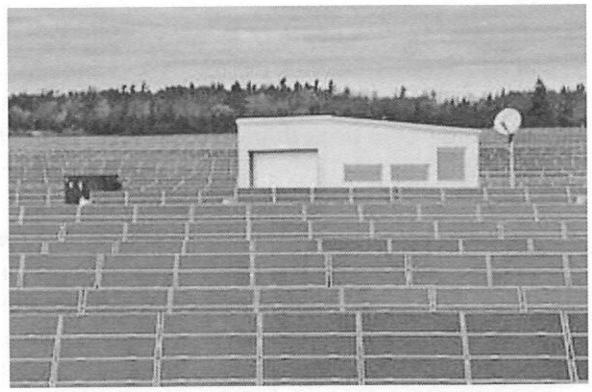
The "Development of Photovoltaic Resource Maps for Canada" project developed a database of photovoltaic potential for over 3,500 municipalities and identified the best location for photovoltaic potential, termed a — photovoltaic hotspot in each province. Canada's average annual photovoltaic potential (for panels tilted at an angle equal to the latitude) is 1113 kWh/kW. The maximum photovoltaic potential occurs in the Prairies (1300 – 1400 kWh/kW) with the greatest concentration in Saskatchewan. Refer to Figure 5.1.

Regway, Saskatchewan, near the United States boundary, had the highest annual photovoltaic potential (1,384 kWh/kW), but Regina at 1361 kWH/kW is first amongst major Canadian cities and municipalities, and listed in sixth place amongst the world's cities with the most photovoltaic potential. It can thus be concluded that Regina has excellent annual solar resource availability. In spite of this enviable rating, the overall annual photovoltaic system efficiencies in the Regina area are estimated to be in the 18to 19% range.

Figure 5.1: PV Potential and Insolation



5.4.2 Proposed System Solar-Photovoltaic



The proposed photovoltaic installation consists of a fixed array of 230 watt DC photovoltaic panels located to the east of the Primary Treatment Plant (refer to Figure 5.3). The photovoltaic panels will be arranged in rows and mounted on concrete pads or piles and will be fixed to face directly south tilted at an angle of 50 degrees to horizontal to optimize their performance in the fixed configuration. The proposed system is based on photovoltaic panels supplied by Canadian Solar (refer to Appendix 9.3 for additional information).

The solar-photovoltaic arrays are interconnected to provide DC power to an AC inverter (refer to Figure 5.2). The inverters will also provide the necessary control to ensure that the system is synchronized with SaskPower. The output voltage will then be transformed to match the current WWTP's 23.5 kV main power distribution voltage. Dedicated switchgear will provide the necessary protection and prevent the array power from back feeding power into the SaskPower grid.

Articulating photovoltaic panels, that automatically swivel and tilt to track the movement of the sun were considered. These installations are more expensive and require motors, rigid foundations and mounting systems and computerized controls. In speaking to the photovoltaic suppliers, the economics of these panels do not justify the additional cost and maintenance, and are typically used for smaller panel sizes and in locations with real estate concerns. The articulating photovoltaic panels were not considered for this installation.

A two position photovoltaic system with a summer position (30 degrees to horizontal) and a winter position (60 degrees to horizontal) could be installed to improve the photovoltaic performance. The panel angle would be adjusted manually twice a year, once in the spring and once in the fall to optimize solar performance. The cost of the two position photovoltaic panel will be similar to the fixed panels, but would have the additional annual operating cost of moving the panels; based on this additional annual cost, the two position panels were not considered.

The land area requirements for the two solar-photovoltaic systems considered ranged from 13,300 m^2 to 30,450 m^2, and it appears that the WWTP has suitable land area for this purpose.

SaskPower indicates that "Net Metering" service is available. "Net Metering" would allow the WWTP to connect their renewable energy system to the grid using a two-way meter. Under an agreement with SaskPower the WWTP would accumulate power credits over a set period of time for any excess electricity that is generated, with the two-way meter allowing the WWTP supply electricity from the grid by drawing down on its credits. In other words, this would allow the WWTP to "give" excess electricity capacity to SaskPower when the sun is shining and "take" the electricity when the sun is not shining, with simplified accounting via the two-way meter.

The analysis was performed on Canadian Solar's CS5P 230 Watt model of photovoltaic panel with the following features:

- Frame tested for heavier snow load and wind pressures (5400 Pa)
- Power tolerance of approximately 5W (plus/minus 2.1%)

The two solar-photovoltaic systems evaluated in this study:

- **Option 1a – 1,890 kW Photovoltaic System Peak Capacity** – This installation would consist of 8,260 interconnected photovoltaic panels and would consist of approximately 13,286 m^2 of panel area. The peak capacity matches the minimum base electrical load of the plant; so no electricity would be sold back to the SaskPower. Also, the 1,890 kW system will annually generate about 3,154 MWhr of power; equivalent to 360 kW of continuous generation for convenient comparison to the other options.
- **Option 1b – 7,000 kW Photovoltaic System Peak Capacity** – This installation would consist of 30,450 interconnected photovoltaic panels and would consist of approximately 48,980 m^2 of panel area. The peak capacity is over 3.5 times the peak electrical load of the plant, so selling the excess capacity back to SaskPower is required. This system will annually generate about 12,615 MWhr; an equivalent of 1,500 kW of continuous generation, sufficient to almost completely offset the electrical needs of the Regina WWTP. Battery storage was also considered as a method of avoiding the need to sell excess electricity back to SaskPower. The cost of battery storage and maintenance for systems of this is size is very high and far exceeds the anticipated cost of connecting to the grid.

The O&M costs associated with the photovoltaic option have been factored into the analysis and include the following:

- Panel Cleaning – the surface of the photovoltaic panel is to be kept clean, and any snow to be removed in the winter to maintain reduce inefficiencies. In our analysis we have allowed for four cleanings per year.
- Major Equipment Replacement – Inverter equipment, associated with converting the photovoltaic panels' DC power into AC power are reported to have a life span of about 10 years, warranties are available at additional cost to extend this to 20 years. The study considers a replacement of the inverters after 10 years of operation.

A schematic of the solar-photovoltaic system and the proposed site layout for both cases is presented in Figure 5.2 and Figure 5.3 below.

Figure 5.2: Solar-Photovoltaic Schematic

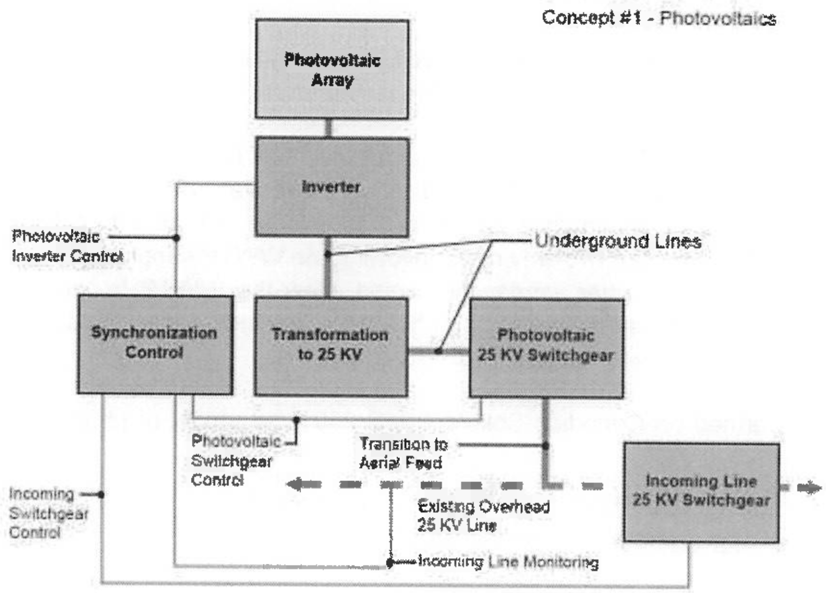
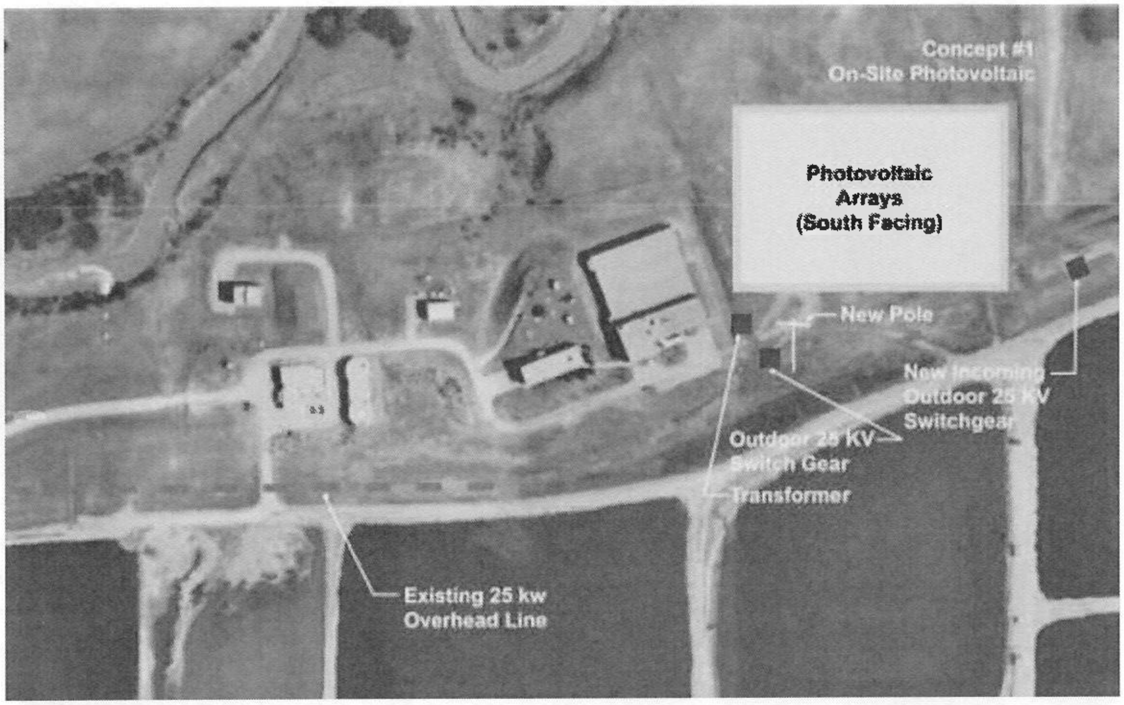


