Criteria for Allocating Resources among Competing Renewable Energy Technologies:

What are the GHG Emissions Reductions Associated with Photovoltaic Projects in Ontario?

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SUMMARY

The Regional Municipality of Peel, taking a leadership role in addressing climate change, is attempting to establish how best to allocate its efforts and resources among competing renewable energy technologies, particularly photovoltaic (PV) and solar hot water systems. One obvious choice of criterion is the greenhouse gas (GHG) emissions reductions that each engenders. This is difficult to establish in the case of PV, however.

This document begins by providing background information on the functioning of the electrical power system, and then surveys existing methodologies for determining the GHG emissions reductions of renewable energy projects. It is concluded that emissions reductions should not be based on the average emissions of all generators, but rather on the emissions of those generators whose output will be increased or decreased in response to an increment or decrement of demand—i.e., those generators that are on the margin.

Two studies have attempted to identify the type of generators on the margin in Ontario. The first, done for Environment Canada's PERRL initiative, predicted that over 2004 to 2007, the margin would be nearly exclusively coal during the summer and imports during the winter, with a mix of these two in the seasons in between. Examining hourly generator data from 2004, a second study, by Gil and Joos, concluded that gas would be on the margin around 25% of the time. Indeed, more recent data show gas being at least partly at the margin, especially when total market demand exceeds 19 GW.

It appears that these studies are irrelevant, however. The Ontario Emissions Trading Code caps NO_x emissions in the electricity sector; all coal and gas generators must have tradable allowances for the NO_x emissions of their output. It is effectively this NO_x cap that determines the mix of coal and gas generation employed over the course of the year (otherwise cheap coal would be used in place of gas, which has lower emissions). Consequently, the output of a PV project that displaces electricity produced by coal plants at a given point in time will not offset coal in the long run: the reduction will mean more of the allowance is available for increased coal generation at a later point in time.

PV generation offsets coal if and only if the PV generator obtains (and does not sell) a NO_x allowance made available under a conservation and renewables set aside. In all other cases, emissions reductions are much lower—as low as 20% those of coal, depending on imports and exports. With the NO_x cap, coal generation may actually *increase* due to PV.

PV projects under the Standard Offer cannot apply for a set-aside allowance, since this right resides with the OPA, the purchaser of the electricity. The OPA has indicated that it will not obtain NO_x allowances for the renewable electricity it purchases.

Based on this, the cost of GHG emissions reductions is around \$1,150 per tonne of CO_2 equivalent for a PV project with NO_x allowance, \$650/tCO_2 for PV under the Standard Offer, and \$400/tCO_2 for domestic solar hot water. It should be cautioned, however, that other criteria may be equally important when choosing among competing renewables.

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Introduction

The Regional Municipality of Peel, taking a leadership role in addressing climate change, is attempting to establish how best to allocate its efforts and resources among competing renewable energy technologies. The Regional Municipality has a budget for renewable energy projects, and wishes to establish some guidelines for how to prioritize potential projects.

One obvious choice of criterion for allocating resources among competing renewable energy technologies is the amount of greenhouse gas emissions reductions that each engenders. Greenhouse gases (GHGs) are recognized as contributing significantly to global climate change, which is expected to cause large, costly disruptions to societies, economies, and ecosystems across the planet over the next several hundred years. To minimize these disruptions, worldwide emissions of GHGs must decline.

Human activity affects GHG emissions in various ways. Dominant among these is the combustion of fossil fuels. Carbon dioxide (CO_2), though not a particularly potent GHG, is emitted in large quantities in combustion processes. Methane (CH_4) and nitrous oxide (N_2O) are more potent GHGs that are products of combustion, but are emitted in much lower quantities. The greenhouse warming effect of methane, nitrous oxide, and other gases are commonly expressed in terms of their equivalent emissions of CO_2.

Worldwide, a major source of GHG emissions is fossil fuel combusted for the purpose of generating electricity. The amount of GHG emissions per unit of electrical energy produced depends on the type of fuel used to generate the unit of electricity, the way it is combusted, and the efficiency of the process for converting the fuel's energy into electricity. Ignoring the GHG emissions associated with manufacturing generation equipment and processing and transporting fuels, the GHG emissions associated with electricity production are approximately 1.0 tonne of carbon dioxide (and its equivalent in other GHGs) per MWh (tCO_2/MWh) for coal generation, 0.5 tCO_2/MWh for natural gas, and 0.9 tCO_2/MWh for bunker oil or diesel; nuclear, hydro-electric, solar, wind, and sustainable biomass generation generate no significant emissions during operation.

In Ontario, electricity is generated with a mix of nuclear, hydro, coal, gas, oil, wood waste, and wind power, with the first four being of primary importance. Electricity is also imported and exported to adjacent areas.

Renewable energy technologies such as photovoltaics (PV), wind, and solar thermal are seen as ways to avoid the negative impacts associated with conventional generation technologies (e.g., GHGs and smog from coal, oil, and gas). With global climate change looming as one of the major challenges ever to face humanity, an obvious question, and possible criterion for selecting among these renewable energy technologies, is "how much are GHG emissions reduced by projects using these technologies?"

In the Region of Peel, natural gas-fired hot water heaters are typical. Thus, it is relatively easy to determine the GHG emissions reductions associated with solar hot water heating in the Region—they are the emissions associated with the reductions in natural gas consumption.

A similar determination for photovoltaics or wind is more complicated. A unit of electricity produced by PV or wind will displace a unit of electricity otherwise generated by one or a mix of nuclear, coal, oil, gas, wind, and hydro electricity. Which of these fuels, or which of mix of these fuels, will actually be displaced? Depending on the answer, emissions reductions associated with wind or PV can range from 0 to 1 tCO_2/MWh. Since the Regional Municipality of Peel is unlikely to pursue major wind projects, it is particularly interested in the case of photovoltaic systems, so that PV technology can be compared with solar hot water technology.

The Functioning of A Power System

The generators available to a power system have different characteristics. Some, like nuclear plants, are expensive to build but cheap to operate; others, like gas turbines, are relatively inexpensive to construct but dear in terms of fuel. They also vary in how well they respond to changes in their loading (the output of a hydro plant can adjust very rapidly, a coal plant less quickly, and a nuclear plant only very slowly) and how long they take to bring on-line (a gas or hydro turbine can be turned on and off in less than an hour, whereas a steam plant fired with coal or oil will take four to eight hours and a nuclear plant may take several days) [Wildi, 1991].

As the total electrical load on the power system changes over the course of the day, the week, and the season, the mix of generators used to meet the load varies. There will be a level below which the load will never fall—this might be the load level during early morning on a spring or autumn weekend. This is typically called the "baseload", although in Ontario the term is often used to refer to the load level that is exceeded 70% of the time [Ontario Power Authority, 2007]. There will also be a small number of hours each year when the total load is very high. The electricity supplied at these high demand levels is the peak load. Between these extremes, the total electrical load varies smoothly over a range known as intermediate load. This is described in a load duration curve, shown in Figure 1.

In a regulated market where a single utility owns all the generators, the utility dictates how demand is met via unit commitment and economic dispatch. Unit commitment is the day-ahead or hour-ahead decision of which generators to use to meet the forecast demand; the forecast is based on a model of how electricity demand responds to inputs such as day of the week, day of the year, exterior air temperature, and current demand.

The utility will typically first commit its units having the lowest operating costs, and as demand rises, add units in order of increasing operating costs. Economic dispatch is the choice of the level at which to operate each of the plants; overall costs are minimized when, for every plant, the additional cost of an increment of output is the same [Wood and Wollenberg, 1996].

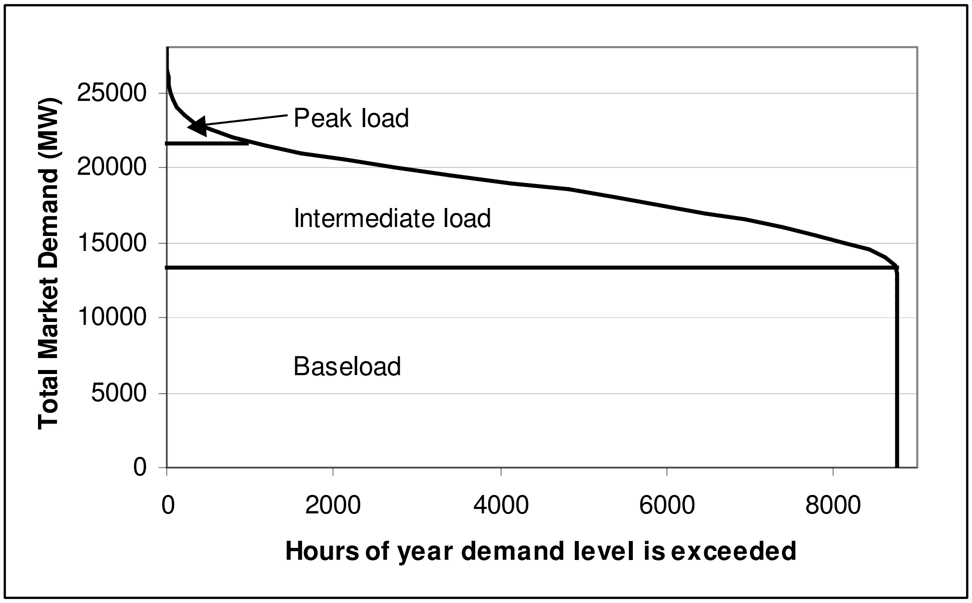

Figure 1. Load Duration Curve based on Total Market Demand for Ontario from August 25, 2005 through August 24, 2007

There are constraints that influence unit commitment and dispatch, however: the mix must include enough generation capable of responding to rapid changes in load ("load following"), must not rely so heavily on any single plant such that the remaining units would be unable to compensate for its failure, and must not expect steam units to be turned on and off overly frequently. Many of these constraints reflect the exigencies of maintaining a stable, reliable electrical system, which trump the criterion of minimizing cost [Wood and Wollenberg, 1996].

