Natural Resources Canada | Ressources naturelles Canada

CanmetENERGY

Leadership in ecoInnovation

UNCERTAINTY IN LONG-TERM PHOTOVOLTAIC YIELD PREDICTIONS

Canada

UNCERTAINTY IN LONG-TERM PHOTOVOLTAIC YIELD PREDICTIONS

Prepared by:

Didier Thevenard, Ph.D., P.Eng.
Numerical Logics Inc.
e-mail: dthevenard@numlog.ca

with contributions from Anton Driesse, P.Eng.
Photovoltaic Performance Labs
and
Dave Turcotte, B. Eng.
Yves Poissant, Ph. D.
CanmetENERGY, Natural Resources Canada

Presented to:

Natural Resources Canada
CanmetENERGY
Dr. Sophie Pelland
NRCan - IETS/CE/CE-VAR
1615 Lionel-Boulet Boulevard
Varennes, QC
J3X 1S6

March 31, 2010

CITATION

Thevenard D, Driesse A, Pelland S, Turcotte D, Poissant Y. Uncertainty in long-term photovoltaic yield predictions, report # 2010-122 (RP-TEC), CanmetENERGY, Varennes Research Center, Natural Resources Canada, March 31 2010, 52 pp.

DISCLAIMER

ACKNOWLEDGEMENT

Financial support for the report project was provided by Natural Resources Canada through the ecoENERGY Technology Initiative, which is a component of ecoACTION, the Canadian government's actions towards clean air and greenhouse gas emission reductions.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report summarizes the uncertainties associated with the prediction of long-term photovoltaic (PV) yield. The report addresses mainly uncertainties facing large-scale PV developers, although some of the conclusions may also be applicable to small systems.

The uncertainties facing developers include factors such as expected yield, government policies and decisions, issues related to permitting, siting and grid connection, cost, availability and quality of equipment, and financing and legal matters. They can differ depending on the type of installation planned (large or small) and the kind of mounting structure (ground-mounted or building integrated). Uncertainties can be reduced, for example, by providing more clarity in policies regarding PV systems and grid connection (e.g. feed-in tariffs, domestic content, municipal taxes), and simplifying permitting requirements or making them more uniform across local jurisdictions.

Statistical simulation tools are helpful to evaluate quantitatively uncertainties related to yield. The uncertainties relate mostly to the evaluation of the solar resource and to the performance of the system itself. In the best of cases, uncertainties are typically 4% for year-to-year climate variability, 5% for solar resource estimation (in a horizontal plane), 3% for estimation of radiation in the plane of the array, 3% for power rating of modules, 2% for losses due to dirt and soiling, 1.5% for losses due to snow, and 5% for other sources of error. A Monte-Carlo type simulation was used to look at the combined effect of these uncertainties on the annual yield of a typical large PV farm in Ontario. It was found that the combined uncertainty (in a RMSE sense) is of the order of 8.7% for individual years, and of 7.9% for the average yield over the PV system lifetime.

The numbers above are thought to be representative of good-quality installations in Ontario. However they could vary significantly from location to location or from system to system. Uncertainties could be further reduced by exploring the following avenues:

- Solar resource: current estimates from various sources vary sometimes widely. Effects of micro-climates are not well known. Reliable data sources are often interpolated over large distances, or supplemented by satellite-derived data which still suffer from serious shortcomings. More work is needed to increase the reliability and spatial coverage of solar radiation estimates.
- Module rating: there is still some confusion as to the tolerance on the initial power of modules. It appears that, at the moment, checking this tolerance is the responsibility of the developer. More clarity is needed to put all manufacturers on a level playing field and to reduce the uncertainty faced by developers.
- Some of the losses experienced by systems are not known with great certainty. This concerns in particular losses due to dirt and soiling, and losses due to snow. Current numbers are

extrapolated from other jurisdictions, but their effects need to be actually measured across the variety of climates experienced in Canada.

1 BACKGROUND

Natural Resources Canada, through its CanmetENERGY Varennes Research Centre, is currently interested in assessing what the uncertainties in long-term photovoltaic (PV) system yield predictions are, and how they can be reduced. Such yield predictions are key to system design and to analyses of the economic viability of photovoltaic systems, and their relative uncertainty can increase risks for system developers and influence their ability to secure financing under favourable terms. In addition, CanmetENERGY is interested in putting PV system yield uncertainties in context, by comparing these to uncertainties about project costs, delays, zoning, permitting and other factors that influence expected financial returns and risks incurred.

With that goal in mind, CanmetENERGY initiated a study to analyze how uncertainties in key factors influencing PV system yield (PV module rating, global horizontal irradiance data available, models to estimate irradiance in the plane of the array, shadowing, module ageing, etc.) translate into uncertainties in long-term (yearly and lifetime) PV yield predictions for Canadian systems.

This study was conducted by Numerical Logics Inc. of Waterloo, ON, and its findings are summarized in this report. The report first presents an overview of the uncertainties facing large developers (section 2). It then provides a discussion of uncertainties (section 3) in parameters of importance in the estimation of the yield of PV systems: solar radiation available at the site, solar resource variability, transposition models, module rating, snow, dirt and soiling, etc. Finally a set of statistical simulations are run (section 4) to evaluate the global uncertainty in predicted yield for a typical solar farm. The study concludes with a few recommendations (section 5) on how this uncertainty could be reduced. Three appendices deal with statistical indicators (Appendix A), solar radiation statistics for selected Canadian locations (Appendix B), and ways to determine the adequate number of runs in Monte Carlo simulations (Appendix C).

2 UNCERTAINTIES FACING LARGE-SCALE PV DEVELOPERS[1]

Looking at uncertainties facing PV developers at this time in Canada inevitably has a strong focus on Ontario. This is where most of the development activity is taking place, and where the majority of Canadian industry is concentrating its efforts. Some sources of uncertainty may appear unique to Ontario's present situation, but they are highly relevant beyond its borders. Experience gained in Ontario in dealing with specific uncertainties may serve to avoid them in other jurisdictions, or at the very least, will help developers there be better prepared for dealing with them.

About a dozen people involved in the PV industry provided input to this review. The group included developers, people involved in providing products or services to the developers, as well as someone from a local distribution company. The discussions were exploratory, and no statistical summary is attempted.

Among large-scale developers, there are two types. The first develops individual MW-scale systems, and the second develops smaller systems—preferably similar in design—in large numbers, adding up to the MW scale. They face some similar challenges, related to sourcing components for example, but there are differences as well, such as grid connection issues.

Most issues identified as causing uncertainty for developers are somehow related to the high anticipated growth rate of the industry. That growth is of course desired by everyone in principle, but at the same time it is apparent from the discussions that a more moderate growth would reduce some of the challenges.

Finally, the same uncertainties are not causing the same reaction in all developers. For some, these factors "just create more work"; for others they're cause for deep concern.

2.1 Typical project timeline

The timeline of a typical project in Ontario will provide the context in which uncertainties are evaluated. This section lists the steps usually encountered in a project[2].

1. Preparation of application to FIT program
   - Preliminary studies, consultation with transmitter/local distribution company to identify connection point.
   - Developer must demonstrate that they have the right to construct and operate a renewable energy project on the entire site (e.g. deed or lease agreement for all of the property that will be the location of any of the generation equipment). This may involve some expenses, such as an option to buy or lease the land.
2. Application

[1] This section was researched and written with Anton Driesse of Photovoltaic Performance Labs, Kingston, ON.
[2] For more details, see
http://fit.powerauthority.on.ca/Page.asp?PageID=1226&SiteNodeID=1058&BL_ExpandID=260

- Developer pays application fee ($0.50 per kW of contract capacity; minimum $500; maximum $5,000) and security ($20/kW ; returned with FIT contract execution).

3. Review by OPA
    - OPA reviews the application according to its eligibility criteria.
    - OPA conducts connection availability assessment. Result is either (a) a FIT contract offer, or (b) placement in production line if connection upgrades are necessary, or (c) placement in reserve for future grid expansion.
4. Developer signs contract
    - Developer submits initial completion and performance security payment of $50 per kilowatt of contract capacity.
5. Developer secures required permits and approvals:
    - *Impact Assessments* - assess the impact of the project on the electricity system, and provides details of what is required to connect the project and how long it will take to connect.
    - *Renewable Energy Approval* - ensures that the project meets provincial setback and noise standards, environmental impact studies and public consultation.
    - *Domestic Content Plan* - check that the project complies with domestic content requirements.
    - *Financing Plan* - lists all sources of equity or debt financing for the development of the project, as well as signed commitment letters from these sources stating their agreement in principle to provide the necessary financing.
6. OPA provides Notice to Proceed (NTP)
    - For projects relying on transmission or distribution expansions, delay between FIT contract award and NTP is typically 15 months.
    - Developer submits second completion security of $25 per kW of contract capacity.
    - Developer must achieve commercial operation within three years.

Note that the securities are paid back to the developer when the project actually comes online. In addition to the costs above, there are of course engineering and development costs; those are normally paid through equity, whereas the actual system may be paid partly through equity and partly through debt. As mentioned, financing has to be in place in step 5. The actual ordering and purchasing of equipment may vary widely depending on the arrangement contracted by the developer. Some developers opt to leave it all to an Engineering Procurement Construction (EPC) firm, and most of the payment differed until production start; others prefer to do it in-house, in which case the price of the equipment, delivery date, and payment (including some down payment when the order is placed) is negotiated with the supplier.

2.2 Consequences of uncertainties

Large-scale PV developers will only build systems if they can foresee profits. Uncertainty itself also increases *expectations* of profitability. As usual with investments, the greater the uncertainty about the profit, the greater the *potential* profit has to be to justify taking the risk.

Uncertainties affect both sides of the profit equation, namely costs and revenues. On the revenue side the uncertainty lies mostly with the amount of energy produced (the energy yield), since the feed-in tariff is usually set. An overview of the uncertainty in energy yield is covered in section 2.3, and will be further developed in the rest of the report. All the other factors identified in sections 2.4 to 2.14 affect cost and will not be further developed outside of these sections.

There is also a category of "show-stoppers". For example, if there is no grid capacity, then there is simply no project. It is not possible to eliminate all obstacles by financial means, so it is important to resolve uncertainties about potential show-stoppers as early as possible in the development process to minimize the losses associated with cancelling a project altogether.

There is a grey area between these two categories, where profitability drops below some threshold and becomes a show-stopper itself.

Finally, there are uncertainties in timing, or delays. Delays can have complex consequences as they ripple through a project down to the suppliers and subcontractors.

The following sections describe the nature of the uncertainties that the PV developers face. There is no clear ranking, although some of the descriptions are intended to convey a sense of importance.

2.3 Energy yield

Energy production, or yield, is of primary importance to large-scale PV projects because it directly determines revenue. The sun is rightly regarded as quite a stable source of input energy, but it is nevertheless subject to local, seasonal and year-to-year variations.

Developers are in the first place concerned with local variations because projects will be subject to those during their entire lifetime. Unfortunately data on local variations are almost non-existent, and developers are for the most part content to use solar radiation measurements that are representative of a fairly large area. Developers are usually not aware of or overly concerned about the origins of the measurements, which are interpolated from sparse ground sites, derived from satellite images, or both.

Year-to-year variations are less of an issue with some developers; but others are very concerned about consistent cash flow. If the first couple of years are below average, this can make interest payments on borrowed money very difficult. For this reason one developer tried to define a probability distribution curve for the yield, rather than just a long-term average (see Section 4 for statistical simulations of PV systems). Another developer mentioned that even seasonal variations have an impact, and he prefers to start producing in spring rather than fall in order to get a quicker start on those payments.

Mitigating the risk associated with both month-to-month and year-to-year variability of the solar resource is a subject of significant interest in particular to re-insurers. The practice is already current with wind farms through the use of weather derivatives. The idea behind weather derivatives is to smooth the volatility of energy production; the derivative kicks in for example when the production falls below a given level, and enables the operator to meet debt payments even in 'bad months'. The predictability of the payment then allows the lender to provide better financing conditions to the project. This is essentially how the operator is expected to recoup the cost associated with the weather derivative itself. The practice of weather derivatives may be applicable to solar farms, provided the required parameters are well understood. Some meaningful parameter (e.g. the probability for a given level of radiation to be exceeded 75% or 90% of the time) may have to be known. Another option is to put aside a certain amount of cash (the reserve) which can be used to dampen the fluctuations in energy production. What percentage of the annual cash flow gets put aside each year for that purpose remains to be determined.

Yield calculations of course depend on more than just solar radiation; variations in the performance of the various components of the system will also affect yield.

Usually some kind of modeling or simulation software is used to predict the energy production of a system, given available solar radiation and the expected characteristics of the system. Many developers do not distinguish between the inputs and the models, and simply do not have any idea of how the calculations are done. So uncertainties in the data and the modeling are lumped together in their perception. Another result of this lack of understanding is that RETScreen output is used for much more than the intended pre-feasibility analysis, and compared on an equal footing with more detailed hourly simulations.

It is therefore easy for developers to be over-confident in yield predictions provided by simulation programs, without realizing the uncertainties attached to these predictions. Even using the best data and methods currently available will leave a level of uncertainty that is significant to developers.

2.4 Government policies and decisions

Government policy in the form of the Renewable Energy Standard Offer Program (RESOP) and Feed-in Tariff (FIT) is the driving force behind the PV development boom in Ontario, but at the same time government policy is also a source of uncertainty. History has shown that policy changes can be made abruptly (like the halt of the RESOP) and project planners are wary of this. It is also very difficult to make contingency plans in case of policy change, since the range of possible changes is endless.

Even if the higher-level policies are clearly set out and accepted as certain, their implementation can create uncertainties, especially in the early stages. There are always plenty of practical what-if scenarios where the application of the policy principles is not obvious. For example, if a simple building is constructed expressly for the purpose of holding a PV array, does it qualify for the higher FIT rate? It takes time to work out these details, and until these cases have been tested their outcome is uncertain.

Similarly, OPA can still cancel a contract up to the notice to proceed (see section 2.1). This introduces an obvious financial risk for the developer.

On top of this, when governments make special agreements with individual companies, such as the recent deal with Samsung, this creates uncertainty about the evolution of the marketplace. This particular deal also reduces access to a limited resource by reserving grid capacity for Samsung.

2.5 Permitting

Under the general heading of permitting we include any kind of formal approval process. It should be noted that in Ontario the RESOP projects are not subject to the same requirements as FIT projects. The Green Energy act considers that PV is essentially a benign technology and has streamlined the processes—but not retroactively.

There is a steep learning curve on both the developer side and the administration side (OPA, Hydro One, LDCs, municipalities). Furthermore, demand for services has required hiring within administration, but of course new staff will take even more time to get up to speed than existing staff. Delays are therefore common and expected, but there is no evidence of a single bottleneck.

Delays with permitting usually occur at the very start of the project development. They would therefore not have the same impact as a delay in the supply of components, for example. At this stage money and resource will not have been committed yet. Nevertheless when it takes 253 days to process a Connection Impact Assessment, as was reported in one instance, the delay represents more than a minor inconvenience.

There is potential for some confusion as well, when local codes and standards differ from provincial ones. And when inspectors are faced with new situations, their individual decisions may vary somewhat depending on how “by the book” they are.

2.6 Siting

The largest systems are planned for ground-mounting. Cost for land is minimal compared to the cost of the PV system, so as long as there is grid capacity the land is no major source of uncertainty.

For roof-mounted systems the story is rather different. While the prospect of generating a new revenue stream from a vacant space is attractive, there are significant challenges and risks that undermine the business case. The evaluation of whether a building can support the additional static and wind loads, and whether earthquake resistance may be affected, is complex and costly, and may lead to project cancellation or a call for expensive reinforcements. Many newer buildings have been very carefully engineered to support the required load and nothing more, and from that perspective they are risky candidates. Some older buildings may turn out not to meet current codes at all, and even a small installation might trigger a requirement to bring the whole roof up to code.

Risk of leaks, and difficulty of access for maintenance and repairs are the main worries of building owners. The fact that revenue from the interior of the buildings may be 2 or 3 orders of magnitude higher than the potential revenue from the roof means that even the slightest possibility of problems can be a show-stopper.

2.7 Grid connection

In order to connect a PV system there must be sufficient grid capacity to carry and absorb the energy to be generated and various standards must be met. The voltage and current-carrying capacity must be appropriate for the size of the array and for the connection point, which may be either at the distribution or transmission level of the grid. Multiple criteria must be fulfilled, and it is up to the Local Distribution Company and/or Hydro One to determine whether there is enough spare capacity to take the additional generation, and what upgrades will be required to make the connection.

Uncertainty arises from this process due to the fact that future expansion plans and other applications for generation capacity all compete for a limited resource. Non-refundable application fees must be disbursed in advance, and further costs may be incurred if grid upgrades are required. In one case a developer received a cost estimate of $40K to $400K for upgrades—a range that could make or break his project. A business plan with such a line item cannot get financing, and the only possible way to move forward is risk more money on a more detailed cost estimate. And then of course there is the question of *when* any required upgrades would actually be completed.