Figure 5.3: Solar-Photovoltaic Site Layout



5.5 Wind Turbine

5.5.1 Introduction

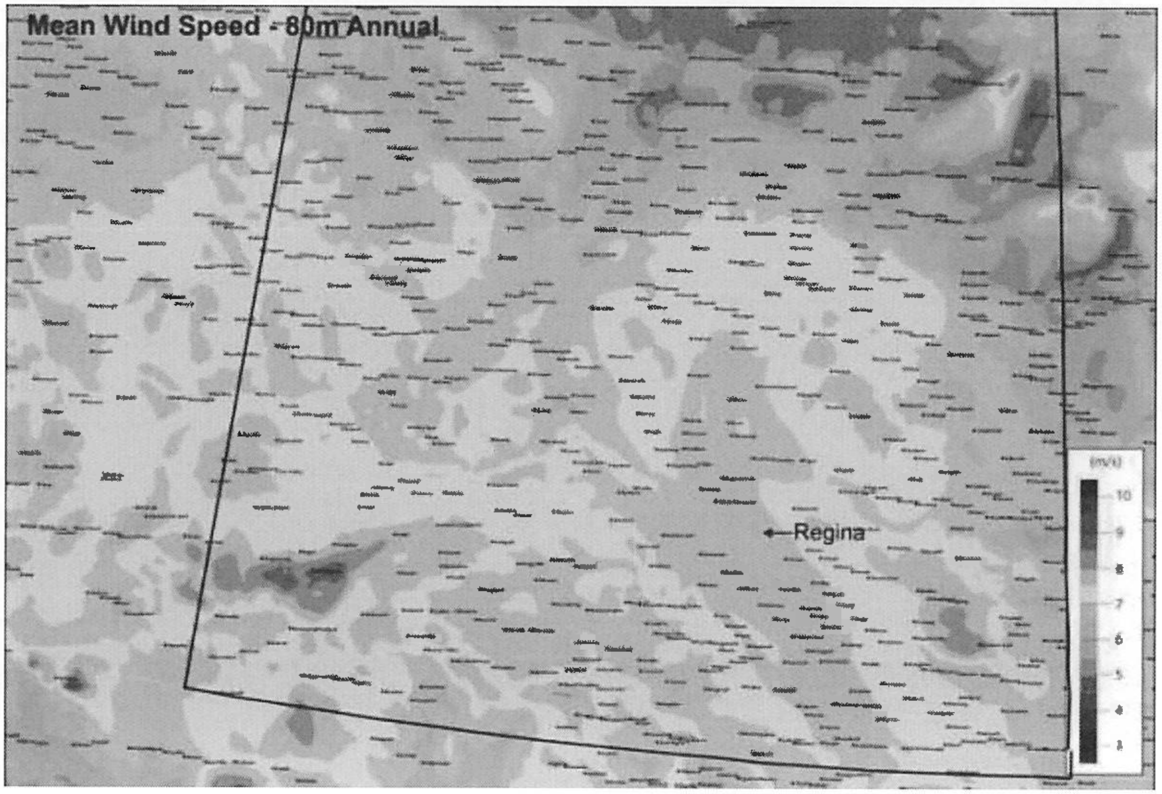
Wind is a renewable resource from which clean energy can be generated. Wind turbines capture the wind's kinetic energy and convert it to electricity. The amount of power that can be harnessed from wind is variable and depends on the turbine's efficiency and on the available wind. The presence of wind and wind speed are a function of the local elevation and the presence of predominant surface features. Areas where winds are stronger and more constant, such as offshore and high altitude sites, are preferred locations for wind turbines; however, successful wind installations have been situated inland in good wind regimes, where proximity and good access to power grids have made it feasible, albeit generally with concessions and incentives from power companies.

Similar to solar-photovoltaic wind energy is intermittent, and the methods suggested for solar-photovoltaic systems (such as storage or reliance on other sources such as SaskPower) would also be required to provide the necessary power during these times.

The Environment Canada – Canadian Wind Energy Atlas data is a good preliminary source and was used for identifying areas with suitable wind speeds and Mean Wind Energy (W/m^2) levels (refer to Figure 5.4). Specific data on wind speeds at 30 m, 60 m, and 80 m for the Regina Airport confirms that the wind speeds are at or above the minimum required wind speed criteria for most turbine manufacturers.

The Wind Atlas provides a calculator which also confirmed that the selected wind turbine would generate the average energy levels anticipated in our analysis.

Figure 5.4: Mean Wind Speed at +80 m



An important consideration is locating the turbine in close proximity to an existing and suitable power transmission infrastructure. The WWTP has a suitable 25 kV transmission line and metering located on the property.

5.5.2 Proposed System – Wind Turbine

The proposed wind turbine installation consists of one or more wind turbines installed on the Regina WWTP property just north of the plant, but south of the Wascana Creek and outside of the creek's flood plain (refer to Figure 5.6). This area was selected based on discussion with WWTP staff, to be further away from the lagoons, where there is significant migratory bird activity. The location of the turbine would have to be studied further for avian considerations.

Also the proposed turbine location at the WWTP site is nearly aligned with the arrival and departure paths from one of the major runways at the Regina International Airport located south east of the WWTP. Consideration for air traffic would need to be made as part of the site selection, planning and design for any wind turbine installation at the WWTP.

The acoustic and other environmental considerations of an operating turbine are also a concern and should be considered in conjunction with staffing and operations of the WWTP.

The analysis for this study was performed on a Vestas V66-1.75 MW – 60 m wind turbine, installed in proximity to the WWTP selected as the most suitable for the WWTP (refer to Appendix for additional information).

The VESTAS wind turbine features the following major components suitable for cold weather operation:

- 1.75 MW rated capacity
- 60 m hub height
- Three-blade rotor design (66 m dia.)
- Cut-in wind speed = 4 m/s
- Nominal Wind Speed = 16 m/s
- Stop wind speed = 25 m/s

The wind turbine will be connected via underground medium voltage (turbine voltage) power lines to a transformer for transformation to 25 kV power (refer to Figure 5.5). The 25 kV power is run through switchgear to synchronize the power with the 25 kV aerial distribution line on site.

Two wind turbine systems were evaluated in this study:

- **Option 2a – 1,750 kW Wind Turbine Peak Capacity** – This installation would consist of a single wind turbine with a rated capacity of 1,750 kW. The peak capacity approximately matches the minimum base electrical load of the plant; so no electricity would be sold back to SaskPower. The 1,750 kW system will annually generate about 3,681 MWhr; an equivalent to 360 kW of continuous generation for convenient comparison to the other options.
- **Option 2b – 7,000 kW Wind Turbine Peak Capacity** – This installation would consist of four wind turbines each rated at 1,750 kW. Similar to the Solar-Photovoltaic Option 1b, the peak capacity is over 3.5 times the peak electrical load of the plant, so selling the excess capacity back to SaskPower is required to make this system viable. This system will annually generate about 14,723 MWhr; an equivalent of 1,500 kW of continuous generation, sufficient to almost completely offset the electrical needs of the WWTP. When the wind is adequate, the system will provide sufficient electrical energy to power the WWTP, and sell the excess to SaskPower. When the wind is insufficient, the WWTP will operate from utility power.

The O&M costs associated with the wind turbine options have been factored into the analysis and include the following:

1. Regular maintenance on the turbines, such as lubrication.
2. Similar to the Solar-Photovoltaic options the inverter equipment, associated with converting the DC power into AC power will require replacement over the lifecycle considered. We've allowed for full replacement of the inverters after 10 years of operation.

As indicated in Figure 5.5, the wind turbine output will be connected to the WWTP through transformation and protective switchgear similar to the Solar-Photovoltaic system mentioned earlier.

Figure 5.5: Wind Schematic

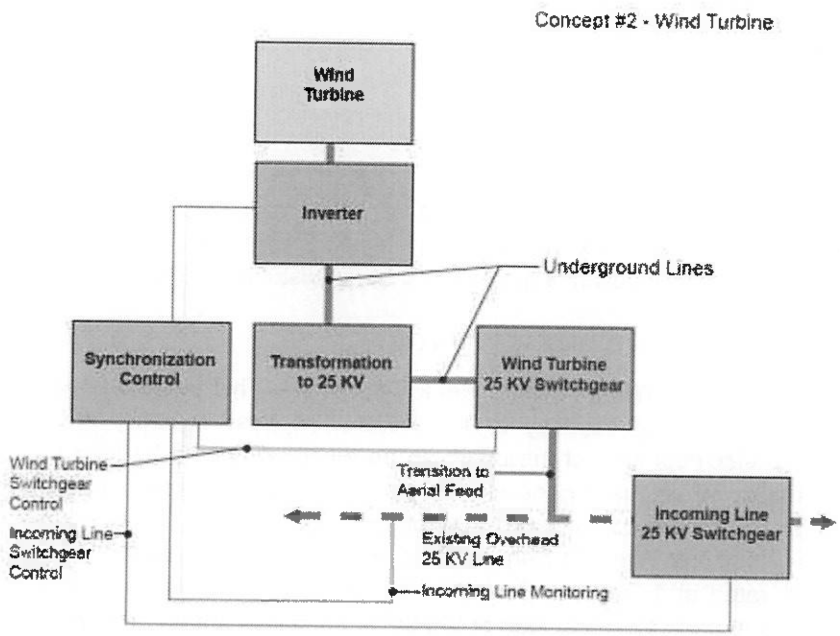
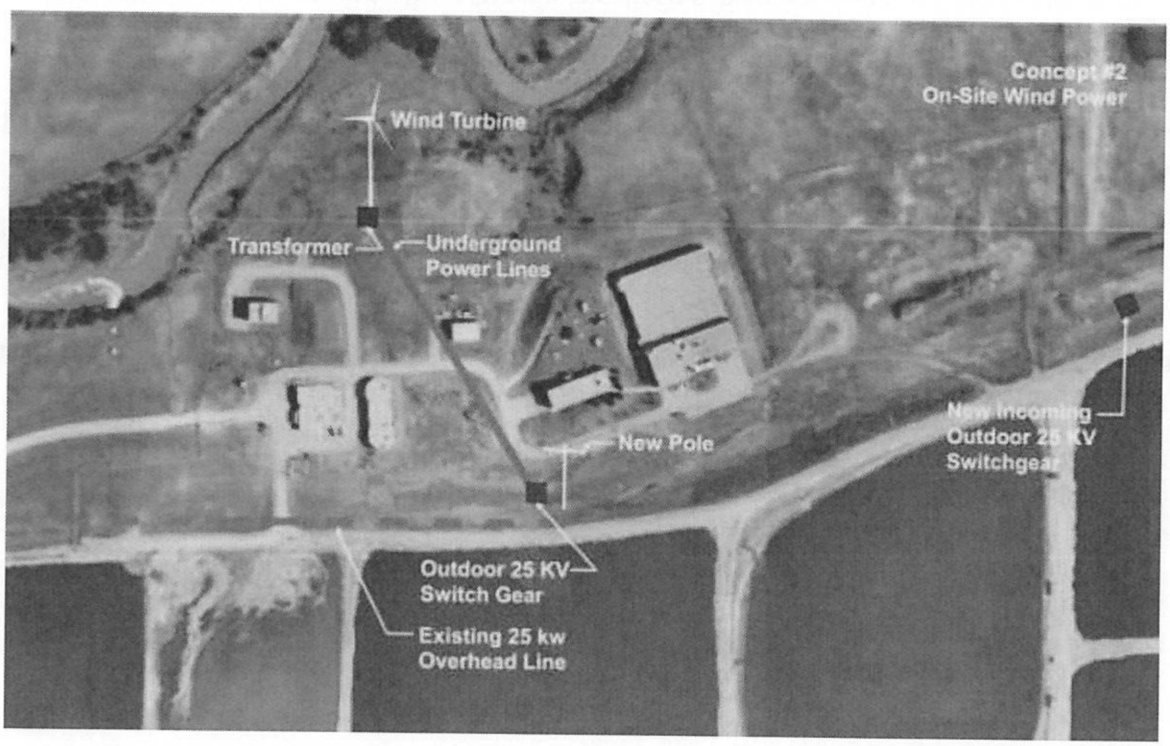


Figure 5.6: Wind Turbine Site Layout



5.6 Biogas – Combined Heat and Power (CHP)

5.6.1 Introduction

The WWTP's anaerobic digesters decompose the waste sludge and produce an ADG or "biogas" containing about 62% CH_4. The gas also contains CO_2, H_2S, Carbon Monoxide (CO), water vapour, and other trace contaminants. These components have corrosive effects when included in the process of combustion, leading to accelerated corrosion of equipment components. This biogas is suitable for combustion, providing approximately 62% of the energy value (620 BTU/ft^3) of the same volume of natural gas (1,000 BTU/ft^3). The corrosive effects of the ADG can be significantly reduced by removing some or all of the corrosive components in a series of gas treatment processes.