In restructured markets such as Ontario, generators are owned by different entities, and such a command and control approach is not possible. Rather, unit commitment occurs through some combination of bilateral contracts between individual generators and consumers and a power pool that serves as a clearinghouse for power bought and sold. An independent scheduling coordinator (in case of Ontario, the Independent Electric System Operator, or IESO) solicits and schedules generation through some form of auction, calling upon the lowest bidders to generate during each hour, where the auction could include day-ahead and hour-ahead markets [von Meier, 2006]. The IESO is also responsible for maintaining the stability of the grid, and may determine the level at which individual generators operate.

The stacking of increasingly expensive generating resources to meet increasing electric demand points to the importance of the generator "at the margin"—for a given point along the load duration curve, the generator that will be used to meet an additional unit of electric demand. In most cases, this will be equivalent to the generating unit that will be curtailed in response to a decrement in demand.

Methodologies for Determining GHG Emissions Reductions

A number of different approaches have been used to determine GHG emissions reductions associated with PV generation. These vary widely in methodology, assumptions, and results. This in large measure reflects the difficulty of answering the question. For while the electricity grid is conceptually a simple system—the combined electricity requirements of a number of interconnected, distributed loads (plus losses in transmission and distribution) are perfectly matched at all times by the combined output of a collection of interconnected generators—the multitude of generators and loads make it a complex system in practice. Predicting how it will react to a unit of PV production (which can be viewed as an equivalent decrement in electric demand) is not trivial.

Nevertheless, it is important to recognize that there is a single correct answer, no matter how difficult it may be to ascertain. The constraint that total generation must at all times precisely equal total demand dictates that a unit of PV production necessitates a reduction in the output of some other plant or mix of plants; the need to make simplifying assumptions in the analysis, and the difficulty of directly observing the operation of the system in order to verify one's answer, does not mean that all sets of assumptions are equally justified.

Several documents provide good surveys of methods for estimating GHG emissions reductions (e.g., [Keith et al., 2003], [Kartha et al., 2003]). The process consists of two parts, 1) quantifying the electricity generated by the proposed project (i.e., the PV project), and 2) predicting the difference in the operation and evolution of the regional power system with the proposed project versus under a baseline scenario (i.e., in the absence of the proposed project).

The first part of this process is relatively straightforward; in the Region of Peel, for instance, a properly designed and installed grid-tied PV system of 1 kWp capacity can be expected to generate roughly 1.2 MWh of electricity. The majority of this will be generated between 9 AM and 3 PM standard time, and the monthly distribution of generation can be estimated fairly accurately with a simple tool such as RETScreen. If hourly solar irradiance and temperature data is available, e.g., for Pearson Airport, the hourly output of a proposed PV plant can also be estimated with a little additional work.

The second part of the process is where the difficulty arises. Broadly speaking, the problem requires two types of predictions: first, how the proposed system will affect the operation of the existing power system, and second, how the building of the proposed system will affect the addition and retirement of generators in the future, and therefore future emissions.

Estimates will be more accurate if they are based on what is happening at the margin, rather than on average. For example, if a unit of electricity generated by PV were fed onto the grid, it would be likely that the output of the most recently added (and typically most expensive to operate) unit of generation would be curtailed, rather than a ramping down of all generators, including those providing low-cost baseload electricity. The emissions displaced by the PV project at a given point in time are those of the generator at the margin at the electricity demand level at that instant.

For this reason, the estimation of baseline emissions in the existing system focuses on the “operating margin”. The estimate of how the proposed project affects the addition and retirement of generating assets is explicitly related to the “build margin”—the next unit of capacity to be added or removed.

It should be noted that in most efforts to determine the baseline, the ultimate goal is to justify a claim to some form of credit for an emissions reduction, such that the project proponents have a vested interest in inflating the baseline. Because of this, accuracy is not the only yardstick applied to methodologies for estimating the baseline. The standard methodologies have been developed to provide “reliable, transparent and conservative baselines” [Kartha et al., 2003]. Implicit in the notion that baseline estimates should be conservative is a preference for low-balling baseline emissions as opposed to picking the best, unbiased estimate with an interval of uncertainty around it; for crafting policy in the Region of Peel, accuracy is preferable to conservatism.

In the determination of the operating margin, several approaches have emerged:

1) Dispatch model simulation: A sophisticated model that simulates all the generators and the interconnections on the power system (and possibly neighbouring power systems whence imports might originate and where exports might flow) estimates the effect of the proposed project on an hour by hour basis throughout the year. The model inputs include operating costs for each of the generators, transmission capabilities, water resources for hydro projects, etc. In a regulated market with a single utility, it may offer the most accurate estimate of the impact of the proposed project, since the utility should be able to provide estimates of the input values for the model; rarely do they make this dispatch model and data available to those outside the utility, however. In a restructured market, the input data for the model may reside with the various entities owning generators, making it more difficult to collect. Dispatch model simulation can be very expensive (a single study is unlikely to cost less than $10,000, and most modelling studies cost considerably more than this [Keith et al., 2003]), and is not very transparent.
2) Dispatch decrement (or data) analysis: Analysis of historical data showing the mix of resources used to meet hourly demand gives an indication of how the electrical power system responds to increments and decrements of demand at all points along the load demand curve. In combination with knowledge of the emissions factors of the different generators, this can be used to generate a marginal emissions curve, which indicates the emissions offset by a unit of electricity produced at any demand level. To the extent that current operating

conditions reflect historical operating conditions, it is an accurate method with the advantages of transparency and moderate cost. Obviously, it is applicable only where historical unit commitment data are available from the utility or system operator.

3) Simple operating margin: In this simplified method, marginal emissions at any demand level are assumed to be equal to the average emissions (weighted by the electrical energy produced by each generator) of all the generators that are not “low-cost/must run” (i.e., generators such as nuclear, hydro, wind, or cogeneration plants that supply base load power or are otherwise unlikely to be curtailed in response to a decrement in demand). In a modified version of this approach, the emissions factor of the low-cost/must run generators are included in the marginal emissions by a weighting related to the fraction of the year that they are on the margin [UNFCCC, 2006], [Sharma, 2006]; this makes this method more applicable to grids, such as Ontario’s, where low-cost/must run generators supply a majority of the electricity. The method sacrifices some accuracy for the sake of transparency and ease of application.
4) Average emissions: In this approach, marginal emissions are assumed to be equal to the average emissions factors for the region. Accuracy may be very poor; on a grid such as Ontario’s, which makes extensive use of nuclear and hydro, marginal emissions factors will be grossly underestimated. Nevertheless, the approach is widely used because it is easy to apply, quick, inexpensive, and easily understood.

For renewable energy projects under the CDM (Clean Development Mechanism—the Kyoto Protocol mechanism for tradable emissions reductions credits resulting from projects in developing countries), guidelines suggest that where possible, dispatch data analysis should be used, with simple operating margin and average emissions requiring justification for their use [UNFCCC, 2006].

For an analysis of project impacts on emissions in the near term, the use of the operating margin makes sense. In the longer term, beyond roughly 3 to 5 years, the effects of the project on the build margin become germane. With power projects in general, the addition of generating capacity has several effects:

1) It increases electricity supply and reduces market prices, making market entry less attractive to potential entrants [Keith et al., 2003]. Typically this delays the arrival of new capacity, and not just in the next building cycle, but in all subsequent building cycles until the retirement of the project under consideration. This effect is considered to exist even for very small power projects that would not normally enter the planning process, because it affects the price signals guiding investors [Kartha et al., 2003].
2) It speeds the retirement of the plants most costly to operate, by increasing supply, reducing cost of electricity, and making them less attractive.

Under CDM projects, the operating margin is used for the near term and the build margin explicitly informs the long-term estimate of the emissions reductions. The build margin is estimated, for these projects, based on the most recent power projects added to the grid. A project might be broken up into three, seven-year periods. In the first period, the operating margin emissions estimate and the build margin emissions estimate are weighted equally (with one exception—discussed below). In the second and third seven-year periods, the build margin is used exclusively [Kartha et al., 2003]. For example, if dispatch data indicated that a proposed project would offset coal in the near term, and the most recently added power plants were natural gas turbines, then for the first seven-year period, the effective emissions reduction factor would be the average of the coal and gas emissions factors. In the second seven-year period, the emissions reduction factor would be recalculated based solely on the most recent capacity additions at the outset of the period.

The explicit inclusion of the build margin is problematic for wind and solar electricity projects, which are inherently intermittent and cannot be dispatched on demand. Planners are reluctant to accord them much value for their capacity, because there is no guarantee that they will be producing significant quantities of electricity at peak generation times. Solar fares a bit better than wind (which has been estimated to have a 17% capacity factor on the hot, still-air days when the Ontario grid peaks), since peaks in electricity usage on power systems such as Ontario's are closely related to hot, sunny days of summer. The correlation is not perfect, however, because peak electric demand occurs in the afternoon and early evening, when solar generation has already declined [Ross, 1999].

It is also questionable how accurate it is to equate the emissions factor of a PV project to that of a dispatchable generator, the construction of which it delayed. For example, consider a power system with nuclear base load, coal intermediate load, and gas peak load that is having difficulty meeting its summer peaks. The only capacity additions for the power system might be gas turbines, so this would be the build margin; in the long term, the PV project is considered to offset gas. In reality, in the long-term the PV project would offset a mix of gas (at peak load times) and coal (at other times).

This is recognized in the CDM methodology, which states that while the operating margin and build margin are to be weighted equally in general, for solar and wind projects the operating margin is given a 75% weighting and the build margin is given a 25% weighting [UNFCCC, 2006].