Fortunately for smaller projects, and hence for developers of large numbers of small projects, grid capacity is not so much of an issue.

2.8 Equipment supply

2.8.1 Cost

It is very difficult to predict market prices for photovoltaic equipment. There are three main reasons for this:

1. The photovoltaic equipment industry has seen enormous swings of supply and demand through 2009 and prices are still somewhat unstable on a global basis.

2. The existing supply chains in Canada and Ontario are used to moving small volumes, and are destabilized by the new surge in demand.
3. The requirement for domestic content in FIT projects means the choice of products is limited, and in many cases planning must be done on assumption (or promise) that a factory will be built in time to supply the needed product. Developers at this stage don't know if they will be able to meet the domestic content before the commercial operation date.

The best guide to future market price of equipment appears to be the FIT price schedule, and everyone is calculating backwards from that - that is, knowing how much will be paid per kWh generated, and how much profit is desired, one can calculate the maximum cost of equipment that can be paid out. But that price schedule itself is subject to revision, and hence not a long-term indicator.

Despite the difficulty, everyone is trying to get firm pricing on all the major components. One developer notes that he is having the most difficulty getting price agreements with module suppliers.

2.8.2 Availability

As alluded to above, just because an equipment supply contract is signed, that does not mean that the equipment is guaranteed to arrive at the construction site when needed. The domestic content rules have led many equipment manufacturers to announce plans to manufacture or assemble equipment in Ontario. Any delays or setbacks with these expansion plans will affect the ability of developers to complete their PV projects. It is also very well possible that some companies will cancel their expansion plans if pre-orders are insufficient, or if a more attractive market opens up for them in another jurisdiction.

One person indicated that some project developers might try to reduce uncertainty about availability by booking orders with multiple suppliers. Of course if many developers were to adopt this strategy it would make it hard for suppliers to determine how much product is really needed.

2.8.3 Quality

New factories or assembly lines take time to get up to speed, both in output volume and quality. Thin-film PV production lines, for example may take 6 months or a year of fine-tuning before producing top efficiency modules. Even with the best intentions of all parties, therefore, there is a greater uncertainty regarding product performance and quality in times of rapid expansion.

2.9 Design and construction

Some PV planners anticipate using an EPC (Engineering, Procurement and Construction) contract to get their systems built. In this case any uncertainty about getting the system built is simply passed on to the EPC contractor, who will reflect it back in the pricing.

Planners who choose to stay in control of the building process are more concerned about the details. Although much of the work can be done by the traditional trades, those trades are also traditionally in high demand. The more specialized knowledge lies with smaller operators who may lack the ability, the aptitude or the desire to work on large projects.

On the design side, even those with experience need to exercise some caution because strategies applied successfully in smaller systems do not necessarily work for very large systems. And designers who have gained experience in places like Germany, Spain or California will need to carefully consider the differences in climate—not only for yield calculations, but also for the physical design, construction scheduling, etc.

2.10 Personnel

With the anticipated growth, most companies directly or indirectly involved in the construction of PV systems will require additional personnel. Positions requiring specialized knowledge will be particularly hard to fill because the training programs themselves are in their infancy or have very low capacity. There is a good chance, therefore, that some of the work will be done by people with inadequate skills, or people who are learning on the job. This carries greater risk of mistakes or delays.

2.11 Operating and other annual costs

In principle the components of PV systems require little or no maintenance - perhaps a little more for those with moving parts, but still much less than most machinery. Component warranties are also long compared to many other products. For the item deemed most likely to fail, the inverter, it is possible to buy extended warranties and service plans, or even to rent the *services* of an inverter with an uptime guarantee instead of purchasing it.

Developers do anticipate there will be need for cleaning, snow removal, security, performance monitoring and verification, miscellaneous repairs. The only problem is that there is no local experience with these tasks, so both the effort and the cost are difficult to estimate.

Developers often assume that the tasks will be performed as a package by company specializing in those services, and that the costs will be marginal. Likewise insurance costs, taxes, and periodic charges from the utilities are all expected to be small compared to revenue; hence uncertainty about annual costs is not seen as a cause for great concern.

One significant exception to this is the lack of consistent policy re. municipal property taxes. Mechanisms similar to those used for wind farms need to be put in place.

2.12 Financing

An engineer might suggest that a project making use of a proven technology to harvest a plentiful and free resource under a 20 year government-backed contract should make a very low-risk investment. Potential lenders or investors are generally more sceptical. Although one can be fairly confident with production numbers, Canadian lenders are not familiar with the technology and tend to adopt a prudent attitude.

For the project developer the questions are, first, whether he or she can find the financing to complete the project, and second, whether the terms of the financing leave sufficient room for profit. Both questions are going to be influenced strongly by the other uncertainties discussed above. Additional uncertainty may come from the sheer number of projects that are *simultaneously* looking for funding.

In the long term, risks related to changes in inflation and interest rates are identical to other business investments.

2.13 Legal and contracts

When things go wrong—and some things *will* go wrong—who will suffer the consequences? New to the industry, lawyers will have more difficulty foreseeing everything that possibly can go wrong, and it will be harder to design contracts that offer the appropriate level of protection to project developers.

Product quality and performance warranties are fundamental to the business cases of large PV systems, and are expected to shield the owner from some uncertainty. Yet when a defect or problem is discovered, there is still ample opportunity for financial impact resulting from disputes about the defects, reductions and interruptions of revenue, shipping and installation costs, and so on.

The question of rights to the solar resource and risk of shading due to future development, particularly in cities, remains largely unexplored.

2.14 Public opposition

Photovoltaic systems are not sufficiently familiar to and understood by the general public in Canada that their support can be taken for granted. In particular, if a proposed system is anywhere near a residence, there are likely to be some sceptical questions. It is not predictable whether the answers to those questions will lead to enthusiastic support or vehement opposition. With the Green Energy Act it is much more difficult to block PV development, but some effort is still required to manage and keep good public relations.

3 UNCERTAINTIES IN PV ENERGY YIELD

3.1 Introduction

When a grid-connected photovoltaic system is considered, the viability of the project will depend chiefly on the amount of AC energy that can be expected from the system on a yearly basis. This amount depends essentially on the quantity of solar radiation available at the site, and the actual performance of the system itself. It is best evaluated using a procedure summarized schematically in Figure 1.

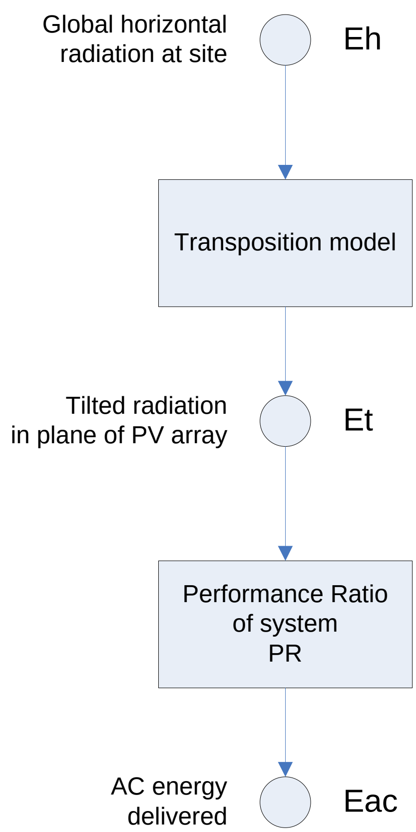

Figure 1 - Procedure to estimate the energy delivered by a grid-connected PV system.

The starting point is the solar resource. It is most generally provided **as solar radiation on a horizontal surface**, Eh, expressed in $kWh/m^2/day$.

Photovoltaic modules are usually not horizontal, but tilted towards the South in order to maximize the amount of incident solar energy. The amount of solar radiation incident on the array, Et, can be calculated from Eh using what is called a **transposition model**.

Finally, the photovoltaic array converts this solar radiation into DC energy, Edc, and the inverter converts the DC energy into AC energy, Eac, which is sold to the grid. The efficiencies of these two conversions can be considered separately, but they are often lumped together in a single number called the **Performance Ratio of the system**, PR, which is a non-dimensional number simply defined as:

$$PR = (Eac \cdot G^*)/(Et \cdot P^*)$$

where P^* is the array rated power under so-called 'standard test conditions' (STC), expressed in kW, and G^* is a reference irradiance equal to 1 kW/m^2. Simply put, the performance ratio quantifies the portion of the system's potential that is actually delivered. It embodies the overall effect of losses on the rated output due to inverter inefficiency, wiring, mismatch, and other phenomena; PV module temperature; incomplete use of irradiance by reflection from the module front surface; soiling or snow; under-performance of the modules; system down-time; and component failures (IEC, 1998; Marion et al., 2005).

Following the procedure outlined in Figure 1, the uncertainties associated with the estimation of Eac fall into three categories:

1. Uncertainty about the solar resource Eh, which is divided into uncertainty in the estimation of mean solar radiation available at the site, and uncertainty associated with the year-to-year variability of yearly or monthly solar radiation.
2. Uncertainties introduced by the use of the transposition model.
3. Uncertainties about the performance of the system itself, characterized by the performance ratio PR.

The following sections explain how to evaluate these different uncertainties.

<u>*Notes*</u>:

1. In this study, only crystalline silicon PV modules are considered. The problems inherent to other technologies (e.g. amorphous silicon) are not covered, although the study could be extended to them.
2. Appendix A contains a summary of some of the statistics used in the report, and how uncertainties can be combined.
3. As mentioned in Appendix A, the term “uncertainty” in this and other sections will be used here to designate root mean squared error (RMSE), unless otherwise specified.

3.2 Estimation of mean solar radiation available at the site

Solar radiation at a site can be estimated from a number of sources. For Canada the most common are measured values, values estimated from terrestrial models, interpolated values, and values estimated from satellite-derived models. They differ not only by the method through which solar radiation is estimated, but also in terms of number of years of data, spatial resolution, and time resolution.

In a comparison of 6 databases covering Europe, Šŭri et al. (2008) found that yearly estimates of global horizontal radiation are within 7% of each other (in a RMS sense) for 90% of the geographical area considered. Similarly Labed and Lorenzo (2004) found that discrepancies among different sources for a given site are commonly between 2 and 7% on a yearly basis (in an RMS sense; their paper presents the results in term of discrepancy), and sometimes more. Appendix B compares long-term averages from various sources for selected Canadian locations.

3.2.1 Measured values

Spatial resolution: limited to only 40 sites
Number of years of data: variable, up to 40+; little data for recent years because of backlog in QC
Time resolution: hourly
Uncertainty: typically 3% on a monthly basis - estimates vary from 2.5 to 6%

Environment Canada (EC) has about 40 sites[3] that monitor solar radiation on an hourly basis. However there is currently an ~8 year backlog in QC for these stations; it is hoped that the backlog will be resolved soon, once EC completes some new automated QA/QC software. Things are also evolving at EC with the addition of autostations what will record solar radiation in one-minute amounts, but when this data will become available is not clear yet.

Studies have shown that uncertainty arising from instrument error is approximately 2.5% for global radiation [presumably for monthly average radiation] (Schroeder et al., 2009). NASA (2009) reports that measurement uncertainties from calibration drift, operational uncertainties, or data gaps may result in uncertainties from 3 to 6% for high quality sites. Myers et al. (2005) use a 5% uncertainty for monthly average radiation. EC/JRC/IES (2007) indicates that measurements with a calibrated pyranometer are accurate within 3 to 5% on a monthly basis.

3.2.2 Values estimated from terrestrial models

Spatial resolution: 235 sites
Number of years of data: variable, up to 40+; no data past 2005
Time resolution: hourly
Uncertainty: 5% or more on a monthly basis

The Canadian solar radiation network is supplemented by modeled solar radiation data. The model used, called HORZ[4], relies on earth-sun geometry, cloud cover information (cloud amount and type by layer), and other parameters. The model is used to fill missing data for stations in the radiation monitoring network, and to generate synthetic hourly radiation data for additional sites

[3] Historically, there have been a total of 74 stations monitoring solar radiation, but many have been discontinued.
[4] The HORZ program actually includes several solar radiation calculation models: MAC3, WON, and interpolation.

with no monitored irradiance. Currently the total number of sites for which HORZ has been run is 235 (this figures includes sites with and without measured solar radiation data).

The mean bias error of the HORZ model is estimated at below 1% (Davies and McKay, 1989; see also Morris and Skinner, 1990) and the RMSE is estimated between 25 and 30% on an hourly basis, 14 to 16% on a daily basis, and 5% to 7% on an monthly basis, but these value are probably optimistic. Thevenard and Brunger (2001) report MBE values in the 6-7% range and hourly RMSEs in the 17 to 40% (or more) range.

Measured and modeled solar radiation data in Canada were combined in a number of products available from Environment Canada:

- Canadian Weather Energy and Engineering Data Sets (CWEEDS). The latest version, produced in 2006, contains data from years 1953-2005 (at most) for 235 sites. The data include solar radiation, dry bulb temperature, wind speed, etc.
- Canadian Weather for Energy Calculations (CWEC) files. These are typical meteorological year files derived from CWEEDS, assembled by selecting individual months chosen for their representativeness. There are currently 75 CWEC files; most are based on years 1960 to 1989.
- Canadian Renewable Energy Resource (CERES) CD-ROM, created in 1998. It contains solar radiation averages, for a variety of orientations (e.g. horizontal, sloped, tracking…), and time bases (e.g. monthly averages for every hour of the day). The CD contains 144 sites. The CD was produced using the same solar radiation data as the CWEEDS and CWEC datasets over the period 1974 -1993.

3.2.3 Interpolated values

Spatial resolution: 0.083° (about 6 × 9 km at 45°N)
Number of years of data: average values
Time resolution: monthly
Uncertainty: 7% or more.

The Photovoltaic potential and solar resource maps of Canada (NRCan, 2008) were derived from the CERES CD-ROM by interpolation. Pelland et al. (2006) estimate that the uncertainty is expected from 3.3 to 14.5% of the network means for monthly values and from 5.6 to 6.9% of the network mean for yearly values. This uncertainty should be compounded with that of the CERES data from which it is derived. Note also that the interpolation does not necessarily respect the values at the points for which data was available (see examples in Appendix B).

3.2.4 Values estimated from satellite observations

Contrary to measured or cloud-derived radiation values, satellite-derived radiation values are available on a global scale (i.e. they cover the whole country). At the moment, global solar radiation data for Canada is available from at least three sources: the SUNY data set, the NASA/SSE data set, and the NARR product.

3.2.4.1 SUNY data set

Spatial resolution: 0.1 ° × 0.1° (about 8 × 11 km at 45°N); data limited to latitudes lower than 58°N.
Number of years of data: 2002-2008
Time resolution: hourly
Uncertainty: 9% on average - better in summer but worse in winter;

The SUNY data set was created in 2009 for Natural Resources Canada (NRCan) and Environment Canada (EC) by Dr. Richard Perez and his team at the Atmospheric Sciences Research Center, State University of New York. The model's main input consists of the visible channel frames of GOES satellites, along with ground elevation, monthly climatological atmospheric turbidity, precipitable water, and ozone content, and daily snow cover. The data is available from NRCan as hourly files and monthly summaries.

The accuracy of the SUNY model has been estimated in various studies. Myers et al. (2005) have estimated the monthly mean daily total to have an MBE of +0.1% and a RMSE of 5% on average[5]. However for individual sites the MBE can range from +10 to -4% and the RMSE from 2 to 13%. Hourly MBE and RMSE are estimated on average at -0.2 W/m^2 and 97.8 W/m^2.

Vignola et al. (2007) report mean bias errors less than 5% on an annual basis for the SUNY model tested in the Pacific Northwest, with hourly RMSE of the order of 12 to 22%.

The data set was tested against measured data from Environment Canada for 10 stations for the period 2002-2008 (Thevenard, 2010). It was found that the SUNY model generally underestimates (in terms of MBE[5]) solar radiation, by 1 to 7% on an annual basis depending upon the sites, and with an uncertainty (in terms of RMSE) of 3.5 to 13.7 % on a monthly basis. Model performance is better in the summer (typically within 4% of actual values) but can be significantly worse in the winter (up to 30%) because the model has trouble distinguishing between clouds and snow.

These estimates are in line with what has been observed by others using similar models: Sŭri et al. (2007) found that satellite data estimates in Europe using the HelioClim database have a bias of less than 1 W/m^2 (0.5%) overall, but the bias may range from -15 W/m^2 (-7%) to +32 W/m^2 (+15%) for individual sites. Average RMSE is 35 W/m^2 (17%) for daily mean irradiance and 25 W/m^2 (12%) for monthly mean irradiance.

<u>Note</u>: Two data sets similar to the SUNY set exist:

[5] The MBE is expressed here as modeled minus measured values to be consistent with the rest of the report. The opposite sign convention is used in Myers et al.

