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Indicative Design, Energy, and Cost Estimate for 2.5 MWac Photovoltaic Project

NorthWestern Energy

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Customer:	NorthWestern Energy 40 East Broadway Butte, Montana 59701	2420 Camino Ramon Suite 300 Tel: +1 925 867-3330 Enterprise No.: 26-2535197
Contact person:	David Fine, Director, Energy Supply Planning	
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Task and objective: Indicative Solar PV Design, Energy Estimate, and CAPEX/OPEX Estimate for a prospective NorthWestern Energy PV project near Anaconda, MT.

Prepared by:	Approved by:
Michael Hall Project Manager	James Vance Manager, Solar Due Diligence

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A	22 September 2015	Initial Draft	Michael Hall	James Vance

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1 INTRODUCTION

NorthWestern Energy has advised DNV GL of its interest in a potential utility-scale solar photovoltaic (PV) facility at a representative location in southwestern Montana (the Project), and has retained DNV GL to support the following scope of work:

- An indicative preliminary array layout for a scalable ~3 MWdc /2.5 MWac ground-mount PV system
- Energy production estimate for the selected site using solar resource data that NorthWestern Energy has purchased from Clean Power Research (CPR)
- Estimate of the capital expenses (CAPEX) to construct the project
- Estimate of operations and maintenance expenses (OPEX)

This Report addresses the scope listed above, with sections discussing meteorological, technical, and financial aspects of the Project. Its findings are based on a combination of files and verbal guidance provided by NorthWestern Energy, supplemented with web-based research and in-house expertise with commercial PV and meteorological simulation software and with proprietary PV analysis tools.

Some of the information relied upon for this Report is not within the control of DNV GL. DNV GL assumes that the information provided by others is true and correct and reasonable for the purposes of this Report. DNV GL has not been requested to make an independent analysis or verification of the validity of such information. DNV GL does not guarantee the accuracy of the data, information or opinions provided by others.

In preparing this Report and the opinions presented herein, DNV GL has made certain assumptions with respect to conditions that may exist, or events that may occur in the future. DNV GL believes that these assumptions are reasonable for purposes of this Report but actual events or conditions may cause results to differ materially from forward-looking statements.

2 INDICATIVE DESIGN

The Project's indicative design is shown below in Figure 2-1. A larger version is attached as Appendix A. This layout was developed to maximize system production based on the location selected by NorthWestern Energy.

The system size is 3.02 MWdc[1] and 2.52 MWac. This ratio of dc-to-ac capacity of 1.2, also referred to as its loading ratio, is a common design value. The system layout assumes a location with level grade, normal soil conditions (not sandy or rocky), and outside of any flood plains or environmentally sensitive areas. The footprint of the system covers approximately 21 acres, based on the area needs of the PV modules and the unused space among them, along with space for access and maintenance roads, setbacks, and security fencing. The racking component consists of a NEXTracker ±60° rotation, ground-mounted single-axis tracking system. The racking is fitted with a quantity of 10,008 Canadian Solar 300 Watt modules, with their dc power feeding four SMA 630 kW inverters, which in turn deliver power to the grid via a pair of 12 kV step-up transformers.

An assortment of balance of system equipment is included in our CAPEX estimate, though these smaller items are not called out in a specific bill of materials (e.g., data acquisition/SCADA, metering, system protection, conduits, wiring, and connectors). The system is divided into two 1.26 MWac blocks, each consisting of 5,004 modules, two inverters, and one 12 kV transformer.

The total project system size can be scaled by increasing or decreasing the number of ac blocks, and, owing to the modularity of PV, the dc nameplate capacity associated with each ac block can be adjusted ±20% without triggering significant changes to the ac hardware.

[1] The subscript dc is often used interchangeably with another shorthand notation, p. Both are equivalent and are used to indicate dc nameplate power under industry-standard *peak* operating conditions. Peak, or Standard Test Conditions (STC), are defined as 1,000 W/m^2 irradiance, 25°C cell temperature, and AM 1.5. The subscript ac is associated with nameplate rated power for ac equipment such as inverters and for full system output.

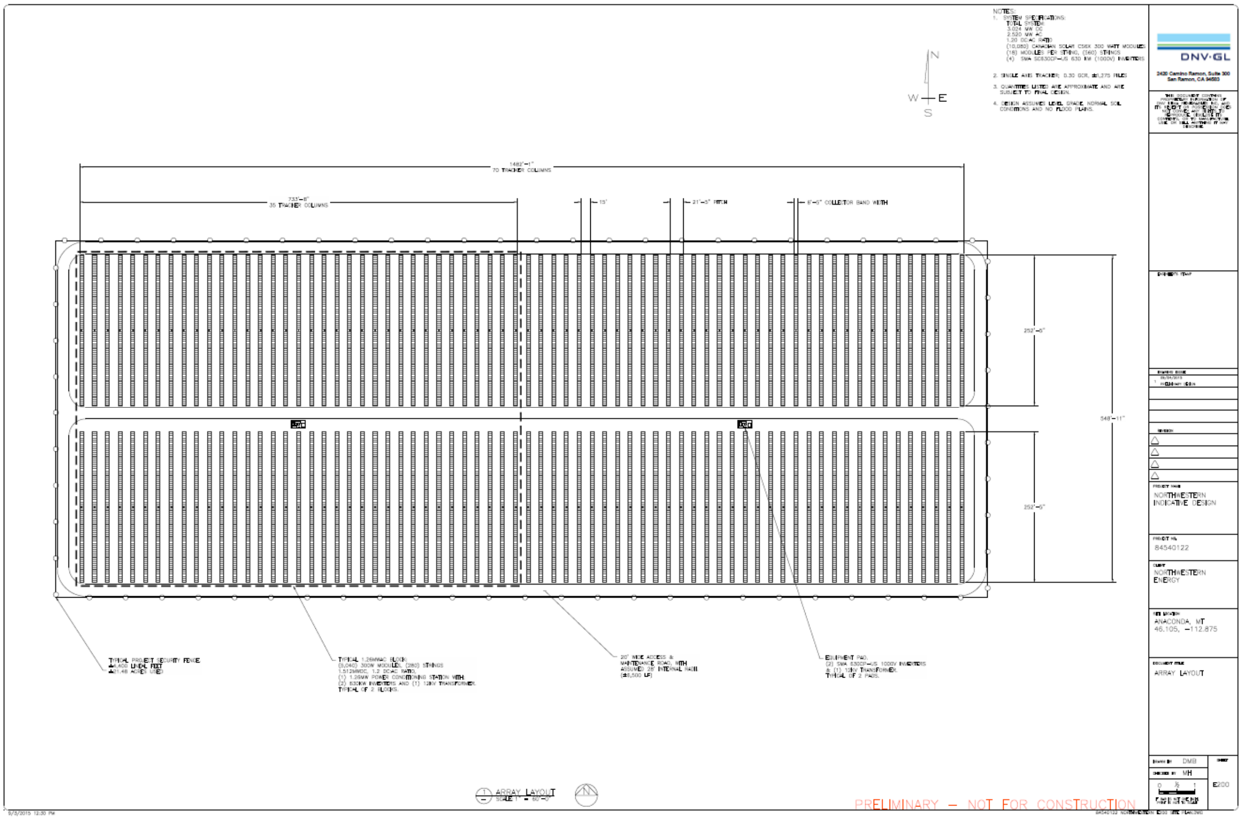

Figure 2-1 Indicative Design - Array Layout

3 SOLAR RESOURCE AND PRODUCTION ESTIMATE

3.1 Energy assessment

PVsyst software was used to generate a first-year energy forecast of 5 GWh (rounded) for the Project. The following sections describe DNV GL's analysis of the available solar resource, the approach used to model the components in PVsyst, and the assumptions for all loss factors used in the forecasts. The first-year energy estimate and related performance terms are summarized at the end of this section.

3.1.1 Weather file selection

The weather file used for this project was provided by the client. The source for the long-term average weather file was Clean Power Research (CPR). This weather file was found to be in excellent agreement with a representative file created using Meteonorm software, an independent commercial source of long-term data that DNV GL regularly draws on. CPR prepared a representative long-term hourly pattern of global horizontal insolation (GHI), air temperature, and wind speed for the Anaconda site. These are the most common parameters used to drive PV simulation programs such as PVsyst, a program long used by DNV GL.

