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Technical and Economic Assessment of Solar Photovoltaic for Groundwater Extraction on the Hanford Site

September 2015

RD Mackley
DM Anderson
JN Thomle
CE Strickland

U.S. DEPARTMENT OF ENERGY
Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

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Summary

Implementing green and sustainable remediation methods in Hanford Site cleanup may help minimize the environmental footprint of these activities. Solar photovoltaic (PV)-powered groundwater extraction alternatives for the Hanford Site were assessed for technical and economic feasibility. Solar PV alternatives ranging in size from 1.2 to 22.1 kW_p DC were evaluated and compared to traditional grid-powered systems based on their pumping performance, operational constraints, and economic indicators. The results from this assessment provide the technical and economic information needed prior to planning and carrying out future implementation of solar PV technology in Hanford groundwater extraction systems. A solar-powered mobile pump-and-treat system for remediation of hexavalent chromium in 200-UP-1 is also presented.

Acknowledgments

The authors would like to express our sincere appreciation to the following individuals for their assistance and support in preparation of this report. Randy Krekel (Land Management Program, DOE Richland Office) and Tim Haddick (Infrastructure, Services, and Information Management Division, DOE Richland Operations Office) were helpful in obtaining Hanford Site electrical utility information. We acknowledge the system design and solar PV technology insights provided by Jonathon Lewis (Renewable Energy/Solar Division, Hire Electric Inc.). Jeff Riddelle (P&T design, CHPRC) provided valuable information on P&T systems. We are thankful to Ryan Butner (PNNL) for helping assemble Hanford rooftop area estimates. We acknowledge the valuable technical reviews and insight by Mark Bassett (PNNL) and Hope Lee (PNNL). We would also like to thank Mike Perkins (PNNL) for graphic design and Matt Wilburn (PNNL) for editorial support.

Acronyms and Abbreviations

AWG	American wire gauge
bgs	below ground surface
BOS	balance of system
CY	calendar year
DNI	direct normal irradiance
DOD	depth-of-discharge
DOE	U.S. Department of Energy
DTW	depth to water
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FY	fiscal year
gpm	gallons per minute
HDPE	high-density polyethylene
HMS	Hanford Meteorological Station
LCOW	levelized cost of pumped water
Li-ion	lithium-ion
MP&T	mobile pump-and-treat
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
O&M	operations and maintenance
OMB	Office of Management and Budget
OU	operable unit
P&T	pump and treat
PSOC	partial state of charge
PV	photovoltaic
REC	renewable energy credit
RL	Richland Operations Office
rpm	revolutions per minute
SBA	strong base anion
SLA	sealed-lead acid
SOC	states of charge
TMY	typical meteorological year
VFD	variable frequency drive
WBA	weak base anion
Wp	peak watts

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1.0 Introduction

1.1 Purpose

The overall goal of environmental remediation is to protect human health and the environment. Green and sustainable remediation is defined by the Interstate Technology and Regulatory Council as: *The site-specific employment of products, processes, technologies, and procedures that mitigate contaminant risk to receptors while making decisions that are cognizant of balancing community goals, economic impacts, and net environmental effects* (ITRC 2011). Implementing renewable energy sources such as solar photovoltaic (PV) in groundwater extraction and pump-and-treat (P&T) systems is an increasingly popular approach for minimizing the environmental footprint of remediation efforts.

As costs for purchasing and installing solar PV systems continue to drop globally, it is becoming more of an economically attractive alternative. The Hanford Site contains more than 300 grid-powered pumping wells associated with seven different groundwater P&T systems across the site. The first step in considering solar power for these extraction wells is assessing the technical and economic feasibility and identifying potential target locations where implementation could be successful.

U.S. Environmental Protection Agency (EPA) guidance for implementing renewable energy into site cleanup (EPA 2011) recommends a renewable energy assessment consisting of the following relevant analyses:

- Energy demand and recommendations for additional energy efficiencies
- Preliminary evaluation of the site's renewable energy resources
- Estimated output of the renewable energy system
- Recommendations on specific locations at which to place the system and associated site conditions
- An estimated cost range for the system, with a list of specifications or conditions that could influence costs
- Lifecycle cost analysis of initial expenses, energy savings, and simple payback

Using this guidance as a general framework, this report provides a technical and economic assessment of solar PV for powering groundwater extraction on the Hanford Site. The information presented here can help provide a basis for planning and decisions regarding potential implementation of solar PV in groundwater extraction as well as other remedial activities on the site.

1.2 Report Organization

Section 2.0 provides general background information on the Hanford Site, including physiography and historical weather conditions. Section 3.0 is a review of groundwater extraction and P&T systems in use currently on the site as well as pertinent information on how power is conveyed to extraction wells. A solar PV resource assessment for the Hanford Site is provided in Section 4.0. Section 5.0 contains a review of solar PV extraction examples and recent literature on the topic, constraints and considerations specific to Hanford, followed by a discussion on the design and operational regime for solar PV alternatives evaluated in this assessment. Sections 6.0 and 7.0 contain the results of the technical and economic assessments, respectively. A discussion of the environmental and societal benefits of adopting renewable technology is contained in Section 8.0. Section 9.0 contains an application of using solar PV for powering a standalone mobile pump-and-treat (MP&T) system used for remediation of hexavalent chromium at 200-UP-1. Conclusions are presented in Section 10.0. An overview of solar PV technology and components is provided in Appendix A. Appendix B contains a discussion of submersible groundwater pump technology and application on the Hanford Site.

2.0 Hanford Site Setting

2.1 Physical Setting

The Hanford Site is located within the semiarid Pasco Basin of the Columbia Plateau in southeastern Washington State (Figure 2.1) and occupies an area of approximately 1,517 km^2 (586 mi^2) north of the confluence of the Snake and Yakima Rivers with the Columbia River (DOE 2013). The Columbia River flows eastward through the northern part of the site and then turns south, forming part of the eastern site boundary. The Yakima River runs along part of the southern boundary and joins the Columbia River at the city of Richland, which bounds the Hanford Site on the southeast. Rattlesnake Mountain, Yakima Ridge, and Umtanum Ridge form the southwestern and western boundaries. The Saddle Mountains form the northern boundary. The communities of Richland, Pasco, and Kennewick (known collectively as the Tri-Cities) border the site to the southeast.

The Hanford Site land surface is composed primarily of shrub-steppe vegetation. The site is restricted to the general public and is uninhabited. The site includes multiple operational, research, and administrative areas (Figure 2.1). These areas contain legacy underground and aboveground waste storage and processing facilities as well as current operations and support services facilities

2.2 Climate and Weather Meteorology

Solar PV performance is highly affected by weather conditions. For example, extreme temperatures can decrease module and battery efficiencies and lifespan, wind and hail can cause physical damage, snow or freezing on the module surfaces block sunlight, fog and clouds can decrease the amount of incoming solar radiation, and dust can coat or soil the module surfaces. For these reason, the climate and weather meteorology of the Hanford Site are summarized here. Historical (1945 to 2014) and recent (2014) weather data have been recorded at the Hanford Meteorological Station (HMS), located in the central part of the Hanford Site between the 200 East and West Areas (Figure 2.1), and are available for online download (http://www.hanford.gov/page.cfm/HMS).

Regionally, the climate (temperatures, precipitation, and winds) is influenced by the presence of mountain barriers. To the west, the Cascade Range creates a rain shadow effect on the Hanford Site. The Rocky Mountains ranges in southern British Columbia protect the basin from the more severe cold polar air masses moving south across Canada and from the winter storms associated with them (Hoitink et al. 2005).

From 1945 to 2014, average monthly temperatures ranged from a low of -0.4°C (31.3°F) in January to a high of 24.9 (76.9°F) in July (Table 2.1). The average annual temperature in 2014 was 13.4°C (56.1°F), which is about 12% higher than the historical average. From March through October, daily low temperatures are generally above freezing conditions (Table 2.2).

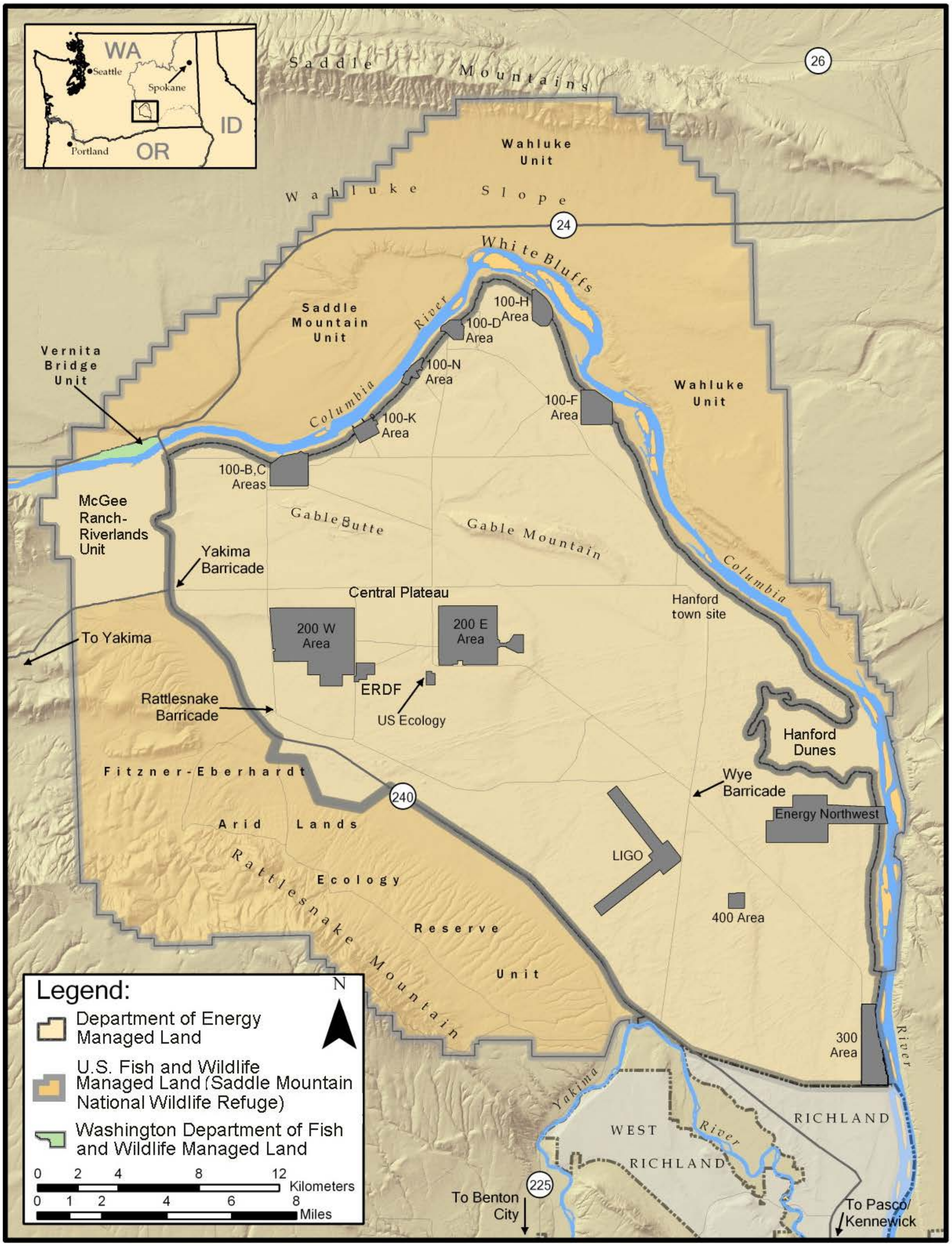

Figure 2.1. Map showing the location of the Hanford Site (from DOE 2013).

Table 2.1. Recent and historical monthly average temperature for the Hanford Meteorological Station.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
	Average Monthly Temperature °C (°F)												
2014	1.8 (35.2)	1.1 (33.9)	8.7 (47.6)	13 (55.4)	18.7 (65.6)	21.6 (70.9)	28.2 (82.8)	26.2 (79.2)	20.7 (69.2)	14.8 (58.7)	3.2 (37.8)	2.8 (37)	13.4 (56.1)
1945 thru 2014	-0.4 (31.3)	3.2 (37.7)	7.4 (45.4)	11.6 (52.9)	16.6 (61.8)	20.7 (69.3)	24.9 (76.9)	24.1 (75.3)	19.1 (66.4)	11.7 (53.1)	4.4 (40)	0.1 (32.2)	11.9 (53.5)

Table 2.2. Recent and historical monthly temperature threshold exceedances for the Hanford Meteorological Station (from HMS website, http://www.hanford.gov/page.cfm/HMS).