- The National Solar Radiation Database (NSRDB) provides gridded hourly solar radiation data for the USA. The database covers southern Canada as well. The values differ somewhat from the Canadian SUNY set. They are typically 1 to 3% lower in the summer and up to 30% lower in winter. The data set is available at ftp://ftp.ncdc.noaa.gov/pub/data/nsrdb-solar/.
- A private company, 3Tier, has implemented their own version of the SUNY Perez algorithm. They claim better accuracy than SUNY but their data have not been verified independently. More information about their methods and data sets can be obtained from their website, http://www.3tier.com/firstlook/.

3.2.4.2 NASA/SSE data set

Spatial resolution: 1°× 1° (about 80 km × 110 km at 45°N)
Period: July 1, 1983 through June 31, 2005
Time resolution: daily
Uncertainty: MBE = -1.8%, RMSE =7.8% on a monthly basis for latitudes below 60°

The NASA/SSE data set is formulated from NASA satellite- and reanalysis-derived insolation and meteorological data and contains more than 200 primary and derived solar, meteorology and cloud related parameters. Uncertainty is estimated in NASA (2009) by comparison with measured Baseline Solar Radiation Network (BSRN) values on a worldwide basis. The data set is accessible from http://eosweb.larc.nasa.gov/sse/.

3.2.4.3 NARR data set

Spatial resolution: 32 km × 32 km
Period: 1979 to present
Time resolution: 3-hourly
Uncertainty: high (20% or more on a monthly basis)

The North American Regional Reanalysis (NARR)[6] is a long-term, high-resolution, high-frequency, atmospheric and land surface hydrology dataset for the North American domain. It is based on a global reanalysis meteorological model, improved with the incorporation (assimilation) of precipitation and land surface data specific to North America, which provide an enhanced analysis of land hydrology and land-atmosphere interaction for the continent. One of the outputs of the model is global horizontal radiation.

A comparison of solar radiation data for 10 sites by Thevenard (2010) confirms what other studies have shown, i.e. that the radiation estimates from NARR are significantly too high (typically 20 to 35% on a monthly basis) and therefore not usable directly. Most of the error actually consists of an offset; some people claim much better results can be achieved by removing the offset, however it is difficult to quantify the effectiveness of that method.

[6] The NARR model is prepared by the National Centers for Environmental Prediction (NCEP). Homepage of the project can be found at http://www.emc.ncep.noaa.gov/mmb/rreanl/. Data access can also be obtained through the Ouranos consortium, http://www.ouranos.ca/. For more detail see Mesinger et al. (2006).

3.2.5 Values found in databases

Solar radiation estimates can also be found in a number of databases, either publicly available (e.g. RETScreen, www.retscreen.net) or commercially available (the most well known product being Meteonorm, www.meteonorm.com). Generally speaking these databases compile data from other sources, with data that is either measured, modeled, or derived from satellite observations. The uncertainty associated with the data for a particular site depends of course on the origin of the data, although this information is often overlooked. For example in Meteonorm version 6.0, where no radiation measurement is nearer than 300 km satellite information is used, and if the nearest site is more than 50 km away, a mixture of ground and satellite information is used[7].

3.3 Solar resource variability

3.3.1 Year to year variability

In an analysis of satellite-derived radiation data, global horizontal irradiance shows low inter-annual variability, typically in the range 4 to 6% (Sŭri et al., 2007). This variability is found to be lowest in arid regions and highest (up to 10%) in coastal and mountainous regions. Monthly solar radiation is of course more variable; variability is found to be lowest for June (12%) and highest in December (20%, with values as high as 35% in some regions).

Appendix B contains a summary of year-to-year variability of annual solar radiation for various Canadian sites, which are typically in the 4% range.

3.3.2 Long term variability of solar radiation

Solar radiation is subject to decadal cycles and other long-term trends, however these seem very small (of the order of 0.05 kWh/m2/day per decade) compared to other uncertainties attached to the estimation of solar radiation (Hinkelman et al., 2009); they can be neglected in the analysis. Similarly, changes in solar radiation due to major volcanic eruptions can be neglected.

3.4 Uncertainties introduced by the use of transposition models

Transposition models calculate solar radiation in the plane of the PV array, given solar radiation on the horizontal surface. There are several kinds of such models; some use monthly averages of solar radiation as input, others hourly or sub-hourly values. This last category requires a breakdown of solar radiation into diffuse and beam components; this is often done with a model as well.

Various transposition models were tested by Cameron et al. (2008). They report mean bias errors between -3.8% and 0.5% and RMS errors between 4.5 an 8.3% on an hourly basis, using measured hourly beam and diffuse or total and beam as the inputs. When a model is used to first calculate beam and diffuse from global, the error is higher.

---

[7] See Meteonorm Handbook Part 1: Software, www.meteonorm.com/media/pdf/mn6_software.pdf.

A study by Gueymard (2009), using one-minute measurements from Golden, CO, shows that with optimal inputs (measured beam, diffuse and ground reflectance) the best transposition have mean bias errors (MBE) typically lower than 1% and an RMSE less than 5% (presumably at the 1-minute level). However when only global irradiance is known and the diffuse and beam components are calculated with a model, and the albedo is not measured but estimated, the MBE tends to become larger (in the range of 0 to -6% for South-facing surface with latitude tilt) and the RMSE in excess of 10% for the latitude-tilted surface (the RMSE is even larger for vertical surfaces). In a similar study with hourly data from a Mediterranean site, Notton et al. (2006) show that most models slightly underpredict tilted irradiance (with MBEs in the range -1 to -4%) and that the RMSE is expected in the range 10 to 15%. Both Gueymard and Notton et al. show that there is no *best* model to use and that the results will vary according to the combination of models used, the characteristics of solar radiation at the site, ground albedo, etc., so it is difficult to eliminate or even reduce the error.

When horizontal solar radiation is known only as a monthly average, the transposition to a tilted surface adds some uncertainty compared to methods using hourly values. The added uncertainty is estimated in RETScreen (2004) to be typically between 4 and 6%.

Ground albedo (i.e. reflectivity) is one of the parameters that play a significant role in most transposition models. Ground reflectivity varies typically from 0.1 for dark surfaces to 0.7 or more in the presence of snow (Thevenard and Haddad, 2006); a value of 0.2 is typically used. Thevenard and Haddad (2006) have estimated the annual increased PV energy production due to reflection of solar radiation on the snow between +0.7 and +2.6% depending on location, for an array tilted at 60°. This effect is also observed anecdotally by Durisch and Bulgheroni (1999). The increase will be smaller for lower tilts, and will be negligible for a system made of several rows of modules, since rows beyond the second one do not 'see' the snowy surface in front of the PV field, although there does not seem to be a general consensus about this.

3.5 Uncertainties about the performance of the system itself

The performance of the system as a whole is considered first, through the evaluation of the Performance Ratio. Then, major factors that can influence the performance ratio are reviewed: rating of the modules, presence of snow, ageing, etc.

3.5.1 System performance ratio

A study of 533 residential systems representing 2.1 MWp of installed capacity in Japan, by Ueda et al. (2009), reveals performance ratios ranging from 66 to 82%. If one takes into account only systems that have a south-facing array, the average PR is 77.3%. The study also points to significant differences between module manufacturers, some performing consistently worse than others – presumably because of unrealistic module power ratings.

Similarly, a study of 461 grid-connected PV systems installed between 1991 and 2005 in various OECD countries yielded a mean annual PR of 0.74 for systems installed in 2005, up from a mean of 0.64 for systems installed in 1991. These systems were primarily small-scale residential or commercial systems, with 96% of systems having a rated power of less than 100 kW. Systems with the best performance had mean annual PR's above 0.875 [I.E.A. 2007].

Since larger (Megawatt-scale) systems have primarily been installed by private developers during the past few years, databases or extended studies of such systems are not yet available. However, performance data has been analyzed for a few individual systems. For instance, Moore and Post (2008) report PR's between 0.78 and 0.81 for the third, fourth and fifth year of operation of a well-designed, well-maintained 3.51 MW_p system in Arizona. More generally, given the size of the associated investments and the fact that feed-in tariffs tie revenues to PV performance, it is expected that large-scale PV systems will have performance ratios at the upper end of the ranges observed for the smaller systems.

3.5.2 Module rating

It is (or was) frequent for the installed power to differ markedly from the nameplate power, with modules typically performing below rather than above their rated power at standard testing conditions (STC). Drif et al. (2007) report differences of 11% and 9% observed on two 70 kWp systems. Deviations from rated power were observed to range from -5% to -26% in Jahn and Nasse (2004) for systems having PR less than 60%, and are identified as a major reason for their low PR's. In a system with a good PR ratio the authors found modules to be only 5% below their rated power.

Module tests carried out in Canada by CanmetENERGY (Poissant (2009)) report differences between actual and nameplate ratings given by manufacturers of -6.5% to -23% on sampled modules. Similarly, module tests in the United States (Atmaram et al., 2008; Detrick et al., 2005) and Australia (Carr and Pryor, 2004) revealed differences between measured and rated module STC power in the range of +4.9% to -19.7%, with average differences of about -3% to -5%.

The standards related to module performance are the IEC 61215 and IEC 61646 which lay down the requirements for the design qualification and type approval of terrestrial PV modules based on crystalline silicon and thin film materials. Modules that have received such certification have successfully passed a number of stringent environmental tests ensuring that they can withstand prolonged exposure in general open-air climates. However, the current 2nd edition and previous 1st edition of IEC 61215 for crystalline silicon modules lack a pass/fail criterion that would ensure that the modules meet the nameplate rating given by the manufacturer. As long as the degradation of the maximum output power as measured before and after the test does not exceed a prescribed limit (usually 5%), and the modules meets a number of additional criteria described in the standard, the module design is deemed to have passed the qualification tests. This loophole has been fixed within the 2nd edition of IEC 61646 currently in use and will also be fixed in the next edition of IEC 61215 under development by requiring that modules meet a minimum rating value specified by the manufacturer. In the meantime the UL 1703 PV module safety standard, and the equivalent ULc 1703 document recognized in Canada, require that, under standard test conditions (STC), the power output of the modules tested be at least 90% of their nameplate rating. This criterion has however been criticized as being too loose and this lack of tighter requirements in PV module standards may have contributed to the observed PV module underperformance in the field.

Using unrealistic module power ratings is detrimental to the accurate estimation of a system's performance ratio. In fact, the rise in PR observed in recent years in the PVPS performance database is attributed in part to the use of more realistic module power ratings (Jahn and Nasse, 2004).

3.5.3 Ageing of PV modules

Ageing of PV modules is actually a combination of two phenomena:

1. An initial, very rapid decrease in efficiency within the first few days of exposure.
2. A long-term decrease in efficiency over the year.

3.5.3.1 Initial decrease

Initial power loss for crystalline PV modules is estimated between 2.3% and 3.9% in Osterwald et al. (2002). Values between 2 and 3% are reported in Sakamoto and Oshiro (2003). Similarly, Dunlop et al. (2003) observed initial degradation of 2.6% ± 1.3% in a field test of 66 crystalline silicon modules. A value of 3% is typical and is included in the PR values documented in section 3.5.1.

3.5.3.2 Long term degradation

In a field test of 204 crystalline silicon PV modules, Skoczek et al. (2009) found that 70% of modules had an annual maximum power degradation rate lower than 0.75%, with only 35 out of 204 modules tested losing more than 20% of their rated power after 25 years. Ageing was fairly consistent among modules of the same type (i.e. manufacturer / construction). Similarly, Sakamoto and Oshiro (2003) reported an average performance loss of less than 0.5% per year for crystalline silicon PV modules based on testing of 150 modules exposed outdoors over a 10 year period. This is in agreement with an NREL study which suggests that monocrystalline and polycrystalline modules degrade at about 0.7% per year (Osterwald et al., 2002). De Lia et al. (2003) report 0.37% per year over 22 years. Based on these studies, it seems reasonable to assume that module degradation can be between 0.3 and 0.8% per year.

Nevertheless, it is worth noting that some studies do report higher degradation rates than this. For instance, a study by Tang et al. (2006) of modules exposed for 27 years to harsh hot desert climatic conditions found that those modules who survived experienced an average degradation of 1.1% per year. Similarly Rabii et al. (2003) report a 60% average loss over 12 years. Of course, since many of these modules were built, module technology has improved with advanced manufacturing and automation, and with improved module and production standards and certifications. This is demonstrated dramatically by Rosenthal et al. (1993) who found that “module failure rates dropped by an order of magnitude” following the implementation of the Block V module qualification test specifications in the early to mid 1980’s.

3.5.4 Availability

Annual availability reported around 95% for 116 systems in Germany, Italy and Switzerland (Jahn and Nasse, 2004). For recent installations, over 90% of systems have an availability greater than 90% and around 55% have an availability greater than 99%.

A study of 21 systems during 10 years of operation revealed that inverters contributed 63% of failures, modules 15% and other components 23%, with a failure occurring on average every 4.5 years (Jahn and Nasse, 2004).

For a 3.51 MWp plant comprising 26 individual systems, Moore and Post (2008) report over 150 unscheduled maintenance events over a 5 year period. This corresponds to a mean time between unscheduled services per system of 7.7 months of operation. Despite this, overall system effective availability was over 99.4% over these years. Failures include problems with the data acquisition system, inverter, junction boxes, PV array, and AC disconnect. Causes varied but included a severe lightning storm strike, high-contact resistance in the AC disconnects, lack of auto reset capability of the inverter, failure of blocking diodes, problems with nesting rodents. The majority of repair costs were associated with the inverters. The authors also mention problems with the utility-side capacity, the response of the PV system to cloud passages creating instabilities in the control system of the nearby coal power plant.

Another study of Japanese systems (Sugiura et al., 2003) reveals that inverters failed in 6% of systems and modules in 1% of systems. 45% of the systems experienced some occurrence of inverter problems (instability, power failure, or shift to power-limit mode). For these systems, the mean time between either problem or outright failure was estimated at 3.55 years, the mean time to repair (MTTR) was estimated at 24.6 days and overall system availability was 99.74%.

Unavailability due to inverter failure is however very variable as demonstrated by Maish et al. (1997) on various quasi identical systems where mean time between failures (MTBF) varied from 6.95 to 16.2 years and MTTR from 78 to 216 days, corresponding to availabilities between 83.5 and 98.3%. Failures are also more prone to occur in early life but usually with a shorter MTTR since products are new and easy to replace. Design of the inverter has a significant impact on its MTBF (Chan and Calleja, 2006), while parts availability and the presence of a local representative will impact the MTTR. Both must be considered to appropriately assess the availability. Another determining factor is fault monitoring: a system with no monitoring whatsoever is more likely to go down and stay that way for an extended period of time. Large systems are well monitored as downtimes can affect their productivity and revenues; thus, these are more likely to have less frequent and especially shorter downtimes. Moreover, large-scale systems will generally present better operating conditions for the inverters (ex: housing with temperature control), further contributing to reduced downtimes.

3.5.5 Presence of snow

Snow was reported as a factor for high losses in winter in an analysis of 500 systems in Japan (Ueda et al., 2008), but these still accounted for less than 2.2 % overall on a yearly basis.

A study by Sugiura et al. (2003) looking at 25 sites in Japan estimated losses due to snow at less than 0.7% in northern Honshu (near latitude 44°N) but as high as 3.5% in Hokkaido (a few degrees further North). Similarly a study by Becker et al. (2006) estimates the decrease of annual yield due to snow at between 0.3 and 2.7% for a 1 MWp system in Munich, Germany, indicating that these values are in line with operational data from other German systems. Wilk et al. (1994) estimated losses due to snow at 1% for one system at 300 m elevation and 3.3% for another system at 1,550 m elevation (with a 60° tilt) in Austria.

There are numerous parameters at play: type of snow (light, heavy), age of snow, radiation, temperature, tilt angle of the modules, type of mounting system, distance of modules to the ground. The complex interactions of these phenomena make it difficult to generalize the findings of the above studies, and render a more precise calculation of snow effects difficult.

3.5.6 Dirt and soiling

Accumulation of dirt and its effect on module performance is difficult to estimate and varies depending on dustiness of location, occurrence and frequency of rain, etc. The California Energy Commission (2001) estimates losses from dirt and dust accumulation at 7%.

Marion et al. (2005) recommend derate factors of 0.95 for soiling, with values ranging from 0.75 to 0.98. They mention that soiling is site- and weather-dependent. Areas with high-traffic, high-pollution and infrequent rain are the most susceptible. They mention up to 25% decrease for some California locations, however they don't substantiate it with data. The data may well represent a maximum derate at the end of the dry season, as suggested in Kimber et al. (2006).

Kimber et al. (2006) discuss the effect of dust on the power of PV systems in the South-Western USA. They show that soiling is a complex interaction of dust and rain. There is a marked decrease in module efficiency during the dry season. They also note that systems located in regions with significant rainfall (at least once a month) do not show significant decline in performance. Systems located in deserts, however, are very susceptible to dust build-up, with performance loss ranging from 0.1 to 0.3% per day. The average annual loss according to the model developed by the authors ranges from 1.5 to 6.2%. Kimber (2007) confirmed that figure in a controlled experiment of three systems in Los Angeles, CA (one washed, the other two not) with annual losses of 3.5% and 5.1%.