The CDM applies to developing countries, whereas in Canada there is no emissions trading scheme and therefore no prescribed methodology for estimating emissions reductions factors. Nevertheless, it serves as a blueprint for efforts in Canada and in other developed nations. For example, the International Emissions Trading Association (IETA) relies on the UNFCCC methodologies. Similarly, Canadian vendors of carbon offsets increasingly attempt to satisfy the requirements of the "Gold Standard", a series of best practices that is based on the UNFCCC methodologies [VREC, 2007], [WWF, 2007], [BASE, 2007].

Not being bound to the UNFCCC methodology, an analyst interested in the most accurate estimate rather than complying with a transparent methodology might prefer to forecast which types of generation are going to be added in the future, or even which types of projects are likely to be delayed by the proposed project, rather than rely on past capacity additions. The analyst might also emphasize the operating margin, even in the long run.

Within Canada, a document that may be useful is the CSA/ISO Standard 14064. This was not purchased in the course of this study. It is likely to contain guidance on measuring and reporting emissions and emissions reductions, rather than methodologies for estimating the impacts of proposed projects.

Existing Estimates of GHG Emissions Reductions for New Renewables in Ontario

There are surprisingly few existing, publicly available studies of GHG emissions reductions associated with solar and wind projects in Ontario. Estimates cited in the literature and associated with past federal government programs have often made use of average system emissions factors [Keith et al., 2003]. These will not be discussed here, since the results will be inaccurate for Ontario.

One study that did conduct an analysis of the generation at the margin was the Environment Canada Pilot Emission Removals, Reductions, and Learnings (PERRL) Initiative. In 2003, a sophisticated forecasting model, the ICF Integrated Planning Model, was used to estimate the generators operating at the margin, on a month-by-month and province-by-province basis, over the period from 2004 through 2007 [Environment Canada, 2007a].

The PERRL study found that the generation at the margin would be nearly exclusively coal during the summer months and imports from the US during the winter months; in the spring and autumn a mix of the two would be seen [Environment Canada, 2007b].

A second study that examined the Ontario power system had different findings [Gil and Joos, 2007]. Although the study focussed on the emissions displaced by wind generation, it is equally applicable to photovoltaic projects. Using hourly data for 2004 from the IESO, the study constructed an effective dispatch stack showing how generators were added to the mix as demand rose. They found that while coal was at the margin for about 75% of the time, gas and oil were also to be found at the margin, as shown in Figure 2. This study ignored imports.

In order to assess these two studies, the hourly IESO data from May 25th through August 20th, 2007 were examined [IESO, 2007a]. Data from every third day, plus five peak days, were studied. From this, it was clear that coal was not exclusively at the margin; in particular, at demand levels above 19 GW, gas met an increasingly large fraction of any increment in demand, largely at the expense of coal. Indeed, it would be hard to explain the roughly 1 TWh of electricity generated by gas each month if gas was never at the margin—the output of must-run gas cogeneration facilities is too small to account for this. (For comparison, coal is used to generate around 2 TWh per month, and imports account for about 0.5 TWh, on average; the seasonal fluctuation in these figures is not nearly as marked as suggested by the PERRL study) [IESO, 2007b]. The picture described by Gil and Joos also seems to be an unnecessary simplification: as demand rises or falls, the transition from one generating technology to another is not abrupt. Rather, different types of generation are present over overlapping ranges of demand, such that an increment or decrement in demand will be apportioned among a mix of generators, all being fractionally at the margin at that demand level.

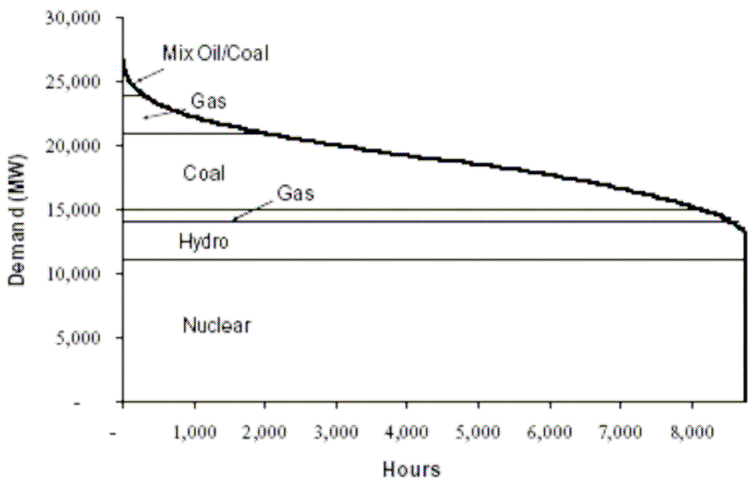

Figure 2. Ontario's Load Duration Curve and Technology Dispatch [Gil and Joos, 2007]

The Overriding Significance of the NO_x Cap

It is debateable, however, whether a marginal analysis as described above is relevant in the case of Ontario. As pointed out by the head of Environment Canada's renewable energy group [Welsh, 2007], in Ontario:

1) It is cheaper to generate electricity with coal than gas, so in the absence of any constraints, coal generation would be maximized at the expense of gas.
2) The Ontario Emissions Trading Code caps the total emissions of NO_x of the electricity sector at 42.8 ktonnes for 2007 (a slightly higher cap was in effect from 2002 through 2006) [Ontario Ministry of the Environment, 2007a].
3) Generating electricity with coal causes significantly greater NO_x emissions than does gas, and it would be impossible to satisfy the NO_x cap with all demand currently met by gas being satisfied by coal.

The consequences of this are that even if a PV project generates power at a given point in time, such that the electricity produced by coal plants at that point in time falls, over a sufficiently long period of time, this action will not offset coal: the reduction will mean more of the allowance is available for increased coal generation at a later point in time.

The Ontario Emissions Trading Code has a provision, called the "set-aside", for renewables and conservation projects to obtain a portion of the NO_x allowance otherwise distributed among coal, oil, and gas-fired generators [Ontario Ministry of the Environment, 2005]. The allowance accorded to them is based on the time of day (with day favoured over night) and season (with winter favoured over spring, and summer and autumn falling in the middle) when the project generates power. The renewable project applies for a set-aside reduction, and once this is granted, can convert this into a tradable NO_x allowance.

Based on this, it is fairly easy to establish emissions reductions factors, or bounds on emissions reductions factors, for PV generation on the Ontario grid. A simplified analysis of the situation is included in Appendix A and the results are summarized below.

If a PV project obtains a NO_x allowance under the set-aside, and retains that allowance (i.e., does not sell it), then the PV project effectively offsets coal; in Ontario, coal-fired electricity generation can be associated with GHG emissions of 0.90 tCO_2/MWh [Welsh, 2007].

In all other cases (the allowance is sold to a coal or gas-fired generator, or no allowance is obtained), the emissions reduction is much lower. If imports and exports are ignored, then the effective GHG emissions reduction factor, $G_{effective}$, is:

$$G_{effective} = -\frac{g_c f_g - g_g f_c}{f_c - f_g}$$

where the subscripts *c* and *g* refer to coal and gas, respectively, and *f* and *g* are NO_x and GHG emissions factors, respectively.

If emissions factors are assumed to be 0.90 tCO_2/MWh and 1.81 tNO_x/GWh for coal [Welsh, 2007] and 0.45 tCO_2/MWh [Natural Resources Canada, 2005] and 0.69 tNO_x/GWh for gas (a figure for combined cycle natural gas generation inferred from [Ontario Ministry of the Environment, 2007b]), then the effective GHG emissions reduction factor is 0.17 tCO_2/MWh—less than 20% that of coal and 40% that of gas!

Note the perverse effect of generating electricity with photovoltaics but not obtaining and retaining an allowance, at least under this set of assumptions: coal-fired generation actually goes up by an amount equal to around 60% of the PV electricity supplied, and gas-fired generation declines by an amount equal to around 160%.

Because this analysis ignores imports and exports, this effective emissions reductions factor can be considered a lower bound, and conclusions about coal generation increasing by an amount equal to 60% of the PV electricity supplied must be taken with a grain of salt. In the case of a decrement in power system demand caused by PV production, the IESO is not obliged to curtail the production of its gas and coal fired generators: it can instead chose to curtail imports or increase exports. In these cases, the PV production will offset the emissions associated with the generator at the margin in the importing or exporting jurisdiction.

Such an analysis is beyond the scope of this study, but it can be speculated that, since coal generation is cheaper than gas, it is most likely that the reduction in imports or increase in exports will offset gas generation. Thus, the effective emissions reduction factor for PV generation in Ontario when a NO_x allowance is not obtained and retained, will lie in the range of 0.17 to 0.45 tCO_2/MWh. Given that imports and exports are not especially significant, the actual figure is likely to be found nearer the bottom end of this range.

One complication is the possibility that NO_x and GHG emissions will be decoupled through NO_x emissions reductions credits permitted under the Ontario Emissions Trading Code. If an entity in an unregulated industry (e.g., outside of the electricity sector) implements a technology, such as a scrubber, that reduces their NO_x emissions, they can obtain credits that can be traded to coal and gas burning electricity generators in Ontario. There is no guarantee that the reduction in NO_x emissions will be accompanied by a decline in GHGs. Still, this should have the effect of merely raising the total allowances available to the coal and gas-fired generators of Ontario; a PV project with an allowance should still have the same effect on gas and coal generators as before.

Of particular concern is how this analysis applies to the Ontario Standard Offer program, which pays $0.42/kWh for PV projects tied to the distribution grid. Under the Standard Offer program, the Ontario Power Authority purchases not just the electricity, but all of its attributes. Thus, the project proponent cannot apply for a NO_x allowance if the electricity is sold under the Standard Offer program; furthermore, the OPA has signalled its intention to *not* obtain NO_x allowances with the electricity purchased through the Standard Offer [Welsh, 2007]. Thus, the effective emissions reduction factor is in the range of 0.17 to 0.45 tCO_2/MWh, as calculated previously.