	90°F (32°C) or above							32°F (0°C) or below						
	Monthly Number of Days													
Season	May	Jun	Jul	Aug	Sep	Oct	Total	Oct	Nov	Dec	Jan	Feb	Mar	Total
2013-2014	2	8	25	20	3	1	59	0	3	14	9	7	1	34
Historical Season Average (1945-2014)	3	8	20	17	6	0	53	0	2	9	10	2	0	23

Historically, most of the annual precipitation falls during November through February, while July and August are the driest months (Table 2.3). The annual precipitation total in 2014 was 16.59 cm (6.53 inches), which was near the historical average. The recent (2013-2014 season) and historical average snowfall total for the Hanford Site is about 36 cm (14 inches) (Table 2.4). Snowfall occurs from November through February.

Table 2.3. Recent and historical monthly precipitation totals for the Hanford Meteorological Station (from HMS website, http://www.hanford.gov/page.cfm/HMS).

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
	Total Precipitation cm (inches)												
2014	0.94 (0.37)	2.84 (1.12)	2.54 (1)	0.97 (0.38)	0.61 (0.24)	0.66 (0.26)	0.1 (0.04)	2.24 (0.88)	0.41 (0.16)	1.96 (0.77)	0.97 (0.38)	2.36 (0.93)	16.59 (6.53)
1945 thru 2014	2.36 (0.93)	1.57 (0.62)	1.3 (0.51)	1.19 (0.47)	1.37 (0.54)	1.42 (0.56)	0.48 (0.19)	0.61 (0.24)	0.76 (0.3)	1.37 (0.54)	2.16 (0.85)	2.62 (1.03)	17.22 (6.78)

Table 2.4. Recent and historical monthly snowfall totals for the Hanford Meteorological Station (from HMS website, http://www.hanford.gov/page.cfm/HMS).

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	Annual
	Snowfall cm (inches)							
2013-2014	0	0	1.0 (0.4)	1.0 (0.4)	30.2 (11.9)	3.8 (1.5)	0	36.1 (14.2)
Historical Season Average (1945-2014)	0.3 (0.1)	4.3 (1.7)	12.4 (4.9)	12.7 (5)	5.8 (2.3)	1.0 (0.4)	Trace	36.6 (14.4)

The prevailing wind direction is west-northwest or northwest for every month of the year (Table 2.5). The highest monthly average wind speeds occur in June and the lowest are in December. The maximum recorded wind speed at the 50-ft level on the HMS instrument tower is 80 mph (35.8 m/s). Hoitink et al. (2005) note that January and December have the highest average number of days with wind gusts exceeding 50 mph (22.4 m/s).

On average, the sky above the Hanford Site can be classified as clear or partly cloudy about 55% of the year (Hoitink et al. 2005). Given the dry and windy conditions of the Hanford Site, dust storms can occur. Blowing dust conditions at the HMS, defined as a reduction in the horizontal visibility to ≤ 6 miles (9.7 km), occur an average of about 5 days per year, and are most severe from March through May (Table 2.6). Surfaces are coated with glaze or freezing rain in sub-freezing conditions an average of about 6 days per year, most frequently in December and January (Hoitink et al. 2005).

Table 2.5. Monthly and annual prevailing wind directions, average speeds, and peak gusts at 50-ft level at the Hanford Meteorological Station, 1945 through 2004 as recorded (from Hoitink et al. 2005).

Month	Prevailing Direction	Average Speed, mph	Highest Average		Lowest Average		Peak Gusts		
			mph	Year	mph	Year	Speed, mph	Direction	Year
Jan	NW	6.3	10.3	1972	2.9	1985	80	SW	1972
Feb	NW	7.0	11.1	1999	4.6	1963	65	SSW	1999[a]
Mar	WNW	8.2	10.7	1977[a]	5.9	1958	70	SW	1956
Apr	WNW	8.8	11.1	1972[a]	7.2	2004	73	SSW	1972
May	WNW	8.9	10.7	1983	5.8	1957	71	SSW	1948
Jun	NW	9.1	10.7	1983[a]	7.3	1982	72	SW	1957
Jul	NW	8.6	10.7	1983	6.8	1955	69	WSW	1979
Aug	WNW	8.0	9.5	1996	6.0	1956	66	SW	1961
Sep	WNW	7.4	9.2	1961	5.4	1957	65	SSW	1953
Oct	NW	6.6	9.1	1946	4.4	1952	72	SW	1997
Nov	NW	6.4	10.0	1990	2.9	1956	67	WSW	1993
Dec	NW	6.0	8.3	1968	3.3	1985	71	SW	1955
Annual	NW	7.6	8.8	1999	6.2	1989	80	SW	Jan 1972

(a) Also in earlier years.

Table 2.6. Average number of days of blowing dust and glaze conditions at the Hanford Meteorological Station, 1945 through 2004 (from Hoitink et al. 2005).

Phenomenon	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Dust or blowing dust	0.4	0.4	0.5	0.6	0.6	0.4	0.4	0.2	0.5	0.3	0.2	0.2	4.5
(Without Volcano)	0.4	0.4	0.5	0.6	0.5	0.3	0.3	0.2	0.5	0.3	0.2	0.2	4.2
Glaze	2.1	0.7	≤0.1	0	0	0	0	0	0	0	0.8	2.4	6.1

3.0 Hanford Site Groundwater Remediation

The Hanford Site mission from the 1940s to the 1980s was primarily focused on producing plutonium for national defense and managing the resulting waste. During this period of past operations and waste disposal practices, radionuclides and other chemicals were released to soil and groundwater (DOE 2009). Since the late 1980s, the site mission has transitioned to focus on cleaning up the extensive soil and groundwater contamination associated with historic operations.

3.1 Role of P&T Systems in Hanford Cleanup

A key objective of this complex and challenging cleanup mission is restoring contaminated groundwater along the River Corridor (e.g., 100 and 300 Areas) and the Central Plateau (e.g., 200 East and West Areas). Other restoration goals include significantly reducing the environmental footprint of the site and making land available for other uses (DOE 2012). For the Central Plateau and the River Corridor, the goals of remedial action are to ultimately restore groundwater to drinking water standards wherever achievable and to meet ambient water quality standards in the groundwater before it is discharged into the Columbia River (DOE 2009).

Since the 1990s, Hanford groundwater remediation actions have included P&T systems. The basic components of a P&T system include groundwater extraction, above-ground treatment, and disposal or reinjection of the treated water. A P&T system typically has two objectives: (1) hydraulically contain or capture the contaminant plume, and (2) reduce the contaminant concentrations to cleanup standards. Figure 3.1 illustrates the concept of hydraulic containment or capture of a groundwater contamination plume. One or more extraction wells draw groundwater into three-dimensional regions of contributing flow known as hydraulic capture zones. There are groundwater extraction systems where hydraulic containment is not the primary objective. For example, an isolated or perched zone of groundwater contamination in low-permeability layers of an aquifer might not be a threat to migrate laterally, but it can act as a continuing source of contamination. Contaminant mass reduction is the extraction objective in these scenarios. Hanford P&T systems in the 100 and 200 Areas are summarized below.

3.2 100 Area P&T Systems

There are currently five ion exchange P&T systems with extraction and injection wells operating in the 100 Area River Corridor for treatment of hexavalent chromium: 100-DX, 100-HX, 100-KR-4, 100-KW, and 100-KX. The 100 Area P&T systems are operated to hydraulically capture and contain the contaminant plume before it reaches the Columbia River. In calendar year (CY) 2013, the five 100 Area P&T systems treated a total of 1.2×10^9 gal (4.5×10^9 L) of groundwater and removed about 816 lb (370 kg) of hexavalent chromium (DOE 2014a). As of the end of CY2013, there were over 90 extraction wells serving the 100 Area P&T systems. Appendix B, Section B.2, provides pumping rates and water-level conditions for these extraction wells.

3.3 200 West P&T System

The 200 West P&T system is located in the Central Plateau. This P&T system consists of extraction and injection wells from the 200-UP-1 and 200-ZP Operable Units (OUs). Contaminants that are treated in the 200 West P&T include technetium-99, hexavalent chromium, nitrate, carbon tetrachloride, trichloroethene, and iodine-129 (DOE 2014b). In CY2013, the 200 West P&T system treated a total volume of 2.8×10^9 L (7.5×10^8 gal) of groundwater and removed 3,049 kg (6,722 lb) of carbon tetrachloride; 195,051 kg (430,014 lb) of nitrate; 71.9 kg (158.5 lb) of chromium (total and hexavalent); 13.1 kg (28.9 lb) of trichloroethene, 78.7 g (1.2 Ci) of technetium-99; and 1.0 g (148.4 µCi) of iodine-129 (DOE 2014b). As of the end of CY2013, 15 extraction wells served the 200 West P&T system. Appendix B, Section B.2, provides pumping rates and water-level conditions for these extraction wells.

3.4 200-DV-1 Perched Water Extraction

In the 200-DV-1 OU in the 200 East Area, contaminated groundwater is “perched” deeply in the aquifer within a localized layer that is bounded vertically and laterally by a fine-grained layer (Figure 3.3). Liquid waste migrated vertically and laterally in the subsurface until it accumulated within this perched layer. The underlying silt layer forms a natural barrier that slows contaminant migration to the aquifer. The objective of groundwater extraction is to recover the perched contamination and remove as much mass as possible so it does not act as a slowly feeding contaminant source to the adjacent aquifer. Contaminants within this perched layer have concentrations well above cleanup standards and include uranium, technetium-99, nitrate, chromium, and tritium (DOE 2014c). Perched water is extracted, transported to the 200 West P&T system via tanker truck or pipeline (yet to be built), and treated prior to reinjection into the aquifer.

Unlike the other Hanford groundwater P&T extraction wells, the perched-water extraction well(s) are pumped cyclically rather than continuously. The thin perched zone only produces 23 to 27 L (6 to 7 gal) before going dry, requiring a recovery period of 25 to 35 minutes (DOE 2014c).

3.5 P&T Power and Water Lines

The two primary components of Hanford P&T systems are (1) the physical facilities or buildings where groundwater is processed and treated and (2) the extraction and injection well networks. Each extraction well contains an electric AC-powered submersible pump that is controlled remotely from the P&T facility using a variable frequency drive (VFD). Flow rates are controlled according to well yield and facility design and operational constraints using the VFD installed with other system control and monitoring instrumentation on a skid adjacent the wells (Figure 3.4).

AC electrical power is provided to the extraction wells via heavy-duty (Type W) power cables laid out on the ground surface (Figure 3.5). To avoid excessive voltage losses on power cables running to distant extraction wells, 480 VAC power is used (as opposed to 120 or 240 VAC) and the power cables are sized with the appropriately sized wire (American wire gauge [AWG] 8 to 4/0, depending on cable length and pump load). The distance of these power cables from the P&T facility can be greater than 1.5 miles for distant well locations. Design criteria for the 100-DX P&T facility specifies that all pumps greater than 1/2 horsepower (HP) be 480 VAC and all motors greater than 1/4 HP operate with three-phase power to minimize motor maintenance costs (Przybylski and Esparza 2010). Water lines carrying influent and effluent water between the wells and the P&T facility consist of flexible high-density polyethylene (HDPE) pipes that are nominally 2 to 5 inches (5 to 13 cm) in diameter and run generally parallel to the electrical power cables along the ground surface (Figure 3.5).