Hammond et al. (1997) note that the effect of soiling increases with the angle of incidence, from 2.3% under normal incidence to 7.7% when the angle of incidence reaches 56°. For the site their consider (Phoenix, AZ), soiling results in a maximum loss of 3% between periods of rain. 5 mm of rain reduces soiling losses to about 0.5%. They also mention that bird droppings are a much more serious problem than dust.

Haeberlin and Graf (1998) describe reduction of yield due to pollution, in their case by iron dust from nearby railway lines which leads to the growth of lichens. Power loss after three years was found to be 8 to 10% and was reversed by cleaning.

IEA PVPS Task 7 (2007) describes the mechanisms through which soiling occurs on modules. Those include dust, accumulation of dirt and growth of lichen (particularly at the lower edge of framed modules). They note that bird droppings represent a serious problem as, contrary to dust, they tend not to be washed away during rainy events. They mention that the average impact on energy production is relatively small, less than 2%, but modules with a tilt of 30° or less and high horizontal frame or cover profiles were found to lose from 2 to 6% on a annual basis. In the worst case the string delivered 18% more power after cleaning. Module soiling is generally reversible with appropriate rainfall, although dirt from exhaust fumes may be very hard to remove (this may be of particular concern for some roof-top systems).

PVUSA ("How Clean is My Array? The Real Dirt on Soiling,"PVUSA Project Update, Third Quarter 1999), cited in Frontier Zero (2010) and other sources, conducted experiments to determine the effect of soiling on modules and concluded that annualized soiling losses are around 7% during a normal rainfall year, but only 4% during a wet year.

3.5.7 Shading and tilt

Some row-to-row shading cannot be avoided in multiple row systems. This shading can be minimized by leaving more space between rows, and using a lower tilt. The combined effect of shading and tilt is best estimated for the location under consideration with the help of a simulation program. Very little or no uncertainty is attached to this as the occurrence of shading can be precisely modelled, so one can design systems to be shade-free most of the time. Nevertheless, array performance under partial shading conditions is still difficult to evaluate.

3.5.8 Other PV system losses

Other losses worth mentioning include thermal losses, spectral losses, losses due to reduced performance at low irradiance, losses due to reflection on the front surface of the modules, wiring and mismatch losses and losses due to DC to AC conversion by the inverter. On a yearly basis, thermal losses are around 2 to 10% (King et al., 2002) losses due to reflection are around 0 to 5% (King et al., 2002); spectral effects are usually in the range +1 to -3% on yearly basis (King et al., 2002). These losses are either small and/or can be well modelled by simulation programs (ex: thermal, angle of incidence and inverter losses), so that their individual contribution to the uncertainty in annual yield estimates is modest. The overall uncertainty in these “other losses” is estimated to be of the order of 3 to 5%.

3.5.9 Post-inverter losses

In most small scale systems, the AC side of the inverter is directly connected to the main distribution panel. Consequently, the only elements between the inverter and the meter are wires, breakers and switchgear. Resistance of switchgear and breakers, when selected according to applicable codes and properly maintained, is negligible. Losses in conductors however may become significant, especially when the inverters are far from the meter. For instance, Rule 8-102 of the CE Code (2009) mandates a maximum of 3% voltage drop at nominal power for the branch circuit and a maximum of 5% total voltage drop between the service entrance (PCC) and the point of utilization (inverter). While it would not be wise to use the minimum wire size for a PV system, the upper range of voltage drops allowed by this rule would be associated with significant losses. Knowing the wire size and length allows detailed simulation software to account for the wiring losses as the output power of the inverter fluctuates. Variation in wire resistance at a specific gauge and temperature is very low since wire manufacturers must strike a narrow balance between minimizing the cost of copper and conforming to maximum resistance standards. The main variables affecting voltage drop in a given system are thus the selection of the initial resistance value and temperature fluctuations. It is important to select the resistance value at the expected cable operating temperature to avoid any bias in estimated losses; this can easily be accomplished by verifying the reference conditions of the resistance tables used and correcting the values if necessary.

Accurately accounting for conductors' temperature variation, on the other hand, is definitely more demanding and is beyond most photovoltaic simulation tools. In order to encompass all the possibilities it is appropriate to consider the full span of temperatures as our uncertainty window. Inside wiring in a heated room could span from room temperature (e.g. 20°C) to wire insulation rating (e.g. 60, 90°C), assuming it has been properly installed. Outside wiring on the other hand can drop in temperature during winter and also rise to its maximum insulation temperature. In what could be considered a worst case scenario of -20 to 90°C temperature span, assuming a 5% maximum voltage drop design, losses would vary between ~2 and 3.5%. On the other hand with a more realistic 1% maximum voltage drop design, losses would only be in the range of ~0.5 to 0.75%.

In multi-megawatt systems or installations with multiple voltage level requirements (e.g. a commercial building supplied at 600V with a 240V PV system) a dedicated post-inverter transformer may be necessary to, usually, step up the voltage. Since this transformer is part of the system owner's installation, losses caused by this transformer will translate into losses of revenue. Transformer losses are divided into two parts: no-load (core) losses and ohmic (winding) losses. No-load losses are constant, whether the transformer is loaded or not and are essentially due to eddy currents and magnetisation of the core. The magnetic material and geometry of the core is the determining factor for these losses. Ohmic losses, on the other hand, are proportional to the loading of the transformer and depend on the material and size of the wires used for the windings of the transformer.

Consequently, transformer construction is a determining factor in establishing their losses. As a rough estimate, for a 1 MVA unit and production typical of a 1MW PV system in Ontario, an amorphous metal based transformer will generally have total losses of around 0.85-1% (core:winding loss proportion of 1:3), a good silicon steel based transformer around 1.5-2% (1.3:1) and a standard transformer around 2-3% (1:2). For accurate simulation, the manufacturer will be able to provide the necessary parameters to simulate the nominal losses. Variability in transformer parameters has been studied by (teNyenhuis and Girgis, 2006) and they conclude that for distribution transformers of the same type, core losses show a *relative* uncertainty in the range of -6% to 10%, while load losses have a *relative* uncertainty between -2% and 1.5%.

To summarize, overall post-inverter losses can be fairly significant, ranging anywhere from about 1% to as high as 7% if poor cabling choices are made. However, if the cabling specifications and lengths are known, as well as the transformer type, uncertainties in post-inverter losses are relatively modest (of the order of 1% or less) compared to that of other losses discussed here.

3.6 Modeling uncertainty

In addition to the uncertainties mentioned in sections 3.2-3.5, modeling of the system itself with simulation tools is a source of uncertainty. Estimates of this uncertainty vary widely but are typically 3 to 5% if the modules are well characterized. For example, Fanney et al. (2009) report predicted DC annual energy production values within 4 to 6% of measured values when using well calibrated modules and irradiance measured in the plane of the array. Jahn and Nasse (2004) report a 3 to 4% difference between annual design values and real performance results (performance indicators used actual, not nominal, module power). Annual performance calculated with various algorithms in the Solar Advisor Model (Cameron et al., 2008) was found to be over-estimated by between 2.4% and 9.1% if wiring and soiling losses and other derates are not taken into account. Inverter modeling is also generally not a major source of uncertainty (< 1%) in simulation programs as inverter efficiency curves are fairly well characterized. Other sources of errors include the effect of mismatch between modules, uncertainty in the initial derating of modules (see section 3.5.3.1), and other hard-to model effects. Generally speaking, modeling uncertainty of less than 5% seems hard to achieve even with well-calibrated software.

4 STATISTICAL SIMULATIONS

The uncertainties described in the previous sections can be combined to estimate the global uncertainty in long-term photovoltaic yield predictions for a specific location. This is illustrated with the use of a statistical simulation for a system located near Toronto, ON. The simulation program used is the Solar Advisor Model[8] (SAM), version 2010.4.12. The study makes use of the statistical capabilities of SAM through the use of its parametric, sensitivity and statistical analysis options. Starting from a base case, we look at the effect of year-to-year climate variability, then separately at the effect of various uncertainties, then finally at the combined effect of uncertainties and climate variability. Ageing and availability are considered in a last set of simulations.

4.1 Base case

The base case is a 10 MW AC solar farm located near Toronto, ON. The system comprises 20 SMA SC500U inverters rated at 506 kWac, and 60,160 BP Solar SX 3200N modules rated at 200 Wp; each inverter is connected to 188 strings of modules in parallel, each string having 16 modules in series. For the purpose of simulation only 1/20th of the system (i.e. one inverter) is considered. As SAM does not allow detailed modelling of post-inverter components (transformers, wiring, etc.), these were excluded from the current analysis, and all deratings were lumped under the pre-inverter derate factor, selected to give a realistic performance ratio for a megawatt-scale PV system. Simulation parameters for this subsystem are summarized in Table 1.

Table 1 - Default system parameters.

Parameter	*Value*
Inverter	SMA SC 500U
Inverter size (kWac)	506.7
PV Modules	BP Solar SX 3200N
Modules per string	16
Strings in parallel	188
Array peak power (kWp)	601.4
Tilt	35°
Azimuth	Due South
Pre-inverter derate factor	0.85
Post-inverter derate factor	1
Ground reflectance[9]	0.1 (no snow) 0.15 (with snow)
Climate file	Toronto Airport (WBAN 04714) CWEC file

[8] https://www.nrel.gov/analysis/sam/
[9] See explanation in section 4.3.4.

Other SAM settings are as follows[10]:

- radiation model is based on total and beam,
- tilt radiation model is Perez,
- no array shading,
- CEC performance model is used for the PV modules,
- Sandia performance model is used for the inverter.

SAM simulation for this system predicts an annual energy output of **717.6 MWh**, i.e. a yield of **1,193 kWh/kWp** and a system performance ratio of **0.80**.

4.2 Effect of climate variability

In this first variability study, system parameters are kept to their nominal value but the climate file is replaced by individual years from the 1960-1989 period, which covers the whole period from which the CWEC file was assembled. This enables us to compare the calculation for a 'typical' year to production for individual years. The results are expressed in terms of yield and are shown in Figure 2. The figure shows that, for the reference system, there is roughly an 80% chance that the annual yield for any year will be between 1142 and 1254 kWh/kWp. The mean yield over all the years is 1,196 kWh/kWp, very close to the value predicted from the typical year (**1,193 kWh/kWp**); the standard deviation is **46.3 kWh/kWp** or **3.9%** of the mean. This is very similar to the year-to-year variability of solar radiation for this location, as can be seen in Table 5 of Appendix B.

[10] For details on the models used, consult the SAM User Guide at https://www.nrel.gov/analysis/sam/

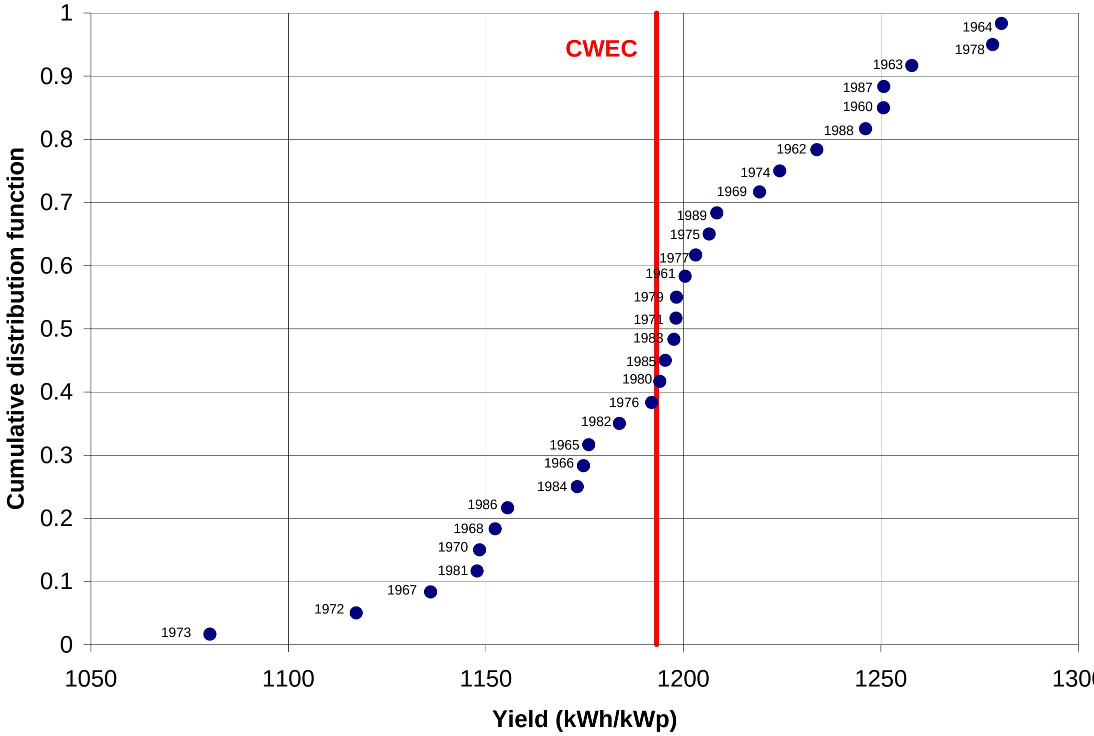

Figure 2 - CDF of yield calculated over 30 years with a nominal system performance.

4.3 Effect of other uncertainties

Uncertainties in solar radiation, characteristics of the system, and modeling, are studied by running a Monte-Carlo simulation with SAM[11]. The various parameters considered in this simulation are summarized in Table 2.

Table 2 - Types of uncertainties modeled.

Variable	*Uncertainty distribution*
Solar radiation	Normal (0%, 5%)
Transposition model	Normal (-2%, 3%)
Power rating of modules	Normal (-3%, 3%)
Dirt and soiling	Normal (-3%, 2%)
Snow	Normal (-2%, 1.5%)
Albedo	Uniform (0.1, 0.15)
Other (modeling errors, spectral effects, etc.)	Normal (-5%, 5%)

The uncertainty distributions in Table 2 were chosen as representative of large scale PV systems, with the spread of the distributions (standard deviation or range) reflecting the range of uncertainties of each variable as discussed in section 3. The reason for those choices, as well as how these distributions are entered into SAM is detailed in the remainder of section 4.3. It is

[11] SAM actually uses a variant of the Monte Carlo method called the Latin Hypercube Sampling or LHS method.

worth noting that variables do not appear here in the same order as in section 3, since certain variables had to be grouped for the purposes of modeling PV yield uncertainty with SAM.

4.3.1 Solar radiation

Uncertainty distribution: Normal (0%, 5%)

While an hourly simulation was performed to estimate annual PV system yield as accurately as possible, annual yield is to a good approximation primarily influenced by the yearly total insolation in the plane of the array, and relatively insensitive to the underlying hourly distribution. Thus, solar radiation uncertainty was represented by uncertainty in the yearly total insolation. While mostly measured data was used in this analysis, an uncertainty of 5% was modelled as representative of an optimal case where data must be either interpolated from other stations or derived from satellite.

SAM does not allow the user to stochastically modify solar radiation read from the climate files. The uncertainty associated with solar radiation therefore had to be manually varied. The normal distribution was divided into five regions of equal probability, and the central point of each region was taken as the representative sample for which simulations were run (this is somewhat akin to stratified sampling; see Gentle, 2003). This is illustrated in Figure 3. The corresponding five points are at -1.2816, -0.5244, 0., 0.5244, and 1.2816. Then, the CWEC file used in the simulation was modified to generate five files corresponding to these five points on the CDF. *All* irradiance values in the CWEC file were multiplied by a constant factor according to the point considered on the CDF. The uncertainty associated with solar radiation being taken as 5%, the multiplicative factors are therefore:

$1 - 1.2816 \times 0.05 = 0.9359$
$1 - 0.5244 \times 0.05 = 0.9738$
$1 + 0.0 \times 0.05 = 1$ (this corresponds to the original CWEC)
$1 + 0.5244 \times 0.05 = 1.0262$
$1 - 1.2816 \times 0.05 = 1.0641$

The method outlined here can of course be criticized, in particular because it could potentially lead to unrealistically high values of solar irradiance. However it has several merits. First, it can receive a simple physical interpretation: the multiplicative factor applied to all radiation values can be viewed, for example, as an improper calibration of the pyranometers. The method also has the merit of being simple and of modeling reasonably well the uncertainty attached to the evaluation of solar radiation. Finally, this method can also be combined with straightforward Monte-Carlo simulations to study the rest of the parameters.