This is an overly bleak assessment, however. The level of the NO_x cap reflects a political decision; the timeline for eliminating coal-fired generation in Ontario is also partly political. Wind and PV projects operating through the Standard Offer program bolster arguments for decreasing the cap and accelerating the elimination of the coal-fired plants. So while their short-term emissions reductions may be very low, their medium-term and long-term emissions reductions should be much more significant.

The Build Margin and Long Term Emissions Reductions Factors

As difficult as it is to establish operating margin emissions reductions factors, guessing what PV's emissions reductions factors will be in the future is a much tougher game. One thing is clear: the government of Ontario has pledged to shut down Ontario's coal-fired generation by 2014. If the promise is kept, coal will not be at the margin beyond 2014.

Past that point, it seems likely that gas and imports will play an increasingly role as generators at the margin, especially during daylight hours, which are associated with higher demand levels and PV generation [Ontario Power Authority, 2007].

As mentioned earlier, photovoltaics is not accorded a hefty capacity benefit in Ontario, and therefore it is unclear whether long-term emissions reductions for photovoltaics in Ontario should be equated with build margins. If so, the argument could be made that photovoltaics, even under the standard offer program, hastens the retirement of coal-fired generators and delays the addition of natural gas, so perhaps in the medium term it replaces coal and gas; past 2014 it could be equated with gas.

Cost of GHG Emissions Reductions

One way to compare competing renewable energy technologies in terms of their GHG emissions reductions is the cost per tonne of reductions. Any such analysis includes many assumptions. Nevertheless, photovoltaics and solar thermal systems were compared in this way.

Three scenarios for 20-year projects were considered using the RETScreen Version 3 PV and Solar Hot Water models:

1) PV with Allowance: In this scenario, a 1 kW_p PV system installed in Mississauga obtains a NO_x allowance and thus offsets coal until 2014. Beyond that time, it offsets natural gas. The system is assumed to cost $10,000 installed; its output is purchased at $0.07 per kWh.
2) PV Under the Standard Offer: The same PV system as in the above scenario, but with its output purchased at $0.42 per kWh according to the standard offer. Until 2014, its emission reductions are assumed to be half those of natural gas; after that, it offsets natural gas at 100%.
3) Home solar hot water system: A solar system with two glazed flat plate collectors totalling 5.9 m^2 installed in Mississauga supplies on an annual basis 53% of the household's 240 l per day hot water requirement. The system costs $4,400 installed, and offsets the combustion of natural gas in a 75% efficient hot water heater. Natural gas costs $0.36/$m^3$.

For all scenarios, a discount rate of 7% and an energy cost escalation rate of 3% were used. The RETScreen analyses are found in Appendix B and results are summarized in Table 1.

Scenario	**Offset fuel (before 2014)**	**Energy Price**	**Project NPV**	**Project IRR**	**Cost of GHG ER**
PV with Allowance	Coal	$0.07/kWh	-$9,133	-12.1%	$1,133/$t_{CO2}$
PV Standard Offer	50% of gas	$0.42/kWh	-$3,392	2.6%	$642/$t_{CO2}$
Solar Hot Water	Gas	$0.36/$m^3$	-$3,031	-4.3%	$382/$t_{CO2}$

Table 1. Summary of Comparison of Costs of Emissions Reductions

The assumptions made here are, of course, debateable. Nevertheless, several conclusions can be drawn. First, none of the projects are profitable. Second, GHG emissions reductions are very expensive for every project. Third, emissions reductions costs are lowest with solar hot water heating.

These findings are for very small, single-family type projects. If larger projects were considered, economies of scale would be greater for solar hot water systems than with PV systems. Solar hot water would likely appear yet more attractive than PV in terms of the cost per unit of GHG emissions reductions.

It should be noted that none of the $0.35/kWh subsidy paid by the Standard offer has been accounted for in the calculation of the cost of GHG emissions reductions. This is another debateable assumption: the subsidy must come from somewhere, and it is likely that a portion of it will be borne by Ontario taxpayers, including those of the Region of Peel. Factoring this in would increase the cost of emissions reductions in the second scenario.

The Big Picture

Given the high costs associated with achieving GHG emissions reductions with either PV or solar hot water, it is difficult to justify investments in them on this basis alone. The cost per unit of GHG emissions reductions should serve as a guide, but other criteria can be equally important:

1) Knock-on effect: Renewable energy technologies are still new, and much of their value resides not in what they can do now, but what they may achieve for us in the future. A single PV system today will not save the planet; 500 million systems 30 years from now may be part of the solution to climate change. Governments—municipal or otherwise—cannot achieve this long-term result on their own, but they can play an important role in stimulating interest and building local capacity to execute further projects. If a project done today captures the imagination, and is reproduced many times over, the overall effect may be more significant than that of a sound project that garners no interest. For example, better building envelopes incorporating higher levels of insulation may achieve GHG emissions reductions at negative cost, but is unlikely to hold the attention of a child or make a citizen contemplate energy issues. Both types of projects are needed—visible and exciting projects have their place, even if they are expensive.
2) Likelihood of Project Success: Because they are still new, renewable energy projects face opposition from people who are unfamiliar with the technology or who have had bad experiences with it in earlier decades. Fighting this opposition is time-consuming and saps energy and resources. It makes sense to pick projects where a local champion with clout presents him or herself; these are the projects with the best chance of success. They are likely to build inertia for the technology, permit the limited human resources of the Regional Municipality to deal with a large number of projects, and generate a positive community response once they are in place.
3) Long-term maintenance: Getting a project built is one thing; keeping it in good operating order is another. Both solar hot water systems and PV systems generate relatively small quantities of energy, and are rarely relied upon to provide all the hot water or electricity for a building or application. As such, the systems are not essential to the principal function of most of the organizations that employ them. It is easy to be distracted by more pressing matters, to let the minimal maintenance required by these systems to slide, and then to shut down the system if a (usually easily fixed) problem arises. These non-functioning systems are nothing more than bad advertising for renewable energy technologies; this has been especially problematic for solar hot water systems in Canada, despite millions of successfully operating systems worldwide. If minimal long-term

support for a renewable energy system cannot be counted upon, the project is best avoided, regardless of how low its GHG emissions cost could be.

In short, GHG emissions reductions, while an important consideration, cannot be the sole determinant of where efforts are directed. As in the business world, promising opportunities for successful projects should be pursued as they present themselves.

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Appendix A: Effect of NO_x Allowances on PV Emissions Reductions Factors

Let the **base case** in Ontario be described as follows:

Assume that over a long period of time (perhaps several years), E_T, the total electrical energy (including exports) not supplied by nuclear, hydro, wind, wood-waste, and imports must be met by coal and gas generation, E_c and E_g, respectively:

$$E_c + E_g = E_T$$

Gas generation is more expensive than coal generation, so in the absence of any constraints, generation would be by coal. There is a limit, L, on total NO_x emissions over this period, however:

$$E_c f_c + E_g f_g \leq L$$

where f_c and f_g are the NO_x emissions factors for coal and gas, respectively. Since it is financially advantageous to maximize the utilisation of coal, and the emission factor for coal is greater than that for gas, this inequality can be changed to:

$$E_c f_c + E_g f_g = L$$

Combining these equations, note that:

$$E_c = \frac{L - E_T f_g}{f_c - f_g}$$

Case 1: Project proponent participates in set-aside and retains allowance

Assume that during the period of interest, the renewable project produces energy E_R. Then coal plus gas generation must fall by an equivalent amount:

$$E_c + E_g = E_T - E_R$$

For this renewable energy, the project proponent applies for a renewables set-aside and allowance for NO_x under the Ontario Emissions Trading Code. The code specifies that daytime generation of electricity by a renewable qualifies for an allowance of 1.7 kg/MWh during the summer, 1.5 kg/MWh during the spring, 1.8 kg/MWh during the autumn, and 2.0 kg/MWh during the winter. Given that a PV system generates most of its output in summer and spring, the average allowance can be estimated at around 1.7 kg/MWh. Average NO_x emissions from Ontario's coal fired power plants were reported in 2001 to be 1.8 kg/MWh. These two emissions factors are sufficiently close that the NO_x allowance accorded to the project can be written as $E_R f_c$. Therefore:

$$E_c f_c + E_g f_g = L - E_R f_c$$

Combining the above two equations and rearranging,

$$E_c f_c + (E_T - E_R - E_c) f_g = L - E_R f_c$$

$$E_c (f_c - f_g) = L - E_R f_c - (E_T - E_R) f_g$$

$$E_c = \frac{L - E_T f_g - E_R (f_c - f_g)}{(f_c - f_g)}$$

$$E_c = \frac{L - E_T f_g}{f_c - f_g} - E_R$$

$$E_c = E_{c,base\ case} - E_R$$

In other words, as long as the proponent retains the allowance (i.e., does not sell it to a coal or gas producer), the PV project offsets coal generation, and therefore the greenhouse gases associated with coal generation.