This biogas can be used for direct combustion in a burner to provide heat (as in a boiler), or to fuel an internal combustion engine or turbine to produce electricity or mechanical energy (pumping, etc.).

The implementation of co-generation systems, where site-generated electricity is combined with a central grid supply is common practice in many locations where biogas is readily available, such as in WWTPs or landfills. A recent installation of a 675 kW co-generation system in the Thunder Bay, Ontario WWTP is a good example of what could be implemented at the Regina WWTP.

Based on the availability of otherwise wasted and thus "free" biogas the co-generation technology produces relatively inexpensive method of generating electricity especially when combined with a heat recovery system. The engine heat rejected by the exhaust and cooling systems can be partly recovered to contribute to process or building heating that would otherwise depend fully on a separate system, such as hot water boilers.

5.6.2 Proposed System – Biogas CHP

The proposed co-generation system consists of a biogas treatment system; co-generation and heat exchange equipment located in a building to be constructed on the south side of the Dewatering Building (refer to Figure 5.8). The co-generation system will consist of the following components:

- **Control Upgrades** – The existing controls system for the biogas collection and flaring system will be upgraded to ensure that biogas is fully utilized by the co-generation unit without flaring due to pressure and flowrate fluctuations. Currently about 47% of the biogas is being flared due to erratic flowrates and inadequate controls. The control upgrades will likely consist of improved regulation and control of the biogas flow to the flare stack. The existing heating plant boilers will remain as is; with the existing boilers running primarily on natural gas with the biogas diverted for use primarily in the co-generation plant. Boiler #1 and #2 would still retain the ability to run either on natural gas or biogas.
- **Gas Treatment System** – A gas treatment system will be installed to scrub the biogas to meet the specification of the co-generation unit to ensure equipment longevity. The proposed gas treatment system will remove moisture, H_2S and siloxanes from the biogas stream in order to protect the co-generation engine from corrosion and deposit damage. H_2S will be reduced from current averages of 6,850 ppm down to less than 100 ppm. The proposed gas treatment system comprises of a refrigeration dryer, filtration system and carbon absorption system, and is based on a scrubber system for the recently completed co-generation system for the City of Thunder Bay.
- **360 kW Co-generation Unit** – Based on data provided in the Methane Report, and the engine manufacturer's technical data the WWTP biogas production is adequate to support continuous generation of up to 360 kW of electrical power generation. The system analyzed is based on a Caterpillar Model G3512 co-generation unit capable of delivering 360 kW of electrical power (refer to **Appendix** for additional information). The 360 kW unit consists of a reciprocating engine running on

treated biogas that drives an electrical generator. The unit was selected to utilize all of the available biogas.

- **Engine Heat Recovery System** – Heat generated from the engine is transferred to the plant-wide heating system via a heat exchanger on the return side of the main boiler loop. Tie-ins to the boiler loop will take place in the tunnels. Heat is captured from the engines in two ways:
  - The engine is cooled by circulating coolant through cavities in the engine body. Excess heat from combustion of digester gas raises the coolant temperature to approximately 120°C. The coolant flows to a heat exchanger where the heat is transferred to the plant heating system, or if the plant heating system cannot accept the heat to a radiator mounted outdoors.
  - The exhaust gas, which leaves the engine at about 450°C, runs through a heat exchanger where it is cooled to about 150°C. The heat is transferred to the plant heating system via the heat exchanger on the main boiler loop.
- **Electrical Integration System** – The electricity generated by the co-generation unit will be fed back into the WWTP electrical system to reduce the amount of electricity purchased from SaskPower. The system will be synchronized to the plant 25 kV system via transformers and switchgear, similar to the first two options.

The operation and maintenance costs associated with the co-generation option have been factored into the analysis. Some of the additional O&M costs are as follows:

1. Replacement of filter media in the gas treatment system, and the associated disposal cost.
2. Regular maintenance on the co-generation unit, such as lubrication, coolant and battery maintenance.

Figure 5.7 shows the biogas schematic including the connection to the WWTP electrical grid which is similar to the Solar-Photovoltaic or Wind Turbine cases. The recovered heat stream is connected into the existing boiler hot-water loop.

Figure 5.7: Biogas Co-generation Schematic

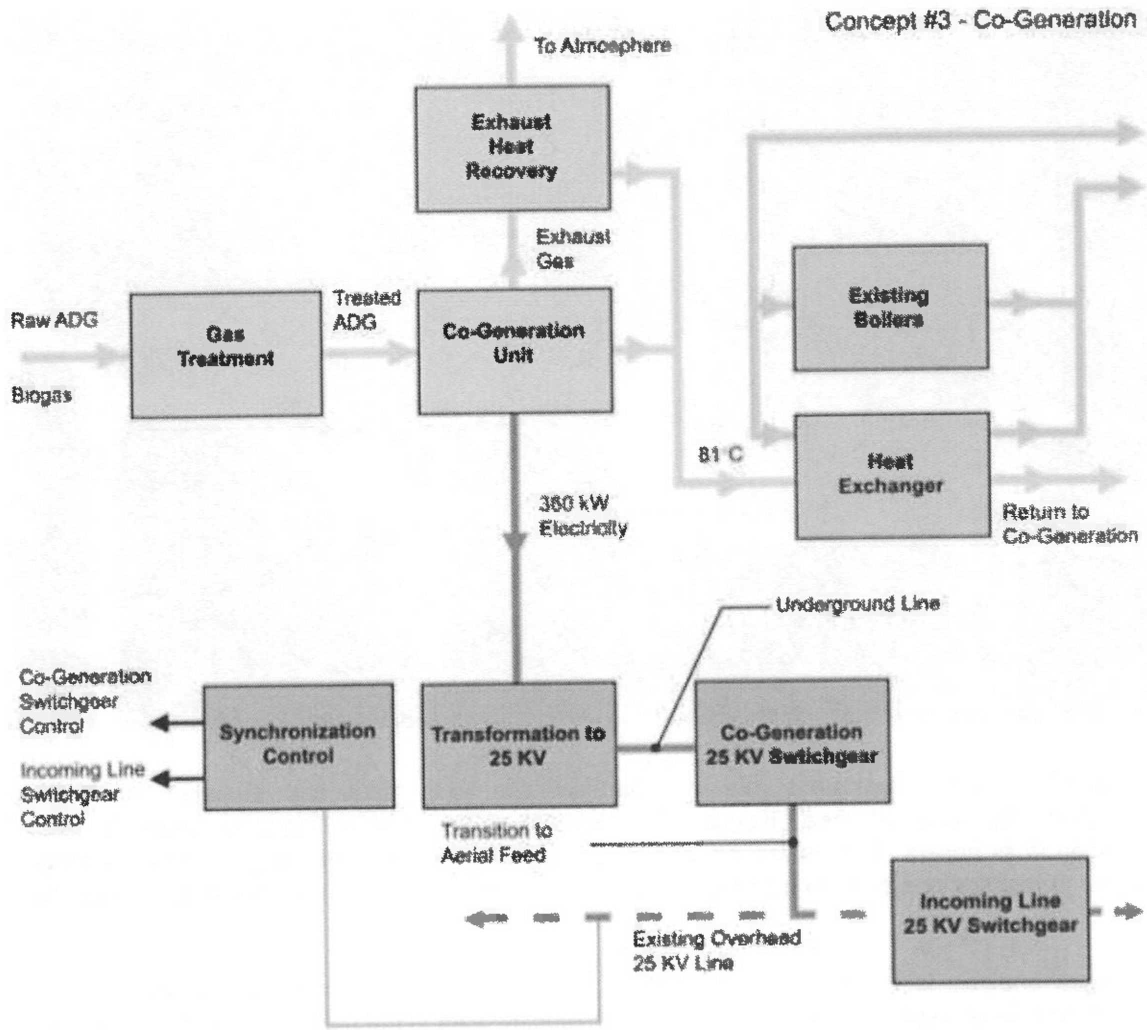
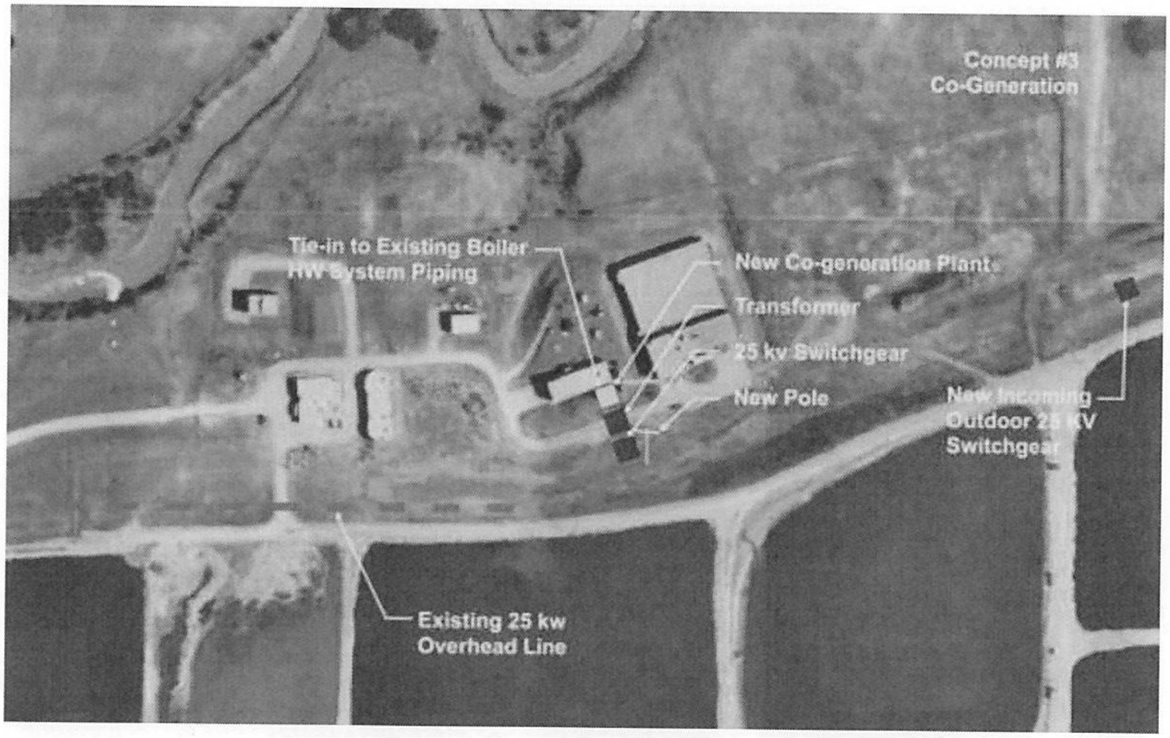