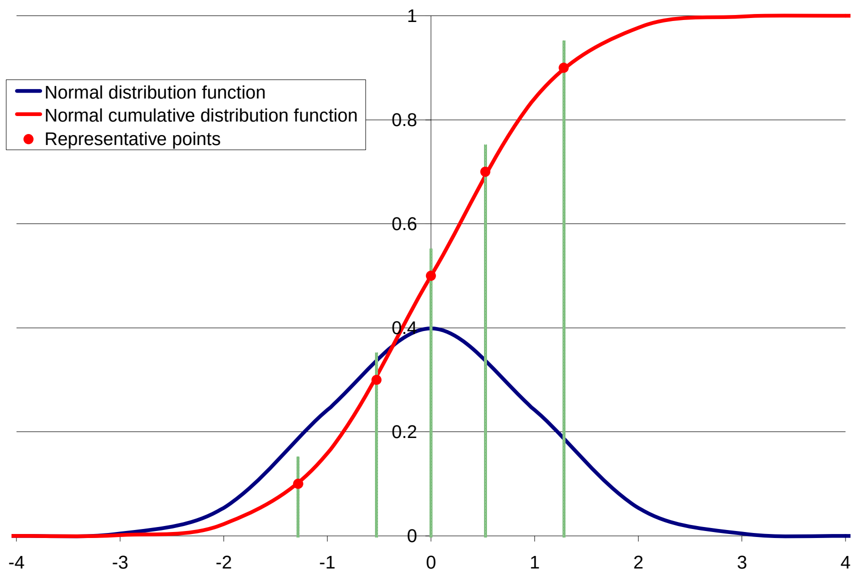

Figure 3 - Points chosen on normal CDF

4.3.2 Transposition model and dirt

Uncertainty distribution: Normal (-2%, 3%)

The uncertainty for the transposition model is the one mentioned in section 3.4. For dirt, it is believed that rain will wash the arrays often enough that the derating should be lower than in California, so a value between 0 and 5% seems appropriate. However some sites may be more susceptible to dirt because of the proximity to busy roads, agricultural operations or heavy industries. This is reflected in using a fairly significant uncertainty (2%) on top of the average value of 3%.

These two uncertainties modify the amount of solar radiation available in the plane of the array, before it reaches the solar cells. Once again SAM does not allow the user to explicitly apply stochastic variations to this quantity, however the program can be tricked into doing so by modifying two of the parameters of the CEC PV module performance model, namely the reference irradiance I_ref and the NOCT irradiance I_noct (by modifying I_noct, one simulates the effect of a lower or higher irradiance on cell temperature). The two uncertainties for transposition and dirt are combined as a normal distribution[12] (-2%-3%=-5%, $[3\%^2+2\%^2]^{1/2}$ = 3.61%).

4.3.3 Power rating of modules

Uncertainty distribution: Normal (-3%, 3%)

The 3% uncertainty used here is typical of the tolerance usually given by the module manufacturers. It assumes that the modules will indeed perform according to their rating, which

[12] For the calculation of combined standard deviation, see Section A.3.

is the case for most modules from reputable manufacturers (big developers may also be able to enforce this to some extent). The uncertainty does not cover the case of unrealistic power ratings given by some manufacturers (see section 3.5.2). The -3% bias is typical of light-induced degradation of PV modules in the first few days of operation.

This uncertainty is simply entered in SAM as a pre-inverter derating.

4.3.4 Albedo

Uncertainty distribution: Uniform (0.1, 0.15)

The albedo value between 0.1 and 0.15 is an educated guess. The value is chosen to account for the fact that rows beyond the second one receive little reflected solar radiation, so albedo should be lower than the frequently used value of 0.2.

In SAM, uncertainty can be applied directly to the albedo. Note that albedo in the presence of snow is varied in the same proportion; a correlation between the two uncertainties is used with SAM.

4.3.5 Snow, post-inverter losses and other modeling errors

Uncertainty distribution for snow: Normal (-2%, 1.5%)

Uncertainty distribution for post-inverter losses, and modeling and other errors: (-5%, 5%)

As indicated in section 3.5.5 the presence of snow seems to have a limited impact on energy production. The uncertainty of 1.5% around an average of -2% seems representative of numbers found in the literature. Modeling and other errors are estimated around 5% as per section 3.6. This figure is taken to include the uncertainty in post-inverter losses of less than 1% discussed in 3.5.9.

These two errors are combined and are applied as a post-inverter derating. This is probably the most appropriate way to take them into account, since they represent global errors that cannot be attached to any particular sub-model in the program (snow is very seasonal, and is therefore not treated the same way as dirt, although the mechanisms are somewhat similar). The resulting error is a normal distribution (-2%-5%=-7%, $[1.5\%^2+5\%^2]^{1/2} = 5.22\%$).

Other uncertainties such as ageing and failures/outages will be treated separately in Section 4.5.

4.3.6 Simulation

SAM was run in statistical mode with the various distributions described above. The 'typical' CWEC climate file was used.

It should be noted that the means of the distributions were ignored in SAM, i.e. all distributions were centered around zero. The reason is that the default case run in Section 4.1 already includes a pre-inverter derating of 15%, which is roughly equivalent to the sum of the biases from the various distributions. *Not* centering the distributions around zero would be equivalent to counting the biases *twice*.

The number of simulation runs[13] necessary to represent properly the uncertainty of the yield is not easy to determine. Appendix C shows that the *average* yield determined from statistical simulations is estimated with a confidence inversely proportional to the square root of the number of simulation runs, and that the *standard deviation* of the yield is estimated with a confidence inversely proportional to the number of simulation runs to the power 1/2. Appendix C indicates that 100 simulation runs provides a reasonable confidence in the results while keeping the run-time short (less than 10 minutes).

SAM performed 100 yearly runs for each of the five climate files considered (the original CWEC file and the four files where radiation has been modified), for a total of 500 simulation runs. The histogram of annual yield simulated by SAM when all the effects above are considered is shown in Figure 4. This figure shows that, for a 'typical' year, there is roughly an 80% chance that the yield of the system is between 1,073 and 1,318 kWh/kWp. The mean yield over all the simulation runs is **1,195 kWh/kWp**, the standard deviation is **93 kWh/kWp** or **7.8%** of the mean.

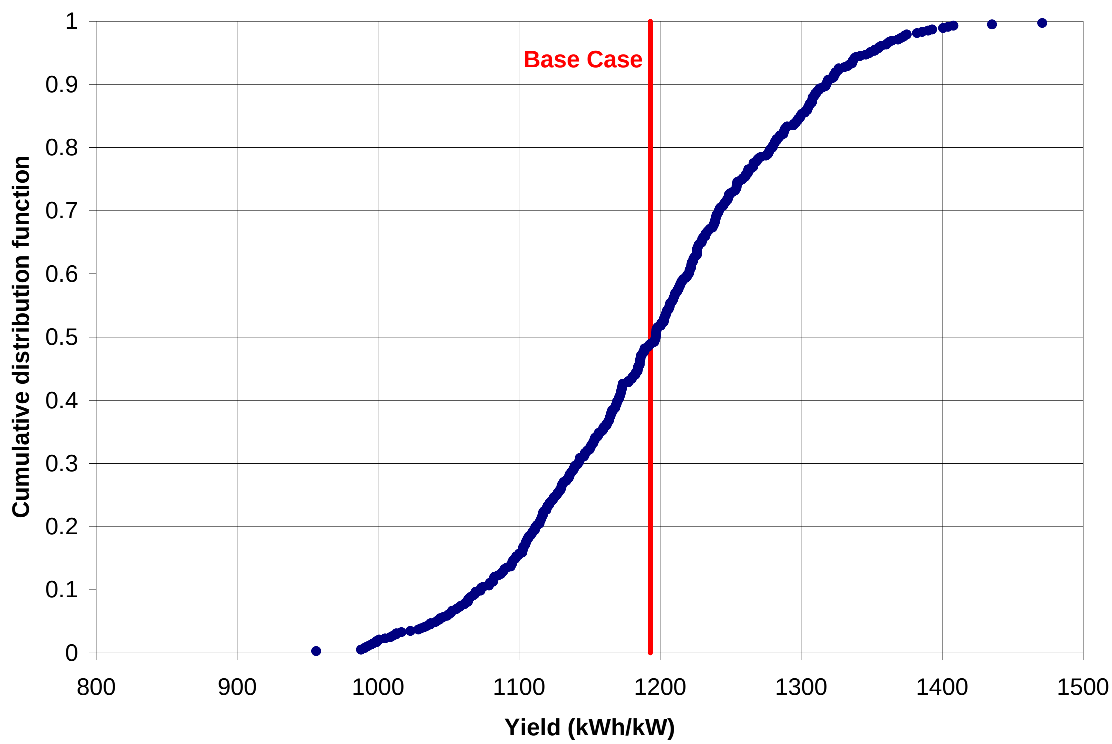

Figure 4 - CDF for all uncertainties but for a typical year.

[13] Monte Carlo simulation runs are also referred to as realizations by some authors.

4.4 Global uncertainty in year one PV predictions

In this set of simulations, the uncertainty due to climate variability (section 4.2) is combined with the uncertainty due to system parameters and modeling (section 4.3) to provide an overall picture of the uncertainty in PV yield prediction.

Unfortunately SAM does not allow the user to vary the climate file as part of the statistical simulation. One way around this is to repeat the procedure of section 4.3 for each of the 30 individual years - but this is a time consuming procedure which requires 30 years × 5 radiation-modified files × 100 runs = 15,000 simulation runs of the program. To speed things up, only 10 individual years were considered. The CDF function of Figure 2 was divided into segments 0.1 wide, and the central point in each segment was chosen as representing the segment (again this is somewhat akin to stratified sampling). Thus, the years 1972, 1970, 1984, 1982, 1985, 1979, 1975, 1974, 1960 and 1978 were chosen. The statistical simulations were run for every combination of year and radiation modification selected, then all the simulations were combined. The total number of simulation runs is 5,000 (10 × 5 × 100). The resulting histogram depicting the global uncertainty in year one PV yield prediction is shown in Figure 7. The figure shows that there is roughly a 80% chance that the yield of the system, for any year, is between 1,068 and 1,337 kWh/kWp. The mean yield over all simulation runs is **1,200 kWh/kWp**; the standard deviation is **105 kWh/kWp** or **8.7%** of the mean.

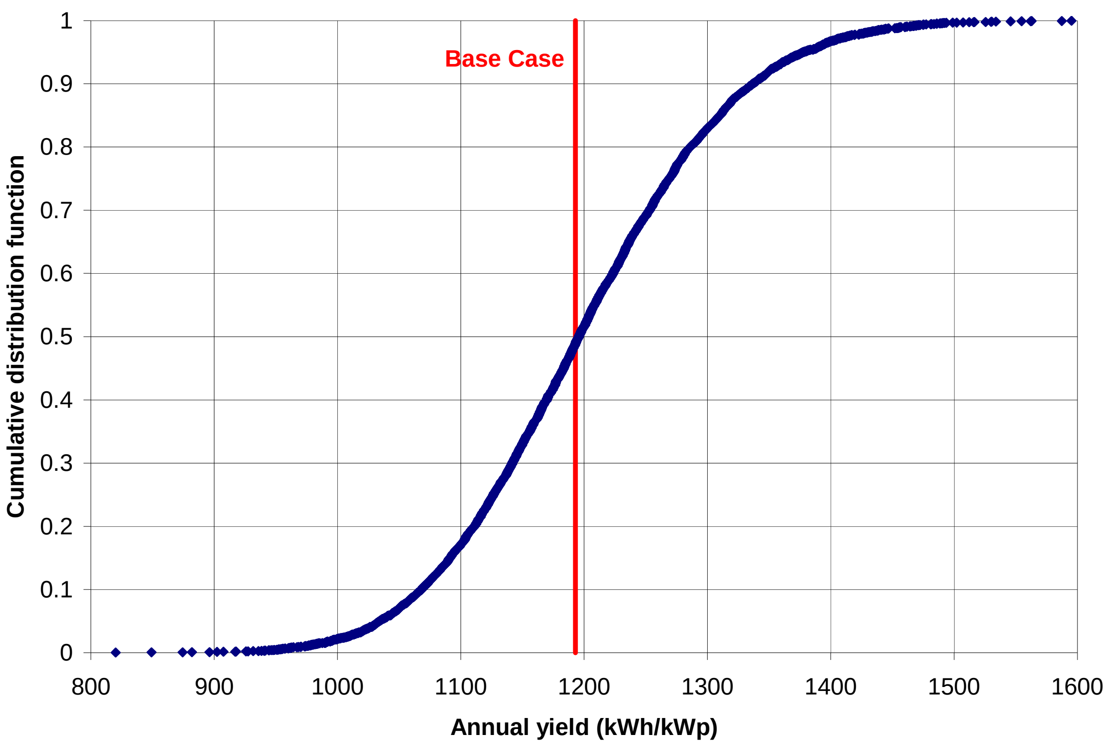

Figure 5 - CDF for year one yield considering all uncertainties and climate variability.

4.5 Lifetime uncertainty

In this final simulation, the results of the previous sections are combined with data about ageing and failure to calculate the 20-year average yield. For the purpose of illustration, ageing is modeled as a uniform distribution [-0.3, -0.8] %/year, as per section 3.5.3.2, and availability is modeled as a uniform distribution [0.985, 0.995], as per section 3.5.4 (this high value of availability is suitable for large, well-monitored systems; it wouldn't be suitable for residential systems).

The quantity of interest here is the yield averaged over 20 years. This means that yearly fluctuations of the solar resource, as studied in section 3.3, can be ignored (standard deviations of the average insolation over different 20 year periods in Toronto are of the order of 0.44%). Instead, the uncertainty related to ageing and failure has to be combined with the curve of Figure 4. This is done through a post-processing of the data previously calculated; no new simulation is run. The resulting CDF is shown in Figure 6. Lifetime average annual yield is **1,119 kWh/kWp**, with a standard deviation of **89 kWh/kWp** or **7.9%** of the mean (only slightly above that of Figure 4).

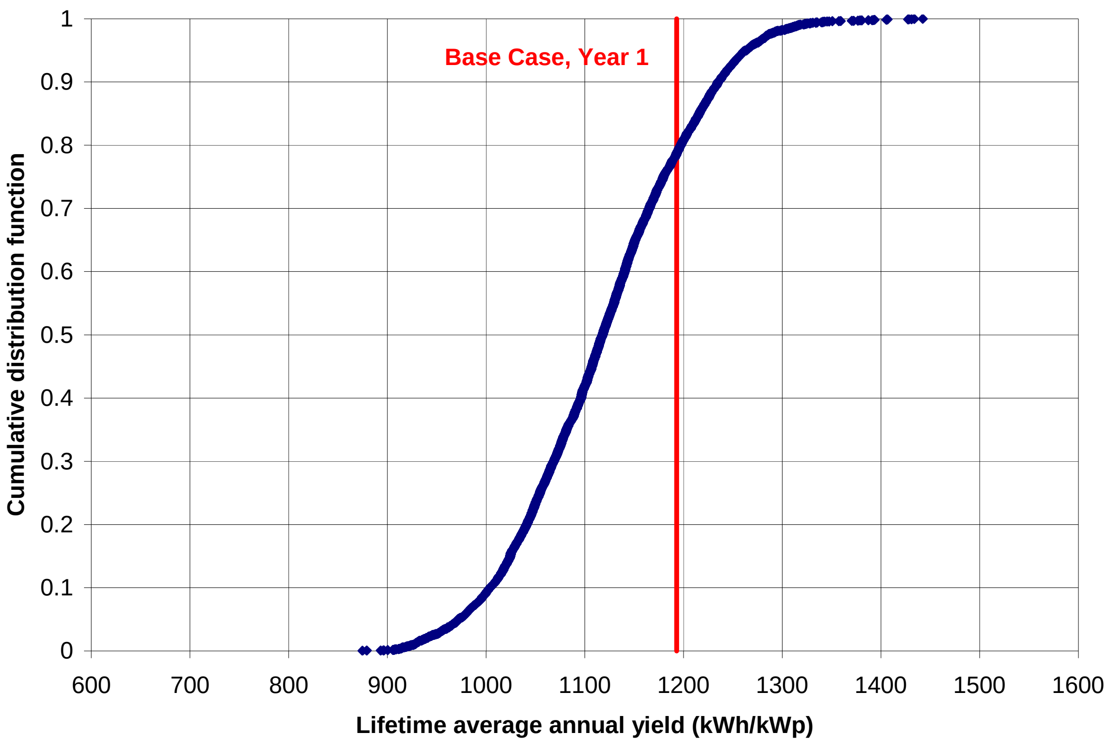

Figure 6 - CDF for lifetime average annual yield.

4.6 Discussion

It is not clear whether Monte-Carlo simulations present a great advantage in the study of PV systems such as the one described in this report. With the exception of the transposition model, all components of a PV are essentially linear (output = input × proportionality factor - offset, with the offset relatively small compared to the phenomenon itself) so the uncertainties combine very roughly according to the rule of squares (Appendix A.3). The main uncertainties used in sections 4.2 to 4.4 are:

3.9% for climate variability
5% for solar radiation
3% for transposition model
3% for power rating of modules
2% for dirt and soling
1.5% for snow
5% for other errors

Using the rule of squares the combined uncertainty is:

$$\sqrt{3.9^2 + 5^2 + 3^2 + 3^2 + 2^2 + 1.5^2 + 5^2} = 9.45\%$$

which is close to the estimate (8.7%) obtained with statistical simulations in section 4.4. This indicates that should different numbers be used for the various uncertainties mentioned in this report, the rule of squares can be used in lieu of full statistical simulations to obtain the global uncertainty attached to the yield of the system.