CPR's site weather file has been branded with the well-established TMY3 format, as published by the National Renewable Energy Laboratory (NREL). As a point of clarity, CPR's custom file should not be mistaken as an NREL TMY3 file, as there are some noteworthy differences. The TMY3 acronym refers to Typical Meteorological Year, version 3. Ordinarily, this designation is reserved for a 15-year (1991-2005) satellite-based subset of NREL's larger National Solar Radiation Data Base (NSRDB). The label TMY3 is also normally associated with a specific network of about 1,000 U.S. locations, the nearest of which is located at the climatically similar Butte airport, about 200 feet higher and 20 miles SE of the proposed Project location.

For this Project, CPR borrowed the term "TMY3" when defining the Anaconda weather file. However, the 1998 through early 2015 period they used is different from, and slightly longer than, the period used for NREL's TMY3 sites. Also, the Anaconda location is not one of the 1,000+ formal sites in NREL's station library. Rather, it is a spot located within one of the many 10x10 km grids that CPR captures via satellite imagery. These differences do not invalidate the quality or accuracy of the file CPR produced, but the buyer should be aware of the differences, as this will avoid any misconceptions about the origin or endorsement of the data. CPR's file does share two key qualities with the NREL TMY3 data sets. One is that both are based on satellite data. The other key quality is that both are saved in the same file format, with all of the same parameters and column styles. This second shared characteristic makes the CPR files readily compatible with commercial PV software.

DNV GL was able to verify excellent agreement between CPR's weather file and one generated for the same location using commercial Meteonorm (ver. 7) software. Meteonorm interpolates for the exact latitude and longitude of the site, using neighboring NREL TMY3 sites and, depending on how remote those stations are, Meteonorm will progressively blend in satellite-based radiation data, too. For sites more than 18 miles from a certified ground-based solar radiation station, Meteonorm will factor in an increasing blend of satellite data, as drawn from a 5-year database at 8x8 km grid resolution. Meteonorm uses a different source and conversion algorithm than that used by CPR. Table 3-1 below lists the three most important weather characteristics for solar PV applications. It shows negligibly small differences of 1% or less in the estimated annual global horizontal insolation (GHI) and the diffuse horizontal insolation (DHI) quantities, and just a 0.4 °C difference in annual air temperature. Given the degree of independence between CPR and Meteonorm, and given the historical uncertainty of about ±8-10% among any source of solar radiation data, the close agreement between these two estimates of the long-term solar resource is reassuring with respect to the accuracy of the site's likely solar potential.

Table 3-1 Annual weather averages for Anaconda, MT

Source	GHI (kWh/m^2)	DHI (kWh/m^2)	T,air (°C)
CPR	1,475	559	5.2
Meteonorm v7	1,460	557	4.8

3.1.2 Modeling of components

DNV GL entered module and system specifications into PVsyst. A summary of loss factors, along with system design parameters and components used, is shown below as Table 3-2.

The modules assumed for modeling this project are top-tier 300 W polycrystalline silicon-based models manufactured by Canadian Solar. The module properties file used in PVsyst was generated by DNV GL, based on information provided by the manufacturer. In terms of interchangeability, it should be understood that more than a dozen readily available products of essentially equal performance and cost could be substituted with no impact on energy or economics.

It is common for as-delivered modules to vary slightly from their nameplate power. For Canadian Solar's CS6X-300P modules, the manufacturer quotes an output tolerance at Standard Test Conditions (STC) of 0 to 1.7%. It is unknown whether the lot averages for 10,000+ modules will match or exceed their nameplate rating. Based on current industry flash-test results, DNV GL assumed that the module distribution will be slightly above the nameplate (+0.1%). This is one input that is factored into the PVsyst catch-all module quality factor (MQF) term.

Another term often factored into the MQF is a small module properties adjustment. PVsyst's module-specific I-V curve definition file returns an STC power that slightly overstates (by 0.1%) the product's nameplate value of 300 W. A 0.1% downward adjustment is included in the MQF to offset this modeling error. Finally, a 0.5% loss is incorporated into the MQF for all simulations to account for non-ideal inverter maximum power point tracking (MPPT). Overall, these losses and gains resulted in a net MQF change of -0.5% for this model of Canadian Solar modules.

An additional module loss factor addresses the initial, irreversible Light Induced Degradation (LID) phenomenon. DNV GL applied a 2% loss to account for LID, based on additional data provided by the manufacturer. Essentially, this term amounts to a permanent 2% reduction in nameplate power, a reduction which manifests itself within the first few hours of exposure to sunlight.

The inverter specified in the energy simulations is an SMA Sunny Central SC630CP-US-1000 inverter, with a rated power at 25°C of 630 kWac. Similar to the module definition file, a custom inverter definition file was used to drive the simulation. The data within this file is typically obtained from efficiency curves provided via 3rd party testing, under guidelines established by the California Energy Commission. Lastly, based on auxiliary power needs calculated by DNV GL for this product on another multi-MW installation, the local power draw needed to run HVAC, lighting, security, and SCADA loads was modeled as a 9 kW daytime load and a 100 W evening parasitic load. These loads were applied to each inverter, and have the effect of reducing gross plant output by about 3% on an annual basis. Parasitic tracker power loads, small in any case, are zero for the NEXTracker product since it relies on an integral dc solar-powered tracker drive.

3.1.3 System design inputs

Assumptions regarding other system level losses such as mismatch, ohmic, shading, soiling, transformer, and equipment availability are discussed below.

Regarding mismatch, the combination of series and parallel mismatch can be estimated analytically via PVsyst as long as the production tolerance, nature of the distribution, and number of series and parallel strings is known. The series mismatch is the most significant source of mismatch, but large numbers of parallel circuits also contribute to the composite mismatch. This is unavoidable and is caused by differing levels of dc voltage drop among parallel circuits within a long row, as each of those circuits feed a common inverter. The combined impact of mismatch effects for systems such as this is minor, hovering in the 0.5% range.

DNV GL assumed 1.5% dc and 0.5% ac ohmic losses, both at STC. These are common design targets for projects of this size. In the case of the ac losses, the 0.5% applies only to the lower voltage ac losses at 315 Vac. A separate medium voltage ohmic loss of 0.1% to the interconnection point is discussed below and lumped in as part of the transformer variable loss estimate.

Topographical data within Meteonorm was used to gain an understanding of the impact of neighboring mountains. The horizon profile from Meteonorm, visually cross-checked on GoogleEarth, was found to have a 1.2% loss impact on energy production.

As the base case recommendation for the Project is to deploy single-axis trackers, it was assumed that conventional backtracking near sunrise and sunset would also be used. The layout assumes a single module would be mounted lengthwise across the tracking axis, a standard configuration for most trackers, including NEXTracker. Tracker spacing was assumed to be 6.53 m, which corresponds to a Ground Cover Ratio (GCR) of 0.30. Tracking rotation limitations of ±60° were assumed, per manufacturer specifications.

Soiling losses result from a combination of many factors, including system orientation, the intensity and amount of rain, snowfall, the accumulation of dust, type of soil, and other site-specific conditions such as bird droppings or proximity to highways, agricultural activity, or particulate settling. DNV GL has assumed that there will be no manual cleanings for this project. Soiling losses were determined from models previously developed for nearby sites, and are expected to be dominated by winter snow soiling losses. The annual energy lost due to soiling in a typical year for each project is shown in Table 3-2. The monthly soiling losses are included in the PVsyst output report shown in Section 5.

The system includes two identical and parallel step-up transformers to increase ac voltage in a single stage, from the inverters' 315 Vac to a more typical distribution voltage of 12 kV. Assumptions regarding core and winding transformer losses are shown in Table 3-2 below.

The NEXTracker system includes an integrally-mounted 30 W PV module, designed to power the tracking motor and wireless communications for each row of modules via a battery-backed local dc source. As a result, tracking motor losses were assumed to be zero.

DNV GL has assumed that reactive power losses are negligible for this combination of plant size, interconnection voltage, and ac equipment.

Energy losses associated with equipment failures, unplanned outages, and planned downtime are applied within PVsyst's production estimate. For unstaffed tracking systems, an equivalent annual downtime loss of 1.5% is presumed. This loss is modeled as four discrete events, one per season, each of about 33 hours' duration. This downtime pattern corresponds to about 5.5 days of lost production per year.

Table 3-2 below summarizes assumptions used in the PVsyst simulation, with most of the terms also visible in the PVsyst report included as an Appendix.