Case 2: Proponent Sells Allowance or does not Receive Allowance

Suppose the renewable project proponent sells the NO_x allowance for the project to a coal or gas electricity generator, or that the proponent does not receive a NO_x allowance under the renewables set-aside. In neither case does the limit on NO_x change. Then:

$$E_c + E_g = E_T - E_R$$

and

$$E_c f_c + E_g f_g = L$$

Solving for E_c:

$$E_c f_c + (E_T - E_R - E_c) f_g = L$$

$$E_c = \frac{L - f_g (E_T - E_R)}{(f_c - f_g)}$$

Compared to the base case, the increase in energy generated with coal is:

$$\Delta E_c = E_c - E_{c,\ base\ case}$$

$$= \frac{L - f_g (E_T - E_R)}{(f_c - f_g)} - \frac{L - E_T f_g}{(f_c - f_g)}$$

$$= E_R \frac{f_g}{f_c - f_g}$$

Since demand has decreased by E_R, the energy produced by gas must have fallen by an amount equal to E_R plus the increase in coal-generated electricity:

$$
\begin{aligned}
\Delta E_g &= -E_R - \Delta E_c \\
&= -E_R - E_R \frac{f_g}{f_c - f_g} \\
&= -E_R \left(1 - \frac{f_g}{f_c - f_g} \right) \\
&= -E_R \frac{f_c}{f_c - f_g}
\end{aligned}
$$

The overall increase in greenhouse gases, given a GHG emissions factor of g_c and g_g for coal and gas respectively, is:

$$
\begin{aligned}
\Delta GHG &= g_c \Delta E_c + g_g \Delta E_g \\
&= g_c E_R \frac{f_g}{f_c - f_g} - g_g E_R \frac{f_c}{f_c - f_g} \\
&= E_R \left(\frac{g_c f_g - g_g f_c}{f_c - f_g} \right)
\end{aligned}
$$

Thus, the effective emissions reduction factor associated with each unit of renewable generation is the factor in parentheses, multiplied by –1.

Appendix B: RETScreen Analyses

First Scenario: Photovoltaic system obtains and retains NO_x allowance

RETScreen® Energy Model - Photovoltaic Project

Training & Support

Site Conditions		Estimate	Notes/Range
Project name		PV retains NOx Allowances	See Online Manual
Project location		Peel Region	
Nearest location for weather data	-	Toronto Int'l. A, ON	Complete SR&SL sheet
Latitude of project location	°N	43.7	-90.0 to 90.0
Annual solar radiation (tilted surface)	MWh/m²	1.57	
Annual average temperature	°C	7.5	-20.0 to 30.0

System Characteristics		Estimate	Notes/Range
Application type	-	**On-grid**	
Grid type	-	Central-grid	
PV energy absorption rate	%	100.0%	
PV Array			
PV module type	-	mono-Si	
PV module manufacturer / model #		ABC Inc.	See Product Database
Nominal PV module efficiency	%	11.7%	4.0% to 15.0%
NOCT	°C	45	40 to 55
PV temperature coefficient	% / °C	0.40%	0.10% to 0.50%
Miscellaneous PV array losses	%	5.0%	0.0% to 20.0%
Nominal PV array power	kWp	**1.00**	
PV array area	m²	8.5	
Power Conditioning			
Average inverter efficiency	%	85%	80% to 95%
Suggested inverter (DC to AC) capacity	kW (AC)	0.9	
Inverter capacity	kW (AC)	0.9	
Miscellaneous power conditioning losses	%	4%	0% to 10%

Annual Energy Production (12.00 months analysed)		Estimate	Notes/Range
Specific yield	kWh/m²	139.8	
Overall PV system efficiency	%	8.9%	
PV system capacity factor	%	13.6%	
Renewable energy collected	MWh	1.405	
Renewable energy delivered	MWh	**1.195**	
	kWh	1,195	
Excess RE available	MWh	**0.000**	
			Complete Cost Analysis sheet

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RETScreen® Solar Resource and System Load Calculation - Photovoltaic Project

Site Latitude and PV Array Orientation		Estimate	Notes/Range
Nearest location for weather data		Toronto Int'l. A, ON	See Weather Database
Latitude of project location	°N	43.7	-90.0 to 90.0
PV array tracking mode	-	Fixed	
Slope of PV array	°	30.0	0.0 to 90.0
Azimuth of PV array	°	0.0	0.0 to 180.0

Monthly Inputs

Month	Fraction of month used (0 - 1)	Monthly average daily radiation on horizontal surface (kWh/m²/d)	Monthly average temperature (°C)	Monthly average daily radiation in plane of PV array (kWh/m²/d)	Monthly solar fraction (%)
January	1.00	1.64	-5.9	2.76	-
February	1.00	2.57	-5.2	3.77	-
March	1.00	3.67	-0.5	4.49	-
April	1.00	4.74	6.5	5.10	-
May	1.00	5.76	13.1	5.69	-
June	1.00	6.31	17.7	6.00	-
July	1.00	6.24	21.0	6.04	-
August	1.00	5.22	19.8	5.41	-
September	1.00	3.92	15.1	4.51	-
October	1.00	2.64	8.5	3.51	-
November	1.00	1.51	3.3	2.21	-
December	1.00	1.25	-2.9	2.01	-

		Annual	Season of use
Solar radiation (horizontal)	MWh/m²	1.39	1.39
Solar radiation (tilted surface)	MWh/m²	1.57	1.57
Average temperature	°C	7.5	7.5

Load Characteristics		Estimate
Application type	-	On-grid

Return to Energy Model sheet

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RETScreen® Cost Analysis - Photovoltaic Project

Type of analysis: Pre-feasibility | Currency: $ | Cost references: None

Initial Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Relative Costs	Quantity Range	Unit Cost Range
Feasibility Study							
Other - Feasibility study	Cost	1	$ -	$ -		-	-
Sub-total :				**$ -**	0.0%		
Development							
Other - Development	Cost	1	$ -	$ -		-	-
Sub-total :				**$ -**	0.0%		
Engineering							
Other - Engineering	Cost	1	$ -	$ -		-	-
Sub-total :				**$ -**	0.0%		
Energy Equipment							
PV module(s)	kWp	1.00	$ 7,000	$ 7,000		-	-
Transportation	project	0	$ -	$ -		-	-
Other - Energy equipment	Cost	0	$ -	$ -		-	-
Credit - Energy equipment	Credit	0	$ -	$ -		-	-
Sub-total :				**$ 7,000**	70.0%		
Balance of Equipment							
Module support structure	m^2	8.5	$ -	$ -		-	-
Inverter	kW AC	0.9	$ -	$ -		-	-
Other electrical equipment	kWp	1.00	$ -	$ -		-	-
System installation	kWp	1.00	$ -	$ -		-	-
Transportation	project	0	$ -	$ -		-	-
Other - Balance of equipment	Cost	1	$ 3,000	$ 3,000		-	-
Credit - Balance of equipment	Credit	0	$ -	$ -		-	-
Sub-total :				**$ 3,000**	30.0%		
Miscellaneous							
Training	p-h	6	$ -	$ -		-	-
Contingencies	%	0%	$ 10,000	$ -		-	-
Sub-total :				**$ -**	0.0%		
Initial Costs - Total				**$ 10,000**	100.0%		

Annual Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Relative Costs	Quantity Range	Unit Cost Range
O&M							
Property taxes/Insurance	project	0	$ -	$ -		-	-
O&M labour	p-h	0	$ -	$ -		-	-
Other - O&M	Cost	0	$ -	$ -		-	-
Credit - O&M	Credit	0	$ -	$ -		-	-
Contingencies	%	0%	$ -	$ -		-	-
Sub-total :				**$ -**	#DIV/0!		
Annual Costs - Total				$ -	#DIV/0!		

Periodic Costs (Credits)		Period	Unit Cost	Amount		Interval Range	Unit Cost Range
Inverter Repair/Replacement	Cost	12 yr	$ 500	**$ 500**		-	-
			$ -	**$ -**		-	-
			$ -	**$ -**		-	-
End of project life		-	$ -	**$ -**		*Go to GHG Analysis sheet*	

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RETScreen® Greenhouse Gas (GHG) Emission Reduction Analysis - Photovoltaic Project

Use GHG analysis sheet? Yes   Type of analysis: Standard

Background Information

Project Information

Project name	PV retains NOx Allowances
Project location	Peel Region

Global Warming Potential of GHG

1 tonne CH_4 =	21 tonnes CO_2	(IPCC 1996)
1 tonne N_2O =	310 tonnes CO_2	(IPCC 1996)

Base Case Electricity System (Baseline)

Fuel type	Fuel mix (%)	CO_2 emission factor (kg/GJ)	CH_4 emission factor (kg/GJ)	N_2O emission factor (kg/GJ)	Fuel conversion efficiency (%)	T & D losses (%)	GHG emission factor (t_{CO2}/MWh)
Coal	30.0%	94.6	0.0020	0.0030	35.0%	8.0%	1.069
Natural gas	70.0%	56.1	0.0030	0.0010	45.0%		0.452
Electricity mix	100.0%	175.4	0.0065	0.0044		2.4%	0.637

Proposed Case Electricity System (Photovoltaic Project)

Fuel type	Fuel mix (%)	CO_2 emission factor (kg/GJ)	CH_4 emission factor (kg/GJ)	N_2O emission factor (kg/GJ)	Fuel conversion efficiency (%)	T & D losses (%)	GHG emission factor (t_{CO2}/MWh)
Electricity system							
Solar	100.0%	0.0	0.0000	0.0000	100.0%	0.0%	0.000

GHG Emission Reduction Summary

	Base case GHG emission factor (t_{CO2}/MWh)	Proposed case GHG emission factor (t_{CO2}/MWh)	End-use annual energy delivered (MWh)		Annual GHG emission reduction (t_{CO2})
Electricity system	0.637	0.000	1.195		0.76
			Net GHG emission reduction	t_{CO2}/yr	**0.76**

Complete Financial Summary sheet

Version 3.2   UNEP/DTIE and NRCan/CETC - Varennes

RETScreen® Financial Summary - Photovoltaic Project

Annual Energy Balance

Project name		PV retains NOx Allowances			
Project location		Peel Region	Nominal PV array power	kWp	1.00
Renewable energy delivered	MWh	1.195	Net GHG reduction	t_{CO2}/yr	0.76
Firm RE capacity	kW	-	Net GHG emission reduction - 20 yrs	t_{CO2}	15.21
Application type		On-grid			