Figure 5.8: Biogas Co-generation Layout



The WWTP's current treatment rate of approximately 68.8 ML/d and produces approximately 1,830,000 m^3 per year of "free" biogas. Approximately 53% of this biogas is presently used for combustion in its boilers. This represents about half of the total boiler fuel energy currently used by the facility for processes and building heating. The balance of the boiler fuel is provided by purchased natural gas.

The biogas analysis is based on the use of all the available biogas from the digesters to fuel the generator-set. As a result, the portion of the ADG previously used in the boilers will no longer be available for that purpose and require replacement by purchased natural gas. The net annual increase in natural gas purchase is estimated to be approximately 700,000 m^3.

This effect will be partly offset by the recovery of a significant portion of the heat normally rejected by the internal combustion engine of the generator set. The analysis indicates that approximately 480 kW of energy can be recovered and is available for heating. Since this is less than the estimated minimum process heating requirements of 550 kW, it could be utilized all year round.

The additional benefits resulting from maximizing the use of the ADG are; reducing the amount of flared ADG and the resulting positive environmental impact, and extended boiler life (and reduced maintenance costs) when compared to the current reported boiler corrosion resulting from the use of ADG.

5.7 Energy From Effluent (EFE)

5.7.1 Introduction

Heat from wastewater can be reclaimed by heat pumps in municipal and institutional wastewater collection and treatment systems. This heat can be used to heat buildings or water. EFE systems have been successfully installed in several municipal WWTP's such as the City of Winnipeg's North End Water Pollution Control Centre and the City of Saskatoon's Ultraviolet Disinfection Facilities. One institutional example, Okanagan College in Kelowna, BC, derives 80 to 100% of heat (depending on weather conditions and heating requirements) from their municipal wastewater treatment system. This saves the college $300,000 annually. In Stockholm, similar heating benefits are implemented and used to offset the cost of municipal wastewater treatment services.

EFE requires the use of heat pumps. Heat pump technology is well proven in countless ground source applications. It absorbs the energy necessary to change the phase of its prime heat transfer media from liquid to gas, from a suitable source, and then releases this absorbed energy to the desired location when the media is condensed.

The heat transfer media, typically existing as a gas at atmospheric pressure, is selected to provide the most efficient and cost effective results based on the temperature of the source of energy. The nature of the evaporation (where energy is absorbed from the source) and subsequent cooling process (where energy is released), is such that the net energy transferred normally exceeds the energy required for; circulating the source pumps, to circulate the media (compressors or pumps) and for condensation (fans). The system thus has a positive coefficient of performance (COP) relative to the purchased energy used for its operation.

5.7.2 Proposed System – Energy from Effluent

The EFE system will draw energy from the relatively warm effluent in the plant. The minimum primary plant influent temperature at the Regina WWTP is about 13°C (monthly average), with the lowest temperature occurring during spring runoff. The total amount of energy available in the effluent is significant, considering the large effluent flow rate. The daily throughput of 68.8 ML/day (approximately 12,600 USGPM) translates to about 20 MW of thermal energy available (based on extracting 6°C of heat from the effluent). The potential capacity of this system will exceed the peak winter heating demand of the plant of 1.9 MW (6,600,000 Btuh) and the excess heat energy available could be sold either to neighbouring developments via underground pipes, or via a district energy system. In this report we have not evaluated this potential.

The energy is extracted from the effluent using a heat exchanger, the temperature of the energy is then increased using heat pump technology. The hot water produced by the heat pumps will be transferred to the plant-wide heating system (refer to Figure 5.9). The EFE system will offset all the year-round heating needs of the WWTP, and eliminate the need for natural gas.

The natural gas boilers will not be required to run in the winter; however, it is recommended that the boilers and natural gas infrastructure remain in place as a backup supply. Implementation of the EFE system will shift the utility dependency from natural gas to electricity; however, at a significantly reduced requirement (with a COP = 3 the heat pumps will use about one third the energy that would be required in the boilers).

The proposed EFE system consists of the following components:

1. **Heat Plant Building** – A new Heat Plant Building will be constructed just east of the Primary Treatment Plant (refer to Figure 5.10) to house the EFE equipment. The Heat Plant Building will have lighting and heat to provide a suitable environment for maintenance.
2. **Effluent Heat Exchange System** – A side stream of effluent will be extracted from the main effluent line leaving the Primary Treatment Plant, just prior to discharge to the Lagoons. The side stream will be pumped through a heat exchanger. The heat exchanger will be selected for efficiency and ease of

cleaning (e.g. a spiral heat exchanger). A primary loop with a 30 hp pump is used to circulate effluent from the main WWTP piping into a primary heat exchanger.

3. **Secondary Heat Transfer Loop** – A secondary loop will transfer heat from the effluent heat exchangers to the heat pumps. The purpose of the secondary loop is to provide a clean, treated water supply as an energy source for the heat pumps, to prevent fouling in the heat pumps that is associated with using the dirty effluent.
4. **Heat Pump System** – A series of heat pumps, powered by electricity, will increase the grade of the effluent heat from 13°C to approximately 60°C. The heat pumps operate on a refrigeration cycle and absorb the energy from the effluent on the evaporator side and provide the upgraded heat on the condenser side.
5. **Plant HVAC and Process Heating Upgrades** – The heat pump system will produce a hot water supply that is approximately 60°C. The temperature of this water is significantly less than the current system which is at 82°C. As a result of the lower supply temperatures, the heating coils in all of the HVAC equipment will have to be replaced with larger coils (e.g. more heat exchange surface area with more fins or rows) in order to accommodate the lower grade of energy.
6. **Electrical Upgrades** – The heat pumps and pumps associated with the EFE system will require new electrical feeds and motor starters.

The EFE system does not take advantage of the available energy in the biogas and would be wasted in the flare stack. The analysis reflects this and penalizes the viability of this option. The City may want to study the EFE option further, in combination with a biogas utilization system such as co-generation.

The O&M costs associated with the EFE option have been factored into the analysis. Some of the O&M costs include:

1. Use of natural gas will be eliminated.
2. Electrical energy use will increase to power additional pumping for the effluent heating system and secondary loop systems. The heat pumps will require significant amounts of energy. Based on an estimated coefficient of performance of 3 (ratio of heat output to electrical output), the electrical requirement for the Heat Pumps will add approximately 482 kW of additional electrical load to the plant.
3. Regular cleaning of the effluent heat exchangers.
4. Heat pump maintenance, lubrication, etc.

Figure 5.9 shows the EFE schematic including the connection to the WWTP electrical grid, which is similar to the Solar-Photovoltaic or Wind Turbine cases. The recovered heat stream is connected into the existing boiler hot-water loop.

Figure 5.9: Energy from Effluent Schematic

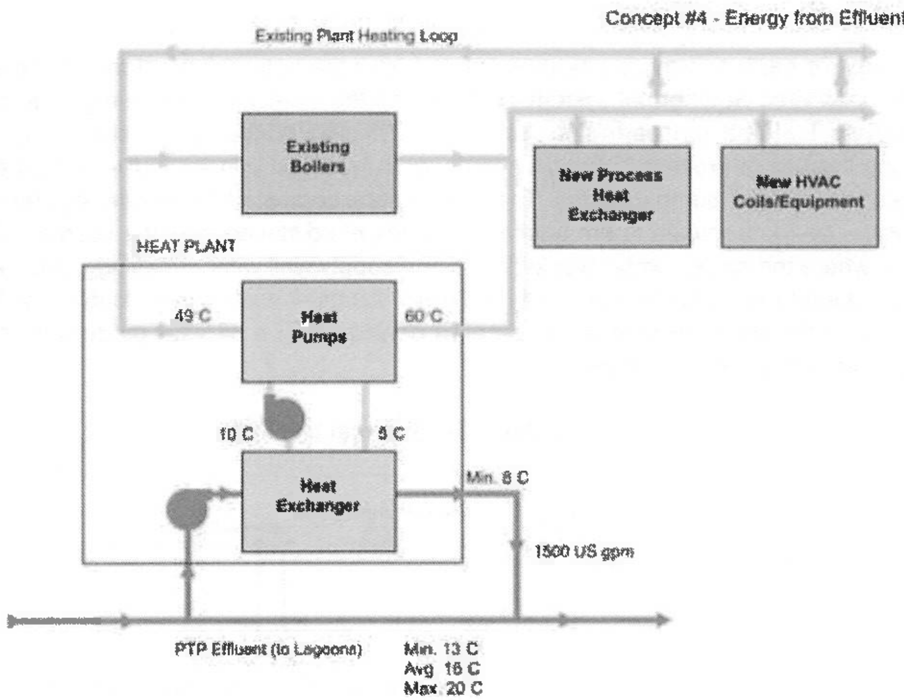
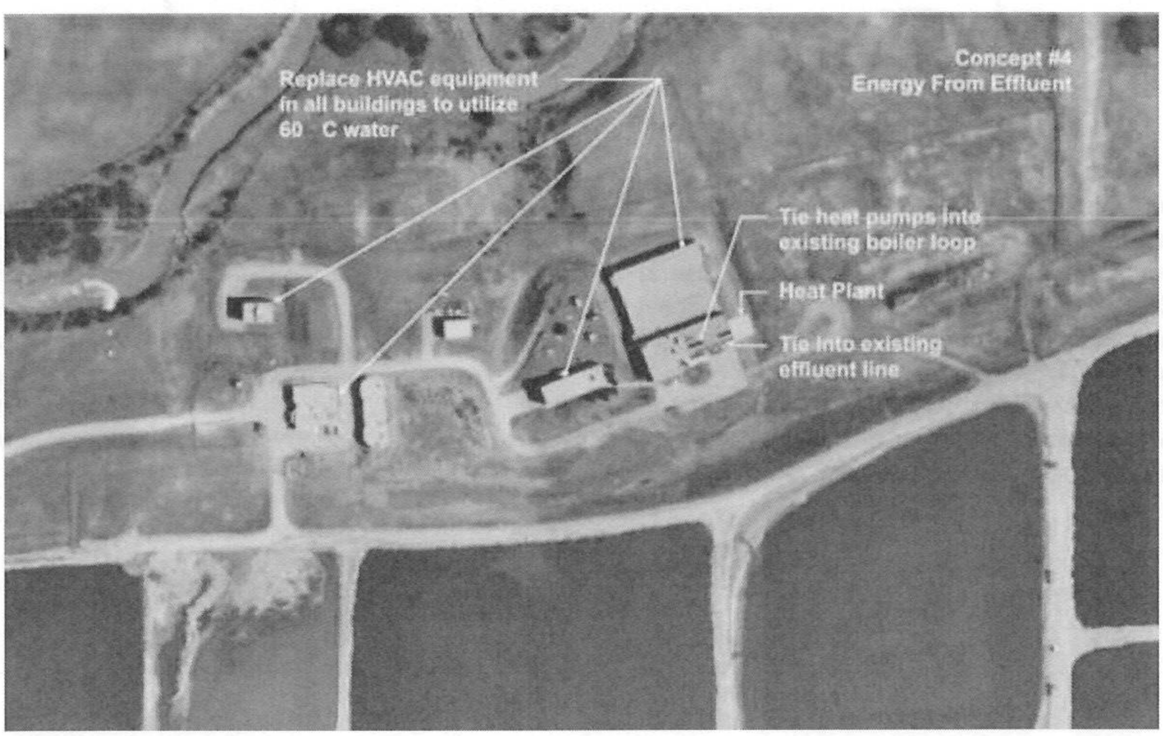