Table 3-2 Energy Estimate Assumptions

Item	Value	Comment
Orientation	Horizontal single-axis tracker at 0.30 GCR, 0° (N-S) axis azimuth, and 6.53 m row spacing	±60° rotation, with backtracking
Lat/Long/Elev.	46.1° N/-112.9° W/1,571 m	
Ground albedo	0.3 in summer months, 0.6 in Dec-Feb and 0.3-0.4 in shoulder months	Assumes 0.70 albedo for new snow and 0.2 for bare ground, with blended monthly average based on typical days of snow cover
Module type	Canadian Solar CS6X-300P-UL	300 W module nameplate rating
Module quantity	10,008, 18 per source circuit, 556 circuits	Dc circuits are distributed evenly among four inverters
Total kW_P/kW_{AC}	3,002.4/2,520	Nameplate dc and ac totals, respectively
Inverter	Qty. 4 x SMA Sunny Central SC630CP-US-1000	1,000 Vdc limit, 315 Vac 3-phase output
Inverter Efficiency (%)	98	Per data from manufacturer, European avg. effic.
Thermal	Fixed loss coefficient, 25 Variable loss coefficient, 1.2	Results in a typical open-rack Nominal Operating Cell Temperature (NOCT) of 47°C, in accordance with manufacturer's spec sheet data
Module quality loss, %	0.5%	Includes 0.1% nameplate gain, 0.1% modeled I-V curve correction, and 0.5% MPPT loss
LID (%)	2%	Per data from manufacturer
Mismatch, %	0.5%	Standard assumption for modern module binning

Wire loss, %	1.5% dc, 0.5% ac	At Standard Test Conditions (STC)
Shade loss, %	1.3%	Horizon loss from neighboring mountains
Snow/Soiling loss, %	1.4%	No manual cleaning
Clipping losses, %	0.1%	Energy sacrificed due to inverter reaching its maximum power limit
Transformer rating, MVA	≈1.26	Transformer rating to match output of two inverters
Transformer losses	1% variable, 0.2% fixed	Standard assumption, incl. 0.1% variable loss for 12 kV wire resistance to POCC/metering point
Loss due to auxiliary loads, %	3%	9.3 kW daytime and 100 W evening auxiliary load per inverter is assumed
Loss due to reactive loads, %	0	Assumed to be negligible
Availability Loss, %	1.6%	Energy loss at left is intended to match anticipated 1.5% downtime, or 5.5 days/yr. Modeled result is essentially equal to the imposed downtime pattern.

3.2 First-year energy estimate results

The long-term average first-year output and yield for this Project may be found in Table 3-3 below. This energy prediction does not include long-term degradation. A detailed discussion of the assumptions and losses used in the energy estimates is provided in the previous section.

The PVsyst output report is attached at the end of this report in Section 5. This includes key simulation inputs and outputs, with tables of key results and a detailed loss tree diagram.

Table 3-3 First-Year Energy Estimate

Project	Output (MWh)	Specific Yield (MWh/MWp)	Performance Ratio (PR, dimensionless yield per unit insolation)	Plane of Array Insolation (kWh/m^2)
NorthWestern Energy, Anaconda	4,987	1,661	0.812	2,045

3.3 Uncertainty analysis

The year to year output from the Project will carry a degree of downside (and upside) risk relative to the standard first-year energy estimate that was prepared using long-term average weather data. On balance, tracking-style PV projects in snowy locations tend to carry a downside risk on the order of about a 7% shortfall in output about once every 10 years. This might also be termed a *p*(90) scenario. This notation indicates there is a 90% likelihood that the plant will produce at least 93% of the average annual energy expected from it in any single year. The average output is commonly denoted as the *p*(50) scenario. Financing entities also look to understand more severe downside cases such as *p*(95) or *p*(99) to represent the 1-in-20 and 1-in-100 cases, respectively. The *p*(99) outcome is itself highly speculative and not viewed as a strong decision lever for financing. This is partly because 100-year histories of solar data are not available and partly because the typical project lifetime is on the order of 30 years. It is common in our experience for systems such as the Anaconda project to carry a *p*(95) downside risk of about 90% of normal and the *p*(99) case to dip to around 80% of normal.

With one notable exception, most of the effects that DNV GL evaluates in terms of downside risk also have upside potential. Long-term degradation is the one effect that has no upside potential, since it exerts a slow, one-way decline of about -0.75%/year. Long-term degradation is treated separately from the other downside risk factors. For pro-forma analyses, the -0.75%/year reduction that is characteristic of a *p*(50) scenario is often coupled with a stress test of more rapid degradation, in which case DNV GL recommends a *p*(90) long-term degradation of about -1.5%/year.

Aside from the long-term decline, each of the other factors that typically fit within a downside risk assessment will either have a:

- fixed lifetime bias, or a
- fluctuating year to year range.

Fortunately, the group of factors do not occur in a time-coordinated fashion, so some statistical averaging is commonly done to estimate the combined impacts of all factors in any single year (again, not including long-term degradation).

With respect to the first bullet item above, there are at least two effects that, once a project is built, introduce a consistent downside – or upside - risk. These include the inherent uncertainty of the energy model (and the energy modeler) and the measurement uncertainty of the weather data used to drive the long-term simulation. While our engineers have been trained to minimize bias and our results are often back-checked against real field performance, the modeled output still carries a typical uncertainty (at 95% confidence) of roughly ±8%, simply due to the inexact nature of the equations and assumptions used to produce an annual energy estimate. Our firm strives to “hit the bulls-eye” in all simulations, as there is no inherent advantage in the Independent Engineering (IE) discipline to produce conservative or optimistic forecasts. This does differentiate the IE from a project developer, whose optimistic slant is understood as a means to attaining better financing, and from a prospective lender, whose conservative nature is understood as a means of minimizing credit risk.

The weather data, which in this context, is principally intended to mean solar radiation data, will also introduce an uncertainty of ±8%, again at a presumed 95% level of confidence. Annually-fluctuating weather terms of minor influence, such as temperature, wind speed, and spectral composition are ignored for the purpose of our downside risk assessments. Both types of fixed sources of risk are viewed as being unbiased before the project is installed, with great care placed on quality-checking solar radiation data, especially those data published by NREL. The magnitudes of the upside and downside risk curves for both of the above-described sources are treated as symmetrical and equal.

The long-term trend in solar radiation for a tracking system in this climate shows a moderately greater downside risk than what would be experienced on a fixed-tilt array in a consistent climate such as San Diego's. Nevertheless, year to year solar radiation variability tends to be somewhat less than a casual observer might estimate. For Anaconda, the *p*(90) level of solar radiation is about 93% of its normal value, and the *p*(95) level is about 90% of normal. While snowfall exhibits a much larger percentage variation from year to year than solar radiation does, its impact is also comparatively far less significant, since even in a normal snow year, the calculated energy loss due to soiling is only 1.4%. The estimated *p*(90) impact of a doubling of annual snowfall is only expected to increase this loss to 2.8%, with an estimated *p*(95) soiling loss of just 4.2% in a year with three times the normal amount of snow. System availability, and the annual variation in that term, is a comparative wildcard with little measured data to base downside risk upon. There is a growing body of data being presented in the literature, and being told to DNV GL by fleet operators, that unstaffed fixed-tilt PV systems are achieving 99% energy-weighted availability. For tracking systems, the additional complexity of maintaining and responding to motor drive failures or aiming errors of any kind are believed to translate into an additional 0.5% annual downtime penalty. Our *p*(50) energy estimate, therefore, assumes an annual downtime energy loss of 1.5%. Beyond that, our modeling of the *p*(90) scenario holds that system downtime will dip from the 98.5% base case expectation to a more conservative 95% availability, and that the *p*(95) outcome will amount to an annual availability of just 90% of normal.

Using log-normal averaging to combine the five independent effects of model bias, measurement bias, radiation variability, snowfall variability, and availability variability, the following downside cases have been prepared. For balance, two upside cases are also shown.

Table 3-4 Anaconda Downside Energy Production Risk

Scenario	**Risk adjustment multiplier to *p*(50) output**
p(50) base case	1.00
p(70) ≈1σ negative downside potential	0.97
p(90) one-in-10 stress test	0.93
p(95) one-in-20 stress test	0.90
p(99) one-in-99 stress test	0.80
p(30) ≈1σ positive upside potential	1.02
p(10) one-in-10 upside potential	1.05

4 CAPEX / OPEX COST ESTIMATES

4.1 CAPEX estimate

DNV GL has estimated CAPEX costs for the Project using a combination of industry literature, internal benchmark data, and engineering assumptions. The costs provided in Table 4-1 below represent DNV GL's estimate for the Project assuming a 2017 installation date using a well-qualified Engineering, Procurement, and Construction (EPC) contractor. Actual costs may vary from these estimates based on final project size, number of projects, site location specifics, equipment selection, EPC contractor selection, installation date, and market changes/fluctuations.