5 CONCLUSIONS AND RECOMMENDATIONS

This report has summarized the uncertainties associated with the prediction of long-term photovoltaic (PV) yield. The report addresses mainly uncertainties facing large-scale PV developers, although some of the conclusions may also be applicable to small systems.

The uncertainties facing developers include factors such as expected yield, government policies and decisions, issues related to permitting, siting and grid connection, cost, availability and quality of equipment, and financing and legal matters. They can differ depending on the type of installation planned (large or small) and the kind of mounting structure (ground-mounted or building integrated). Uncertainties can be reduced, for example, by providing more clarity in policies regarding PV systems and grid connection (e.g. feed-in tariffs, domestic content, municipal taxes), and simplifying permitting requirements or making them more uniform across local jurisdictions.

Developers can also ensure that their procurement and contracting strategies minimize risks and uncertainties. For instance, PVUSA (Dows et al., 1995) studied “procurement, acceptance and ratings practices” for PV power plants and included detailed guidelines for utilities or other developers. These include recommendations such as making the final payment dependent on system rating as determined in a “30 day rating period” after system installation is complete. This helps ensure that module rating reflects initial degradation and offsets uncertainty in the PV module ratings by stipulating that either the module cost or the number of modules delivered will be adjusted based on the rating obtained in the field.

Statistical simulation tools are helpful to evaluate quantitatively uncertainties related to yield. The uncertainties relate mostly to the evaluation of the solar resource and to the performance of the system itself. In the best of cases, uncertainties are typically 4% for year-to-year climate variability, 5% for solar resource estimation (in a horizontal plane), 3% for estimation of radiation in the plane of the array, 3% for power rating of modules, 2% for losses due to dirt and soling, 1.5% for losses due to snow, and 5% for other sources of error. A Monte-Carlo type simulation was used to look at the combined effect of these uncertainties on the annual yield of a typical large PV farm in Ontario. It was found that the combined uncertainty (in a RMSE sense) is of the order of 8.7% for individual years, and of 7.9% for the average yield over a 20 year system lifetime.

The numbers above are thought to be representative of good-quality installations in Ontario. However they could vary significantly from location to location or from system to system. Uncertainties could be further reduced by exploring the following avenues:

- Solar resource: current estimates from various sources vary sometimes widely. Effects of micro-climates are not well known. Reliable data sources are often interpolated over large distances, or supplemented by satellite-derived data which still suffer from serious shortcomings. More work is needed to increase the reliability and spatial coverage of solar radiation estimates.

- Module rating: there is still some confusion as to the tolerance on the initial power of modules. It appears that, at the moment, checking this tolerance is the responsibility of the developer. More clarity is needed to put all manufacturers on a level playing field and to reduce the uncertainty faced by developers.
- Some of the losses experienced by systems are not known with great certainty. This concerns in particular losses due to dirt and soiling, and losses due to snow. Current numbers are extrapolated from other jurisdictions, but their effects need to be actually measured across the variety of climates experienced in Canada.

6 REFERENCES

Atmaram et al. (2008) Need for uniform photovoltaic module performance testing and ratings, Proceedings of the 33rd IEEE Photovoltaic Specialists Conference, 1-6.

Becker et al. (2006) An approach to the impact of snow on the yield of grid-connected PV systems. Proc. European PVSEC, Dresden. Preprint available from http://www.sev-bayern.de/content/snow.pdf.

California Energy Commission (2001) A guide to photovoltaic system design and installation. Downloadable from http://www.energy.ca.gov/reports/2001-09-04_500-01-020.PDF

CE Code (2009) C22.#-01 Canadian Electrical Code, Part 1, 21st Edition, Canadian Standards Association, 590 pages.

Carr AJ and Pryor TL (2004) A comparison of the performance of different PV module types in temperate climates, Solar Energy 76, 285-294.

Cameron CP, Boyson WE and Riley DM (2008) Comparison of PV system performance-model predictions with measured PV system performance. Proc 33rd IEEE PVSC, San Diego, CA.

Chan F and Calleja H (2006) Reliability: A New Approach in Design of Inverters for PV Systems, 10th IEEE International Power Electronics Congress, 6 pages.

Crandall KC and Seabloom RW (1970) Engineering fundamentals in measurements, probability, statistics, and dimensions. McGraw-Hill.

Davies and McKay (1989) Evaluation of selected models for estimating solar radiation on horizontal surfaces. Sol Energy 43 (3) 153-168.

De Lia F, Casteloo S and Abenante L (2003) Efficiency degradation of C-Silicon photovoltaic modules after 22-year continuous field exposure. Proceedings of the 3rd World Conference on Photovoltaic Energy Conversion, May 11-18, Osaka, Japan, 2105-2108.

Detrick A, Kimber A and Mitchell L (2005), Performance Evaluation Standards for Photovoltaic Modules and Systems, Conference Record of the Thirty-first IEEE Photovoltaic Specialists Conference, 1581-1586.

Dows RN, Gough EJ and PVUSA Project Team (1995) PVUSA Procurement, Acceptance and Rating Pratices for Photovoltaic Power Plants. Pacific Gas and Electric Co R&D Report # 95-30910000.1.

Drif et al. (2007) Univer project. A grid connected photovoltaic system of 200 kWp at Jaén University. Overview and performance analysis. Sol Energ Mat Sol C 91, 670-683.

Dunlop ED (2003) Lifetime performance of crystalline silicon PV modules, Proceedings of the 3rd World Conference on Photovoltaic Energy Conversion, May 11-18, Osaka, Japan, 2927-2930.

Durisch W and Bulgheroni W (1999) Climatological investigation for solar power stations in the Swiss Alps.

EC/JRC/Institute for Environment and Sustainability (2007) Scientific Technical Reference System on Renewable Energy and Energy End-Use Efficiency – Status Report 2006. Chapter 7: Solar resource data and tools for an assessment of photovoltaic systems. Downloadable from http://re.jrc.ec.europa.eu/refsys/pdf/REFREE%20Status%20Report%202006.pdf

Fanney AH, Dougherty BP and Davis MW (2009) Comparison of predicted to measured photovoltaic module performance. J. Sol Energy Engineering, 131, 021011-1 to 021011-9.

Frontier Zero (2010) http://frontierzero.com/springervillesolar.htm

Gentle JE (2003) Random number generation and Monte Carlo methods, 2nd edition. Springer.

Gueymard C (2009) Direct and indirect uncertainties in the prediction of tilted irradiance for solar engineering applications. Solar Energy 83, 432-444.

Haeberlin H and Graf JD (1998) Gradual reduction of PV generator yield due to pollution. Proc. 2nd PVSEC, Vienna, Austria. Downloadable from http://labs.ti.bfh.ch/fileadmin/user_upload/lab1/pv/Pollpv2.pdf

Hammond R, Srinivasan D, Harris A, Whitfield K, and Wholgemuth J (1997) Effects of soling on PV module and radiometer performance. Proc. 26th IEEE PVSC, Sep 30-Oct 3, Anaheim, CA.

Hinkelman LM et al. (2009) Surface insolation trends from satellite and ground measurements: comparisons and challenges. J Geophys Res 114, D00D20.

IEA PVPS Task 7 (2007) Reliability Study of Grid Connected PV Systems - Field Experience and Recommended Design Practice. Report IEA-PVPS T7-08: 2002, March 2002. Downloadable from: http://www.iea-pvps.org/products/download/rep7_08.pdf

IEA PVPS Task 2 (2007) Cost and performance trends in grid-connected photovoltaic systems and case studies. Report IEA-PVPS T2-06: 2007

IEC (1998) Standard IEC 61724 ed 1.0, Photovoltaic system performance monitoring – Guidelines for measurement, data exchange and analysis. International Electrotechnical Commission.

Jahn and Nasse (2004) Operational performance of grid-connected PV systems on buildings in Germany. Prog Photovolt Res Appl 12, 441-448.

Kimber A, Mitchell L, Nogradi S and Wenger H (2006) The effect of soiling on large grid-connected photovoltaic systems in California and the Southwest region of the United States. Proc. 4th IEEE World Conference on Photovoltaic Energy Conversion, Waikoloa, Hawaii, USA; May 7-12, 2006.

Kimber A (2007) The effect of soiling on photovoltaic systems located in arid climates. Proceedings 22nd European Photovoltaic Solar Energy Conference.

King DL, Boysen WE and Kratochvil JA (2002) Analysis of Factors Influencing the Annual Energy Production of Photovoltaic Systems. Proc. 29th IEEE PVSC, New Orleans, May 20-24, 2002.

Labed S and Lorenzo E (2004) The impact of solar radiation variability and data discrepancies on the design of PV systems. Renew Energ 29, 1007-1022.

Maish AB et al. (1997) Photovoltaic System Reliability. Conference Record of the Twenty-Sixth IEEE Photovoltaic Specialists Conference, Anaheim, CA, USA, 1049-1054.

Marion B et al. (2005) Performance parameters for grid-connected PV systems. Proc 31st IEEE PVSEC, Lake Buena Vista, FL, USA, Jan 3-7. Downloadable from http://www.nrel.gov/docs/fy05osti/37358.pdf.

Marion B, Rodriguez J and Pruett J (2009) Instrumentation for evaluating PV system performance losses from snow. Proc 2009 ASES National Solar Conference, Buffalo, NY. Downloadable from http://www.nrel.gov/docs/fy09osti/45380.pdf.

Mesinger F, Dimego G, Kalnay E, Mitchell K, Shafran P, Ebisuzaki W, Jovi D, Woollen J, Rogers E, Berbery E, Ek M, Fan Y, Grumbine R, Higgins W, Li H, Lin Y, Manikin G, Parrish D and Shi W (2006) North American Regional Reanalysis. Bulletin of the American Meteorological Society 87, 3, 343-360. Downloadable from http://journals.ametsoc.org/doi/pdf/10.1175/BAMS-87-3-343.

Moore LM and Post HN (2008) Five years of operating experience at a large, utility-scale photovoltaic generating plant. Prog Photovolt Res Appl 16, 249-259.

Morris RJ and Skinner WR (1990) Requirements for a solar energy resource atlas for Canada. Proc. 16th annual conference of the Solar Energy Society of Canada, Inc., Halifax, NS, June 18-20, 1990, 196-200.

Myers DR et al. (2004) Optical radiation measurements for photovoltaic applications: instrumentation, uncertainty and performance. Proc SPIE's 49th annual meeting, Denver, CO, Aug 2-6, 2004. Downloadable from http://www.nrel.gov/docs/gen/fy04/36321.pdf.

Myers DR et al. (2005) Broadband model performance for an updated national solar radiation database in the United States of American. ISES 2005 Solar World Congress, Orlando, FL, Aug 6-12, 2005. Available at http://www.nrel.gov/docs/fy05osti/37699.pdf.

NASA (2009) Surface meteorology and Solar Energy (SSE) Release 6.0 - Methodology. Available from http://eosweb.larc.nasa.gov/sse/documents/SSE6Methodology.pdf.

Notton G et al. (2006) Predicting hourly solar irradiations on inclined surfaces based on the horizontal measurements: performances of the association of well-known mathematical models. Energ Convers Manag 47, 1816-1829.

NRCan (2008) Photovoltaic potential and solar resource maps of Canada. Available at https://glfc.cfsnet.nfis.org/mapserver/pv/index_e.php

Osterwald CR, Anderberg A, Rummel S and Ottoson L (2002) Degradation analysis of weathered crystalline silicon PV modules. Proc. 29th IEEE PVSC, 1392-1395.

Pelland S et al. (2006) The development of photovoltaic resource maps for Canada. Proc. 31st Annual Conference of the Solar Energy Society of Canada (SESCI). Aug. 20-24th 2006, Montréal .

Poissant Y (2009) Field Assessment of Novel PV Module Technologies in Canada, Proc. 4th Canadian Solar Buildings Conference, June 2009, Toronto. Paper available on CanmetENERGY website: http://canmetenergy-canmetenergie.nrcan-nrcan.gc.ca/eng/renewables/standalone_pv/publications/2009105.html

Queen's University,(2010) Effects of snow on photovoltaic performance. Applied Sustainability Research Group page at http://www.appropedia.org/Effects_of_snow_on_photovoltaic_performance

Rabii AB, Jraidi M and Bouazzi AS (2003) Investigation of the degradation in field-aged photovoltaic modules. Proceedings of the 3rd World Conference on Photovoltaic Energy Conversion, May 11-18, Osaka, Japan, 2004-2006.

RETScreen (2004) RETScreen - Photovoltaic Project Analysis - e-Textbook chapter. Downloadable from http://www.retscreen.net/ang/textbook_pv.html

Rosenthal AL, Thomas MG and Durand SJ (1993) A ten year review of performance of photovoltaic systems, Conference record of the 23rd IEEE Photovoltaic Specialists Conference, 10-14 May 1993, Louisville, KY, p1289-1291.

Sakamoto S and Oshiro T (2003) Field test results on the stability of crystalline silicon photovoltaic modules manufactured in the 1990's. Proceedings of the 3rd World Conference on Photovoltaic Energy Conversion, May 11-18, Osaka, Japan, 1888-1891.

Schroeder TA, Hamber R, Copps NC and Liang S (2009) Validation of solar radiation surfaces from MODIS and reanalysis data over topographically complex terrain. J. App. Meteor. Climat. 48, 2441-2458.

Skoczek A, Sample T and Dunlop E (2004) The results of performance measurements of field-aged crystalline silicon photovoltaic modules. Prog Photovolt Res Appl 17, 227-240.

Sugiura T et al. (2003) Measurements, analyses and evaluation of residential PV systems by Japanese monitoring program. Sol Energ Mat Sol C 75, 767-779.

Sŭri M et al. (2007) Uncertainties in photovoltaic electricity yield prediction from fluctuation of solar radiation. Proc. 22nd European PVSEC. Downloadable from http://re.jrc.ec.europa.eu/pvgis/doc/paper/2007-Milano_6DV.4.44_uncertainty.pdf

Sŭri M et al. (2008) First steps in the cross-comparison of solar resource spatial products in Europe. Proc. Eurosun 2008, Lisbon, Portugal. Downloadable from http://re.jrc.ec.europa.eu/pvgis/doc/paper/2008_Eurosun2008_Cross-comparison_extended_preprint.pdf

Tang Y et al. (2006) An evaluation of 27 years old photovoltaic modules operated in a hot-desert climatic condition. Proc 4th IEEE Conv PV Ener Conv, 2145-2147

teNyenhuis EG and Girgis RS (2006) Measured Variability of Performance Parameters of Power & Distribution Transformers. 2005/2006 IEEE PES Transmission and Distribution Conference and Exhibition, 523 – 528.

Thevenard D and Brunger A (2001) ASHRAE Research Project 1015-RP, Typical Weather Years for International Locations: Final Report. American Society of Heating, Refrigerating and Air-Conditioning Engineers, Atlanta, GA, USA.

Thevenard D and Haddad K (2006) Ground reflectivity in the context of building energy simulation. Energ Buildings 38, 972-980.

Thevenard D (2010) Evaluation of global solar radiation models for use in Canada. Report to Environment Canada.

Ueda et al. (2008) Advanced analysis of grid-connected PV system's performance and effect of batteries. Electr Eng Jpn 164 (1) 21-33.

Ueda et al. (2009) Performance analysis of various system configurations on grid-connected residential PV systems. Sol Energ Mat Sol C 93, 945-949.

Vignola et al. (2007) Analysis of satellite derived beam and global solar radiation data. Solar Energy 81, 768-772. Downloadable from http://solardat.uoregon.edu/download/Papers/AssessmentofSatelliteData.pdf

Wilk et al. (1994) Field Testing and Optimization of Photovoltaic Solar Power Plant Equipment, Progress Report 1994 », 12th European Photovoltaic Solar Energy Conference, 11-15 April 1994.

APPENDIX A - STATISTICAL INDICATORS

A.1 Definition of MBE , RMSE, standard deviation, and uncertainty

The uncertainty associated with an estimate is often expressed in terms of mean bias error (MBE) and root mean square error (RMSE). They are defined as:

$$MBE = \frac{1}{N}\sum_{i=1}^{N}\left(X_{est,i} - X_{act,i}\right) \tag{1}$$

$$RMSE = \sqrt{\frac{1}{N}\sum_{i=1}^{N}\left(X_{est,i} - X_{act,i}\right)^2} \tag{2}$$

where X is the quantity under consideration, the subscripts *est* and *act* refer respectively to estimated and actual values, and N is the number of samples under consideration. For example if 8 years of monthly mean daily radiation values derived from a model can be compared to measurements over the same period, the $X_{est,i}$ would represent the modeled values of monthly mean daily radiation, the $X_{act,i}$ would represent the measured values, and the sample size would be 8 years ×12 months = 96.

The RMSE represents the uncertainty associated with the quantity, whereas the MBE represents the systematic part of that uncertainty.

The MBE and RMSE are expressed in the same units as the quantity under consideration. Sometimes it is also convenient to express them as a % of the average value.