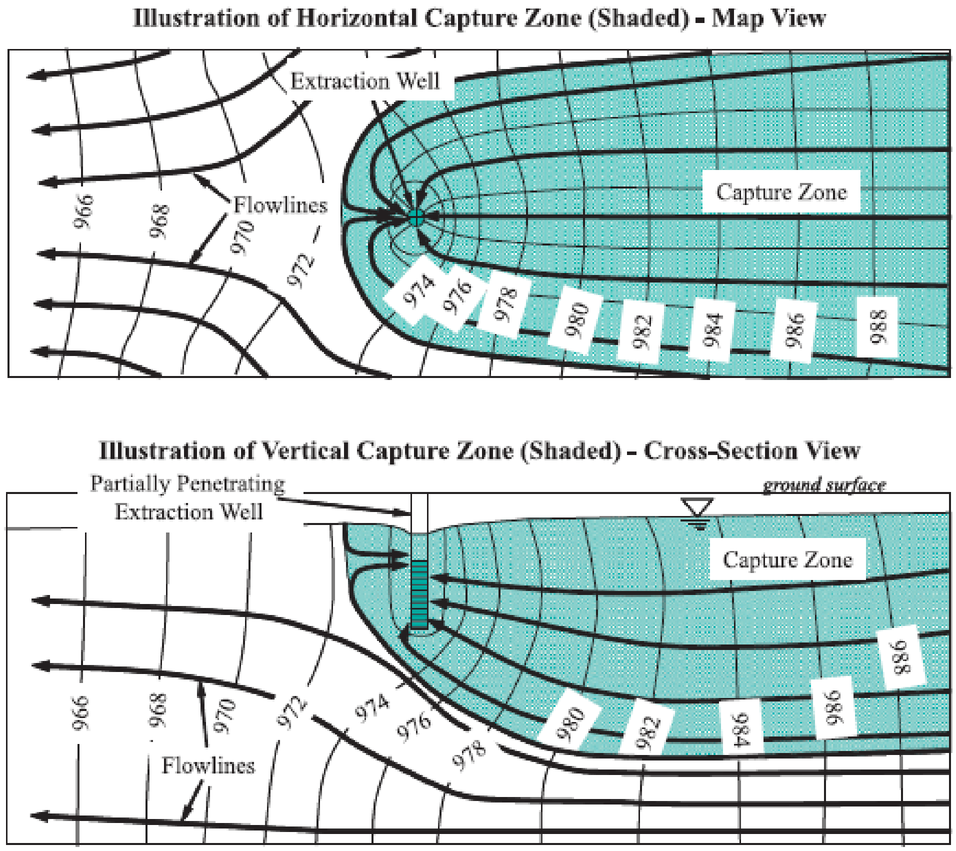

Figure 3.1. Example of a capture zone created by an extraction well pumping contaminated groundwater from an aquifer from plan (top) and cross-sectional (bottom) views (from EPA 2008a).

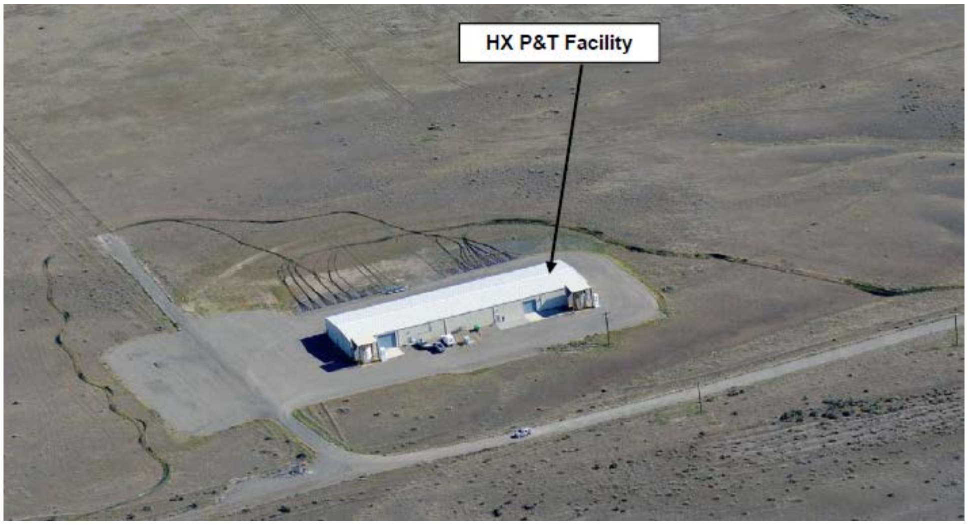

Figure 3.2. Aerial view (looking to the northeast) of the 100-HX P&T facility. Influent and effluent water lines and power cables can be seen coming into the north side of the building (image from DOE 2014a).

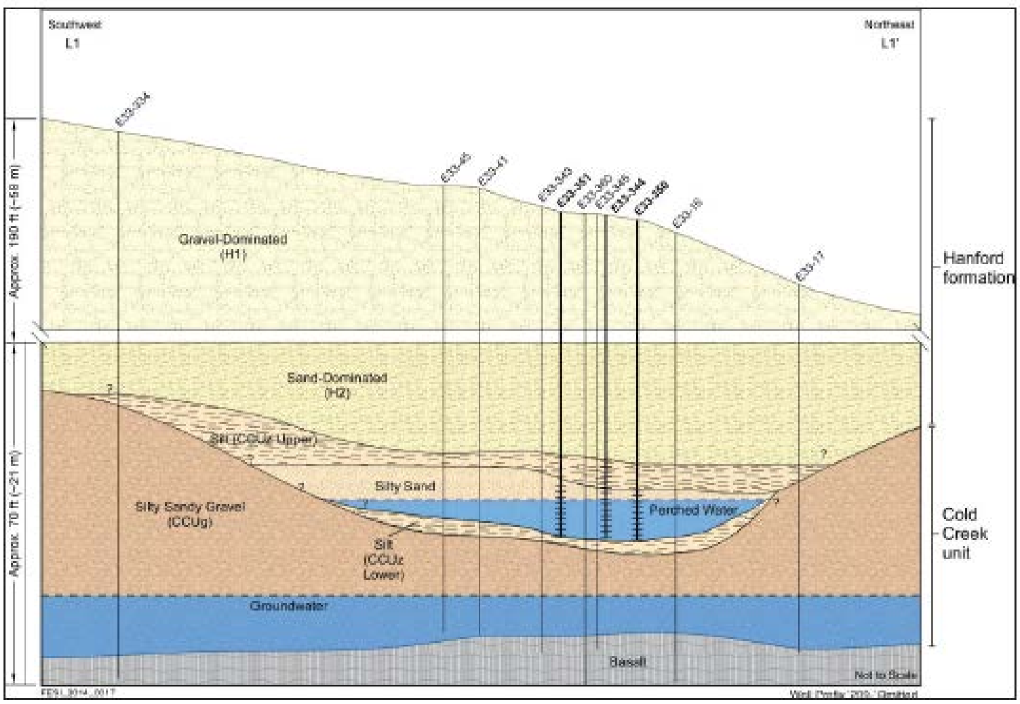

Figure 3.3. Cross-sectional representation of the 200-DV-1 perched water unit.

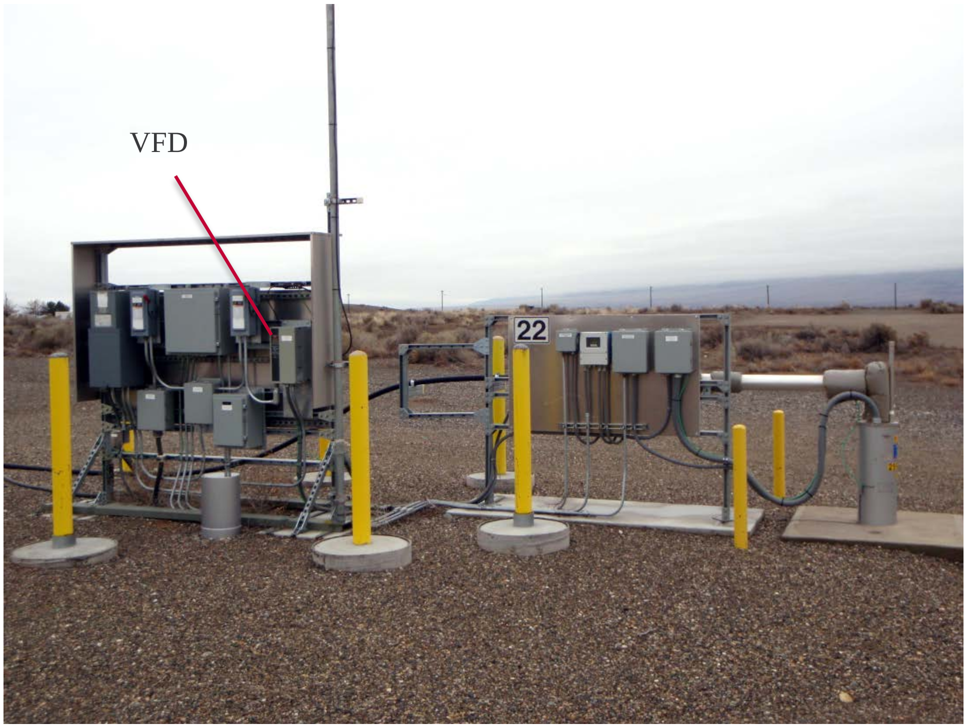

Figure 3.4. Photograph showing a typical Hanford pump-and-treat extraction well (299-W22-91) with accompanying electrical control and monitoring instrument skids (including VFD controller as noted).

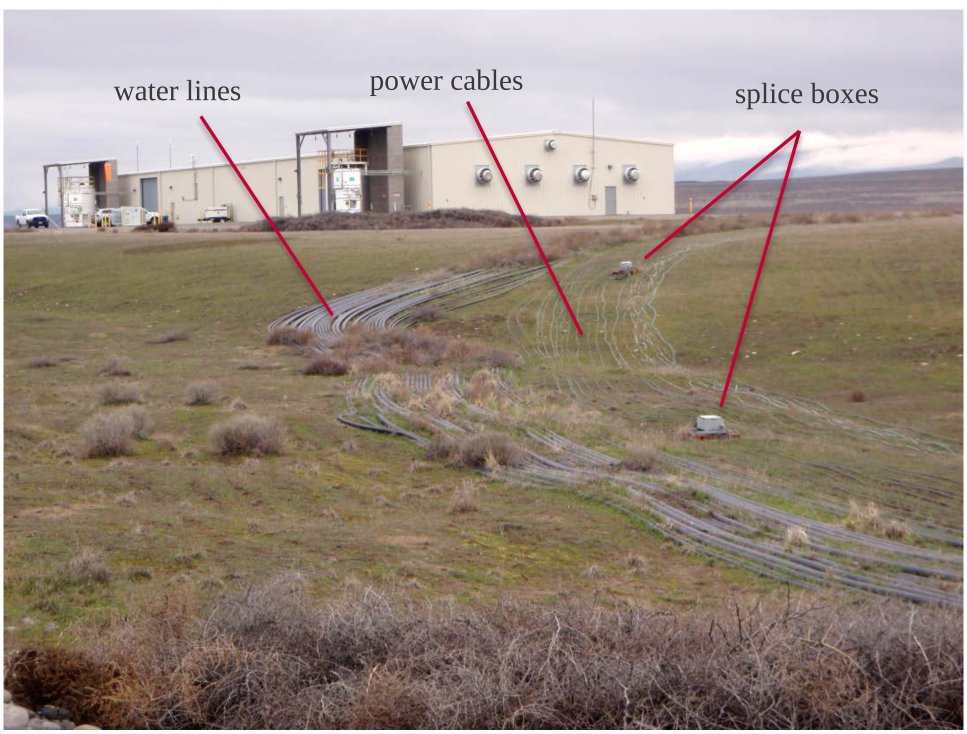

Figure 3.5. Photograph showing above-ground water lines (flexible HDPE pipe) and electrical power cables (Type W 480 VAC three-phase) running from the 100-HX P&T facility to distant wells.

4.0 Site Solar Resource Potential

The feasibility of solar PV for groundwater extraction on the Hanford Site partly depends on the adequacy and abundance of an available solar resource. Fortunately, there is a National Solar Radiation Database (NSRDB) Class II station on the Hanford Site that contains historical hourly solar and meteorological data that can be used to evaluate the solar PV potential. This section discusses the types and sources of solar radiation and meteorological data and summarizes the site-specific solar irradiance for a typical meteorological year (TMY). A preliminary evaluation of the potential for rooftop solar on larger buildings near the 100 and 200 Area P&T facilities is also provided.

4.1 Types and Source of Solar Resource Data

Solar irradiance data describe how much of the sun's energy arrives at a specific surface location on Earth during a particular interval of time and are generally reported as energy per unit of area (e.g., kWh/m^2). The amount of solar radiation reaching the Earth's surface varies temporally due to atmospheric conditions (e.g., clouds, pollution), the time of and length of day, and the season. As seen in Appendix A, Figure A.6, there are two main components of solar radiation important to solar PV: direct beam (also known as direct normal irradiance [DNI]) and diffuse radiation. The reflected portion of the direct beam radiation received by a solar PV module is much less significant at typical tilt angles. The relative contributions of the two components of incoming solar radiation vary with cloud cover.

Solar irradiance data for the Hanford Site were obtained from the NSRDB. As described in Section 2.0, there are historical data for the Hanford Site dating back to 1945. The NSRDB includes a station on the Hanford Site (Site# 727840) containing hourly meteorological and solar data from 1991 to 2010 (Wilcox 2012). These historical data were further processed into a single TMY to simulate the representative annual solar energy performance. For the Hanford Site, the newer version of TMY data (TMY3; Wilcox and Marion 2008) is available. The TMY3 dataset contains global horizontal (GHI), direct normal (DNI), and diffuse irradiance data, as well as temperature, dew point, surface pressure, wind direction, and wind speed. It is important to note that since TMY3 data represent typical solar conditions on a given calendar day and not the extremes, they are not well suited for evaluating worst-case scenarios.