Most of the unit costs provided in Table 4-1 below are provided in $/Wdc, as is customary in the PV industry. The inverter unit costs are provided in $/Wac, as the cost of this piece of equipment scales with the ac system size. Extended costs are provided in total $ based on the preliminary Project size of 3 MWdc and 2.5 MWac, utilizing crystalline silicon modules and a ground-mount, 1-axis tracking structure.

Table 4-1 Project CAPEX Estimate

Description	Unit	Unit Cost	Extended Cost
Modules	Wdc	$0.73	$2,190,000
Inverters	Wac	$0.20	$500,000
Structure	Wdc	$0.30	$900,000
Foundations	Wdc	$0.15	$450,000
Labor	Wdc	$0.35	$1,050,000
Electrical BOS	Wdc	$0.20	$600,000
Site Preparation	Wdc	$0.20	$600,000
Misc., incl. SCADA	Wdc	$0.25	$750,000
EPC Overhead and Profit	Wdc	$0.30	$900,000
CAPEX TOTAL	Wdc	$2.65	$7,940,000

Module prices decreased steadily and significantly between about 2005 and 2013. Prices stabilized in early 2013 due to stronger global demand and price increases on polysilicon. Module prices are expected to continue to decrease going forward, however, at a much slower rate. With the steady decrease in module prices, BOS costs of inverters and racking/tracking are seeing increased market pressure for price reduction.

4.2 OPEX estimate

4.2.1 Operations, maintenance, and asset management

Utility-scale PV systems require a mix of O&M services that are rarely administered under a single agreement or fee structure. Operating costs as a whole include several additional items that don't involve physical maintenance of the plant, but are nevertheless treated as variable and ongoing costs of operation. Such items can regularly double or triple the traditional on-site contracted O&M cost. They include items such as insurance, taxes, land lease, and reports and other filings that must be done on a recurring basis. This section covers the broad scope of activities that should be covered in some contracted or financial accounting.

To better characterize O&M services, it is helpful to consider O&M tasks as planned (preventive activities) or unplanned (corrective activities). Planned services can be categorized as those that are covered under the blanket fixed fee offered by the O&M provider, while other planned services are considered "optional" and will require additional cost. Typically, the O&M provider is also designated as the plant Operator, as distinguished from the plant Owner or from the several specialized types of subcontract O&M technicians and auxiliary service providers that are normally needed to assist the Operator and Owner.

While little concrete data exist in the literature, certain cost relationships are supported by evidence gathered from interviews and contractor experience. Despite the large uncertainty in estimating total plant O&M, the uncertainty seems to shrink for larger plants. This is because dedicated staff tends to be available for both on-site work and off-site management on large PV systems. As a result, the fraction of total O&M costs assignable to planned activities tends to be high for utility scale systems.

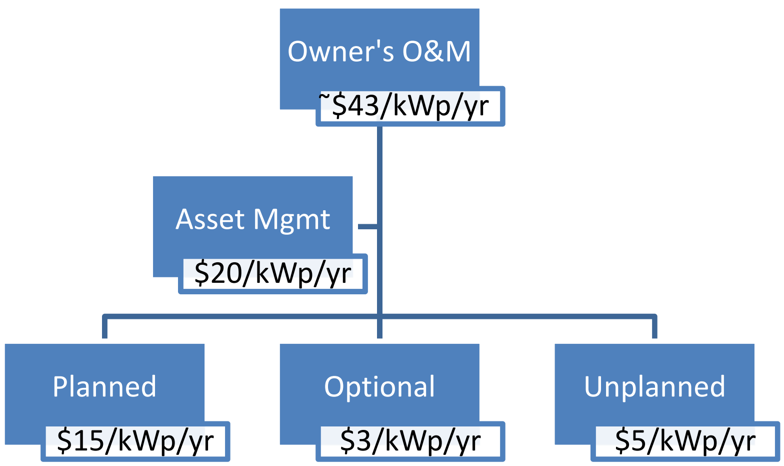

Table 4-2 below shows how a typical O&M arrangement would consist of planned, optional, unplanned activities, as well as asset management. Typical costs for each are also provided. Further discussion below provides some examples for each of these areas.

Table 4-2 Project OPEX Estimate

Description	Unit	Unit Cost	Extended Cost
Planned Activities	$/kWp/year	15	$45,000
Optional Activities	$/kWp/year	3	$9,000
Unplanned Activities	$/kWp/year	5	$15,000
Asset Management	$/kWp/year	20	$60,000
OPEX TOTAL	$/kWp/year	43	$129,000

Planned Activities: These would include a variety of regularly scheduled preventative maintenance activities provided by the Operator, with some performed by subcontractors on behalf of the Operator. Examples typically include: system monitoring, weekly or monthly energy and site incident reporting, regular visual inspection of all components, component preventative maintenance, periodic electrical testing, and inventory management. Work is typically handled by a combination of regular electrical technicians and physical plant operators, with specialized trades brought in to handle occasional medium voltage work or inverter maintenance. This work is typically included in a base, fixed fee package, which as noted above is typically on the order of $15/kWp/year. On-site staffing to handle some of these responsibilities typically occurs for projects larger than 25 MWp.

Availability guarantees and performance assurance are often included in with the base, fixed-fee O&M package, particularly for larger projects. Availability guarantees often include uptime guarantees for inverter and tracker availability. Performance assurance generally covers alerts and performance alarms, which signal if inverters are operating below acceptable thresholds, and if the SCADA system is not functioning properly.

Planned inverter maintenance is also typically part of the base, fixed fee O&M package. This typically includes annual planned inspections of inverter components, checks for proper functionality, and part replacement as part of the scheduled maintenance. Inverter warranties are typically 5 years, with 10-year warranties increasingly available. Unplanned inverter maintenance is covered as part of "Unplanned Activities" discussed below.

Optional Activities: This category typically includes module washing, but can also include costs such as additional site visits, public outreach, or promotions. Depending on the climate, module cleaning (either washing or snow removal) is often a borderline decision and one which adds significantly to the cost of annual O&M. Therefore, module cleaning, whether to remove dust or snow, is best treated as an optional task with the decision trigger typically left to the Owner to approve in consultation with the plant Operator. These services, whether for snow or dust removal, typically cost in the range of $1.5 - $3/kWp/year (for one cleaning, including all materials). The module cleaning cost has been omitted from Table 4-2 above as the energy estimate for this Project assumes no annual cleanings. However, a value of $3/kWp/year has been included for other optional activities.

Unplanned Activities: This would include any unscheduled troubleshooting and non-warranty–eligible repairs which should be approved by the Owner. These are typically handled on a T&M basis, and cost approximately $5/kWp/year. Examples include unscheduled inverter repairs, plant vandalism, and tracker repairs. Unscheduled inverter repairs might include replaceable printed circuit board failures, fan failures, and contactor failures. Plant vandalism may include: cutting of perimeter or security fencing; theft of modules, theft of wire, plant tools, utility vehicles, spare parts, and breakage of modules from thrown rocks. Unplanned tracker repairs include: burned out motors; bent or cracked drive shafts, actuators, and bearings; and failed controller electronics.

Asset Management: This is a planned and necessary set of tasks, but is normally considered "out of scope" by an Operator, and is normally handled on a fixed-fee basis by a third party. The scope typically includes such items as: billing and collections, contract and warranty administration, taxation forms and returns, account management and high-level annual compliance reporting, insurance and legal issues, payment for auxiliary power and communications, and sometimes, handling security service contracts.

Nominally, asset management costs are now in the $20/kWp/year range. DNV GL has represented Asset Management services here as a cost which scales directly with project size. DNV GL estimates that this is the case for a majority of the overall cost, which includes items such as insurance, taxes, and auxiliary power, which all increase with project size. There are likely other, smaller portions of the total, such as administrative costs associated with reports and filings that are only weakly related to project size.

4.3 Projected economic results

Deciding whether to go forward with a PV installation is a complex matter involving tangible cost and benefit calculations and intangible societal and green power attributes. The following discussion and results only concern the tangible cost and benefit calculations. Consolidating the various costs associated with installing a PV system, operating it, and decommissioning it, and then comparing those costs to the benefits realized through electricity production are the fundamental decision threshold associated with any power project.

The base case tracking system detailed in this report was selected as the best of an economic stack of four fixed and tracking system configuration options that are commercially available and, in our view, potentially feasible. Even as the best choice in terms of lifecycle economics, the base case tracker does not appear to be an attractive investment under the current mix of capital cost, climate, and avoided costs that govern the decision. However, the following analysis illustrates how the absolute economic results and stacking order were determined.