Financial Parameters

Avoided cost of energy	$/kWh	0.070	Debt ratio	%	0.0%
RE production credit	$/kWh	-			
GHG emission reduction credit	$/$t_{CO2}$	-	Income tax analysis?	yes/no	No
Energy cost escalation rate	%	3.0%			
Inflation	%	2.0%			
Discount rate	%	7.0%			
Project life	yr	20			

Project Costs and Savings

Initial Costs				**Annual Costs and Debt**		
Feasibility study	0.0%	$	-	O&M	$	-
Development	0.0%	$	-	Fuel	$	-
Engineering	0.0%	$	-			
Energy equipment	70.0%	$	7,000	**Annual Costs and Debt - Total**	**$**	**-**
Balance of equipment	30.0%	$	3,000			
Miscellaneous	0.0%	$	-	**Annual Savings or Income**		
Initial Costs - Total	100.0%	**$**	**10,000**	Energy savings/income	$	84
Incentives/Grants		$	-			
				Annual Savings - Total	**$**	**84**
Periodic Costs (Credits)						
Inverter Repair/Replacement		$	500	Schedule yr # 12		
		$	-			
		$	-			
End of project life -		$	-			

Financial Feasibility

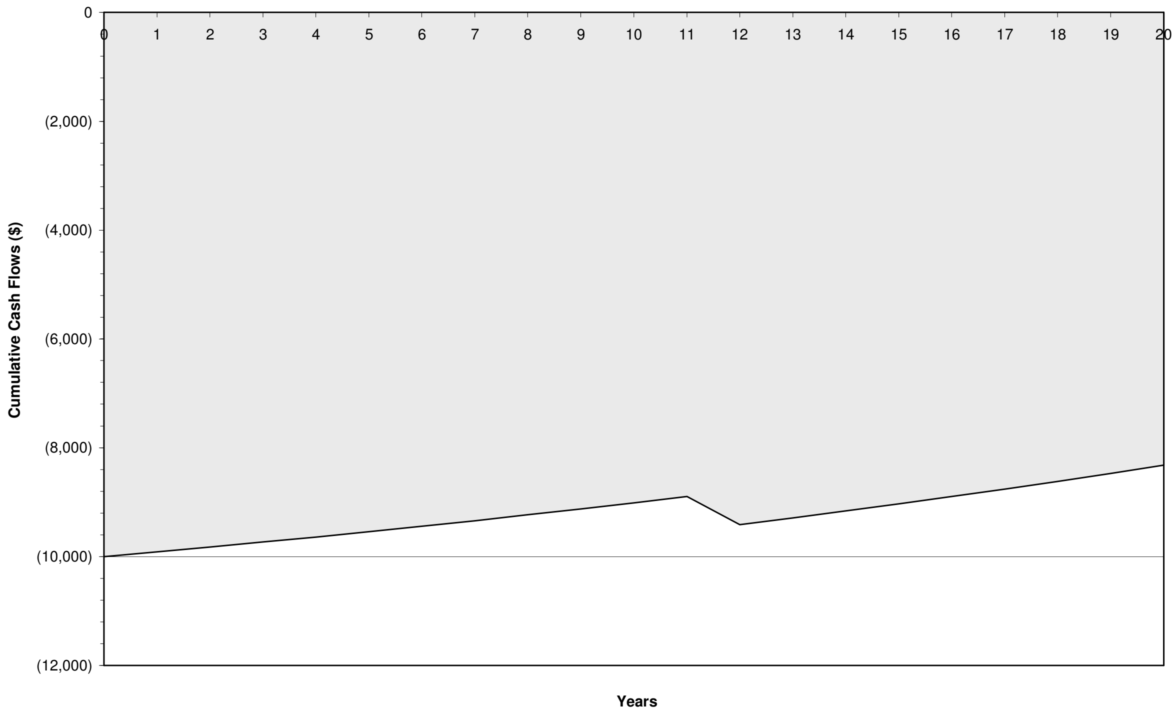
			Calculate energy production cost?	yes/no	No
Pre-tax IRR and ROI	%	-12.1%			
After-tax IRR and ROI	%	-12.1%	Calculate GHG reduction cost?	yes/no	Yes
Simple Payback	yr	119.6	GHG emission reduction cost	$/$t_{CO2}$	1,133
Year-to-positive cash flow	yr	more than 20	Project equity	$	10,000
Net Present Value - NPV	$	(9,133)			
Annual Life Cycle Savings	$	(862)			
Benefit-Cost (B-C) ratio	-	0.09			

Version 3.2

Cumulative Cash Flows Graph

Photovoltaic Project Cumulative Cash Flows
PV retains NOx Allowances, Peel Region

Renewable energy delivered (MWh/yr): 1.195 **Total Initial Costs: $ 10,000** **Net average GHG reduction (t_{CO2}/yr): 0.76**



Year-to-positive cash flow: more than 20 yr **Net Present Value: $ -9,133**

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Second Scenario: PV project paid under Standard Offer

N.B.: The following three sheets identical to corresponding sheets in First Scenario:

- Energy Model
- Solar Resource and System Load
- Cost Analysis

RETScreen® Greenhouse Gas (GHG) Emission Reduction Analysis - Photovoltaic Project

Use GHG analysis sheet? Yes   Type of analysis: Standard

Background Information

Project Information
Project name: PV-Standard Offer
Project location: Peel Region

Global Warming Potential of GHG
1 tonne CH_4 = 21 tonnes CO_2 (IPCC 1996)
1 tonne N_2O = 310 tonnes CO_2 (IPCC 1996)

Base Case Electricity System (Baseline)

Fuel type	Fuel mix (%)	CO_2 emission factor (kg/GJ)	CH_4 emission factor (kg/GJ)	N_2O emission factor (kg/GJ)	Fuel conversion efficiency (%)	T & D losses (%)	GHG emission factor (t_{CO2}/MWh)
Natural gas	15.0%	56.1	0.0030	0.0010	45.0%	8.0%	0.491
Natural gas	70.0%	56.1	0.0030	0.0010	45.0%	8.0%	0.491
Nuclear	15.0%	0.0	0.0000	0.0000	30.0%	8.0%	0.000
Electricity mix	100.0%	115.2	0.0062	0.0021		8.0%	0.417

Proposed Case Electricity System (Photovoltaic Project)

Fuel type	Fuel mix (%)	CO_2 emission factor (kg/GJ)	CH_4 emission factor (kg/GJ)	N_2O emission factor (kg/GJ)	Fuel conversion efficiency (%)	T & D losses (%)	GHG emission factor (t_{CO2}/MWh)
Electricity system							
Solar	100.0%	0.0	0.0000	0.0000	100.0%	0.0%	0.000

GHG Emission Reduction Summary

	Base case GHG emission factor (t_{CO2}/MWh)	Proposed case GHG emission factor (t_{CO2}/MWh)	End-use annual energy delivered (MWh)	Annual GHG emission reduction (t_{CO2})
Electricity system	0.417	0.000	1.195	0.50
			Net GHG emission reduction t_{CO2}/yr	**0.50**

Complete Financial Summary sheet

Version 3.2 UNEP/DTIE and NRCan/CETC - Varennes

RETScreen® Financial Summary - Photovoltaic Project

Annual Energy Balance

Project name		PV-Standard Offer			
Project location		Peel Region	Nominal PV array power	kWp	1.00
Renewable energy delivered	MWh	1.195	Net GHG reduction	t_{CO2}/yr	0.50
Firm RE capacity	kW	-	Net GHG emission reduction - 20 yrs	t_{CO2}	9.97
Application type		On-grid			

Financial Parameters

Avoided cost of energy	$/kWh	0.420	Debt ratio	%	0.0%
RE production credit	$/kWh	-			
GHG emission reduction credit	$/$t_{CO2}$	-	Income tax analysis?	yes/no	No
Energy cost escalation rate	%	3.0%			
Inflation	%	2.0%			
Discount rate	%	7.0%			
Project life	yr	20			

Project Costs and Savings

Initial Costs				**Annual Costs and Debt**		
Feasibility study	0.0%	$	-	O&M	$	-
Development	0.0%	$	-	Fuel	$	-
Engineering	0.0%	$	-			
Energy equipment	70.0%	$	7,000	**Annual Costs and Debt - Total**	**$**	**-**
Balance of equipment	30.0%	$	3,000			
Miscellaneous	0.0%	$	-	**Annual Savings or Income**		
Initial Costs - Total	100.0%	**$**	**10,000**	Energy savings/income	$	502
Incentives/Grants		$	-			
				Annual Savings - Total	**$**	**502**
Periodic Costs (Credits)						
Inverter Repair/Replacement		$	500	Schedule yr # 12		
		$	-			
		$	-			
End of project life -		$	-			