4.2 Hanford Site Solar Irradiance Data

The average annual solar resource usable to solar PV systems (tilt angle = latitude) in the contiguous U.S. ranges from about 3 to 6.8 $kWh/m^2/day$ (Figure 4.1). The range for Washington State is about 3.5 to 5.5 $kWh/m^2/day$ (Figure 4.2). The average annual DNI for the Hanford Site is 5.2 $kWh/m^2/day$ (Figure 4.3). It fluctuates seasonally from a low of 2.0 in November to a high of 8.7 $kWh/m^2/day$ in July.

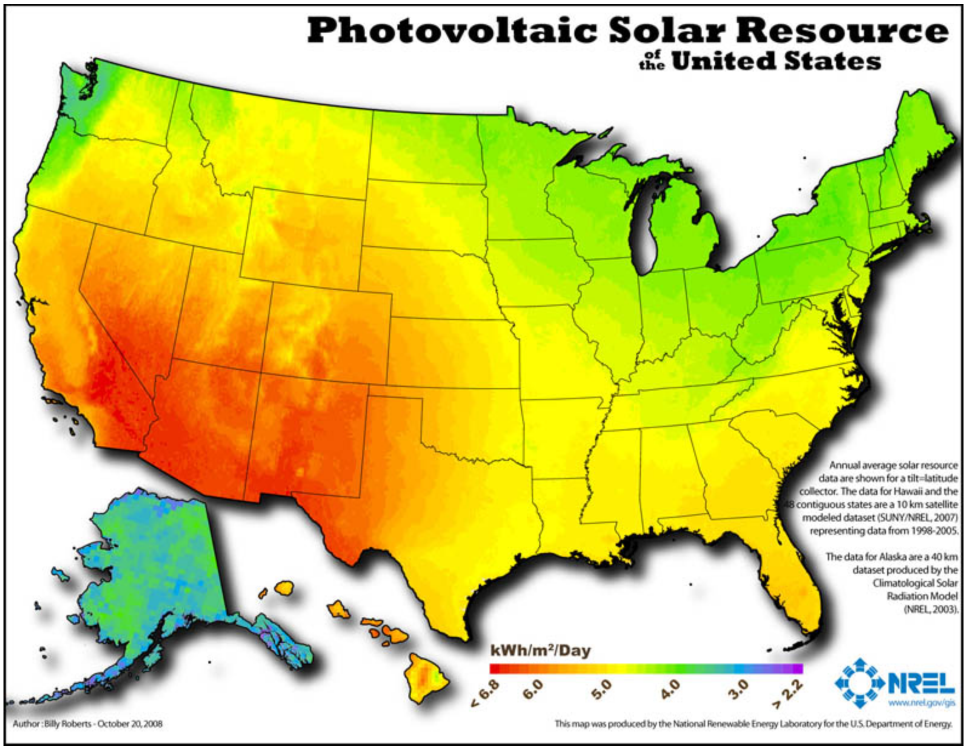

Figure 4.1. Average annual solar PV resource map for the United States (courtesy of the National Renewable Energy Laboratory [NREL]; http://www.nrel.gov/gis/mapsearch/).

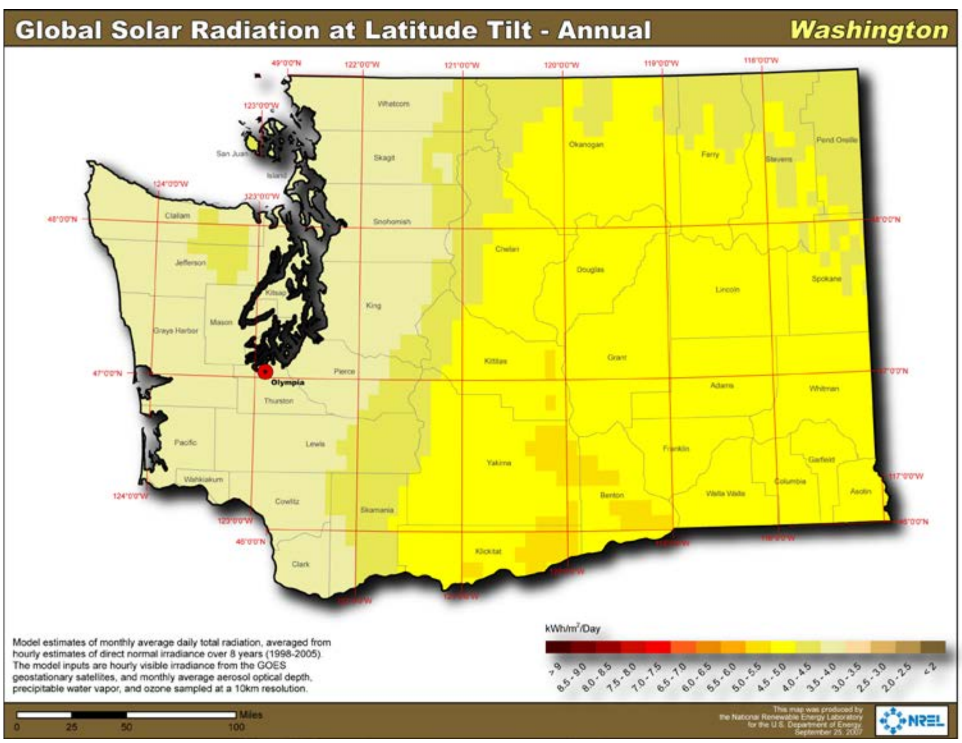

Figure 4.2. Average annual solar PV resource map for the Washington State (courtesy of NREL; http://www.nrel.gov/gis/mapsearch/).

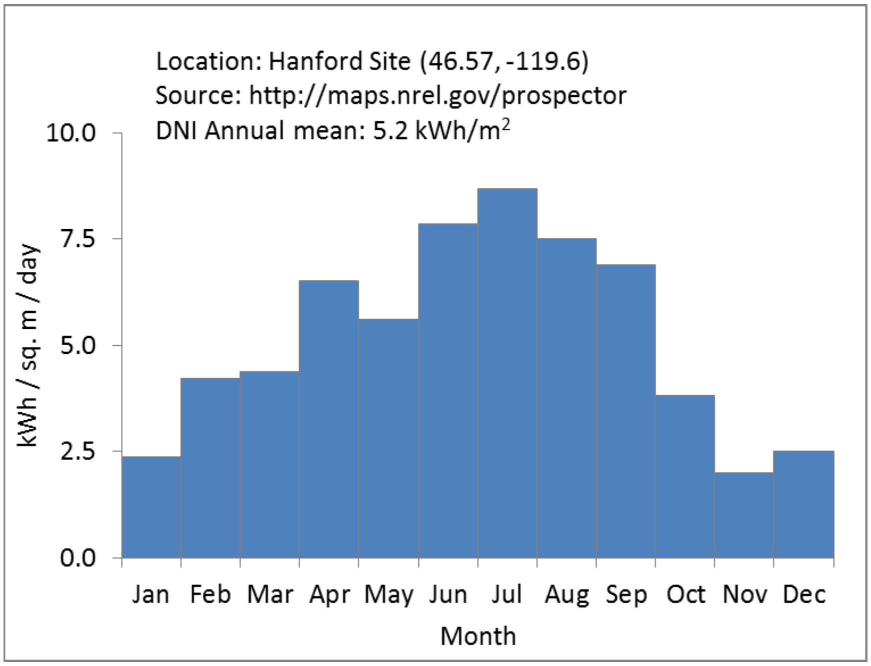

Figure 4.3. Direct normal irradiance (kWh/m^2/day) averaged by month for the Hanford Site based on NREL TMY3 data.

4.3 PV Module Tilt Angles and Tracking Effects on PV Energy Output

The angle of a flat-panel PV module's surface relative to the sun affects its ability to receive incoming solar radiation. Performance is increased when the module's angle is perpendicular to direct-beam radiation (Appendix A, Figure A.6). The sun's azimuth and elevation angle vary seasonally. The Hanford Site is a mid-latitude northern hemisphere location, and as such, the sun has a more overhead angle during the summer months and becomes more shallow and southern exposure in the winter (Figure 4.4).

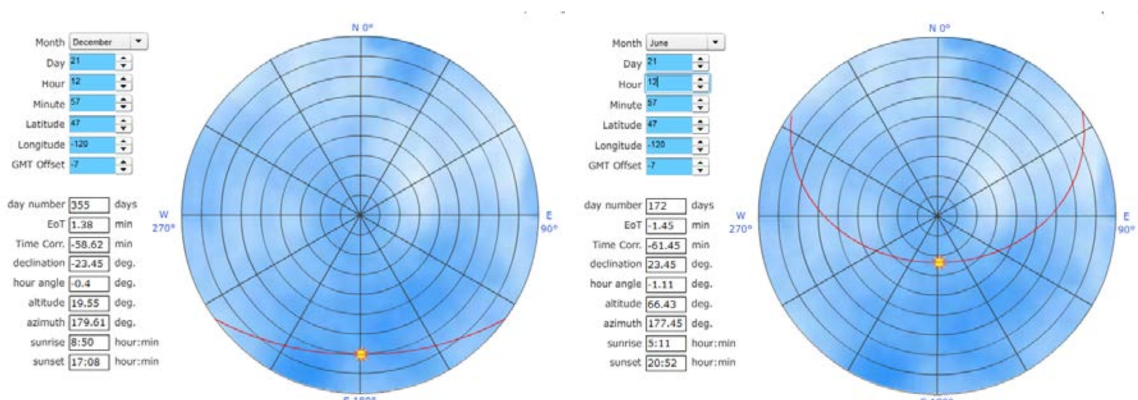

Figure 4.4. Polar plots showing the sun's azimuth and elevation angle at midday for the Hanford Site on comparison days in 2015: June 21 (left) and December 21 (right). Plots were created using a Sun Position Calculator at http://www.pveducation.org.

The variation in solar PV module performance as a function of angle and solar tracking mode was evaluated using TMY3 data for the Hanford Site in combination with the PVWatts (Dobos 2014) solar resource evaluation software. Tilt angles were varied from 0 to 90 degrees (from horizontal) in increments of 10 degrees for the fixed-angle systems, and the 1-axis (with backtracking) and 2-axis tracking systems were included for further comparison. The same 1kW$_p$ DC solar PV system (Table 4.**1**) was used in each of the tilt angle and tracking scenarios.

Table 4.1. PV system specifications and input parameters for fixed-angle and tracking system comparisons performed using PVWatts software.

Location and Data Source	Hanford Site, WA (TMY3 data)
Latitude (deg N)	46.57
Longitude (deg W)	119.6
Elevation (m)	223
DC system size (kW$_p$)	1.0
Module type and efficiency	Premium (crystalline silicon) 19%
Tilt angles for fixed-angle systems (deg)	0, 10, 20, 30, 40, 50, 60, 70, 80, 90
Fixed-angle azimuth (deg)	180
Tracking systems	1-axis and 2-axis tracking
Ground coverage ratio for 1-axis tracking	0.4
System losses (soiling, shading, wiring, etc.)	14%

For the fixed-angle systems, the maximum annual energy output for the solar PV system corresponds to an angle of 40 degrees (Figure 4.5), which is slightly less than the latitude of the site. The latitude of a site is often used as a rule-of-thumb approximation for the ideal tilt angle. However, the difference is only 3% between 40 and 50 degrees. The energy output during the warmer months from March to October is of interest in the application of a P&T system since this is the period when water lines are less likely to freeze. During this period, the sun is more overhead and the tilt angle corresponding to maximum energy production is 30 degrees (Figure 4.5). However, the difference is insignificant for tilt angles between 30 and 50 degrees. The time-varying nature of the PV system performance as a function of tilt angle and tracking is further illustrated by viewing the monthly energy totals (Figure 4.6). During the summer months, differences in energy outputs are relatively insignificant for tilt angles between 20 and 50 degrees.

Table 4.2 tabulates the results of the time-varying relationship between various tilt angles and tracking systems for the Hanford Site. Tracking systems produce more annual energy than fixed-angle systems, but the differences are even more noticeable during the summer months, when daylight hours are longer (Figure 4.6). The 1-axis and 2-axis tracking systems provide 22% and 33% more annual energy, respectively, than any fixed-axis system (Figure 4.6). For tracking systems to be economic, the installed cost premium would need to be higher than the performance gains. A recent report from Barbose and Darghouth (2015) shows that tracking systems have about a 15% higher installed cost compared to fixed-angle systems. However, these figures come from large systems that approach utility scales (>500 kW); thus, they may not represent the size range (1 to 50 kW) of a standalone solar PV system used for Hanford groundwater extraction. Cost premiums for tracking in these smaller systems would likely be higher and negate any potential performance gains.