4.3.1 System options

For this prospective system, we analyzed the full complement of likely costs and benefits for the recommended 3 MW_P tracking system, but also compared the lifecycle economics to three other reasonably foreseeable configurations for this PV installation. Along with the ±60° tracking range system detailed within, three other system variants were considered for the lifecycle economic comparison: a tracker with a smaller ground footprint, denser row spacing, and narrower ±45° tracking range; a small footprint fixed-tilt array at a 30° tilt angle; and a larger footprint fixed-tilt array at a 45° tilt angle.

Some of the rationale for the envisioned options is as follows: the more closely-packed tracker with the smaller rotation range has seen more commercial prominence over the past decade than the more recent products offering the broader rotation range, though the wide ±60° rotation feature has had some commercial presence, too, dating as far back as 1990. The fixed-tilt systems offer lower capital cost, lower operating cost, and historically, better reliability. The more steeply inclined 45° system is 33% less prone to snow retention than its 30° counterpart. It is also less likely to trigger the O&M dilemma of whether to dispatch a crew to manually remove snow during prolonged cold/snow cycles. However, the shallower tilt option permits a smaller footprint and experiences less row-to-row shading loss if installed on a site of comparable acreage. Among the four options, the shallower fixed-tilt type has been the most prominent, though latitudes as far north as Anaconda's require some reconsideration of what the optimal tilt should be, since most commercial PV history has been centered in non-snowy climates at lower latitudes south of Montana's. As the results below will show, the choice of which fixed-tilt angle is preferred turned out to be a toss-up, with offsetting values for the various pros and cons cited above.

4.3.2 Economics assumptions

The capital cost for the fixed-tilt array was assumed to be 10% less than for the tracking array, and the operating cost for the fixed-tilt array was assumed to be 20% less than for the tracking array. Of course, the annual energy production is less for each of the three alternate configurations than it is for the base case ±60° tracking range system (2% less for the small footprint tracker and 16% less for either fixed-tilt option), but all options were presumed to decline at the same 0.75% per year system degradation rate and all were analyzed on the same 30-year lifetime basis.

Among the key financing assumptions, a 10-year, 6% loan at 0% down payment was assumed. A discount rate of 8%, electricity escalation of 3.5%, and general escalation of 2.5% were used. A 10% Federal investment tax credit was used, since it is unlikely this project will be installed in time to qualify for the current 30% tax credit. Accelerated depreciation (MACRS) would still apply to the asset, however, so this benefit was included. Lacking a state tax in Montana, a Federal 35% tax rate was nevertheless assumed to apply. Salvage at 5% of initial capital cost was included at the end of Year 30. Land-related cost differences were ignored for this analysis, except to the extent that annual operating costs are scaled according to area and were therefore higher for the tracking systems than for the fixed-tilt systems.

Energy was valued at $60/MWh, based on a search for NorthWestern Energy's avoided energy costs (sources: Montana Environmental Information Center, NorthWestern's main web site, and MT PSC docket D2012.1.3, Commissioner Kavulla's concurring opinion).

4.3.3 Results

Table 4-3 below lists key characteristics and financial results for the base case and three sensitivity cases considered for the 3 MW_P Anaconda installation.

Table 4-3 Economics summary for four Anaconda 3 MW_P PV system options

Case	Ground Cover Ratio (GCR) and Acreage needed	Installed Cost, $MM	1st-yr MWh	Levelized Cost of Power (LCOP), $/MWh	Benefit/Cost (b/c) ratio	Net Present Value (NPV), $MM
Base: ±60° tracker	0.30 21 acres	$7.96	4,987	118	0.74	-1.63
±45° tracker	0.33 19 acres	$7.96	4,873	121	0.72	-1.74
45° fixed-tilt	0.35 18 acres	$7.23	4,181	132	0.66	-1.97
30° fixed-tilt	0.45 14 acres	$7.23	4,179	132	0.66	-1.97

As the results above show, none of the four identified options demonstrate a positive net present value or a b/c ratio exceeding 1.0. The LCOP of $120-130/MWh does not compare favorably against NW Energy's current avoided cost of about $60/MWh, so on these bases, the potential PV installation does not appear promising on sheer economic value alone. Should a 30% Federal tax credit become attainable (instead of 10%, as was assumed herein), or should avoided costs be viewed as substantially higher than $60/MWh, then the absolute economics of the above cases will improve. Also, should externalities and other intangible benefits be factored in, the overall investment could be viewed more favorably.

The following plots show the undiscounted and discounted annual cash flows for the base case. Cost cash flows include items such as loan amortization and operating expenses. Benefits include items such as energy production revenue at avoided cost, depreciation, and tax savings due to interest payments. While the undiscounted cash flow shows a near-positive cash flow in the earliest years and a simple payback that is attained during the 29th year, the cash flow trends are diminished quite a bit when shown instead on a discounted basis. Discounted to present value, the cumulative worth of the investment dips until the loan is paid off after 10 years, then rises gradually to the finish-line NPV of minus $1.6 million as it nears the 30-year mark. Based on the discounted cash flow trend, there is no indication that a longer operating lifetime would result in a different outcome.