Financial Feasibility

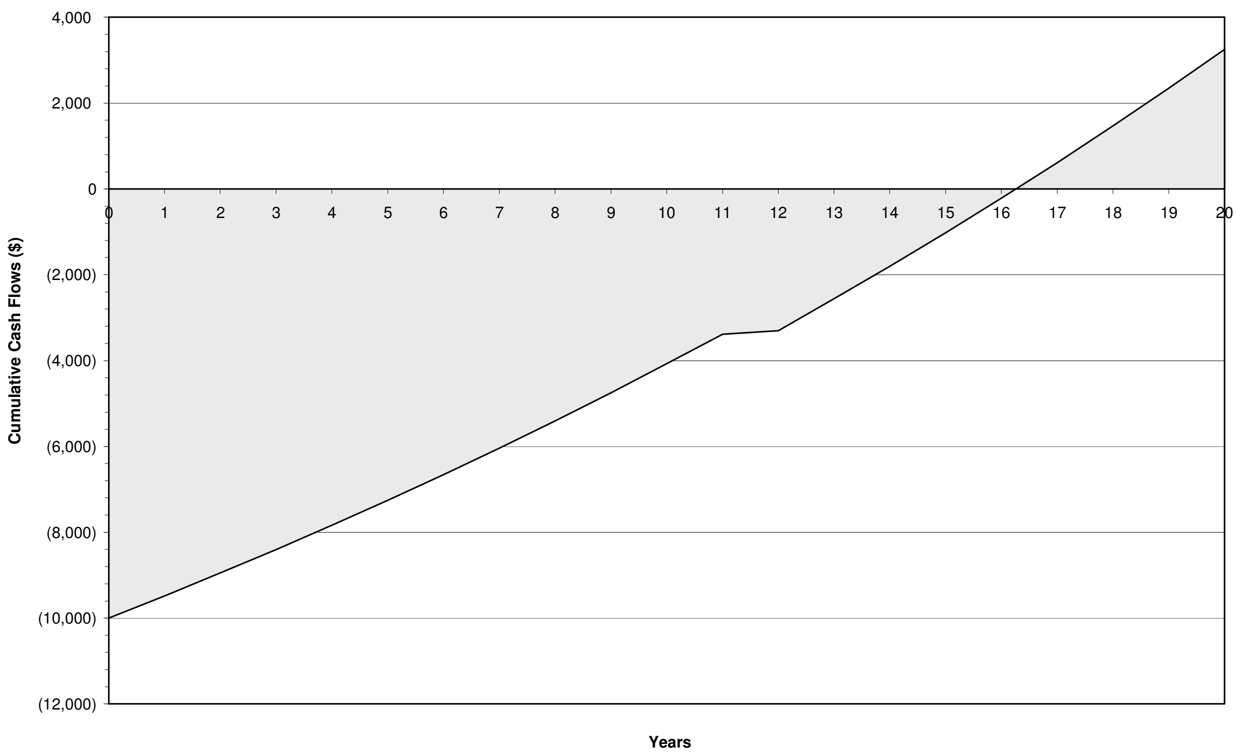
			Calculate energy production cost?	yes/no	No
Pre-tax IRR and ROI	%	2.6%			
After-tax IRR and ROI	%	2.6%	Calculate GHG reduction cost?	yes/no	Yes
Simple Payback	yr	19.9	GHG emission reduction cost	$/$t_{CO2}$	642
Year-to-positive cash flow	yr	16.3	Project equity	$	10,000
Net Present Value - NPV	$	(3,392)			
Annual Life Cycle Savings	$	(320)			
Benefit-Cost (B-C) ratio	-	0.66			

Version 3.2

Cumulative Cash Flows Graph

Photovoltaic Project Cumulative Cash Flows
PV-Standard Offer, Peel Region

Renewable energy delivered (MWh/yr): 1.195 **Total Initial Costs: $ 10,000** **Net average GHG reduction (t_{CO2}/yr): 0.50**



IRR and ROI: 2.6% **Year-to-positive cash flow: 16.3 yr** **Net Present Value: $ -3,392**

Version 3.2 NRCan/CETC - Varennes

Third Scenario: Solar Hot Water System on Single Family Dwelling

RETScreen® Energy Model - Solar Water Heating Project

Training & Support

Site Conditions		Estimate	Notes/Range
Project name		Domestic Hot Water	See Online Manual
Project location		Region of Peel	
Nearest location for weather data		Toronto Int'l. A, ON	Complete SR&HL sheet
Annual solar radiation (tilted surface)	MWh/m²	1.55	
Annual average temperature	°C	7.5	-20.0 to 30.0
Annual average wind speed	m/s	4.0	
Desired load temperature	°C	60	
Hot water use	L/d	240	
Number of months analysed	month	12.00	
Energy demand for months analysed	MWh	5.36	

System Characteristics		Estimate	Notes/Range
Application type		Service hot water (with storage)	
Base Case Water Heating System			
Heating fuel type	-	Natural gas - m³	
Water heating system seasonal efficiency	%	75%	50% to 190%
Solar Collector			
Collector type	-	Glazed	See Technical Note 1
Solar water heating collector manufacturer		Thermo Dynamics	See Product Database
Solar water heating collector model		G32	
Gross area of one collector	m²	2.96	1.00 to 5.00
Aperture area of one collector	m²	2.78	1.00 to 5.00
Fr (tau alpha) coefficient	-	0.74	0.50 to 0.90
Fr UL coefficient	(W/m²)/°C	5.25	1.50 to 8.00
Temperature coefficient for Fr UL	(W/(m·°C)²)	0.00	0.000 to 0.010
Suggested number of collectors		2	
Number of collectors		2	
Total gross collector area	m²	5.9	
Storage			
Ratio of storage capacity to coll. area	L/m²	72.0	37.5 to 100.0
Storage capacity	L	400	
Balance of System			
Heat exchanger/antifreeze protection	yes/no	Yes	
Heat exchanger effectiveness	%	70%	50% to 85%
Suggested pipe diameter	mm	10	8 to 25 or PVC 35 to 50
Pipe diameter	mm	10	8 to 25 or PVC 35 to 50
Pumping power per collector area	W/m²	5	3 to 22, or 0
Piping and solar tank losses	%	8%	1% to 10%
Losses due to snow and/or dirt	%	5%	2% to 10%
Horz. dist. from mech. room to collector	m	5	5 to 20
# of floors from mech. room to collector	-	1	0 to 20

Annual Energy Production (12.00 months analysed)		Estimate	Notes/Range
SWH system capacity	kW_{th}	4	
	MWth	0.004	
Pumping energy (electricity)	MWh	**0.05**	
Specific yield	kWh/m²	483	
System efficiency	%	31%	
Solar fraction	%	53%	
Renewable energy delivered	MWh	**2.86**	
	GJ	10.29	
			Complete Cost Analysis sheet

Version 3.1 NRCan/CETC - Varennes

RETScreen® Solar Resource and Heating Load Calculation - Solar Water Heating Project

Site Latitude and Collector Orientation		Estimate	Notes/Range
Nearest location for weather data		Toronto Int'l. A, ON	See Weather Database
Latitude of project location	°N	43.7	-90.0 to 90.0
Slope of solar collector	°	25.0	0.0 to 90.0
Azimuth of solar collector	°	0.0	0.0 to 180.0

Monthly Inputs

(Note: 1. Cells in grey are not used for energy calculations; 2. Revisit this table to check that all required inputs are filled if you change system type or solar collector type or pool type, or method for calculating cold water temperature).

Month	Fraction of month used (0 - 1)	Monthly average daily radiation on horizontal surface (kWh/m²/d)	Monthly average temperature (°C)	Monthly average relative humidity (%)	Monthly average wind speed (m/s)	Monthly average daily radiation in plane of solar collector (kWh/m²/d)
January	1.00	1.64	-5.9		4.9	2.64
February	1.00	2.57	-5.2		4.5	3.67
March	1.00	3.67	-0.5		4.7	4.42
April	1.00	4.74	6.5		4.8	5.05
May	1.00	5.76	13.1		3.9	5.69
June	1.00	6.31	17.7		3.7	6.02
July	1.00	6.24	21.0		3.3	6.05
August	1.00	5.22	19.8		3.0	5.38
September	1.00	3.92	15.1		3.3	4.46
October	1.00	2.64	8.5		3.7	3.46
November	1.00	1.51	3.3		4.3	2.17
December	1.00	1.25	-2.9		4.4	1.98

		Annual	Season of Use
Solar radiation (horizontal)	MWh/m²	1.39	1.39
Solar radiation (tilted surface)	MWh/m²	1.55	1.55
Average temperature	°C	7.5	7.5
Average wind speed	m/s	4.0	4.0

Water Heating Load Calculation		Estimate	Notes/Range
Application type	-	Service hot water	
System configuration	-	With storage	
Building or load type	-	House	
Number of units	Occupant	4	
Rate of occupancy	%	100%	50% to 100%
Estimated hot water use (at ~60 °C)	L/d	240	
Hot water use	L/d	240	
Desired water temperature	°C	60	
Days per week system is used	d	7	1 to 7
Cold water temperature	-	Auto	
Minimum	°C	2.8	1.0 to 10.0
Maximum	°C	12.3	5.0 to 15.0
Months SWH system in use	month	12.00	
Energy demand for months analysed	MWh	5.36	
	GJ	19.29	

Return to Energy Model sheet

Version 3.1 NRCan/CETC - Varennes

RETScreen® Cost Analysis - Solar Water Heating Project

Type of project: Pre-feasibility | Currency: $ | Cost references: None

Initial Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Relative Costs	Quantity Range	Unit Cost Range
Feasibility Study							
Other - Feasibility study	Cost	0	$ -	$ -		-	-
Sub-total :				$ -	0.0%		
Development							
Other - Development	Cost	0	$ -	$ -		-	-
Sub-total :				$ -	0.0%		
Engineering							
Other - Engineering	Cost	0	$ -	$ -		-	-
Sub-total :				$ -	0.0%		
Energy Equipment							
Solar collector	m²	5.9	$ 250	$ 1,480		-	-
Solar storage tank	L	400	$ 1.00	$ 400		-	-
Solar loop piping materials	m	19	$ 15.00	$ 290		-	-
Circulating pump(s)	W	28	$ 30.00	$ 834		-	-
Heat exchanger	kW	3.3	$ 60	$ 200		-	-
Transportation	project	1	$ -	$ -		-	-
Other - Energy equipment	Cost	0	$ -	$ -		-	-
Sub-total :				**$ 3,204**	72.8%		
Balance of System							
Collector support structure	m²	5.9	$ 30	$ 178		-	-
Plumbing and control	project	1	$ 251	$ 251		-	-
Collector installation	m²	5.9	$ 80	$ 474		-	-
Solar loop installation	m	19	$ 10.00	$ 193		-	-
Auxiliary equipment installation	project	1	$ 100	$ 100		-	-
Transportation	project	1	$ -	$ -		-	-
Other - Balance of system	Cost	0	$ -	$ -		-	-
Sub-total :				**$ 1,195**	27.2%		
Miscellaneous							
Training	p-h	0	$ 60	$ -		-	-
Contingencies	%	0%	$ 4,400	$ -		-	-
Sub-total :				$ -	0.0%		
Initial Costs - Total				**$ 4,400**	100.0%		