Other measures of uncertainty often mentioned are the *standard deviation*, σ, or the variance, σ^2. RMSE, MBE and σ are related through the following relationship:

$$RMSE^2 = MBE^2 + \sigma^2 \tag{3}$$

Uncertainty U sometimes receives a mathematical definition as:

$$U^2 = MBE^2 + 2 \cdot \sigma^2 \tag{4}$$

the factor 2 'inflates' the random component to provide approximately 95% confidence interval for the computed uncertainty (Myers et al., 2004). In this report this definition of uncertainty is not used, RMSEs are simply considered in lieu of uncertainty.

A.2 Relationships between yearly, monthly, daily and hourly uncertainties

When comparing uncertainties, one should pay attention to whether they are expressed for yearly, monthly, daily or even hourly quantities. For example, uncertainty about solar radiation can be expressed for hourly values, daily values, monthly values or yearly values. Generally speaking:

- the MBE will be the same whether calculated from hourly values or from daily, monthly or yearly averages;

- the standard deviation will decrease as variables are averaged over longer time periods, because random errors tend to cancel each other. The general rule of thumb is that if a quantity is averaged over N values, σ is divided by $\sqrt{N}$. However, conditions need to be satisfied for the rule above to be apply, in particular, all sets of *N* samples must have the same mean. This is rarely the case with solar radiation, for example because of seasonal bias, and therefore the rule above should not be used.

A.3 Combining uncertainties

Uncertainties can be combined as follows (Labed and Lorenzo, 2004): If X is a function $X = f(X_1, X_2, ..., X_N)$ of N *independent* variables X_1, X_2, ..., X_n with uncertainties ε_1, ε_2, ..., ε_N , then the total uncertainty ε_t is given by (Crandall and Seabloom, 1970):

$$\varepsilon_t = \sqrt{\frac{\partial f}{\partial X_1}\varepsilon_1^2 + \frac{\partial f}{\partial X_2}\varepsilon_2^2 + ... + \frac{\partial f}{\partial X_N}\varepsilon_N^2}$$

This makes it easy to calculate the relative uncertainty if the quantity X under consideration is the product of N *independent* variables X_1, X_2, ..., X_n, as in $X = \alpha \cdot X_1 \cdot X_2 \cdot ... \cdot X_N$ with α a constant: then the relative combined uncertainty in X is calculated as (Crandall and Seabloom, 1970):

$$\frac{\varepsilon_t}{X} = \sqrt{\frac{\varepsilon_1^2}{X_1^2} + \frac{\varepsilon_2^2}{X_2^2} + ... + \frac{\varepsilon_N^2}{X_N^2}}$$

This provides a convenient way to calculate the total relative uncertainty, knowing the relative uncertainty of each of the multiplicative terms.
For example, if ε_s is the relative (ex: percent) uncertainty about mean solar radiation at the site, and ε_r the relative uncertainty due to natural variability of solar radiation, then for any individual year solar radiation should be expected within ε_t of the predicted value with

$$\varepsilon_t = \sqrt{\varepsilon_s^2 + \varepsilon_r^2}$$

APPENDIX B - RADIATION STATISTICS FOR SELECTED CANADIAN LOCATIONS

The following tables contain:

- A comparison of long-term averages of solar radiation from CERES, PVMaps, CWEC, SUNY, SSE, and Meteonorm, for a number of Canadian sites with mostly measured data. These tables show that all models predict roughly the same amount of solar radiation on a yearly basis, but sometimes with very high differences on a monthly basis, particularly for satellite-derived sets (SUNY, SSE) which seem to have trouble resolving cloud from snow in the winter.
- Standard deviations of annual average solar radiation, recalculated directly from the CWEEDS files for a few stations.

The locations were chosen because their CWEEDS files have mostly measured solar radiation data: usually over 90% for the period considered, the remaining 10% being modeled from cloud cover. CWEEDS monthly averages were calculated for the periods indicated and are therefore used as the 'reference' to which other values are compared.
Note that Meteonorm values where obtained from version 6.1, using the 'Default values' option when retrieving data.

Table 3 – Comparison of annual horizontal radiation from various sources.
All values in kWh/m^2/d. For errors expressed in % relative to CWEEDS 'measured' values, see Table 4.

Station	Lat	Long	WBAN	Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Yr
Port Hardy	50.68	-127.37	25223	CWEEDS 1968-1994	0.76	1.44	2.56	3.72	4.83	5.12	5.29	4.43	3.18	1.76	0.86	0.6	2.89
				CERES	0.76	1.41	2.57	3.76	4.72	5.11	5.19	4.52	3.26	1.75	0.84	0.60	2.88
				PVMaps	0.72	1.42	2.47	3.69	5.08	5.42	5.61	4.72	3.17	1.75	0.86	0.58	2.97
				CWEC	0.72	1.29	2.39	3.87	4.72	4.90	5.27	4.42	3.13	1.76	0.82	0.62	2.83
				SUNY	0.83	1.61	2.39	3.80	4.84	4.91	4.67	4.09	2.98	1.60	0.91	0.58	2.77
				SSE	0.87	1.68	2.67	3.93	4.88	5.05	5.46	4.66	3.57	1.96	1.02	0.70	3.04
				Meteonorm	0.74	1.43	2.52	3.73	4.84	5.10	5.29	4.42	3.07	1.74	0.87	0.58	2.86
Vancouver UBC	49.25	-123.25	94238	CWEEDS 1959-1986	0.82	1.54	2.83	4.22	5.64	6.00	6.32	5.20	3.67	2.03	0.99	0.67	3.33
				CERES	0.84	1.54	2.86	4.17	5.30	5.86	6.05	5.18	3.87	2.08	0.98	0.69	3.29
				PVMaps	0.86	1.61	2.75	4.06	5.39	5.89	6.19	5.28	3.67	2.06	1.00	0.69	3.31
				CWEC	0.79	1.57	2.65	4.55	5.61	5.97	6.56	5.31	3.92	1.79	0.94	0.64	3.37
				SUNY	0.97	1.91	2.87	4.69	5.65	5.98	6.25	5.46	3.85	1.90	1.01	0.72	3.45
				SSE	1.12	2.02	3.13	4.53	5.37	5.66	5.97	5.18	3.99	2.20	1.27	0.92	3.45
				Meteonorm	0.84	1.71	2.97	4.20	6.00	6.47	6.42	5.39	3.77	2.03	1.00	0.61	3.45
Summerland	49.57	-119.65	94152	CWEEDS 1962-1988	0.92	1.79	3.20	4.59	5.81	6.25	6.43	5.47	3.96	2.32	1.07	0.70	3.57
				CERES	0.86	1.69	3.12	4.49	5.54	6.09	6.27	5.34	3.96	2.35	1.08	0.68	3.46
				PVMaps	1.08	2.03	3.44	4.78	5.81	6.31	6.61	5.58	4.06	2.44	1.19	0.81	3.69
				CWEC	0.90	1.86	3.06	4.80	5.85	6.32	6.45	5.62	3.91	2.29	1.06	0.69	3.58
				SUNY	0.96	1.85	2.97	4.64	5.39	5.70	6.38	5.33	3.71	2.17	1.08	0.71	3.42
				SSE	1.30	2.25	3.49	4.71	5.46	5.80	6.33	5.48	4.13	2.44	1.36	1.05	3.65
				Meteonorm	1.00	1.86	3.35	4.57	6.03	6.73	6.68	5.58	4.10	2.32	1.07	0.71	3.67
Edmonton Stony Plain	53.55	-114.1	25145	CWEEDS 1967-2003	1.00	1.95	3.42	4.81	5.61	6.03	6.06	5.06	3.47	2.13	1.09	0.75	3.47
				CERES	1.00	1.98	3.43	4.88	5.64	6.23	6.13	5.04	3.50	2.21	1.11	0.74	3.49
				PVMaps	1.03	1.92	3.47	4.86	5.72	6.28	6.14	5.11	3.44	2.19	1.11	0.75	3.50
				CWEC	1.07	1.99	3.59	4.51	5.64	6.14	5.76	4.94	3.38	2.21	1.15	0.71	3.43
				SUNY	0.67	1.51	2.59	4.23	5.47	5.83	6.03	4.80	3.20	1.87	0.88	0.47	3.14
				SSE	0.93	1.85	3.24	4.51	5.23	5.50	5.64	4.79	3.36	2.06	1.12	0.59	3.24
				Meteonorm	1.00	1.96	3.45	4.87	5.71	6.20	6.19	5.13	3.47	2.19	1.13	0.74	3.51
Swift Current	50.27	-107.73	25028	CWEEDS 1961-1989	1.41	2.43	3.81	5.05	5.91	6.50	6.75	5.62	3.87	2.60	1.46	1.08	3.88
				CERES	1.41	2.40	3.64	5.05	5.82	6.53	6.63	5.52	3.89	2.58	1.49	1.06	3.84
				PVMaps	1.33	2.31	3.78	5.03	5.94	6.47	6.69	5.56	3.86	2.50	1.39	1.03	3.83
				CWEC	1.37	2.48	4.03	5.05	6.10	6.30	6.60	5.44	3.91	2.57	1.44	1.05	3.87
				SUNY	0.85	1.77	2.96	4.87	5.65	5.95	6.80	5.33	3.82	2.41	1.23	0.70	3.54
				SSE	1.14	2.06	3.31	4.80	5.57	5.84	6.29	5.14	3.72	2.39	1.35	0.95	3.55
				Meteonorm	1.35	2.39	3.77	5.03	5.97	6.43	6.81	5.68	3.97	2.58	1.43	1.06	3.87
Winnipeg	49.9	-97.23	14996	CWEEDS 1958-1995	1.45	2.47	3.76	4.97	5.81	6.26	6.30	5.25	3.68	2.24	1.32	1.09	3.74
				CERES	1.43	2.41	3.71	5.00	5.89	6.26	6.30	5.19	3.59	2.25	1.34	1.09	3.71
				PVMaps	1.33	2.36	3.78	4.97	5.72	6.19	6.28	5.17	3.56	2.25	1.25	1.00	3.67
				CWEC	1.43	2.37	3.72	4.93	6.12	6.44	6.40	5.39	3.64	2.29	1.32	1.15	3.77
				SUNY	0.98	1.79	2.86	5.42	5.52	6.08	6.25	5.08	3.65	2.15	1.16	0.75	3.48
				SSE	1.28	2.20	3.47	4.76	5.55	5.81	5.89	5.03	3.51	2.31	1.42	1.00	3.52
				Meteonorm	1.45	2.46	3.94	5.00	5.90	6.23	6.52	5.39	3.67	2.29	1.33	1.06	3.77

Toronto Met Res Stn	43.67	-79.38	04714	CWEEDS 1956-2000	1.42	2.27	3.42	4.46	5.44	6.07	6.14	5.19	3.91	2.57	1.37	1.10	3.63
				CERES	1.62	2.54	3.58	4.59	5.56	6.25	6.18	5.12	3.88	2.57	1.44	1.19	3.72
				PVMaps	1.61	2.61	3.67	4.58	5.50	6.22	6.22	5.25	3.92	2.56	1.39	1.17	3.72
				CWEC	1.47	2.26	3.18	4.35	5.60	6.14	6.03	5.16	4.10	2.57	1.30	1.07	3.61
				SUNY	1.43	2.02	3.39	4.21	5.33	5.95	6.66	5.79	4.53	2.58	1.48	1.12	3.72
				SSE	1.54	2.40	3.33	4.37	5.16	5.86	5.86	5.05	3.99	2.66	1.56	1.27	3.59
				Meteonorm	1.65	2.54	3.61	4.77	5.48	6.13	6.16	5.19	3.87	2.52	1.37	1.16	3.70
Ottawa NRC	45.45	-75.62	04772	CWEEDS 1958-1983	1.63	2.62	3.77	4.61	5.47	5.95	5.90	4.97	3.70	2.39	1.32	1.21	3.63
				CERES	1.65	2.70	3.92	4.57	5.41	5.95	5.93	5.02	3.65	2.41	1.42	1.26	3.66
				PVMaps	1.53	2.50	3.67	4.58	5.36	5.92	5.92	5.00	3.67	2.31	1.33	1.14	3.58
				CWEC	1.48	2.67	3.90	4.63	5.48	6.09	6.04	4.86	3.76	2.40	1.33	1.30	3.67
				SUNY	1.11	1.96	3.16	4.32	5.32	5.73	6.43	5.65	4.34	2.59	1.21	1.11	3.59
				SSE	1.60	2.57	3.70	4.54	5.18	5.65	5.65	4.92	3.75	2.42	1.50	1.30	3.56
				Meteonorm	1.68	2.79	4.00	4.73	5.81	6.23	6.03	5.00	3.90	2.52	1.33	1.26	3.78
Montreal Jean Breb.	45.5	-73.62	04770	CWEEDS 1965-1984	1.49	2.41	3.50	4.37	5.27	5.71	5.86	4.79	3.72	2.30	1.27	1.09	3.48
				CERES	1.58	2.57	3.81	4.45	5.48	5.92	5.95	5.03	3.72	2.41	1.42	1.24	3.64
				PVMaps	1.50	2.47	3.61	4.47	5.28	5.81	5.78	4.89	3.64	2.28	1.33	1.14	3.53
				CWEC	1.68	2.41	3.35	4.18	5.09	5.73	6.08	4.66	3.97	2.46	1.20	1.11	3.50
				SUNY	1.30	2.25	3.20	4.46	5.34	5.70	6.15	5.40	4.25	2.59	1.38	1.36	3.62
				SSE	1.58	2.52	3.62	4.46	5.09	5.61	5.52	4.91	3.77	2.38	1.45	1.28	3.52
				Meteonorm	1.58	2.61	3.87	4.60	5.68	6.20	6.03	4.87	4.03	2.55	1.23	1.16	3.70
Sept-Iles	50.22	-66.25	77912	CWEEDS 1974-1994	1.23	2.22	3.30	4.26	5.15	5.52	5.29	4.65	3.25	2.02	1.20	0.92	3.26
				CERES	1.24	2.26	3.35	4.30	5.20	5.54	5.32	4.66	3.27	2.01	1.20	0.93	3.28
				PVMaps	1.19	2.11	3.42	4.39	5.03	5.36	5.25	4.47	3.08	1.86	1.11	0.89	3.19
				CWEC	1.18	2.36	3.34	4.39	5.11	5.46	5.54	4.67	3.49	2.33	1.25	0.88	3.34
				SUNY	1.15	1.69	2.85	4.40	5.42	6.00	4.60	4.93	3.28	2.17	0.96	0.79	3.19
				SSE	1.30	2.25	3.51	4.73	5.26	5.37	4.71	4.23	3.03	1.90	1.26	1.01	3.21
				Meteonorm	1.16	2.18	3.23	4.20	5.10	5.53	5.29	4.74	3.27	2.03	1.17	0.90	3.23
Fredericton	45.92	-66.62	14670	CWEEDS 1961-2002	1.54	2.45	3.45	4.22	5.04	5.58	5.52	4.88	3.66	2.40	1.39	1.19	3.46
				CERES	1.56	2.42	3.50	4.13	5.08	5.47	5.49	4.78	3.64	2.37	1.41	1.23	3.43
				PVMaps	1.44	2.36	3.50	4.31	5.06	5.61	5.56	4.89	3.67	2.33	1.36	1.08	3.44
				CWEC	1.60	2.32	3.72	4.39	4.59	5.39	5.54	4.83	3.58	2.61	1.47	1.23	3.44
				SUNY	1.12	1.95	3.34	3.95	5.55	5.81	5.46	5.35	3.59	2.54	1.24	1.29	3.44
				SSE	1.61	2.50	3.72	4.48	4.96	5.43	5.23	4.80	3.81	2.52	1.54	1.32	3.50
				Meteonorm	1.52	2.43	3.42	4.30	5.00	5.57	5.55	4.87	3.63	2.42	1.40	1.16	3.44
Charlottetown	46.25	-63.13	14688	CWEEDS 1972-1994	1.53	2.46	3.48	4.23	5.07	5.54	5.67	4.88	3.65	2.22	1.29	1.07	3.45
				CERES	1.54	2.47	3.56	4.20	5.14	5.74	5.69	4.89	3.67	2.24	1.28	1.08	3.46
				PVMaps	1.36	2.25	3.42	4.19	5.03	5.61	5.56	4.89	3.69	2.28	1.33	1.03	3.39
				CWEC	1.53	2.49	3.45	4.25	5.66	5.41	5.56	4.80	3.75	2.20	1.33	1.04	3.46
				SUNY	1.24	1.76	3.35	3.62	5.92	5.63	5.90	5.31	3.64	2.40	1.20	0.96	3.42
				SSE	1.35	2.14	3.26	4.30	5.45	6.02	6.02	5.25	3.98	2.41	1.30	1.01	3.54
				Meteonorm	1.65	2.68	3.87	4.77	5.61	6.27	6.03	5.10	3.80	2.39	1.33	1.13	3.72
St. John's West CDA	47.52	-52.78	14521	CWEEDS 1965-1996	1.16	1.95	2.91	3.80	4.57	5.31	5.40	4.44	3.33	1.97	1.16	0.87	3.09
				CERES	1.16	1.98	3.03	3.79	4.65	5.15	5.32	4.47	3.32	2.02	1.19	0.89	3.09
				PVMaps	1.14	1.92	2.97	3.86	4.75	5.39	5.53	4.47	3.47	2.00	1.17	0.86	3.14
				CWEC	1.11	2.01	3.09	3.73	5.20	5.54	5.65	4.03	3.36	1.99	1.14	0.85	3.15
				SUNY	1.03	1.52	2.55	3.88	5.32	5.28	6.09	4.80	3.29	2.20	1.01	0.74	3.15
				SSE	1.28	2.11	3.31	4.18	4.74	5.14	4.88	4.38	3.31	2.15	1.27	1.02	3.15
				Meteonorm	1.13	1.93	2.90	3.77	4.55	5.27	5.48	4.39	3.33	1.94	1.17	0.87	3.06

Table 4 – Comparison of annual horizontal radiation from various sources.
All values expressed as difference from, and as a percentage of, CWEEDS 'measured' values.
For absolute values, see Table 3.