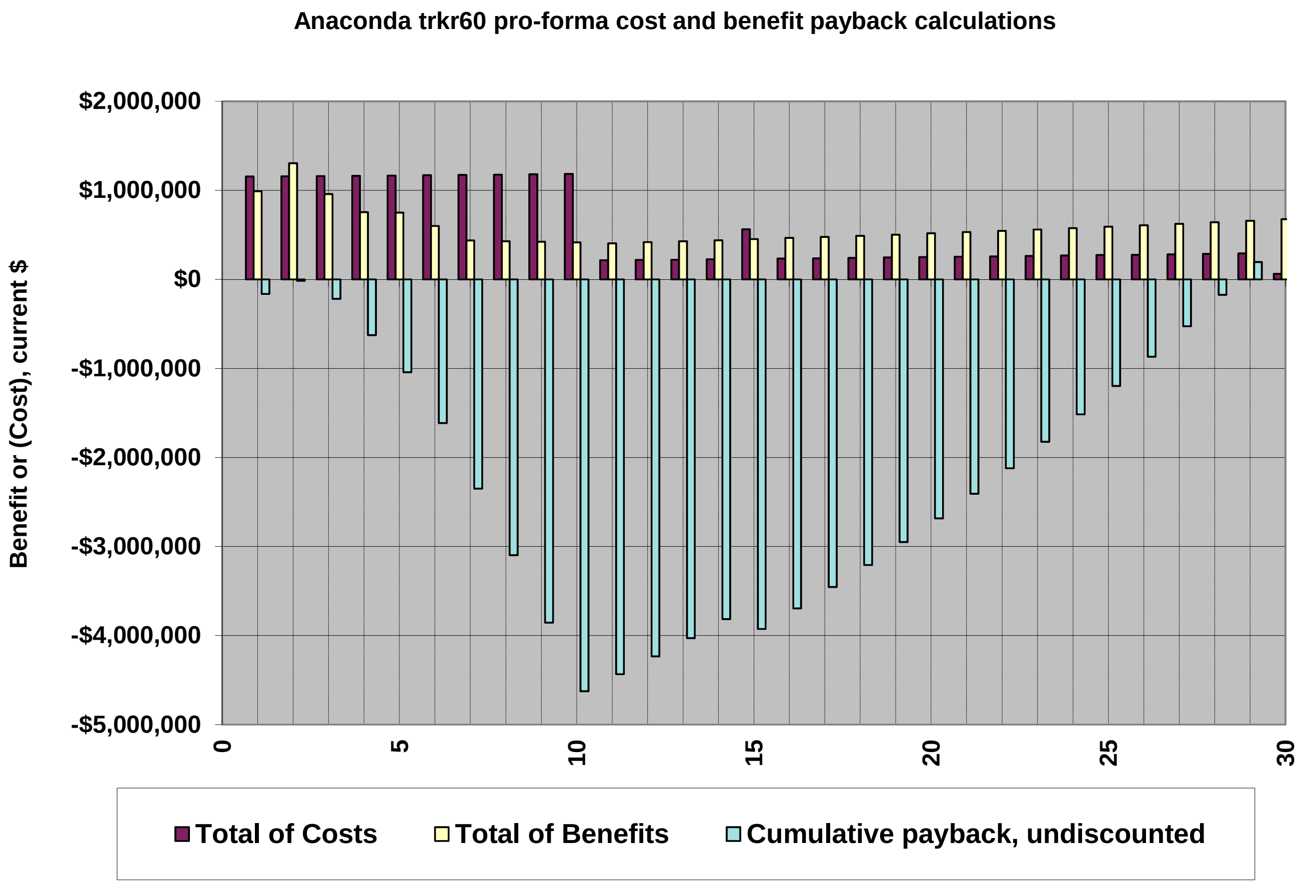

Figure 4-1 Undiscounted cash flows for base case

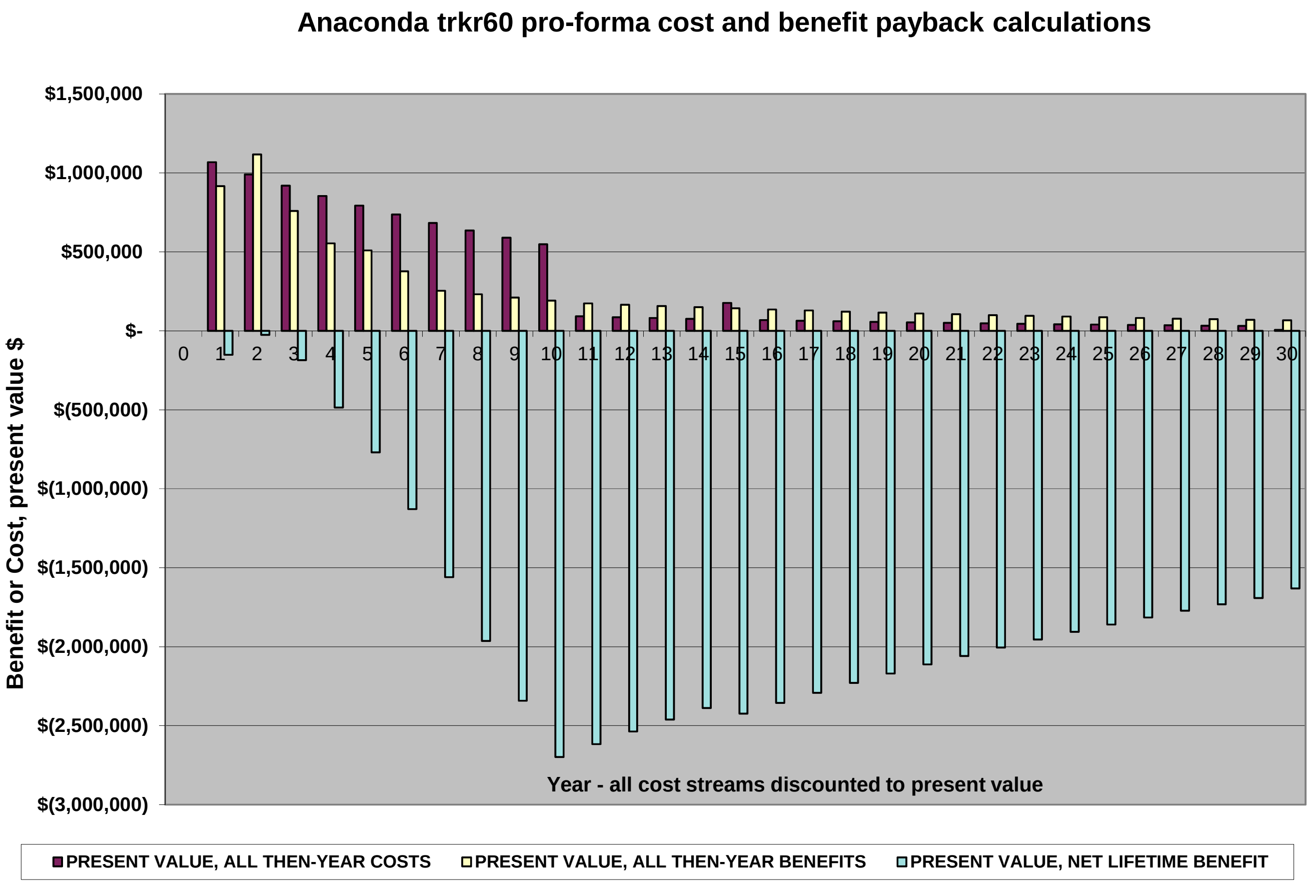

Figure 4-2 Discounted cash flows for base case

5 PVSYST OUTPUT REPORT

PVsyst's detailed report for the base case system design is attached below. This report lists all input assumptions, shows a rendered model layout, and includes monthly results and an annual loss tree diagram.

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Grid-Connected System: Simulation parameters

Project : **Grid-Connected Project at AnacondaSubstation**

Geographical Site	**AnacondaSubstation**	Country	**United States**
Situation Latitude	46.1°N	Longitude	112.9°W
Time defined as Legal Time	Time zone UT-7	Altitude	1570 m

Monthly albedo values

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
Albedo	0.60	0.60	0.40	0.30	0.20	0.20	0.20	0.20	0.20	0.20	0.40	0.60

Meteo data **Northwestern Energy - Dggs Site_sa_ghiav** TMY - NREL: TMY3 hourly DB (1991-2005)

Simulation variant : **w/snow loss, trkr60deg, SolarAnywhere met**

Simulation date 12/09/15 12h13

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	6.53 m	Collector width	1.96 m
Inactive band	Left	0.02 m	Right	0.02 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Average Height	2.4°		
Near Shadings	According to strings		Electrical effect	70 %

PV Array Characteristics

PV module Si-poly	Model	**CS6X-300P-UL APP02**		
	Manufacturer	Canadian Solar Inc.		
Number of PV modules	In series	18 modules	In parallel	556 strings
Total number of PV modules	Nb. modules	10008	Unit Nom. Power	300 Wp
Array global power	Nominal (STC)	**3002 kWp**	At operating cond.	2668 kWp (50°C)
Array operating characteristics (50°C)	U mpp	575 V	I mpp	4637 A
Total area	Module area	**19204 m²**	Cell area	17539 m²
Inverter	Model	**Sunny Central 630CP-US-XL APP01**		
	Manufacturer	SMA		
Characteristics	Operating Voltage	500-820 V	Unit Nom. Power	630 kWac
Inverter pack	Nb. of inverters	4 units	Total Power	2520 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
3.0%	2.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%	5.0%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.1 mOhm	Loss Fraction	1.5 % at STC

Grid-Connected System: Simulation parameters (continued)

LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	0.5 %
Module Mismatch Losses			Loss Fraction	0.5 % at MPP
Incidence effect, ASHRAE parametrization	IAM =	1 - bo (1/cos i - 1)	bo Param.	0.05

System loss factors

AC wire loss inverter to transfo	Inverter voltage	315 Vac tri		
	Wires: 3x4000.0 mm²	36 m	Loss Fraction	0.5 % at STC
External transformer	Iron loss (24H connexion)	5865 W	Loss Fraction	0.2 % at STC
	Resistive/Inductive losses	0.3 mOhm	Loss Fraction	1.0 % at STC
Unavailability of the system	5.5 days, 4 periods		Time fraction	1.5 %

User's needs : Unlimited load (grid)

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Grid-Connected System: Horizon definition