Figure 5.10: Energy from Effluent Layout

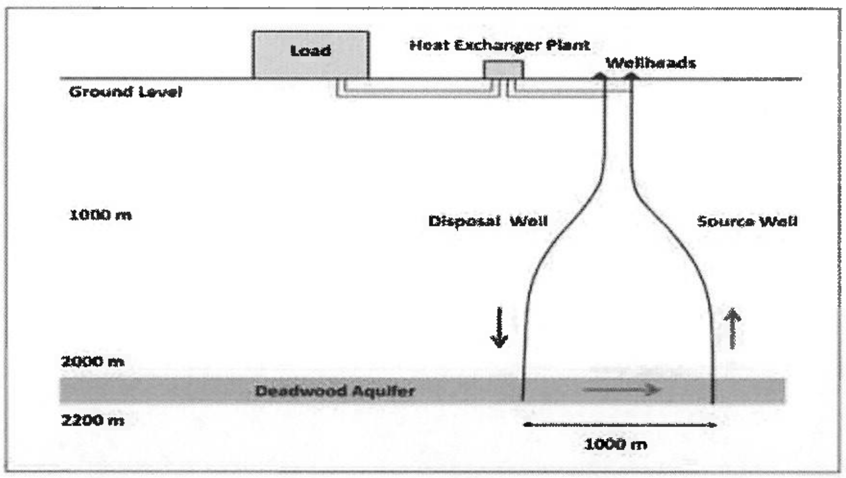


5.8 Deep Well Geothermal

5.8.1 Introduction

Geothermal energy, or earth energy, is energy extracted from the natural heat stored in the earth's core. The principle of Deep Well Geothermal systems is based on the increased heat energy that can be found at greater distances beneath the earth's surface. These higher temperatures allow direct use of the energy in building heating or process heating systems, or in heat pump loops that are more efficient than conventional geothermal heat pump systems. The high mineral content of the deeper aquifers require that the discharge water be reintroduced to the aquifer at a sufficient distance from the source well to prevent short circuiting – where the cooled water would flow to the supply well without having gained enough heat to maintain the required temperature. Even with sufficient distance, such a well doublet will have a finite life, but estimates for the southern Saskatchewan area consider that a 35 year production of 65°C water would be achievable with a 1 km separation.

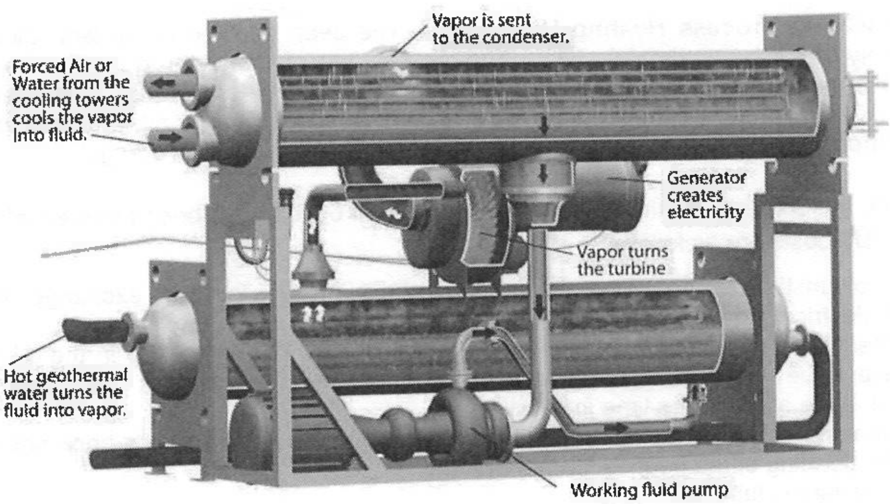
Figure 5.11: Deep Geothermal System



Source: Saskatchewan's Deep Geothermal Energy Potential: It's Application and Feasibility, 2009

Geothermal sources with temperatures greater than 180°C have been successfully used to drive steam turbines and produce electricity directly from the source or through a simple heat exchanger. Electrical production is also possible with lower temperature ground source water using the Organic Rankin Cycle (ORC) turbine. Instead of water used in a conventional steam turbine installation, the ORC uses selected working fluid, such as refrigerants or hydrocarbons, with an enough low boiling point so that they can be successfully evaporated with ground loop temperatures below that for normal steam turbine operation. The evaporated media is then supplied to a turbine, where it is allowed to expand, with an accompanying reduction in pressure, thus powering the turbine. The turbine is connected to an electrical generating device, which provides output power. Figure 5.12 shows a section through a typical ORC Unit.

Figure 5.12: Organic Rankin Cycle Electric Generation Unit



There has been dedicated research on the Deep Well Geothermal concept at the University of Regina, including drilling of one 2200 m deep test well. A major study by Helix Geological Consultants Ltd. (Regina) provided great detail regarding the situation in southern Saskatchewan, and indicated that the most favourable areas may be in the south-east corner of Saskatchewan.

The potential of the deep aquifers in the Regina area were confirmed in the Helix Geological Consultants Ltd. report. The output of the source, typically at 60°C, would be limited only by the size of the wells and the flow extracted and is reported to provide a consistent source of energy for 35 years. The technology to drill to several kilometres in depth is now relatively common and well understood in Saskatchewan due to recent oil exploration events. The use of directional drilling would provide the required minimum distance (approximately 1 km) between the supply (extraction) and return wells, to avoid cross-contamination and premature cooling of the supply water aquifer.

Two Deep Well Geothermal options (5a and 5b) were explored. Option 5a utilizes geothermal water as heat source for the plant and process heating, while Option 5b consists of using the deep well geothermal water to generate electricity using Organic Rankin Cycle (ORC) generation units.

5.8.2 Proposed System – Deep Well Geothermal (Option 5a)

Deep Well Geothermal Option 5a consists of the following components:

1. **Deep Geothermal Wells** – Two wells, a supply and disposal well will be drilled to a depth of approximately 2,200 m into the Deadwood Aquifer where the water temperature is approximately 58°C. The wellheads will be located close to each other just east of the Primary Treatment Plant (refer to Figure 5.14), and will be accessible for maintenance. The wells will be directionally drilled to provide a minimum 1,000 m distance between the intake and discharge to prevent thermal breakthrough in the aquifer. The wells will have standard 9 5/8" steel casing and the supply well will have a submersible pump, similar to those used in the oil industry, to draw the water from the aquifer and pump the water to the surface. The inefficiency of the submersible pump will be rejected into the water supply as heat, increasing the water temperature to about 61°C.
2. **Heat Plant Building** – A new Heat Plant Building will be required and constructed just east of the Primary Treatment Plant to house the heat exchange and pumping equipment. The Heat Plant Building will have lighting and heat to provide a suitable environment for maintenance.
3. **Geothermal Heat Exchange System** – A heat exchanger will extract the heat from the geothermal loop and inject it into the existing plant-wide heating system. The heat will be connected to the plant

heating loop near the boiler room. Pumps will be installed to overcome pipe and heat exchanger friction.

4. **Plant HVAC and Process Heating Upgrades** – The deep geothermal system will produce a hot water supply that is approximately 59°C. The temperature of this water is significantly less than the current system which is at 82°C. As a result of the lower supply temperatures the heating coils in all of the HVAC equipment will have to be replaced with larger coils (e.g. more heat exchange surface area with more fins or rows) in order to accommodate the lower grade of energy.

The O&M costs associated with the Deep Well Geothermal option have been factored into the analysis. Some of the O&M costs are as follows:

1. Electricity to run the geothermal well pump and the pumps in the heat exchange plant. This is a significant electrical load.
2. Replace the submersible pump once every 4 years. Based on experience in the oil industry these pumps have to be replaced on a regular basis due to wear and tear. It is also recommended to do well maintenance at the same time interval.
3. Regular cleaning of the heat exchangers. The Deadwood Aquifer water is a brine solution which will necessitate cleaning of the heat exchange system.
4. Pump maintenance, lubrication, etc.