Station	Lat	Long	WBAN	Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Yr
Port Hardy	50.68	-127.37	25223	CWEEDS 1968-1994	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	0	-2	0	1	-2	0	-2	2	3	0	-3	1	0
				PVMaps	-5	-2	-3	-1	5	6	6	7	0	-1	0	-3	3
				CWEC	-5	-10	-7	4	-2	-4	0	0	-2	0	-5	3	-2
				SUNY	9	12	-7	2	0	-4	-12	-8	-6	-9	5	-4	-4
				SSE	14	17	4	6	1	-1	3	5	12	11	19	17	5
				Meteonorm	-2	-1	-2	0	0	0	0	0	-4	-1	1	-3	-1
Vancouver UBC	49.25	-123.25	94238	CWEEDS 1959-1986	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	3	0	1	-1	-6	-2	-4	0	5	2	-1	3	-1
				PVMaps	5	5	-3	-4	-4	-2	-2	1	0	1	1	4	-1
				CWEC	-3	2	-6	8	-1	0	4	2	7	-12	-5	-4	1
				SUNY	18	24	2	11	0	0	-1	5	5	-6	2	8	3
				SSE	37	31	11	7	-5	-6	-6	0	9	8	28	37	4
				Meteonorm	2	11	5	0	6	8	2	4	3	0	1	-9	4
Summerland	49.57	-119.65	94152	CWEEDS 1962-1988	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	-7	-6	-2	-2	-5	-2	-3	-2	0	1	1	-2	-3
				PVMaps	18	13	8	4	0	1	3	2	2	5	12	15	3
				CWEC	-2	4	-4	5	1	1	0	3	-1	-1	-1	-1	0
				SUNY	4	4	-7	1	-7	-9	-1	-2	-6	-7	1	1	-4
				SSE	41	26	9	3	-6	-7	-2	0	4	5	27	50	2
				Meteonorm	9	4	5	-1	4	8	4	2	4	0	0	1	3
Edmonton Stony Plain	53.55	-114.1	25145	CWEEDS 1967-2003	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	0	1	0	1	1	3	1	0	1	4	2	-1	1
				PVMaps	3	-2	2	1	2	4	1	1	-1	3	2	0	1
				CWEC	7	2	5	-6	1	2	-5	-2	-3	4	5	-6	-1
				SUNY	-33	-23	-24	-12	-2	-3	0	-5	-8	-12	-19	-37	-10
				SSE	-7	-5	-5	-6	-7	-9	-7	-5	-3	-3	3	-21	-7
				Meteonorm	0	1	1	1	2	3	2	1	0	3	4	-1	1
Swift Current	50.27	-107.73	25028	CWEEDS 1961-1989	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	0	-1	-4	0	-1	1	-2	-2	0	-1	2	-2	-1
				PVMaps	-5	-5	-1	0	1	0	-1	-1	0	-4	-5	-5	-1
				CWEC	-3	2	6	0	3	-3	-2	-3	1	-1	-1	-3	0
				SUNY	-40	-27	-22	-4	-4	-8	1	-5	-1	-7	-16	-35	-9
				SSE	-19	-15	-13	-5	-6	-10	-7	-9	-4	-8	-8	-12	-9
				Meteonorm	-4	-2	-1	0	1	-1	1	1	2	-1	-2	-1	0
Winnipeg	49.9	-97.23	14996	CWEEDS 1958-1995	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	-1	-3	-1	1	1	0	0	-1	-3	1	1	0	-1
				PVMaps	-8	-4	0	0	-2	-1	0	-2	-3	0	-5	-8	-2
				CWEC	-2	-4	-1	-1	5	3	2	3	-1	2	0	5	1
				SUNY	-33	-28	-24	9	-5	-3	-1	-3	-1	-4	-12	-31	-7
				SSE	-12	-11	-8	-4	-4	-7	-7	-4	-5	3	8	-8	-6
				Meteonorm	0	0	5	1	2	0	3	3	0	2	1	-2	1

Toronto Met Res Stn	43.67	-79.38	04714	CWEEDS 1956-2000	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	14	12	5	3	2	3	1	-1	-1	0	5	8	2
				PVMaps	13	15	7	3	1	3	1	1	0	-1	1	6	3
				CWEC	3	0	-7	-3	3	1	-2	-1	5	0	-5	-2	-1
				SUNY	1	-11	-1	-6	-2	-2	9	12	16	0	8	2	2
				SSE	8	6	-3	-2	-5	-3	-5	-3	2	4	14	15	-1
				Meteonorm	16	12	6	7	1	1	0	0	-1	-2	0	6	2
Ottawa NRC	45.45	-75.62	04772	CWEEDS 1958-1983	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	1	3	4	-1	-1	0	1	1	-1	1	7	4	1
				PVMaps	-6	-5	-3	-1	-2	-1	0	1	-1	-4	1	-6	-1
				CWEC	-9	2	3	1	0	2	2	-2	1	0	1	7	1
				SUNY	-32	-25	-16	-6	-3	-4	9	14	17	8	-8	-8	-1
				SSE	-2	-2	-2	-2	-5	-5	-4	-1	1	1	14	7	-2
				Meteonorm	3	6	6	3	6	5	2	1	5	5	1	4	4
Montreal Jean Breb.	45.5	-73.62	04770	CWEEDS 1965-1984	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	6	7	9	2	4	4	2	5	0	5	12	14	4
				PVMaps	1	3	3	2	0	2	-1	2	-2	-1	5	4	1
				CWEC	12	0	-4	-4	-3	0	4	-3	7	7	-6	2	1
				SUNY	-12	-7	-8	2	1	0	5	13	14	12	9	25	4
				SSE	6	5	3	2	-3	-2	-6	3	1	3	14	17	1
				Meteonorm	6	8	11	5	8	9	3	2	8	11	-3	7	6
Sept-Iles	50.22	-66.25	77912	CWEEDS 1974-1994	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	1	2	2	1	1	0	1	0	1	-1	0	1	1
				PVMaps	-3	-5	4	3	-2	-3	-1	-4	-5	-8	-7	-3	-2
				CWEC	-4	6	1	3	-1	-1	5	0	7	16	4	-5	2
				SUNY	-7	-24	-14	3	5	9	-13	6	1	7	-20	-15	-2
				SSE	6	1	6	11	2	-3	-11	-9	-7	-6	5	10	-2
				Meteonorm	-6	-2	-2	-1	-1	0	0	2	1	1	-3	-2	-1
Fredericton	45.92	-66.62	14670	CWEEDS 1961-2002	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	2	-1	1	-2	1	-2	-1	-2	0	-1	1	3	-1
				PVMaps	-6	-4	1	2	0	1	1	0	0	-3	-2	-9	0
				CWEC	4	-6	8	4	-9	-3	0	-1	-2	9	6	3	0
				SUNY	-27	-20	-3	-6	10	4	-1	10	-2	6	-11	9	0
				SSE	5	2	8	6	-2	-3	-5	-2	4	5	11	11	1
				Meteonorm	-2	-1	-1	2	-1	0	1	0	-1	1	1	-2	-1
Charlottetown	46.25	-63.13	14688	CWEEDS 1972-1994	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	1	1	2	-1	1	4	0	0	1	1	-1	1	0
				PVMaps	-11	-9	-2	-1	-1	1	-2	0	1	3	3	-4	-2
				CWEC	0	1	-1	0	12	-2	-2	-2	3	-1	3	-3	0
				SUNY	-19	-29	-4	-14	17	2	4	9	0	8	-7	-10	-1
				SSE	-12	-13	-6	2	7	9	6	8	9	9	1	-6	3
				Meteonorm	8	9	11	13	11	13	6	4	4	8	3	6	8
St. John's West CDA	47.52	-52.78	14521	CWEEDS 1965-1996	-	-	-	-	-	-	-	-	-	-	-	-	-
				CERES	0	2	4	0	2	-3	-1	1	0	3	2	2	0
				PVMaps	-2	-2	2	2	4	1	2	1	4	2	1	-1	2
				CWEC	-5	3	6	-2	14	4	5	-9	1	1	-2	-2	2
				SUNY	-11	-22	-12	2	16	-1	13	8	-1	12	-13	-15	2
				SSE	10	8	14	10	4	-3	-10	-1	-1	9	9	17	2
				Meteonorm	-3	-1	0	-1	0	-1	2	-1	0	-2	1	0	-1

Table 5 – Standard deviation of annual and monthly average solar radiation, expressed as a percentage of their long-term values.

Station	Lat	Long	WBAN	Source	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Yr
Port Hardy	50.68	-127.37	25223	CWEEDS 1968-1994	19	17	9	12	11	13	12	14	12	13	18	15	4.3
Vancouver UBC	49.25	-123.25	94238	CWEEDS 1959-1986	16	15	13	11	9	12	9	11	11	14	15	17	3.9
Summerland	49.57	-119.65	94152	CWEEDS 1962-1988	14	12	9	7	8	8	8	9	10	10	9	9	3.4
Edmonton Stony Plain	53.55	-114.1	25145	CWEEDS 1967-2003	9	7	7	9	7	8	7	8	13	7	13	9	2.5
Swift Current	50.27	-107.73	25028	CWEEDS 1961-1989	7	8	11	9	8	8	7	8	11	9	11	7	3.3
Winnipeg	49.9	-97.23	14996	CWEEDS 1958-1995	9	8	10	9	11	9	6	8	9	13	10	8	3.6
Toronto Met Res Stn	43.67	-79.38	04714	CWEEDS 1956-2000	10	12	9	10	9	9	6	6	9	11	15	16	3.7
Ottawa NRC	45.45	-75.62	04772	CWEEDS 1958-1983	10	12	11	9	11	9	7	7	11	14	16	13	5.0
Montreal Jean Breb.	45.5	-73.62	04770	CWEEDS 1965-1984	12	13	11	11	12	9	6	5	9	10	13	12	3.2
Sept-Iles	50.22	-66.25	77912	CWEEDS 1974-1994	8	10	9	12	11	10	7	8	7	10	9	6	3.3
Fredericton	45.92	-66.62	14670	CWEEDS 1961-2002	10	10	11	11	12	10	10	9	11	8	14	12	4.3
Charlottetown	46.25	-63.13	14688	CWEEDS 1972-1994	9	9	11	10	10	7	9	8	9	7	13	16	3.8
St. John's West CDA	47.52	-52.78	14521	CWEEDS 1965-1996	13	13	11	11	10	9	11	10	9	9	11	13	4.5

APPENDIX C - ESTIMATING THE ADEQUATE NUMBER OF SIMULATION RUNS IN A MONTE CARLO SIMULATION

The shape of the CDF curves shown in section 4, and the average and standard deviations calculated in the various subsections, depend somewhat on the number of runs used in the statistical simulations. Intuitively one can understand that if too few simulation runs are used, then they will not statistically cover the whole range of possibilities for the various distributions mentioned in Table 2. On the other hand the use of an extremely large number of simulation runs will give a better representation of the statistics of the problem, but at the expense of run time.

The variation of statistics as a function of the number of simulation runs is studied in the case of the 'basic' statistical SAM run used in this report, i.e. the run exposed in section 4.3, with the notable exception of no uncertainty attached to solar radiation (only the 'nominal' solar radiation is used). The study is based on the use of *batches*, as explained in Gentle (2003, p. 237).

When N simulation runs are used, a CDF of the yield can be plotted (as in Figure 4) and the statistics of the yield distribution can be calculated. Let us call $\overline{Y}_N$ and $\sigma_{Y,N}$ the mean and standard deviation of the yield thus calculated with N simulation runs. If a different set of N simulations is run, the calculation of $\overline{Y}_N$ and $\sigma_{Y,N}$ will lead to slightly different results, because the parameters used for the runs will be different. If one runs enough sets of N simulations, one obtains statistical distributions of $\overline{Y}_N$ and $\sigma_{Y,N}$.

The distributions themselves depend on the number N of simulation runs (intuitively, if N is larger the distributions will be narrower). To characterize these distributions, 6,000 simulations were run. Then the results were divided into batches of N = 10, 20, 50, 100, and 200 simulations; for example there are 600 batches of 10 simulations, 300 batches of 20 simulations, etc., and 30 batches of 200 simulations. For each set of batches corresponding to a value of N, the standard deviation[14] of $\overline{Y}_N$ and of $\sigma_{Y,N}$ can be calculated, then the results are plotted against N in a log-log graph as shown in Figure 7.

The figure indicates that the standard deviation of $\overline{Y}_N$ is inversely proportional to $N^{1/2}$. This does not come as a great surprise as the uncertainty on the mean of a sample of p values varies as $1/\sqrt{p}$ (see Appendix A.2). As for the standard deviation of $\sigma_{Y,N}$, its behaviour is slightly less obvious but it seems to be also inversely proportional to $N^{1/2}$.

With N = 100 as chosen for the study, the estimated standard deviation on $\overline{Y}_N$ is 6.8 kWh/kWp; and on $\sigma_{Y,N}$ it is 6.3 kWh/kWp. Those numbers are small compared to the average value of the yield (~1200 kWh/kWp) and to its typical standard deviation (~93 kWh/kWp), so the number of simulation runs seems adequate[15].

---

[14] This is becoming complicated, but all that is done here is the calculation of the standard deviation of the estimation of the average, and of the standard deviation of the estimation of the standard deviation.
[15] Since it is extremely time-consuming, the study of the adequate number of simulation runs was not extended to include the uncertainty on solar radiation.

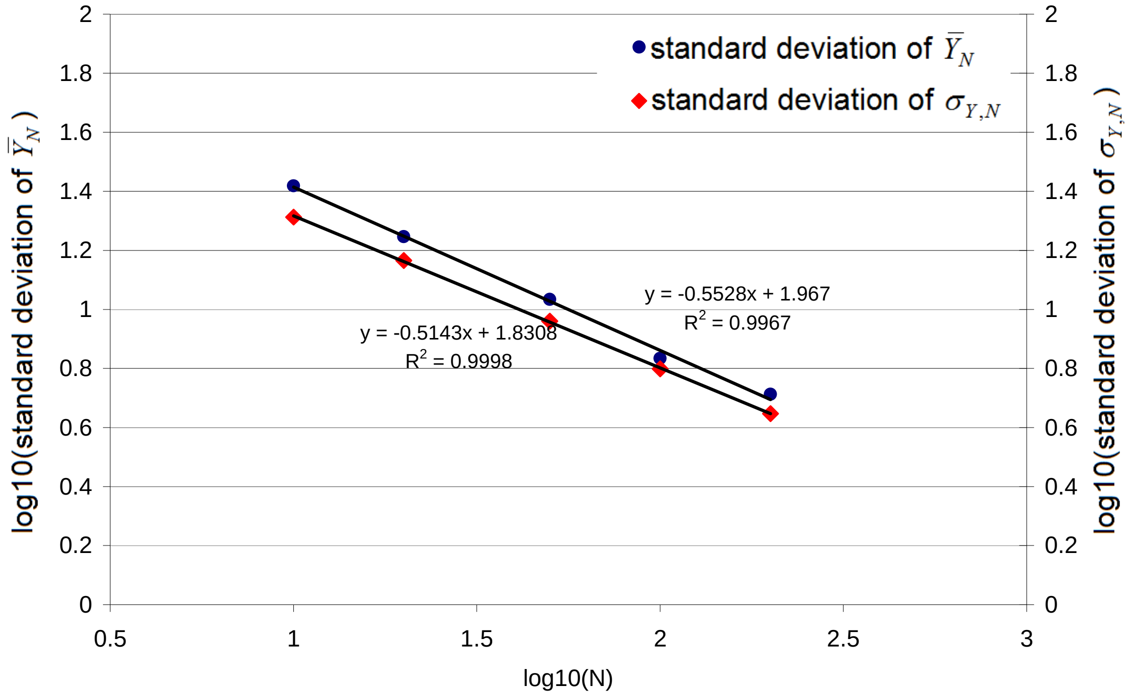

Figure 7 - Standard deviation of $\overline{Y}_N$ and $\sigma_{Y,N}$ as a function of the number of simulation runs N .