Project : **Grid-Connected Project at AnacondaSubstation**

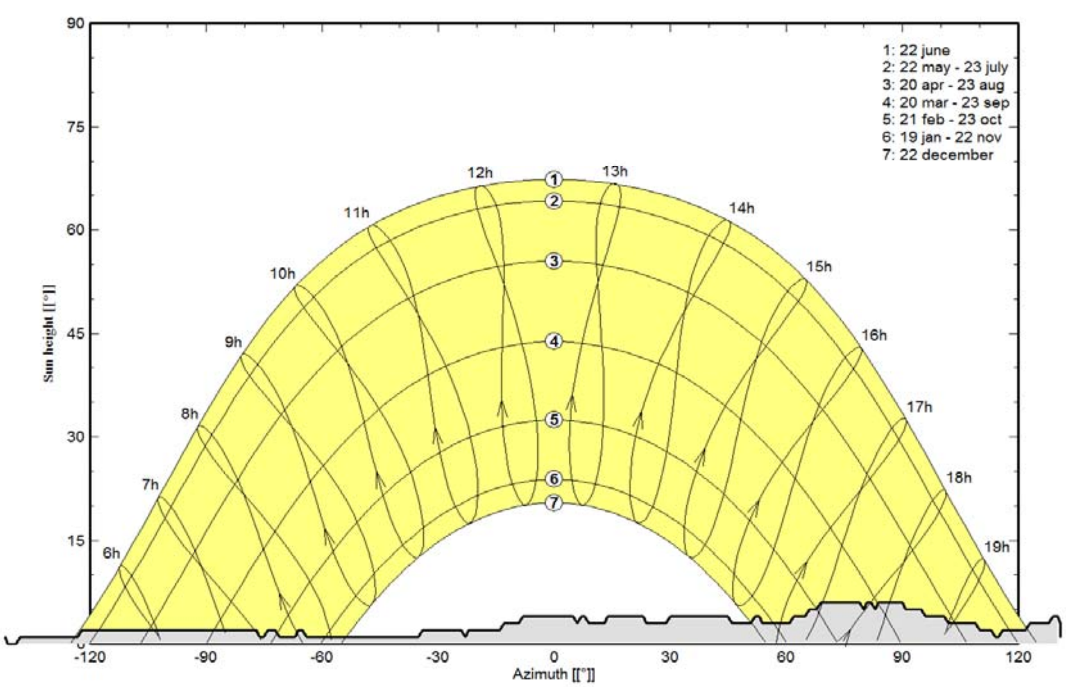
Simulation variant : **w/snow loss, trkr60deg, SolarAnywhere met**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	According to strings		Electrical effect	70 %
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS6X-300P-UL APP02	Pnom	300 Wp
PV Array	Nb. of modules	10008	Pnom total	**3002 kWp**
Inverter		Sunny Central 630CP-US-XL APP01	Pnom	630 kW ac
Inverter pack	Nb. of units	4.0	Pnom total	**2520 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	2.4°	Diffuse Factor	0.95
	Albedo Factor	100 %	Albedo Fraction	0.80

Height [°]	1.0	1.0	0.0	1.0	2.0	1.0	1.0	2.0	1.0	2.0	1.0	1.0	2.0	1.0
Azimuth [°]	-180	-179	-139	-138	-77	-76	-75	-72	-71	-65	-64	-35	-24	-23
Height [°]	3.0	3.0	4.0	3.0	4.0	3.0	4.0	4.0	3.0	4.0	4.0	3.0	4.0	4.0
Azimuth [°]	-13	-9	-8	6	7	13	14	23	29	30	45	51	52	53
Height [°]	3.0	3.0	4.0	4.0	5.0	6.0	6.0	6.0	6.0	5.0	6.0	5.0	5.0	3.0
Azimuth [°]	54	61	62	65	68	69	79	81	82	83	90	91	95	102
Height [°]	3.0	2.0	1.0	1.0	3.0	3.0	4.0	3.0	3.0	3.0	3.0	2.0	1.0	1.0
Azimuth [°]	109	113	114	115	123	128	132	133	159	163	164	176	177	180

Meteonorm horizon for, Lat. = 46.105°, Long. = -112.875°



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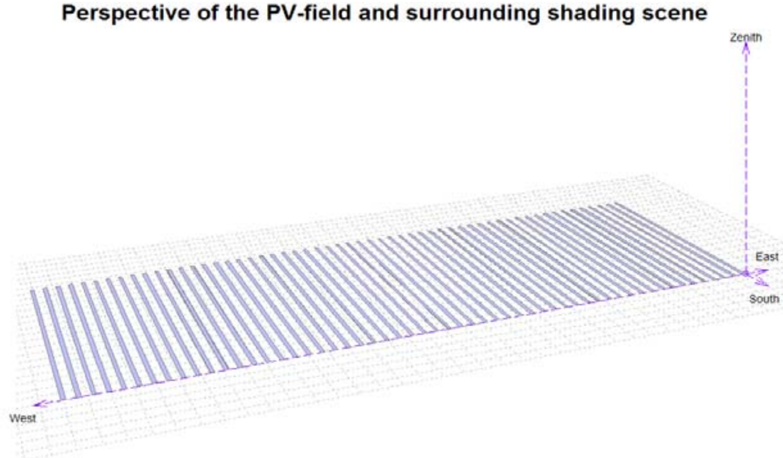
Grid-Connected System: Near shading definition

Project : **Grid-Connected Project at AnacondaSubstation**

Simulation variant : **w/snow loss, trkr60deg, SolarAnywhere met**

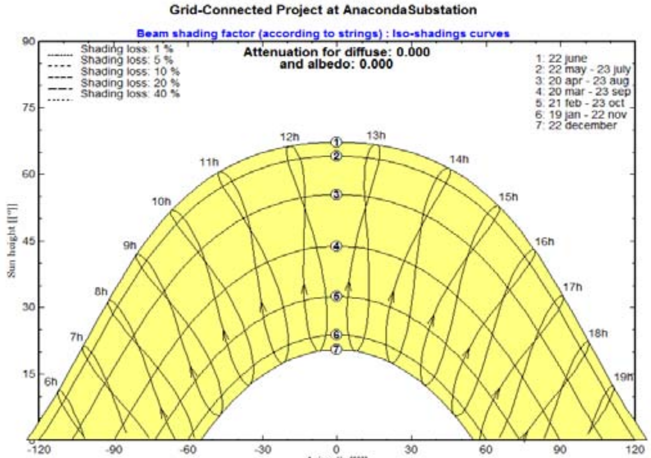
Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	According to strings		Electrical effect	70 %
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS6X-300P-UL APP02	Pnom	300 Wp
PV Array	Nb. of modules	10008	Pnom total	**3002 kWp**
Inverter		Sunny Central 630CP-US-XL APP01	Pnom	630 kW ac
Inverter pack	Nb. of units	4.0	Pnom total	**2520 kW ac**
User's needs	Unlimited load (grid)			

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram

Grid-Connected Project at AnacondaSubstation



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Grid-Connected System: Main results

Project : **Grid-Connected Project at AnacondaSubstation**

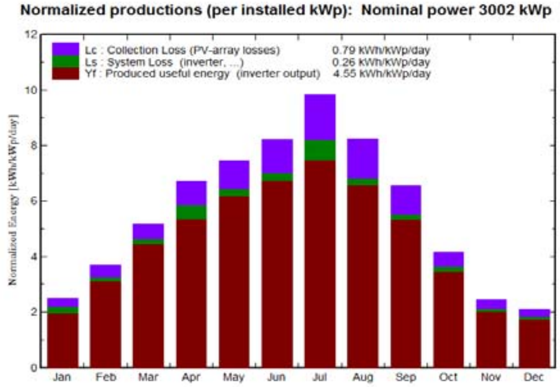
Simulation variant : **w/snow loss, trkr60deg, SolarAnywhere met**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	According to strings		Electrical effect	70 %
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS6X-300P-UL APP02	Pnom	300 Wp
PV Array	Nb. of modules	10008	Pnom total	**3002 kWp**
Inverter		Sunny Central 630CP-US-XL APP01	Pnom	630 kW ac
Inverter pack	Nb. of units	4.0	Pnom total	**2520 kW ac**
User's needs	Unlimited load (grid)			

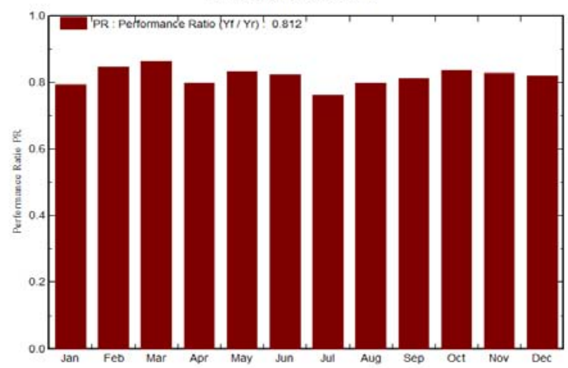
Main simulation results

System Production	**Produced Energy**	**4987 MWh/year**	Specific prod.	1661 kWh/kWp/year
	Performance Ratio PR	81.2 %		

Normalized productions (per installed kWp): Nominal power 3002 kWp



Performance Ratio PR



w/snow loss, trkr60deg, SolarAnywhere met

Balances and main results

	GlobHor	T Amb	GlobInc	GlobEff	EArray	E_Grid	EffArrR	EffSysR
	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	%	%
January	49.3	-5.83	77.4	67.1	204.2	184.4	13.73	12.40
February	70.0	-1.30	103.2	91.5	273.9	262.3	13.83	13.24
March	113.3	-2.42	160.1	145.1	432.2	415.4	14.06	13.51
April	149.5	4.71	201.3	188.7	530.0	482.9	13.71	12.49
May	176.3	8.16	231.3	218.2	600.7	578.1	13.52	13.02
June	188.4	13.50	246.4	233.0	631.4	608.3	13.34	12.86
July	220.1	16.25	304.9	290.5	765.0	696.9	13.07	11.90
August	186.1	18.19	255.3	242.5	635.2	612.3	12.95	12.49
September	138.8	14.77	196.8	185.3	497.6	479.2	13.17	12.68
October	90.5	5.24	129.0	119.7	342.5	324.0	13.82	13.08
November	51.2	-0.74	73.4	64.6	192.4	182.6	13.64	12.95
December	41.4	-8.47	65.5	55.4	170.8	161.2	13.57	12.81
Year	1474.8	5.19	2044.7	1901.5	5275.9	4987.5	13.44	12.70