Figure 5.13: Deep Well Geothermal Schematic

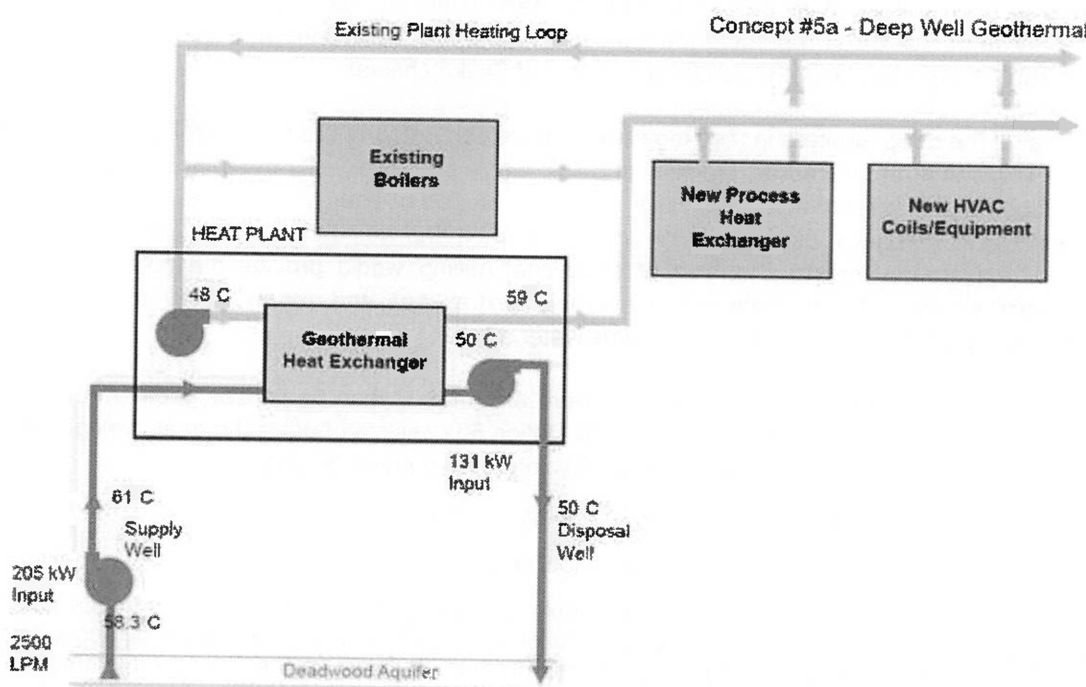
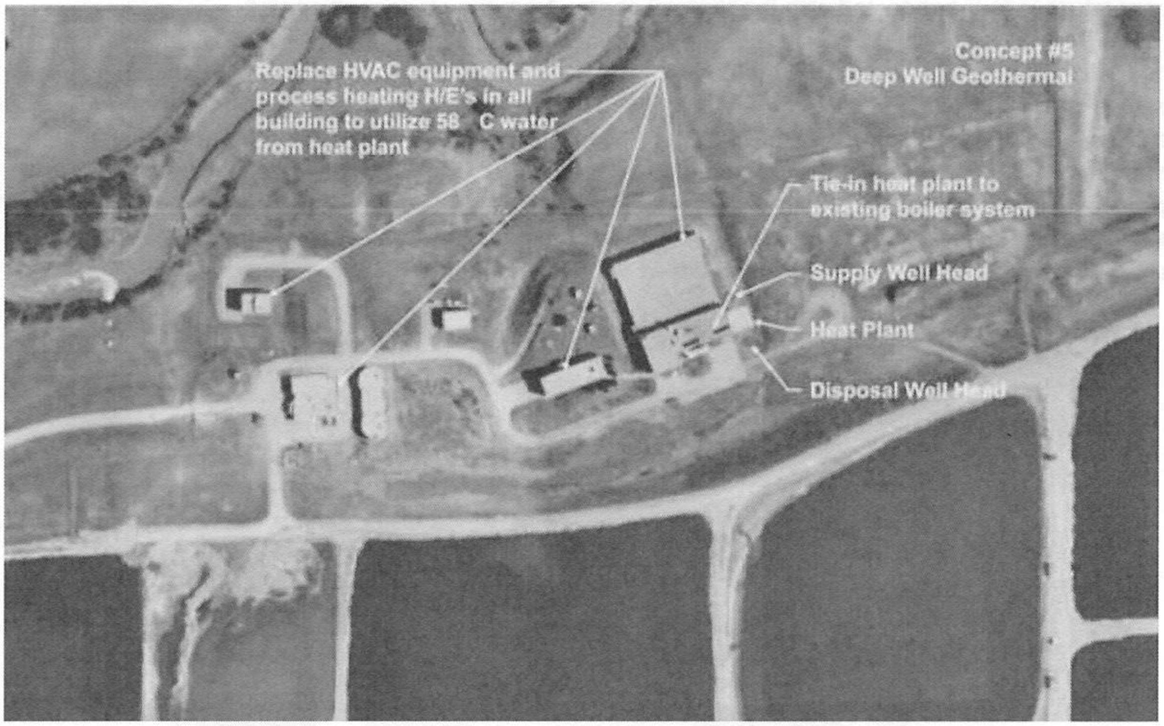


Figure 5.14: Deep Well Geothermal Layout



5.8.3 Proposed System – Deep Well Geothermal with ORC Electrical Generation (Option 5b)

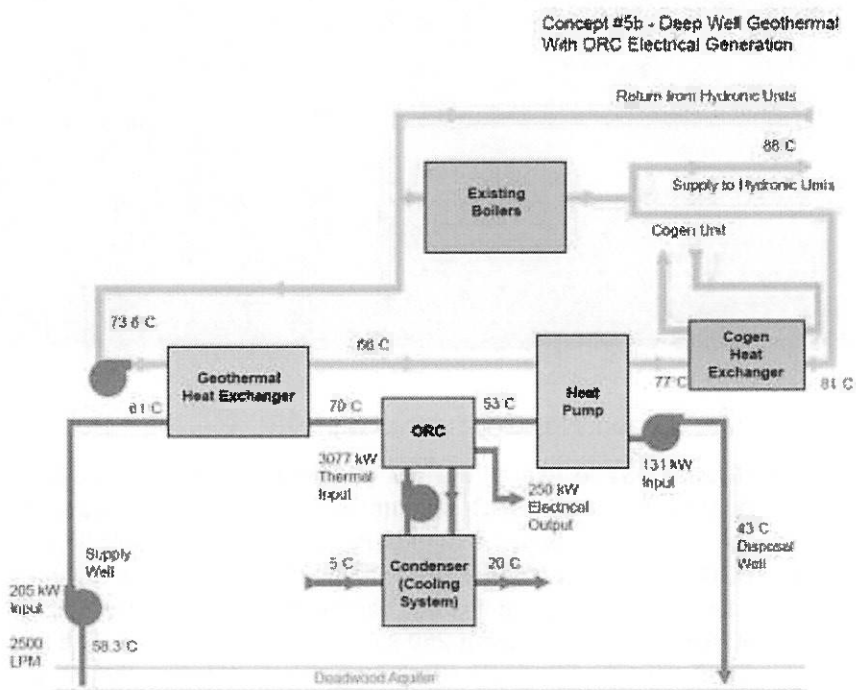
The initial concept investigated was to use all the hot geothermal water in an ORC unit for electrical generation; with the residual heat from the ORC evaporator discharge water used for plant and process heating. Unfortunately, the geothermal water temperature of 58.3°C available in the Regina area is insufficient to operate an ORC unit which requires a minimum 70°C water source; therefore, this concept was not explored further. It's worth noting that if water had been of sufficient temperature, a single ORC unit would have been only able to generate about 250 kW of continuous power. The low efficiency of the ORC (about 10% thermal efficiency) combined with the high cost of drilling the deep geothermal wells (over $5,000,000) and ORC equipment (approximately $350,000 for a 250 kW ORC generation unit) made the economics of this option unviable.

We also investigated a second option, similar to the first one, except it included a heating system (biogas boiler system) to raise the temperature of the geothermal water up the required temperature to operate the ORC unit. This option did not make economic sense, again due to the low thermal efficiency of the ORC unit and high cost of equipment. Further, it didn't make sense to use biogas or natural gas to create hot water (at say 80% efficiency), to raise the temperature of water to feed an ORC unit so that it could generate electricity at 10% efficiency; whereas the biogas and natural gas could be much more efficient in other options. As well, if the biogas was used for ORC water heating it would no longer be available for plant heating; therefore, additional natural gas would have to be purchased for plant and process heating.

The final version of Option 5b uses the existing boiler system to inject heat (via a heat exchanger) into the deep geothermal well water supply to raise the temperature of the water to 70°C. The ORC will generate 250 kW of continuous electricity, sufficient to drive the geothermal supply well pump. A heat pump (which requires additional electricity) is used to further extract energy from the geothermal water and inject it into the plant heating loop. Prior to biogas supplied to the existing heating system, the boiler loop water temperature is further boosted with the thermal energy from the co-generation unit.

The option which appeared the most promising was to combine the ORC generation unit with a co-generation system, to utilize the waste thermal heat from co-generation to heat the deep well geothermal water to raise it to a sufficient temperature to operate the ORC unit. The concept is shown schematically in Figure 5.15. Unfortunately, this option could not be made to work as a cooling water supply on the condenser water supply was required to be at 5°C, a very low temperature. To make the option work requires a chilled water supply that requires additional energy input, exceeding the net benefit. Therefore, this option was not analysed or developed further.

Figure 5.15: Deep Well Geothermal with ORC Electrical Generation



6. Energy from Bio-Solids

6.1 Energy Available from Biosolids

The primary purpose for harvesting energy from biosolids is to (a) convert the biosolids into a form that can be disposed of and (b) to reduce the mass of biosolids sent to disposal. The secondary purpose is to achieve energy self-reliance or even better, produce energy for other parts of the plant. Energy self-reliance can only be achieved by reducing consumption while increasing production. Biosolids processing is normally sized based on total and volatile solids loading.

6.1.1 Terminology – Total and Volatile Solids

Total Dried Solids
"Solids" is the suspended and/or dissolved matter in wastewater. "Total Solids" is the term applied to the residue left in a vessel after evaporation of a sample and its subsequent drying in an oven at a temperature between 103 to 105°C.

Fixed and Volatile Solids
In order to determine the "fixed solids", the sample (previously dried at 103 to 105ºC) is ignited to a constant weight at 550ºC. The method defines the solids lost during firing as "Volatile Solids" and those remaining in the vessel as "Fixed Solids". This is a "method defined" parameter in that the temperature defines what is "fixed" and what is "volatile" solids.

The difference between Volatile Solids as measured in the Water Industry to that measured in the Thermal Reduction Industry is that solid fuels are analyzed for volatile and total combustibles. Unlike Standard Method 2540 E, volatile solids are determined by heating the fuel in the absence of air at 725ºC. The difference between the two results is the fixed carbon. The fixed carbon is driven off in the combustibles test.

6.1.2 Higher Heating Value (HHV) of Biosolids

The HHV of a fuel is defined as the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C. In North America, the heating value is normally quoted as HHV unless noted otherwise. As noted above, volatile solids as measured in the water industry include fixed carbon while total combustibles in the power industry do not. The two are used interchangeably in the water industry because the fixed carbon is a small portion of the total solids. Biosolids is typically a mix of protein, carbohydrates, fats, fiber and ash. Analytical results, such as those shown below, are dependent on the method used to digest the sample. Therefore, we can compare only two samples that were analyzed using the same digestion method.

6.1.3 Value as a Fuel for Combustion

There is a tenuous link between the type of sludge and the fuel and substrate value. The data below was taken from a study of sludges at a large UK WWTP. The primary sludge, known to be a good substrate when compared with activated sludge, has a higher fraction of fat and fibre.