Annual Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Relative Costs	Quantity Range	Unit Cost Range
O&M							
Property taxes/Insurance	project	0	$ -	$ -		-	-
O&M labour	project	0	$ -	$ -		-	-
Other - O&M	Cost	0	$ -	$ -		-	-
Contingencies	%	0%	$ -	$ -		-	-
Sub-total :				$ -	0.0%		
Electricity	kWh	52	$ -	$ -	0.0%	-	-
Annual Costs - Total				$ -	0.0%		

Periodic Costs (Credits)		Period	Unit Cost	Amount	Interval Range	Unit Cost Range
Glycol replacement	Cost	5 yr	$ 200	**$ 200**	-	-
				$ -	-	-
				$ -	-	-
End of project life		-		$ -		

Go to GHG Analysis sheet

Version 3.1 NRCan/CETC - Varennes

RETScreen® Greenhouse Gas (GHG) Emission Reduction Analysis - Solar Water Heating Project

Use GHG analysis sheet? Yes   Type of analysis: Standard

Background Information

Project Information

Project name	Domestic Hot Water
Project location	Region of Peel

Global Warming Potential of GHG

1 tonne CH_4 =	21 tonnes CO_2	(IPCC 1996)
1 tonne N_2O =	310 tonnes CO_2	(IPCC 1996)

Base Case Electricity System (Baseline)

Fuel type	Fuel mix (%)	CO_2 emission factor (kg/GJ)	CH_4 emission factor (kg/GJ)	N_2O emission factor (kg/GJ)	Fuel conversion efficiency (%)	T & D losses (%)	GHG emission factor (t_{CO2}/MWh)
Natural gas	100.0%	56.1	0.0030	0.0010	45.0%	8.0%	0.491
Electricity mix	100%	135.5	0.0072	0.0024		8.0%	0.491

Base Case Heating System (Baseline)

Fuel type	Fuel mix (%)	CO_2 emission factor (kg/GJ)	CH_4 emission factor (kg/GJ)	N_2O emission factor (kg/GJ)	Fuel conversion efficiency (%)	GHG emission factor (t_{CO2}/MWh)
Heating system						
Natural gas	100.0%	56.1	0.0030	0.0010	75.0%	0.271

Proposed Case Heating System (Solar Water Heating Project)

Fuel type	Fuel mix (%)	CO_2 emission factor (kg/GJ)	CH_4 emission factor (kg/GJ)	N_2O emission factor (kg/GJ)	Fuel conversion efficiency (%)	GHG emission factor (t_{CO2}/MWh)
Heating system						
Electricity	1.8%	135.5	0.0072	0.0024	100.0%	0.491
Solar	98.2%	0.0	0.0000	0.0000	100.0%	0.000
Heating energy mix	100.0%	2.5	0.0001	0.0000		0.009

GHG Emission Reduction Summary

	Base case GHG emission factor (t_{CO2}/MWh)	Proposed case GHG emission factor (t_{CO2}/MWh)	End-use annual energy delivered (MWh)	Annual GHG emission reduction (t_{CO2})
Heating system	0.271	0.009	2.86	0.75
			Net GHG emission reduction t_{CO2}/yr	**0.75**

Complete Financial Summary sheet

Version 3.1

 UNEP/DTIE and NRCan/CETC - Varennes

RETScreen® Financial Summary - Solar Water Heating Project

Annual Energy Balance

Project name		Domestic Hot Water	Electricity required	MWh	0.05
Project location		Region of Peel			
Renewable energy delivered	MWh	2.86	Net GHG reduction	t_{CO2}/yr	0.75
Heating fuel displaced	-	Natural gas - m³	Net GHG emission reduction - 20 yrs	t_{CO2}	14.99

Financial Parameters

Avoided cost of heating energy	\$/m³	0.360	Debt ratio	%	0.0%
GHG emission reduction credit	\$/t_{CO2}	-	Income tax analysis?	yes/no	No
Retail price of electricity	\$/kWh	-			
Energy cost escalation rate	%	3.0%			
Inflation	%	2.0%			
Discount rate	%	7.0%			
Project life	yr	20			

Project Costs and Savings

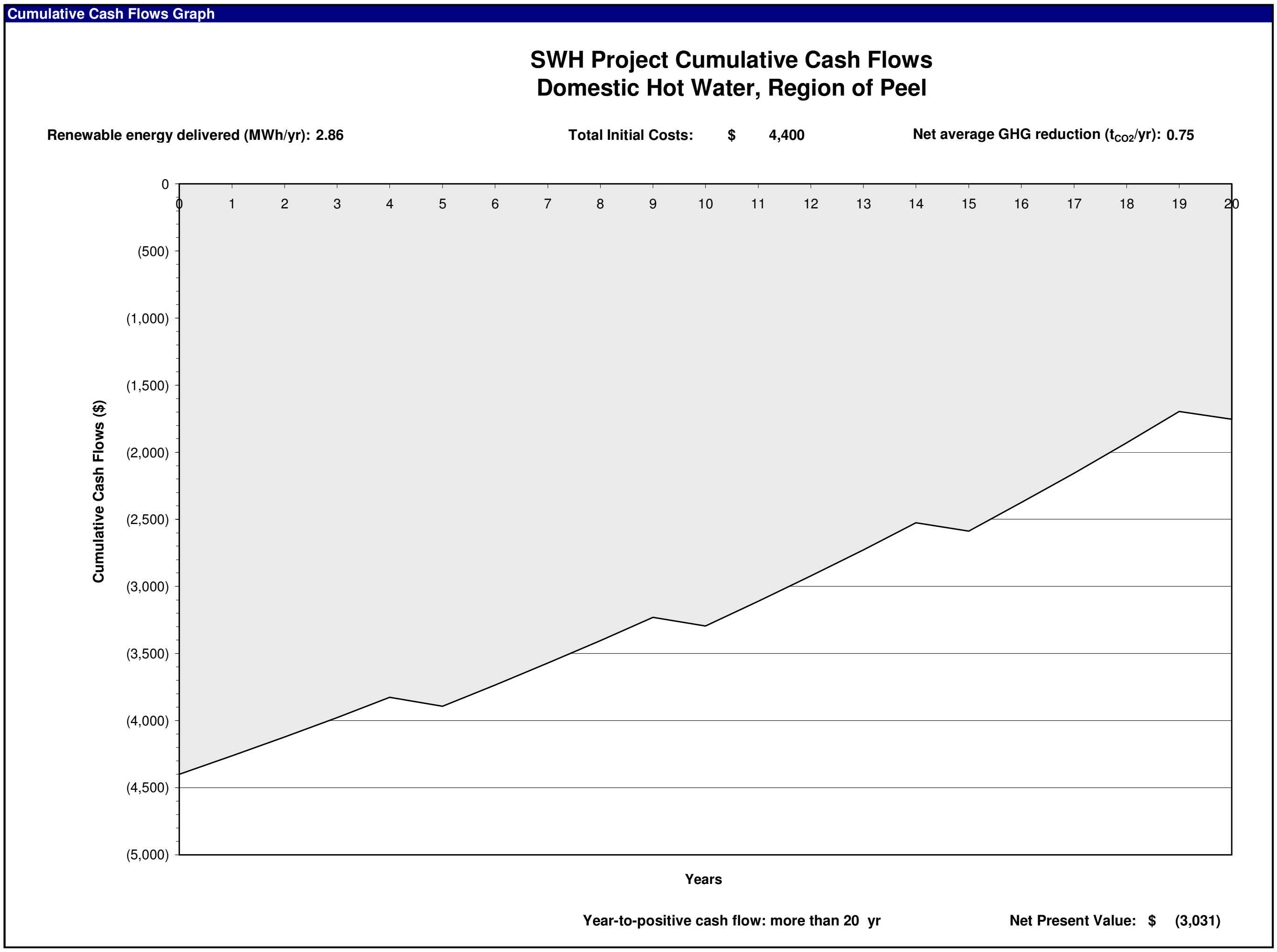
Initial Costs				**Annual Costs and Debt**		
Feasibility study	0.0%	\$	-	O&M	\$	-
Development	0.0%	\$	-	Electricity	\$	-
Engineering	0.0%	\$	-			
Energy equipment	72.8%	\$	3,204	**Annual Costs and Debt - Total**	**\$**	**-**
Balance of system	27.2%	\$	1,195			
Miscellaneous	0.0%	\$	-	**Annual Savings or Income**		
Initial Costs - Total	100.0%	**\$**	**4,400**	Heating energy savings/income	\$	133
Incentives/Grants		\$	-			
				Annual Savings - Total	**\$**	**133**
Periodic Costs (Credits)						
Glycol replacement		\$	200	Schedule yr # 5,10,15,20		
		\$	-			
		\$	-			
End of project life -		\$	-			

Financial Feasibility

Pre-tax IRR and ROI	%	-4.3%	Calculate GHG reduction cost?	yes/no	Yes
After-tax IRR and ROI	%	-4.3%	GHG emission reduction cost	\$/t_{CO2}	382
Simple Payback	yr	33.1	Project equity	\$	4,400
Year-to-positive cash flow	yr	more than 20			
Net Present Value - NPV	\$	(3,031)			
Annual Life Cycle Savings	\$	(286)			
Benefit-Cost (B-C) ratio	-	0.31			

Version 3.1

Cumulative Cash Flows Graph



Version 3.1

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