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

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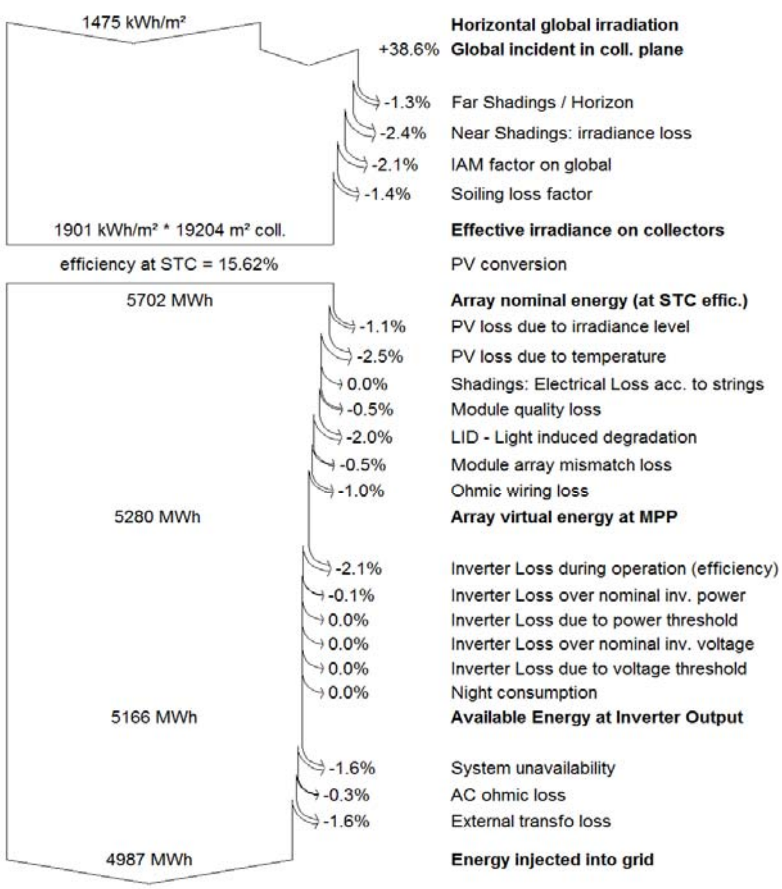
Grid-Connected System: Loss diagram

Project : **Grid-Connected Project at AnacondaSubstation**

Simulation variant : **w/snow loss, trkr60deg, SolarAnywhere met**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	According to strings		Electrical effect	70 %
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS6X-300P-UL APP02	Pnom	300 Wp
PV Array	Nb. of modules	10008	Pnom total	**3002 kWp**
Inverter		Sunny Central 630CP-US-XL APP01	Pnom	630 kW ac
Inverter pack	Nb. of units	4.0	Pnom total	**2520 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



APPENDIX A

NOTES:
1. SYSTEM SPECIFICATIONS:
   TOTAL SYSTEM:
   3.024 MW DC
   2.520 MW AC
   1.20 DC:AC RATIO
   (10,080) CANADIAN SOLAR CS6X 300 WATT MODULES
   (18) MODULES PER STRING, (560) STRINGS
   (4) SMA SC630CP-US 630 KW (1000V) INVERTERS
2. SINGLE AXIS TRACKER; 0.30 GCR, ±1,275 PILES
3. QUANTITIES LISTED ARE APPROXIMATE AND ARE SUBJECT TO FINAL DESIGN.
4. DESIGN ASSUMES LEVEL GRADE, NORMAL SOIL CONDITIONS AND NO FLOOD PLAINS.

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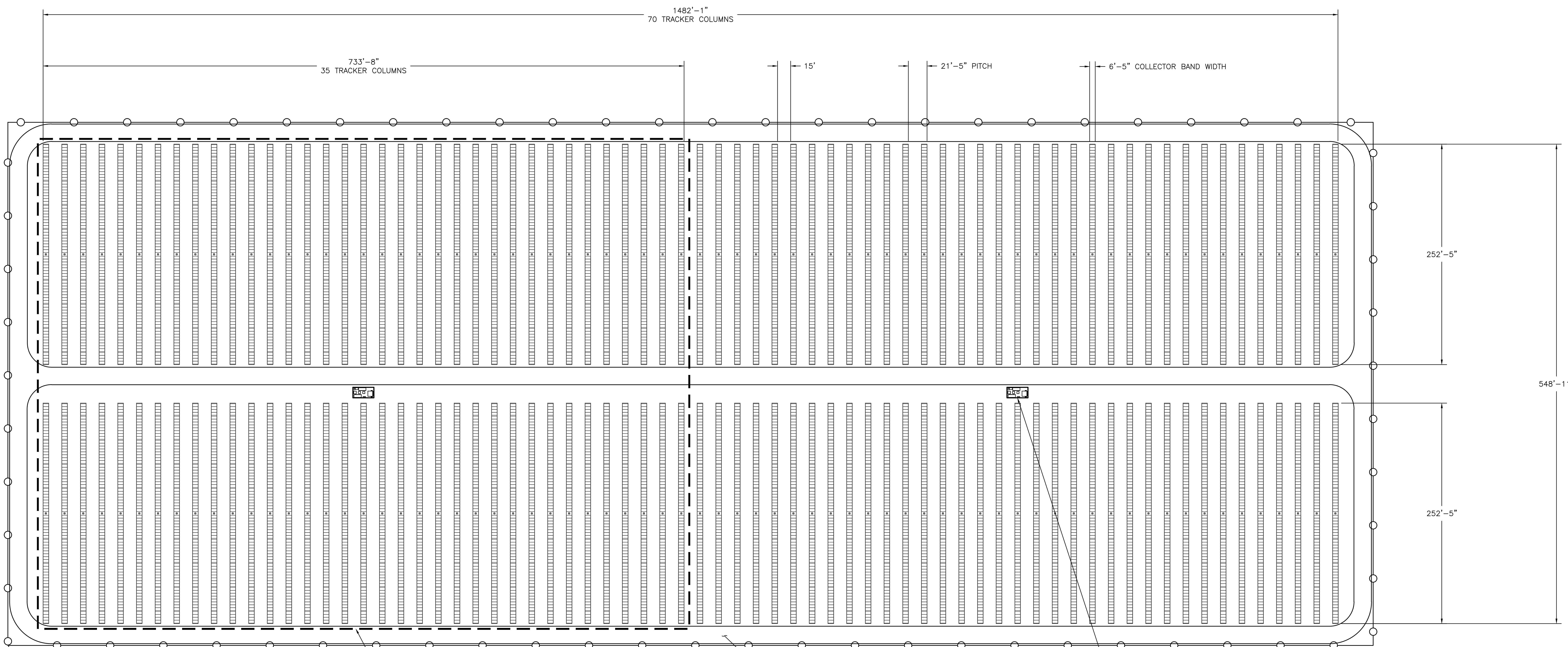

TYPICAL PROJECT SECURITY FENCE.
±4,400 LINEAL FEET
±21.48 ACRES USED

TYPICAL 1.26MWAC BLOCK:
(5,040) 300W MODULES, (280) STRINGS
1.512MWDC, 1.2 DC:AC RATIO,
(1) 1.26MW POWER CONDITIONING STATION WITH;
(2) 630KW INVERTERS AND (1) 12KV TRANSFORMER.
TYPICAL OF 2 BLOCKS.

20' WIDE ACCESS & MAINTENANCE ROAD, WITH ASSUMED 28' INTERNAL RADII. (±6,500 LF)

EQUIPMENT PAD.
(2) SMA 630CP-US 1000V INVERTERS
& (1) 12KV TRANSFORMER.
TYPICAL OF 2 PADS.

1 ARRAY LAYOUT
SCALE: 1" = 60'-0"

N

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San Ramon, CA 94583

ENGINEER'S STAMP

DRAWING ISSUE
1 09/04/2015 PRELIMINARY DESIGN

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NORTHWESTERN ENERGY

SITE LOCATION
ANACONDA, MT
46.105, -112.875

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