Table 6.1: Typical Characterization (using the Glacial Acetic Acid Method)

Sludge Component	Primary Sludge (%)	Activated Sludge (%)	Digested Sludge (%)
Protein	23.6	46.8	24.5
Fibre	15.4	0.2	3.8
Fat	19.4	2.5	3.4
Carbohydrates	17.9	31.6	31.7
Ash	23.7	18.9	36.6

The typical higher heating value used for biosolids is 10,000 BTU/lb (23 MJ/kg) of combustibles. This is equivalent to a low grade bituminous coal. This is twice the value of municipal solid waste. The fuel value of primary sludge is higher than that of digested sludge. For example, the thermal value of raw primary sludge combustibles may be as high as 32 MJ/kg while that of digested sludge is nearer to 20 MJ/kg. Typical values are shown below.

Table 6.2: Energy Value of Biosolids

Component	% Combustible	BTU/lb Dry Solids	BTU/lb Combustible	MJ/kg Combustible
Grease and Scum	88%	16,700	18,977	44
Primary Sludge	74%	10,300	13,918	32
Digested Sludge	60%	5,300	8,833	20

6.1.4 Value as a Substrate

The rule of thumb is that 1 kg of mixed volatile solids destroyed produces at best 1 m^3 of biogas (at a pressure of 101.325 kPa and at a temperature of 15°C). One cubic meter of biogas contains 22 MJ of energy. The maximum destruction of nitrifying activated sludge/primary sludge is about 40%. If we enhance the digestion process by pre-treating the sludge, then we can increase the destruction to between 60% and 70%. Therefore, the maximum energy we can recover in the digester 14 MJ/kg VS applied or 22 MJ/kg VS destroyed.

6.1.5 The Problem with Water

The key parameter that determines if a process is a net producer or consumer of energy is the water associated with biosolids.

Example 1: Mesophilic Anaerobic Digester – A mesophilic anaerobic digester operates at 35°C. If we assume the feed to the digester is at 15°C, the digester hydraulic retention time is 15 days, the digester loses 0.5°C per day and the co-generation engine running on biogas returns 33% of the biogas energy as heat to the digester, then at 3% solids, the plant will need to purchase natural gas to heat the digesters. However, at 6% dried solids, it does not. For this reason, most digesters are now fed at concentration above 6% dried solids.

Example 2: Incineration – The heat released by burning wastewater solids must be sufficient to raise the temperature of all substances entering from ambient levels to those of the exhaust and solids residue streams. This includes excess air (provided for combustion) and the water associated with the biosolids. For example, it takes almost 4.64 MJ/kg to vaporize water and raise the water vapour to exhaust temperatures. In other words it takes 1 kg of volatile solids to evaporate 5 kg of water.

For example, a raw sludge can be dewatered to 28% dried solids. The sludge is 73% volatile (the plant practices chemical phosphorus removal). The incinerator is autogenous (does not require auxiliary fuel once it has started up). A digested sludge dewaters to about 25% and the sludge is 57% volatile. In this case, the plant requires an additional 2.3 MJ/kg of biosolids processed. For this reason, incinerator plants usually burn raw sludge or enhanced digested sludge (that dewaters to above 30% dried solids). In many cases, the sludge is dewatered and dried prior to incineration.

6.1.6 Energy Recovery from Thermal Destruction of Biosolids

Thermal destruction occurs when heat is applied to biosolids. The end product will vary depending on the oxygen supply. For example, Advanced Thermal Oxidation or Incineration occurs when the oxygen supply is in excess of what is required to support the combustion process. The end product is heat and ash. This is complete decomposition of the organic matter in the biosolids. By limiting the oxygen supply and adjusting the temperature, the end product can be varied from ash to oils and tars to syngas.

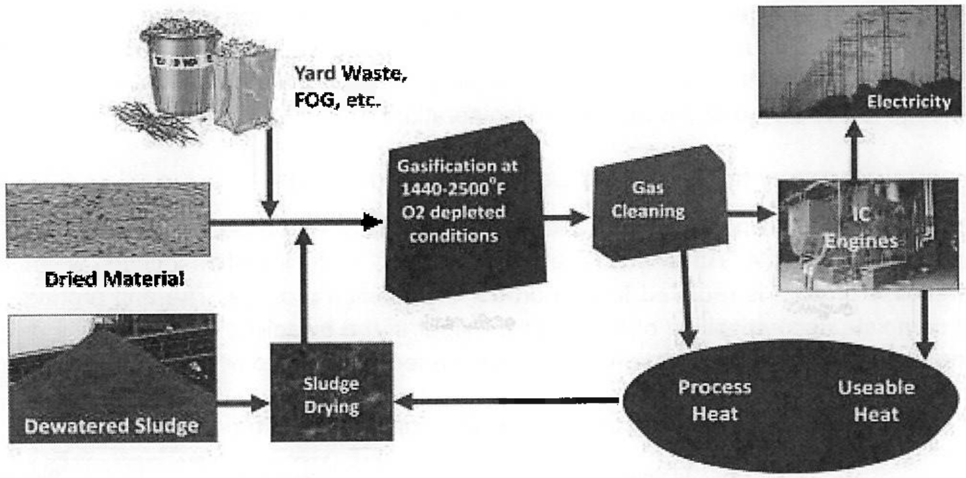
Table 6.3: Energy Recovery from Thermal Destruction of Biosolids

Description	Incineration (Combustion)	Gasification	Pyrolysis
Temperature (°C)	1,980	590-980	200-590
Oxygen Supplied	Excess	Partly Starved	None
End Product	CO_2, H_2O, Ash	CO, H_2, Ash	Oils, Tars
Energy Recovery	Heat to Produce Steam	Combustion of Syngas	Combustion of Oils, Tars

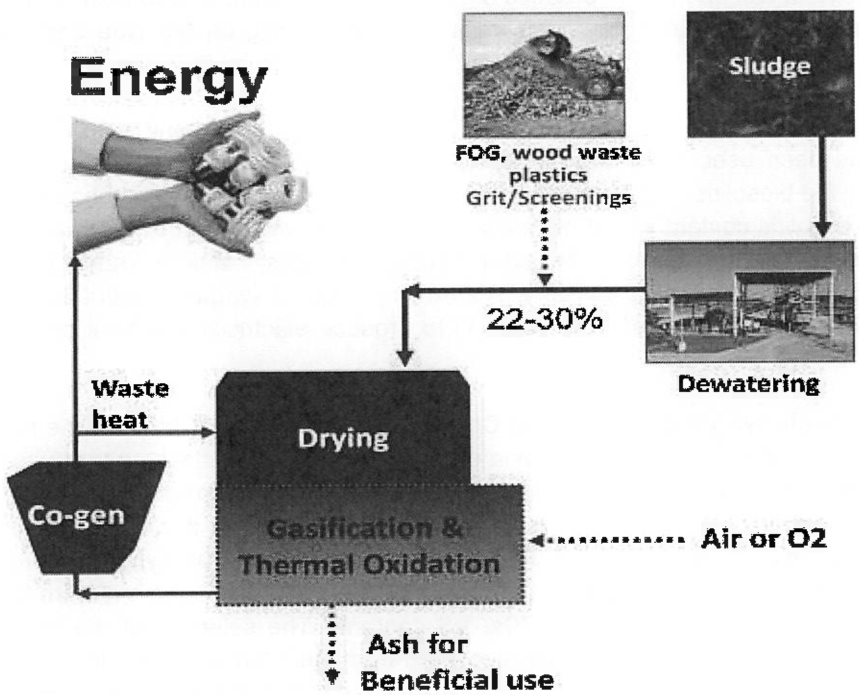
Incineration – Incinerators produce heat. Low grade heat can be used to heat buildings or digesters while high grade heat can be used to produce steam. Once the steam is produced, only 15 to 30% of the energy is converted into electricity by a steam turbine (depending on the type and size of the steam turbine).

Gasification – Gasification is an established process for converting organic waste to a fuel gas called syngas, and has been used since the 1800's to generate fuel gas from coal and other biomass. To effectively gasify the biosolids, most commercially available gasifiers require that the biosolids are dried to greater than 75% solids content. Dried biomass such as wood waste or straw can be added to the dried biosolids to increase gas production. The gas produced from gasification is known as syngas, which is primarily composed of CO, CO_2, H_2 and CH_4. The heating value of syngas is about 25% of that of biogas. The syngas can be used in one of two ways: (1) to produce electricity and heat or (2) to just produce heat.

Gasification through Syngas Cleaning and Co-generation – The syngas is cleaned and burned in an internal combustion engine to produce heat and electricity. Methods for cleaning the syngas are still being developed and tested. There is a full scale installation built by Kopf (Germany) at the WTE Facility at the Balingan WWTP. Nexterra has proposed a facility for Stamford, CT. At this stage, GE and Nexterra are developing gas cleaning technologies for Jenbacher engines running on syngas. From an energy and mass balance stand point, one can expect to obtain about ~ 1 MWe of electricity from 25 dtpd dried and undigested biosolids (~7500 BTU/lb and ~70% VS content). The selection of the drying technology is important for allowing use of this waste heat recovered from the internal combustion engines. This waste heat is not sufficient to remove water from the biosolids cake to the desired dryness and thus some other form of energy such as natural gas must be purchased.



Gasification through Syngas Thermal Oxidation and Co-generation – The second system for energy recovery from syngas does not require syngas cleaning and is accomplished by oxidizing the syngas generating high temperature (~9080°C) flue gas. The heat in this flue gas is used to dry the biosolids reducing amount of fossil fuel purchased for the drying step. The gasification plant Sanford, FL which has been in operation since May 2009 uses this mode of operation.



6.1.7 Alternatives to Internal Combustion Engines

For large facilities steam turbines can be used. However, for small to medium facilities, an ORC engine may be more suitable. The electrical efficiency is low; however, the heat in the flue gas can be recovered and used to dry the sludge. Some but not all dryer technologies can use the waste heat from the ORC engine.

7. Evaluation of Alternatives

7.1 Evaluation of Alternatives

7.1.1 General

Our analysis of each of the alternative energy sources is summarized in **Table 7.1** below. The comparative analysis quantifies viability of each alternative based on costs and benefits for each alternative presented here.

GHG reductions are significant for most of the alternatives. A GHG credit would improve the viability of Options 2a and 2b when considering a monetary value for the GHG reductions. The value we considered based on an application rate of $15/tonne represents an improvement in simple payback, NPV and IRR of about 4%.