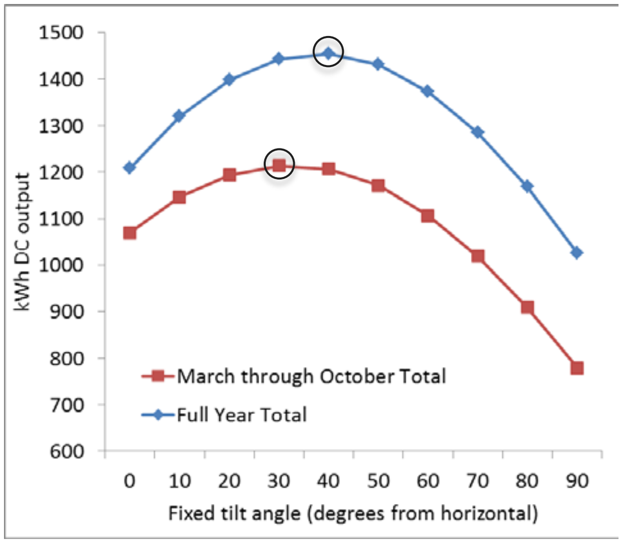

Figure 4.5. Total solar PV energy output for the Hanford Site at varying tilt angles for a 1 kW_p DC system running the full 12-month year (blue curve) and only during the warmer months of March through October (red curve). Optimum tilt angles based on energy output for the two operation scenarios are circled.

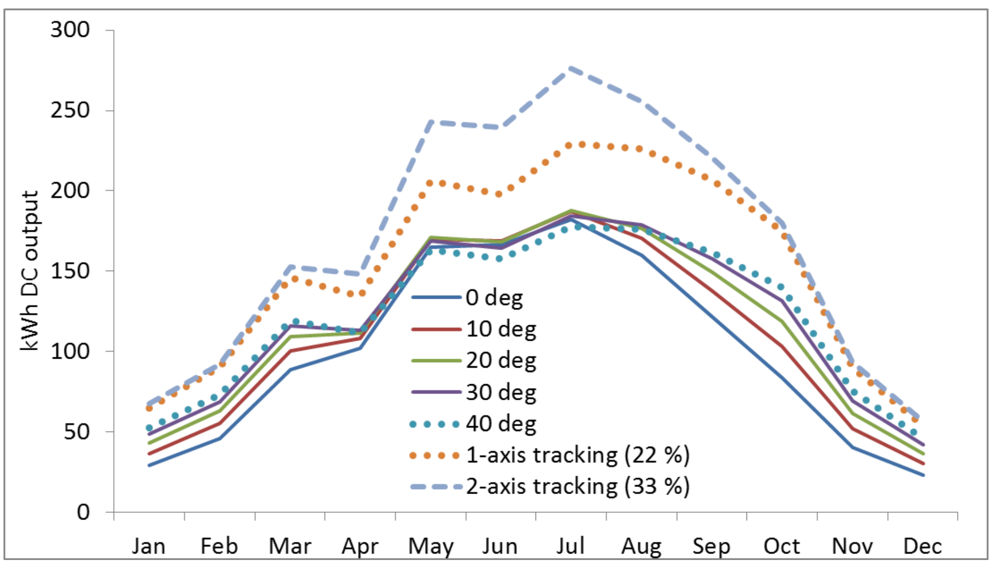

Figure 4.6. Monthly energy output for a 1-kW_p DC solar PV system on the Hanford Site at varying tilt angles compared to 1- and 2-axis tracking systems. Percent differences in annual energy production between the 40-degree fixed angle and the tracking systems are shown in parentheses for the two tracking cases.

Table 4.2. Energy output of a 1-kW$_p$ DC solar PV system on the Hanford Site at varying fixed-tilt angles and tracking system tabulated on monthly, annual, spring-summer, and fall-winter time periods of interest.

	Fixed-Tilt Angle (degrees)										1-Axis	2-Axis	Angle of
	0	10	20	30	40	50	60	70	80	90	Track	Track	Max Output
Month	1-kW$_p$ Solar PV Array Output (kWh DC)												(degrees)
January	29	37	43	49	53	56	58	58	57	55	65	67	70
February	46	55	63	69	73	76	76	75	72	67	90	92	60
March	89	101	110	116	119	120	117	112	104	94	146	152	50
April	102	108	112	113	112	108	102	93	83	71	135	148	30
May	165	170	171	169	163	154	141	126	109	89	206	243	20
June	166	169	168	164	158	147	134	119	102	83	198	239	10
July	182	187	188	184	178	167	152	134	114	92	229	276	20
August	160	170	177	179	176	169	158	143	124	103	226	256	30
September	122	138	150	158	161	161	157	148	135	119	207	221	40
October	84	103	119	131	140	145	146	144	137	127	175	180	60
November	41	52	62	70	75	79	81	81	79	75	90	93	60
December	23	30	37	42	46	49	51	52	51	49	54	57	70
Annual Total	1208	1320	1398	1443	1455	1431	1373	1285	1169	1026	1820	2025	
Mar-Oct Total	1070	1146	1194	1214	1207	1171	1107	1019	909	779	1521	1716	
Nov-Feb Total	139	174	204	229	248	260	266	266	260	247	299	309	

4.4 Available Rooftop Area for Solar PV

Rooftop solar PV installation could provide energy to P&T process and transfer buildings. For example, a large solar PV array installed atop the 100-DX or -HX facilities could provide a retrofitted central power source to extraction wells since power cables already run from the building out to the extraction wells. In the evaluation of the alternatives for powering groundwater well sites in this study, it became apparent that the available rooftop area for the potential installation of rooftop solar PV could be substantial. Estimating the available rooftop area for solar PV installations provides a first-order resource evaluation.

We analyzed a geographic information system (GIS) database of all structures on the Hanford Site and filtered those to just those structures located in the 100 and 200 Areas. We further filtered out inactive, decommissioned, temporary, and non-building structures. Finally, structures having less than 46.5 m^2 (500 ft^2) of rooftop area also were filtered out to eliminate numerous small buildings from consideration. The resulting set of buildings was visually inspected using aerial imagery, and several additional buildings were eliminated from consideration based on having roof obstructions such as large HVAC unites or other types of equipment or based on being sun-obstructed.

After filtering the database of buildings on the site, 131 buildings appear to be potentially viable for rooftop solar PV installation in the general vicinity of the 100 and 200 Areas. These buildings represent a total rooftop area of approximately 1.63×10^5 m^2 (1.75×10^6 ft^2). The majority (65%) of these buildings appear to have slanted or pitched roofs, including some slanted to the north. Assuming half of the total rooftop area would actually work out to be physically viable, there may be as much as 8.13×10^4 m^2 (8.75×10^5 ft^2) of viable roof area for solar PV installation.

Using a peak total solar irradiance striking the Earth's surface of 1,000 W/m^2 and an assumed solar PV module efficiency of 19% (premium crystalline silicon), it is estimated that the total peak solar power from 100 and 200 Area buildings would be 15.4 MW_p DC. Solar systems run during the daytime and at peak capacity only on clear, sunny days. TMY3 data for the Hanford Site indicate a solar PV capacity factor of about 16%, resulting in an annual energy output of about 2.5 MWH DC with rooftop solar.

A detailed analysis of the rooftop PV resource for the Hanford Site was not in the scope of this research effort, and these results are admittedly cursory and preliminary, but they illustrate the magnitude of the potential. The analysis did not go beyond estimating the viable roof area. Some of the buildings may store hazardous or radioactive waste or be located in a controlled area that would preclude them from rooftop solar PV applications. Further refinement of this first-order evaluation would be necessary to confirm the viability of each building. Other issues such as the need for related electric or structural infrastructure (substations, etc.) have not been considered. No economic analysis has been performed to determine whether what might be physically viable would be economic for the site.

5.0 Solar PV Alternatives in Groundwater Remediation

Solar PV has been successfully implemented in green and sustainable remediation activities for decades. Dellens (2007), EPA (2008b), and EPA's Clean-Up Information website (www.clu-in.org) highlight examples of groundwater P&T systems powered by solar PV:

- BP Paulsboro Site (Paulsboro, New Jersey): 275-kW solar PV system pumps 300 gallons per minute (gpm) of groundwater contaminated with petroleum products and chlorinated compounds through a P&T. Six extraction well pumps, aerators, blowers, and transfer pumps are powered with solar PV. System produces 350 MWh of annual energy, meeting 20% to 25% of the total P&T energy demand.
- Frontier Fertilizer Superfund Site (Davis, California): 5.7-kW rooftop and 68.9-kW ground-mounted solar PV systems provide 100% of energy demands for P&T and in situ thermal treatment for remediating pesticides, carbon tetrachloride, and other contaminants from groundwater and soil. The two solar PV systems generate 109 MWh of annual energy.
- Lawrence Livermore National Laboratory Site 300 (Livermore, California): Four solar PV systems with combined total of 3.2 kW are used to pump groundwater contaminated with volatile organic compounds through granular activated carbon treatment systems. The systems are standalone and incorporate battery storage to allow some pumping during low-sunlight periods.
- Apache Powder Company Superfund Site (St. David, Arizona): 1.44-kW solar PV system that powers a centrifugal pump used to recirculate water within a constructed wetlands during daylight hours for the remediation of heavy metals, nitrate, and the explosive dinitrotoluene.

The energy demands of P&T systems vary with the number of extraction and injection wells, types of contaminants, treatment technology, and hydrologic conditions. In many stances, solar PV systems can similar in scale to residential and commercial installations meet a portion or all of these energy demands (Collins et al. 2013). However, there are challenges, constraints, and limitations inherent to solar PV that require proper assessment and careful planning to implement this technology in successful target applications.

Recent studies have documented and evaluated the performance of solar-powered extraction alternatives in P&T systems. Published studies have mainly focused on evaluating capture zones and water volumes of P&T systems implemented with solar PV powered extraction wells (e.g., Collins et al. 2013; Conroy et al. 2014; and Cortes Di Lena and Elmore 2014). Cortes Di Lena and Elmore (2014) conducted a capture-zone analysis under variable pumping rate schedules for a P&T system using solar PV with and without energy storage. They concluded that capture zones and water volumes increase proportionally more by increasing the pumping rate with larger solar PV arrays than they do by using a costly energy storage component. The unstated assumption is that the extraction well would need to be able to sustain a higher pumping rate.

When extraction wells are already being pumped at maximum sustainable flow rates, adding an energy storage component may be the only way to increase performance. Conroy et al. (2014) found that solar PV extraction systems with an energy storage component provide a higher pumping-time ratio since additional pumping can take place during the night and low-sunlight hours. This translated to capture zones that were wider, more efficient, and less seasonally varied as well as increased overall volume of water extracted. While several of these studies briefly discussed the costs of these systems in relation to their performance, they did not conduct a rigorous cost:benefit analysis or lifecycle analysis similar to the economic assessment presented in Section 7.0.

5.1 Initial Considerations for Targeting Solar PV Alternatives at Hanford

Assessing the potential technical and economic feasibility of solar PV alternatives for Hanford groundwater extraction requires considering solar PV system performance in the context of the installation scenarios. As discussed in Section 3.0, groundwater extraction and treatment is taking place at multiple locations on the site. Existing and future extraction locations, limitations, constraints, and benefits of solar PV extraction systems were evaluated together based on an initial set of techno-economic feasibility indicators and considerations (Table 5.1).

Extraction well networks associated with Hanford P&T systems are inherently spread out over a large geographic area due to the extent of groundwater contamination. Many of the extraction wells are located over a mile from the associated P&T facility. As discussed in Section 3.0, the current practice for powering many of the extraction well pumps consists of running long distances of expensive above-ground power cables from the P&T facility to the well site. A standalone solar PV power source alternative would be sited at the well and avoid these upfront cable costs.

The hydrologic conditions and P&T objectives need to be considered. Extraction wells in the 200 West Area, located on the Central Plateau, pump from a much deeper and more transmissive aquifer than those in the 100 Areas near the Columbia River, and require extraction pumps with significantly larger horsepower ratings (Appendix B, Figure B.2). On one hand, higher energy loads could increase cost avoidances with a solar PV system over the project lifecycle since this energy would not need to be purchased from the utility provider. On the other hand, solar PV extraction systems in deep or high-yield aquifers may require excessively large solar arrays and energy storage to provide pumping rates and consistency similar to the grid-powered case. Furthermore, extraction systems where hydraulic containment is a critical priority would also require large and expensive solar arrays and costly energy storage to maintain effective plume capture. Solar PV systems may not be able to provide similar flow rates and continuity under higher-energy load conditions and still be practical and economical. Initial indications also suggest that ideal sites are those where the intermittent nature of solar PV pumping is compatible with pumping operation schedules such as the cyclical extraction of perched groundwater at 200-DV-01. Intermittent pumping (as opposed to continuous operation) prevents the need for costly energy-storage components.