Several important factors that are not addressed by our analysis are:

- Environmental and regulatory costs associated with any of the alternatives
- GHG reduction value

Table 7.1: Summary of Alternative Energy Options

	1a Solar Photovoltaic (1.9 MW)	1b Solar Photovoltaic (7 MW)	2a Wind Turbine (1.8 MW)	2b Wind Turbine (7 MW)	3 Biogas CHP (360 kW)	4 EFE (1.9 MW)	5a Deep Well Geothermal (1.9 MW)
Electrical Capacity (kW)	1,890	7,000	1,750	7,000	360	0	0
Heating Capacity (kW)	0	0	0	0	560	1935	1935
Capital Cost	$ 25,000,000	$ 90,700,000	$ 5,700,000	$21,400,000	$ 3,300,000	$ 4,500,000	$ 9,700,000
Annual Energy Saving	$ 221,000	$ 813,000	$ 258,000	$ 1,031,000	$ 223,000	$ 138,000	$ 155,000
Annual O&M Cost	$ 70,000	$ 212,500	$ 102,000	$ 351,000	$ 108,000	$ 51,500	$ 105,000
GHG Reduction (tonnes/yr)	2,550	9,395	2,976	11,904	2,466	-346	-148
GHG credit ($/yr)	$ 38,250	$ 140,925	$ 44,640	$ 178,560	$ 37,000	-$ 5,184	-$ 2,214
Simple Payback (years)	132	122	28.3	25	22	55	199
NPV	-$ 22,600,000	-$ 80,700,000	$ 1,050,000	$ 6,600,000	$ 2,100,000	-$ 4,400,000	-$ 7,000,000
IRR (%)	Negative	Negative	10.8	15.6	29.0	Negative	Negative

7.1.2 Solar-Photovoltaic – Options 1a & 1b

Both of the Solar-Photovoltaic options were found to have very high initial capital costs as well as significant O&M costs through their lifecycle. The energy savings are substantial; however, not enough to offset costs. The best simple payback of 132 years for Option 1b is too high. Both Option 1a and 1b cannot be considered as feasible.

New technology panels are being developed that claim a lower initial cost than the panels we analyzed. These newer panels also have a reduced efficiency and/or output capability than the alternative we considered, and would not improve the feasibility of this option enough.

7.1.3 Wind Turbine – Options 2a & 2b

Both of these wind options were found to have very high initial capital costs as well as significant O&M costs through their lifecycle. The simple payback (approximately 25 years) in both cases is much closer to the target maximum (20 years). The payback of more than 24 years makes it unfeasible for this scale of wind operation based on the City's criteria of 7 to 20 years.

Either wind option could be considered more viable if other independent (government) sources of funding were provided to subsidize the capital and/or operating costs. The NPV and IRR are both showing a good positive return on initial investment after 20 years, making an excellent case for the wind option alternatives evaluated.

7.1.4 Biogas CHP – Option 3

The Co-generation option presents a simple payback of 22 years and a positive NPV and IRR making it unfeasible. The WWTP is already consuming a reasonable amount of the biogas generated and this option redirects all of this gas to generate electricity, resulting in the need to purchase additional natural gas. This option could be feasible when used in conjunction with another technology such as EFE.

7.1.5 Energy from Effluent – Option 4

This alternative does not utilize any of the biogas resulting in 100% of the biogas being flared off. The value of the biogas being flared off is estimated at $431,000 (based on 2008 biogas data and $0.35/m^3$ for natural gas). This option presents a 55 year simple payback and negative NPV and IRR making it unfeasible. Consideration for biogas utilization in conjunction with EFE might make this slightly more attractive.

7.1.6 Deep Well Geothermal – Option 5a

This alternative is also penalized because the biogas is not utilized, and will be 100% flared. In other words, $431,000 of available energy is wasted. Consideration for biogas utilization in conjunction with EFE might make this slightly more attractive. This option presents a 199 year simple payback and returns a negative NPV and IRR, primarily due to the very high initial cost and operating and high maintenance costs.

7.1.7 Deep Well Geothermal w. Electricity via ORC – Options 5b

The efficiency of converting geothermal thermal energy to electricity is very low (in the order of 10% efficiency). Combined with high initial cost of ORC equipment, it is unlikely to prove economically viable on this scale of project. This option was not evaluated further due to technical hurdles:

- ORC required a geothermal source water which is a minimum of 70°C. The Deadwood Aquifer at Regina produces water which is 58.3°C; therefore, not viable as a direct electrical generator.
- Our analysis developed a configuration in combination with co-generation where the boiler system would boost the temperature of the geothermal water via a heat pump system. However, we were unable to obtain a source of cooling water that would work with this configuration and this option had to be abandoned as well.

7.1.8 Biosolids as Fuel

The use of biosolids as a potential fuel to fire a turbine and generator to produce electricity may be possible and requires further study. The most significant challenge is reducing the water content in the biosolids to make it a viable fuel.

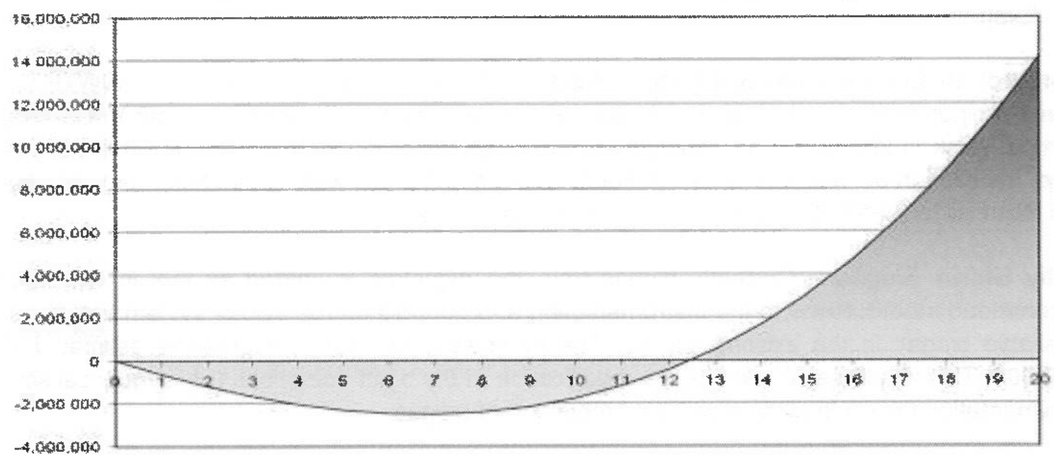
8. Conclusions and Recommendations

8.1 General

None of the alternatives analyzed fit the City's criteria for simple payback of 7 years up to 20 years on the outside. Of the alternatives studied the wind turbines with 7 MW of capacity (Option 2b) and the Biogas CHP Option 3 offer the best ROI. This wind option comes with a larger upfront capital investment of $21.4M and represents the alternative with the largest GHG reduction at 11,900 tonnes/yr.

The Biogas CHP Option 3 analysis presents a very good investment opportunity with a NPV of almost $2,100,000 and an IRR of 29.0% over a 20 year lifecycle. Both wind turbine options do present a positive long-term business opportunity when considered over the 20 year lifecycle. Wind Turbine Option 2b analysis results in the more favourable of the two with a NPV of $6,600,000 and an IRR of 15.6% (see Figure 8.1). The significant initial capital investment and potential regulatory issues make this a less desirable option for the City without a more detailed review.

Figure 8.1: 7 MW Wind Turbine Cash Flow (Option 2b)



Our review of the base case concludes that the do nothing alternative is also not acceptable given the potential for electricity rate increases. Based on our analysis of the alternatives and our review of the City's WWTP the best value for capital investment that will reduce dependence on utility supplied electricity and reduce GHG are:

1) **Biogas CHP (Option 3)** – Proceed with feasibility and preliminary engineering to implement this option. The feasibility study should include a review of possible synergies between biogas and the proposed new WWTP development.

2) **7 MW Wind Turbine (Option 2b)** – The 7 MW wind turbine provided the best long-term investment with significant payback and should be studied further.

3) **1.8 MW Wind Turbine (Option 2a)** – Although this option is not as attractive as the 7 MW option it is still a favourable long-term investment at a reduced capital cost.

8.2 Other Considerations

In preparing this report, additional considerations or recommendations were identified as follows:

1) **Reduce Electrical Load in the Future Plant Upgrade** – The City's WWTP is a high consumer of electricity per ML treated when compared to other WWTP's. This is primarily due to the type of treatment processes currently used (e.g. aerated lagoons, plant hydraulics). The City should reduce electrical base load where possible. The best opportunity is in the future WWTP expansion. This should include consideration of more efficient wastewater treatment processes and efficiency improvements to reduce electrical and natural gas loads.

2) **Integration of Alternative Energies in the Future Plant Upgrades** – With the planned expansion at the WWTP consideration should be given to study synergies between alterative energy sources and the new WWTP development including:
   - Examine the potential use of thermal energy from deep geothermal or EFE to:
     - Reduce capital costs of future expansion through pre-heat of influent stream to improve plant performance.
     - Utilize excess thermal heat as revenue potential to other business developments (i.e. warehouse development to the south).
   - Examine co-generation in combination with EFE.
   - Examine the use of biosolids as a fuel.

3) **Conduct an Energy Audit of Existing Plant** – Carry out an energy audit at the WWTP to identify areas for potential electrical load reduction. For example, opportunities to retrofit VFDs on process pumps, peak load shaving and adjustment of power factor could further reduce the electrical base load. Installation of Heat Recovery Ventilation Systems in areas with high outdoor air ventilation loads (as required by NFPA 820) could reduce natural gas loads.

4) **Fully Utilize Biogas** – Currently biogas from the digesters is utilized as fuel in the boilers. We recommend modifications to the instrumentation and controls on the biogas system to fully utilize the available biogas in the existing boilers. The potential cost for this upgrade is estimated at about $80,000. This would be coupled with a modification of the plant operations (i.e. sequential scraping of sedimentation tanks) to allow a uniform production of biogas.

   The instrumentation and control upgrades could potentially reduce the amount of biogas being flared from the current 47% to an estimated 14% of total. This represents an annual reduction in natural gas consumption at the WWTP of 636,000 m^3 or an equivalent of $126,200/year based on biogas containing 62% CH_4. The simple payback in this scenario is less than one year.

   The potential upgrades required for this scenario require further investigation but could include:
   - Pressure controller/instrumentation to allow automatic switchover from raw gas to natural gas on the boilers.
   - Upgraded instrumentation/control from improved control of air/fuel ratios on the boilers.

5) **Biogas Treatment** – Evaluate a gas treatment system for the existing boilers. This investment could reduce or eliminate the current boiler maintenance of $55,000 per year, which is currently the result of corrosion damage caused by running untreated biogas in the boilers (e.g. high H_2S, siloxanes, and moisture content). Based on a gas treatment system roughly estimated at $1M, the simple payback would be 18 years. However, the biogas treatment system would require additional maintenance (such as media replacement) which would offset the savings in maintenance. This concept would require additional review.

9. List of Appendices

9.1 *RETScreen* Definitions

9.2 *RETScreen* Analysis

9.3 Supplier Data and Information

9.4 WWTP 2008 Electric and Natural Gas Utility Bills Summary

9.5 Future Cost of Energy in Saskatchewan

9.6 Biosolids Article

Appendix 9.1

RETScreen Definitions