Table 5.1. Initial considerations for solar PV groundwater pumping alternatives.

Characteristics	Effects and Considerations on the Technical and Economic Feasibility of a Solar PV Alternative
Remoteness or distance to closest grid-power source	Remote extraction well locations require long and expensive above-ground power cables running from the P&T facility or the closest grid-tied power source. Avoiding upfront power cable costs in a standalone solar PV alternative could be in excess of $130k per mile (see Section 5.4.2)
Hydrologic conditions: • Water-table depth • Pumping rate	Pumping from greater depths and at higher flow rates requires more energy, which could increase energy costs over the project lifecycle in a solar PV alternative. On the other hand, a solar PV system may not be able to provide similar flow rate and continuity under higher-energy load conditions and still be practical and economical. Shallower water table and lower pumper rate conditions may provide a more technically feasible situation for solar PV.
Extraction system objectives: • Plume capture • Mass reduction	Plume capture and hydraulic containment are known to be critical objectives to some of the P&T systems (e.g., preventing contamination migration from groundwater to the Columbia River in the 100 Areas). Maintaining similarly effective capture zones in a solar PV alternative may require energy storage components and excessively large PV arrays given the intermittent nature of solar power, leading to additional upfront and lifecycle costs. Extraction locations where mass reduction is the primary objective (e.g., 200-DV-1 perched water) may be a more technically and economically scenario.
Seasonal Variation	Low incoming solar radiation levels and freezing air temperatures in the late fall, winter, and early spring create challenges. Currently, P&T extraction takes place year-round. A solar PV alternative would have the challenge of maintaining a consistent critical flow in the water lines to keep them from freezing in the winter, particularly at the Hanford site, where lines are above ground.

5.2 Other Design Considerations

Evaluating every aspect and component of the solar PV system was not the intent of this study. Therefore, initial considerations were made concerning certain common components used in each solar PV system. The basis for these initial design considerations are discussed below.

The benefits of a portable or mobile solar PV system were also considered. Mounting the solar PV systems on trailers allows them to be moved to another location. It eliminates the need for additional excavation at the well site, which saves time and money compared to a ground-mounted system. As discussed in Appendix A, Section A.2, vendors offer pre- and custom-engineered PV systems on mobile trailer platforms that can be purchased as a complete system and delivered to the site ready for deployment. The benefits of trailer mounted solar PV do come at an added cost and represent a more conservative cost-benefit scenario in the economic evaluation. As discussed later, trailer-mounted platforms have higher upfront costs than ground-mounted. Another drawback to trailer-mounted systems is that they would require some maintenance (tire repair, trailer lights, etc.) and could incur comparatively higher lifecycle costs. It is anticipated that the PV modules would be mounted to the trailer platforms using fixed-angle mounts due to space limitations. Solar resource evaluations discussed in Section 4.3 confirm that 1-and 2-axis tracking systems offer performance gains; however, they require a larger physical footprint and would require an excessive amount of space not available on trailer platforms.

Since performance gains of solar tracking systems may be offset by the higher initial installation and maintenance costs, fixed-angle mounting was selected as the preferred option.

Currently, Hanford P&T wells employ 480-VAC submersible well pumps. As discussed in Appendix B, DC pumps marketed for solar applications have higher efficiencies than typical AC pumps (Table B.1 and Figure B.4). DC pumps also eliminate the need for an inverter, which further increases system efficiency and reduces upfront and lifecycle costs. Despite this, AC submersible pumps were used in all of the solar PV extraction systems evaluated. Including AC pumps adds another degree of conservativeness to the performance and economic evaluations by slightly lowering the overall system efficiency. Holding the pump type constant also simplifies cost comparisons between solar PV and a grid-powered system.

We are at a figurative crossroads with respect to energy storage systems for solar PV applications. As discussed in Appendix A, Section A.2, sealed-lead acid (SLA) batteries have been used extensively and reliably for many years. Indications are that other emerging battery technologies, such as lithium-ion and flow batteries, might be more efficient, require less maintenance and replacement, and allow a deeper depth-of-discharge (DOD) than SLA batteries. However, these batteries are double or more the upfront cost and lack the long track record of SLA technology. Given these factors, it is assumed that SLA batteries would be used in the solar PV alternatives that include energy storage.

To reduce the number of variables and focus the evaluation, the alternatives were constrained to nominal hydrologic conditions representative of extraction wells in the 100 Areas. Total head and well-yield capacity were prescribed to 100 feet (30.5 m) and 20 gpm (75.7 L/min), respectively. Appendix B, Section B.1, provides a more complete discussion of the range of pumping rates and water-table depths for Hanford P&T wells. Note that the general concept designs used in the solar PV systems evaluated here have similar application to Central Plateau (200 Area) locations where the nominal water table depths and pumping rates are much higher.

5.3 Solar PV Extraction Alternatives

A set of solar PV alternatives to be evaluated for powering extraction wells on the Hanford Site was developed based on the solar resource potential of the site (see Section 4.0) and the above-mentioned economic and technical feasibility considerations (Table 5.2). These solar PV alternatives vary in PV power output, energy storage capability, pumping schedule, pumping rate, and suitability for various locations and applications for Hanford P&T operations. Five alternatives using four different systems were identified. Note that PV2a and 2b share the same system design but differ in the operation of this system. The remainder of this section provides additional details and discussion on the design specifications and parameters of these solar PV alternatives as well as price estimates based on vendor quotes.

As noted above, the solar PV alternatives were constructed in combination with the solar resource potential for the Hanford Site (see Section 4.0). Hourly solar irradiance predictions representative of a TMY on the Hanford Site were generated using the online PVWatts software (Dobos 2014) according to the system specifications and input parameters outline in Table 5.3. Additional PV and energy storage system parameters are listed in Table 5.4.

Table 5.2. Summary of solar PV alternatives evaluated for powering Hanford groundwater extraction wells at a prescribed total head of 100 feet and maximum sustainable well-yield of 20 gpm (typical of 100 Area wells).

Scenario	Solar PV System Description	PV Output (kWp DC)	Energy Storage (kWh DC)	Estimated Purchase Price (2015 dollars)
	Three-season extraction: March 1 to October 31			
PV1	• Intermittent pumping (daytime only) • PV array is sized to provide peak pumping rate equal to the well-yield capacity • Peak pumping rate occurs during peak solar conditions	1.2	None	$18,000
PV2a	• Intermittent pumping (daytime only) • The well-yield constraint is ignored • Peak pumping rate is increased proportional to the increased PV array • Peak pumping rate occurs during peak solar conditions	5.6	None	$60,000
PV2b	• Intermittent pumping (daytime only) • Same PV array as alternative 2a • Peak pumping rate is limited to the sustainable well-yield • Excess solar energy is wasted during ideal solar conditions	5.6	None	$60,000
PV3	• Continuous “24-7” pumping • Constant pumping rate equal to the sustainable well-yield • Excess solar energy is stored in batteries and used during the night and non-ideal solar conditions	11.2	167	$160,000
	Year-round extraction			
PV4	• Continuous day and night pumping • Constant pumping rate equal to the sustainable well-yield • Excess solar energy is stored in batteries and used during the night and non-ideal solar conditions	22.1	444	$280,000

Table 5.3. PV system specifications and input parameters for hourly solar data generated with PVWatts online software tool.

Parameter	Value	Source	Assumption/Justification
Processing date	8/8/2015		
PVWatts version	5.1.0		
Location and data source	Hanford Site, WA (TMY3 data)		
Latitude (deg N)	46.57		
Longitude (deg W)	119.6		
Elevation (m)	223		
Module type and efficiency	Premium crystalline silicon; 19%	Appendix A, Section A.2, of this report and Dobos 2014	Expect that vendors will use high-efficiency module given decreasing trends in module costs.
Tilt angle for fixed-angle system (deg)	40	Section 4.3 of this report	Differences in PV output for tilt angles between 30 and 50 degrees are insignificant. 40 degrees was preselected as a nominal value.
Fixed-angle azimuth (deg)	180	Dobos 2014	Standard practice is to orient modules to the south.
PV system losses (soiling, shading, wiring, etc.)	14%	Dobos 2014	Assumed default losses were representative and no excessive loss in efficiency due to soiling from dust based on performance of local PV installations.

Table 5.4. Additional system specifications and input parameters for components attributed to solar PV groundwater extraction alternatives.

Parameter	Value	Source	Assumption/Justification
Mounting platform	Mobile flat-bed trailer(s)	Appendix A, Section A.2, of this report	Section 5.2 in this report
Pump type	Submersible	Appendix B, Section B.1, of this report	Section 5.2 in this report
Pump-motor voltage	480 VAC	Section 3.5 of this report	Section 5.2 in this report
Motor-pump efficiency	35%	Appendix B, Section B.3, of this report	Average efficiency for AC pumps evaluated was 38%. 35% represents a slightly more conservative value.
Battery type	SLA	Appendix A, Section A.2, of this report	Section 5.2 in this report
Maximum battery DOD	50%	Appendix A, Section A.2, of this report	50% is the recommended DOD for SLA batteries. It prevents deep discharges that cause permanent damage.
Battery energy transfer efficiency	90%	Appendix A, Section A.2, of this report	Typical efficiency of SLA batteries is 80% to 90%. Expect vendor to provide high-efficiency model of battery.
Battery temperature compensation model	Second order polynomial where % capacity decreases with hourly cell temperatures	Appendix A, Section A.2, of this report	Expect that vendor will supply battery with a temperature-capacity function similar to the Trojan Reliant L16 AGM battery (http://www.trojanbattery.com/product/reliant-l16-agm/).
Charge controller efficiency	95%	Appendix A, Section A.2, of this report	Typical efficiencies are 90% to 95%. Expect that vendor will supply high-efficiency model.
DC to AC inverter efficiency	96%	Appendix A, Section A.2, of this report and Dobos 2014	Typical efficiencies are 95% to 98%. 96% represents default value of PVWatts, which is within the range of published values.

Table 5.2 shows that four of the five solar PV alternatives (PV1, 2a, 2b, and 3) operate only during the warmer months of March through October. Historically (1945-2014) and recently (2013-2014), the Hanford Site experiences freezing conditions very infrequently during this 8-month period (Table 2.2). Operating during the warmer months overcomes the technical challenge of keeping the water lines and well head from freezing during the winter when the system is either running at low pumping rates or not at all (e.g., during the night). During the winter months, the solar PV extraction system would presumably sit dormant in a winterized mode, and would then be restarted prior to the spring startup. Limitations of the three-season schedule are lower annual volumes of pumped groundwater and loss of hydraulic containment during the winter. For extraction wells where plume capture is critical, this would not be technically feasible.

Extraction wells typically have a maximum pumping rate that they can sustain without experiencing excessive lowering of the water level in the well (well-yield capacity), a fact that is often overlooked in previous studies evaluating performance and benefits of solar PV for groundwater extraction. Cortes Di Lena (2014) found that capture-zone efficiency and volume of pumped groundwater are improved more by increasing the pumping rate rather than using an energy storage component to increase the pumping-time ratio (time pumping divided by total time). However, if the well is already being pumped at its maximum well-yield, increasing the pumping rate may not be an option. The peak or constant pumping rate was set equal to a well-yield capacity term in four of the five alternatives (PV1, 2b, 3, and 4) to represent this constraint. The well-yield capacity was ignored in PV2a and the pumping rate was allowed to run proportional to the solar PV output.

Three of the alternatives (PV1, 2a, and 2b) are direct solar systems where there is no energy storage (i.e., batteries). Pumping rates are intermittent and vary according to incoming solar irradiance. They do not run at night and vary from sunrise to sunset and seasonally. PV 1 is a system where the solar PV array is sized to provide peak power output (1.2 kW_p DC) required to pump at a rate equal to the well-yield of 20 gpm, while factoring in system efficiencies and losses (Table 5.3 and Table 5.4). The size of the PV array is increased for alternatives 2a and 2b (5.6kW_p DC). As noted in the preceding paragraph, the well-yield restriction is ignored in alternative 2a, allowing a peak pumping rate of 91 gpm (344 L/min). Figure 5.1 depicts this type of system.

Alternatives PV3 and 4 include battery energy storage at two different system scales and operation modes. PV3 has an 11.2 kW_p DC PV array that recharges a 167 kWh DC battery bank (about 75 deep-cycle batteries) large enough to provide a temperature-corrected reserve capacity of about 4 days. The system would run continuously (day and night) at a flow rate of 20 gpm from March 1 to October 31.

PV4 is the only solar PV system that provides continuous (day and night) year-round pumping. It is directly comparable to the current grid-powered systems. This alternative may be the technically attractive option for extraction locations where hydraulic containment is critical (e.g., between migrating plumes and the Columbia River). Given the available solar PV resource of the Hanford Site and the prescribed hydrologic conditions of 20 gpm at 100 ft of total head, this requires a very large PV array and a massive battery storage system. PV4 was designed to meet the energy demands of a continuous pumping system even during the winter when solar irradiance levels are low and variable. This system consists of a 22.1 kW_p DC solar PV array and 444 kWh DC of energy storage (about 200 deep-cycle batteries) corresponding to a temperature-corrected reserve capacity of about 10 days. A PV array and battery bank system this large (depicted in Figure 5.2) would require at least two heavy-duty trailers. It should be mentioned that running the system during freezing conditions would likely require the well-head to be protected with heat tape and insulation. The amount of heat tape and additional associated energy demands were not known and therefore were not included in the overall energy budget of the system. It is assumed that the energy demands of the heat tape are small in relation to the groundwater pump.

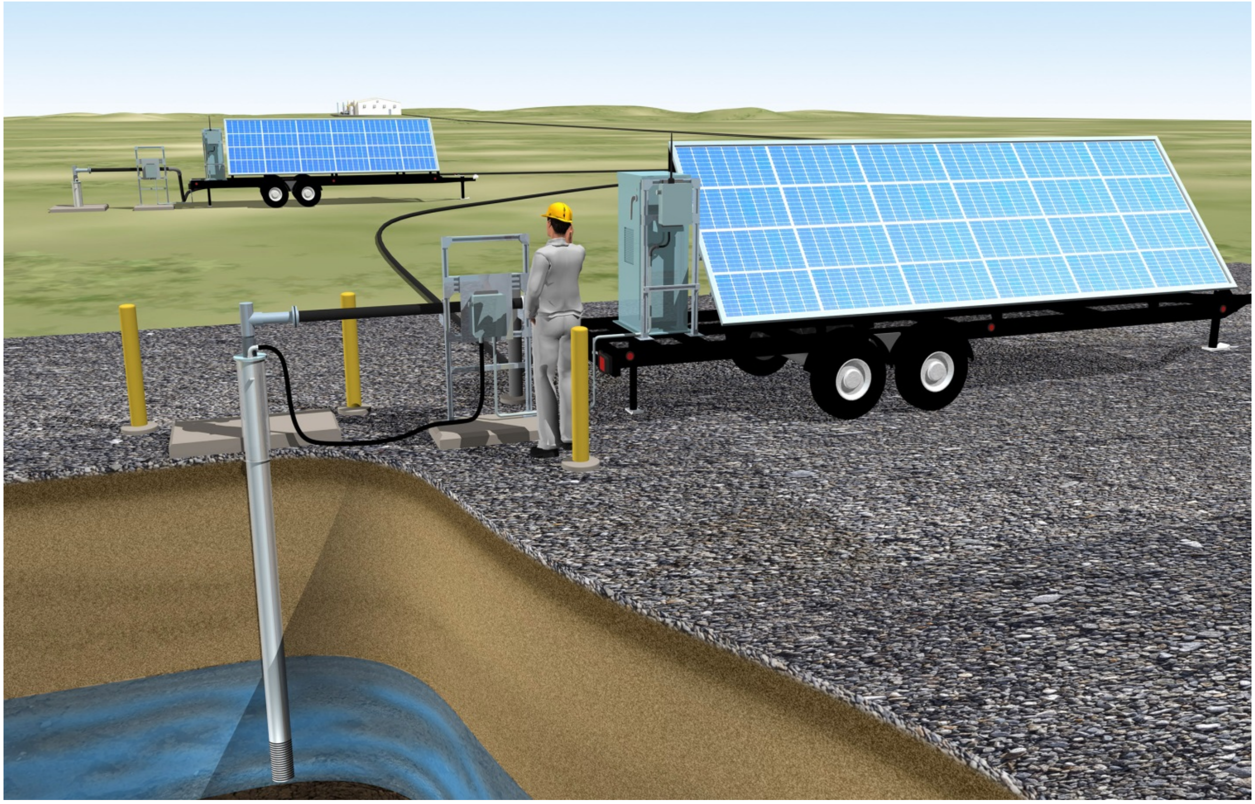

Figure 5.1. Trailer-mounted solar PV systems that power three-season intermittent pumping of Hanford P&T extraction wells (e.g., PV1, 2a, and 2b).

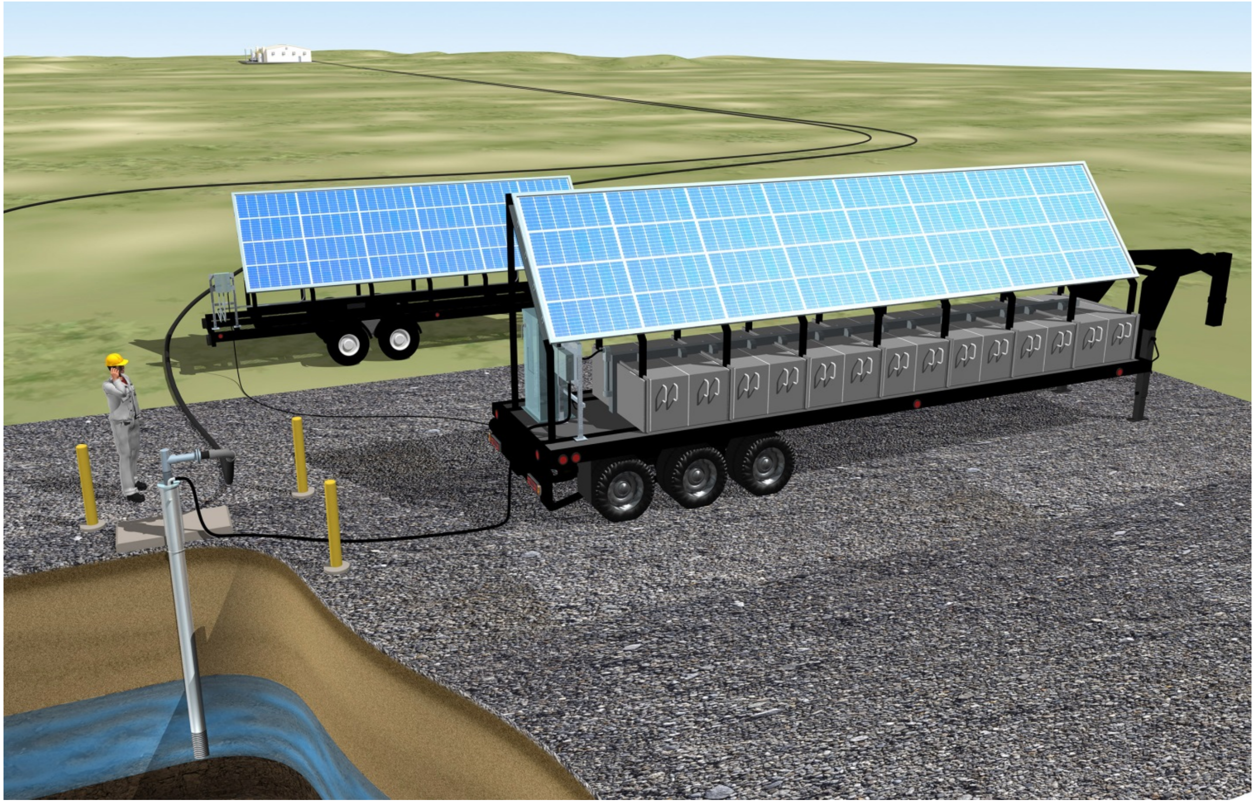

Figure 5.2. Trailer-mounted solar PV arrays coupled to a large energy storage system in order to provide continuous year-round pumping at a Hanford P&T extraction well (e.g., PV3 and 4).

5.4 System Component Cost Estimation

5.4.1 Solar PV Components

Upfront capital costs of a solar PV system can be estimated using reported costs that are based on a dataset of previous installations or created from bottom-up modeling of individual cost components and processes. Published reports tracking annual price trends and installed costs for solar PV systems (e.g., Barbose and Darghouth 2015) are based primarily on residential and commercial installations, most of which were installed in California and other regions of the U.S. These reports are very informative because they show price trends in market (e.g., the shrinking costs of PV modules) and provide a perspective on how installed costs vary as a function of residential vs. commercial, geographic location, system size, new vs. retrofit installation, component efficiency, and tracking vs. fixed-angle. Installed costs are typically reported as $/W$_{DC}$ (peak) installed, and include the solar PV module and rest of the balance of system components for a ground- or rooftop-mounted system. They do not include the additional costs of solar energy storage components or installation on a trailer-mounted platform. ***Even for a system of similar size and type, these published installed costs may not accurately represent costs for installation on the Hanford Site given the additional radiological, cultural, and health, and safety requirements and associated costs related to the Hanford Site.***

For this assessment, upfront capital costs for solar PV system components were estimated using a bottom-up approach since published costs were not considered accurate for this application. Bottom-up estimation involves designing and costing the individual elements of a system around a functional energy demand (flow and head conditions) and operational schedule (e.g., intermittent vs. continuous, three-season vs. year round). Quotes from vendors are then obtained based on the system design specifications. Vendor quotes were obtained for three of the four systems (PV2a/2b, 3, and 4) summarized in Table 5.2. The cost estimate for solar PV1 was developed based on scaling down the price quote for system 2a/2b to a smaller-sized PV array. Table 5.2 contains the estimated costs in 2015 U.S. dollars for a system ready for deployment as delivered to the Hanford Site by the vendor. It should be mentioned that these are non-binding quotes provided by the vendor for estimating system costs and represent current market prices at the time of this assessment (spring and summer 2015). Additional costs associated with procuring and installing the mobile solar PV systems at a well location are discussed further in the economic assessment (Section 7.0).

5.4.2 Grid-Power Cable Cost Estimations

Above-ground power cables are currently used to extend grid power to the P&T extraction wells. The cost of these power cables is central to economic comparisons of conventional grid-power to solar PV alternatives. The avoidance of power cables is an obvious benefit of the solar PV alternative. These cable runs can be over a mile in length for wells located large distances from the P&T facility or nearest line-power source. As discussed in Section 3.5, extensive distances require heavy-duty (Type W or similar) power cables to minimize voltage losses and ensure electrical safety. Four-conductor Type W power cables with wire conductor sizes ranging from AWG 8 to 4/0 are used to convey power to Hanford P&T extraction wells depending on the HP rating of the pump and the cable distance. Intuitively, power cables with larger wire conductors (e.g., AWG 4/0) are much more expensive than those with relatively smaller wire. Thus, the actual AWG of the power cable controls the unit cost and could significantly affect the overall cost of the cable.

Presumably, there are engineered drawings and records that detail the length, wire size, and purchase price for power cables running to the P&T extraction wells. However, this information was not readily available from P&T contractor, so power cable wire sizes were approximated. Recommended wire sizes (AWG) were obtained for varying cable lengths using an online wire-size calculator (http://www.paigewire.com/pumpWireCalc.aspx) with the following inputs: 20 amps, 3-phase, 480 VAC, acceptable voltage loss of 3%, and copper wire. The current load was set to a conservative value of 20 amps to supply the current at peak pumping rates and total head conditions prescribed for the four solar PV systems. An extraction pump with an assumed wire-to-wire efficiency of 35% (Appendix B Section B.3, and Table 5.4) operating at the peak pumping rate of 91 gpm (solar PV alternative 2a) and total head of 100 feet would require about 7 HP of electrical power (Eq. 5.1). This would result in a current load of about 11 amps at 480 VAC. Selecting a current load of 20 amps in the recommended wire-size calculation allows for a factor of safety. Vendor quotes for cable unit cost (per foot) for each recommended AWG wire size were used to calculate total costs for lengths between 0.1 and 1.4 miles (0.16 to 1.6 km). Table 5.5 summarizes the recommended cable wire sizes and costs as a function of length (extraction well distance).

$$HP_{input} = \frac{GPM * Total\ head\ (ft)}{3960 * Wire\ to\ water\ efficiency} \tag{5.1}$$

Where:

3,960 = 33,000 ft-lb/min/HP ÷ 8.33 lb/gal

HP_{input} = input HP to pump motor = electrical power input in kW $*$ 1.34

Total head (ft) = pumping water level + Discharge head

Discharge head (ft) = discharge pressure in PSI $*$ 2.31 ft/PSI

Table 5.5. Recommended copper wire size (AWG) and cost estimates based on lengths of cable for a 20-amp load at 480 VAC 3-phase.

Cable Length (miles)	Wire Size (AWG)	Capital Cost for Type W 4-Conductor Power Cable (estimated 2015 dollars)
0.1	8	$2,100
0.2	4	$8,400
0.3	3	$17,400
0.4	2	$23,200
0.5	1	$39,600
0.6	1/0	$50,700
0.7	1/0	$59,100
0.8	2/0	$88,700
0.9	2/0	$99,800
1.0	3/0	$137,300
1.1	3/0	$151,000
1.2	4/0	$221,800
1.3	4/0	$240,200
1.4	4/0	$258,700

6.0 Technical Assessment

The technical feasibility and operational constraints of solar PV alternatives in Hanford groundwater extraction need to be evaluated to successfully implement this renewable-energy technology. An objective of this assessment was to provide comparative performance results for solar PV systems of various designs and operational regimes as applied to an example extraction location on the Hanford Site. This section presents the system performance results for solar PV extraction alternatives and discusses key considerations of technical feasibility.

Initial techno-economic elements related to the overall feasibility of solar PV for groundwater extraction were preliminarily considered (see Sections 5.1 and 5.2) and provided the basis for the system designs and operational approaches used in the solar PV alternatives (Table 5.2) evaluated here. Technical considerations include the remoteness of the well location, hydrologic conditions (water-table depth and target flow rate), and remediation objectives (hydraulic containment vs. mass reduction). They also include operational constraints such as the need to avoid freezing of well-heads and influent water lines as well as the ability of the P&T facilities to effectively process incoming groundwater at flowrates that vary with solar conditions. These technical elements provide the context and perspective to properly evaluate and the performance results for the five solar PV alternatives and compare them to one another and the grid-powered case.

6.1 Energy and Pumping Performance

The primary system performance for the five solar PV alternatives discussed in the previous section (refer to Table 5.2 for a summary) is measured in terms of power, energy, and groundwater pumping output. Table 6.1 summarizes these performance metrics for the PV systems evaluated in this assessment.

The three-season solar alternatives without energy storage (PV1, 2a, and 2b) pump during daylight hours only, which averages 13 hours per day during this period from March 1 to October 31 (Table 6.1), which results in pumping 37% of the total year. PV3 is also a three-season system, but its energy-storage system provides continuous day and night pumping, allowing it to run 67% of the year. PV4, with its large PV array and battery bank, pumps groundwater 100% of the year. As expected, power, energy output, and groundwater pumping output increases with the size of the solar PV array and energy storage system as well as the length of the operation schedule (Table 6.1). Annual AC energy output from the five solar PV alternatives range from 1.424 to 9.435 MWh/yr. Annual volumes of extracted groundwater range from 1.587 to 10.517 million gallons.

PV1 and 2a are both scenarios where instantaneous pumping rates are directly proportional to the available solar power since the pumps are not throttled down or capped below their potential. They use all available energy of the system (after energy losses), which is reflected in energy-utilizations equal to 100% (Table 6.1). In the case of PV1, the solar PV array and pump were scaled intentionally to provide a peak pumping rate of 20 gpm (equal to the well-yield capacity) under the most ideal solar conditions. PV1 and 2 represent the systems that provide the highest energy and pumping returns, as reflected in having the highest ratios of annual pumped groundwater to PV array rating (Table 6.1).

Comparison of results for PV2a and 2b provides an evaluation on the effects of having a well-yield term in a solar PV extraction system. The PV systems are the same, but PV2b honors the well-yield limit and caps the pumping rate at 20 gpm even when solar conditions would permit a higher flow rate. In comparison, PV2a uses all of the available instantaneous power output and peak pumping rates are as high as 91 gpm. PV2a pumps more than twice as much annual groundwater using the same solar PV system as a result (Table 6.1). This emphasizes the need to consider the well-yield capacity or competing hydrologic effects (neighboring pumping systems, decrease in drawdown efficiency, etc.) in solar PV groundwater extraction systems to avoid overestimating pumping volumes. PV2b only uses 42% of the available energy.

Solar alternatives PV3 and 4 both have energy storage and solar PV arrays of proportionately increased size to recharge batteries while simultaneously providing enough power at a constant pumping rate of 20 gpm. The batteries allow them to pump continuously day and night. However, as noted above, the larger PV array and energy storage system in PV4 allows it to operate year-round (365 days), which results in 150% more annual energy and groundwater (Table 6.1). Constant year-round pumping comes at an efficiency cost. PV3 and 4 have energy utilizations of 57% and 36%, respectively (difference of 45%). The ratio of annual groundwater pumped per rated PV system output for PV4 is 0.5 million gal/kW_p DC, which is the lowest among the PV alternatives.

Variations in system energy and pumping output parameters by month and solar PV alternative are summarized in Table 6.2 to Table 6.6 and shown in Figure 6.1. Seasonal variations in available energy, inherent to solar PV systems, are reflected by increased pumping duration, flow rate, and volume during the summer months for the three-season systems without energy storage (PV1, 2a, and 2b). Monthly pumping volumes for the energy-storage alternatives with constant daily pumping rates (PV3 and 4) fluctuate only due to number of days in the month (Figure 6.1).

Table 6.1. Power, energy, and pumping results for solar PV groundwater extraction alternatives.

		PV1	PV2a	PV2b	PV3	PV4
Pumping schedule (days)		March 1 to October 31 (245 days)				Year round (365)
Rated PV array (kWp DC)		1.2	5.6	5.6	11.2	22.1
Rated energy storage (kWh DC)		-	-	-	167	444
System power output (kW AC)	Peak	1077	4898	4898	1077	1077
	Average	398	1102	1102	1077	1077
Annual energy output (MWh/yr AC)		1.424	6.478	6.478	11.100	26.350
Annual energy consumed by pumping (MWh/yr AC)		1.424	6.478	2.737	6.333	9.435
Energy utilization % (energy consumed in pumping divided by available energy)		100	100	42	57	36
Battery DOD %	Peak	-	-	-	48	48
	Average	-	-	-	9	5
20-year lifetime energy total (MWh)		28.48	129.56	129.56	126.66	188.7
Annual volume pumped (millions of gallons)		1.587	7.221	3.051	7.059	10.517
20-year lifetime volume pumped (millions of gallons)		31.740	144.420	61.020	141.180	210.340
Pumping rate (gpm)	Peak	20.0	91.0	20.0	20	20
	Average	8.1	36.9	15.6	20	20
Scheduled pumping time % (time pumping divided by available time within operation schedule)		55	55	55	100	100
Annual pumping time % (time pumping divided by available time during entire year)		37	37	37	67	100
Average daily hours pumping		13.3	13.3	13.3	24	24
Annual volume pumped per rated solar PV array (millions of gallons per kWp DC)		1.3	1.3	0.6	0.6	0.5

Table 6.2. Monthly energy and pumping results for PV1.

Month	Average Hours Pumping Per Day	Average Daily % Time Pumping	Daily Average Pumping Rate (gpm)	Monthly Total Volume Pumped (1000 gal)	Monthly Total Energy Available (kWh AC)	Monthly Total Energy Consumed in Pumping (kWh AC)
Jan	-	-	-	-	-	-
Feb	-	-	-	-	-	-
Mar	11.7	48.9	3.5	157	140,399	140,399
Apr	13.6	56.5	3.4	146	131,025	131,025
May	14.3	59.7	4.8	215	192,613	192,613
Jun	15.6	65.1	4.8	207	185,610	185,610
Jul	15.5	64.4	5.2	234	209,650	209,650
Aug	13.5	56.3	5.2	232	207,992	207,992
Sep	11.8	49.0	4.9	213	190,852	190,852
Oct	10.4	43.3	4.1	185	165,600	165,600
Nov	-	-	-	-	-	-
Dec	-	-	-	-	-	-
Average	13.3	55.4	4.5	198.4	177,968	177,968
			Annual Total	1,587	1,423,741	1,423,741

Table 6.3. Monthly energy and pumping results for PV2a.

Month	Average Hours Pumping Per Day	Average Daily % Time Pumping	Daily Average Pumping Rate (gpm)	Monthly Total Volume Pumped (1000 gal)	Monthly Total Energy Available (kWh AC)	Monthly Total Energy Consumed in Pumping (kWh AC)
Jan	-	-	-	-	-	-
Feb	-	-	-	-	-	-
Mar	11.7	48.9	16.0	712	638,764	638,764
Apr	13.6	56.5	15.4	665	596,116	596,116
May	14.3	59.7	21.9	977	876,320	876,320
Jun	15.6	65.1	21.8	941	844,458	844,458
Jul	15.5	64.4	23.8	1063	953,833	953,833
Aug	13.5	56.3	23.6	1055	946,288	946,288
Sep	11.8	49.0	22.4	968	868,306	868,306
Oct	10.4	43.3	18.8	840	753,420	753,420
Nov	-	-	-	-	-	-
Dec	-	-	-	-	-	-
Avg	13.3	55.4	20.5	902.6	809,688	809,688
			Annual Total	7,221	6,477,505	6,477,505

Table 6.4. Monthly energy and pumping results for PV2b.

Month	Average Hours Pumping Per Day	Average Daily % Time Pumping	Daily Average Pumping Rate (gpm)	Monthly Total Volume Pumped (1000 gal)	Monthly Total Energy Available (kWh AC)	Monthly Total Energy Consumed in Pumping (kWh AC)
Jan	-	-	-	-	-	-
Feb	-	-	-	-	-	-
Mar	11.7	48.9	7.3	326	638,764	292,412
Apr	13.6	56.5	8.1	348	596,116	312,473
May	14.3	59.7	9.2	412	876,320	369,717
Jun	15.6	65.1	9.7	420	844,458	376,540
Jul	15.5	64.4	9.7	433	953,833	388,210
Aug	13.5	56.3	9.2	410	946,288	367,508
Sep	11.8	49.0	8.5	369	868,306	331,046
Oct	10.4	43.3	7.5	333	753,420	298,827
Nov	-	-	-	-	-	-
Dec	-	-	-	-	-	-
Avg	13.3	55.4	8.6	381.3	809,688	342,092
			Annual Total	3,051	6,477,505	2,736,733

Table 6.5. Monthly energy and pumping results for PV3.

Month	Average Hours Pumping Per Day	Average Daily % Time Pumping	Daily Average Pumping Rate (gpm)	Monthly Total Volume Pumped (1000 gal)	Monthly Total Energy Available (kWh AC)	Monthly Total Energy Consumed in Pumping (kWh AC)
Jan	-	-	-	-	-	-
Feb	-	-	-	-	-	-
Mar	24	100	20	893	1,096,796	801,288
Apr	24	100	20	864	1,026,050	775,440
May	24	100	20	893	1,501,976	801,288
Jun	24	100	20	864	1,448,871	775,440
Jul	24	100	20	893	1,634,561	801,288
Aug	24	100	20	893	1,619,211	801,288
Sep	24	100	20	864	1,484,627	775,440
Oct	24	100	20	893	1,288,309	801,288
Nov	-	-	-	-	-	-
Dec	-	-	-	-	-	-
Avg	24.0	100	20	882.4	1,387,550	791,595
			Annual Total	7,059	11,100,401	6,332,760

Table 6.6. Monthly energy and pumping results for PV4.

Month	Average Hours Pumping Per Day	Average Daily % Time Pumping	Daily Average Pumping Rate (gpm)	Monthly Total Volume Pumped (1000 gal)	Monthly Total Energy Available (kWh AC)	Monthly Total Energy Consumed in Pumping (kWh AC)
Jan	24	100	20	893	957,818	801,288
Feb	24	100	20	807	1,326,312	723,744
Mar	24	100	20	893	2,160,284	801,288
Apr	24	100	20	864	2,020,940	775,440
May	24	100	20	893	2,958,340	801,288
Jun	24	100	20	864	2,853,741	775,440
Jul	24	100	20	893	3,219,483	801,288
Aug	24	100	20	893	3,189,249	801,288
Sep	24	100	20	864	2,924,167	775,440
Oct	24	100	20	893	2,537,493	801,288
Nov	24	100	20	864	1,366,960	775,440
Dec	24	100	20	893	834,864	801,288
Avg	24.0	100	20	876.4	2,195,804	786,210
			Annual Total	10,517	26,349,649	9,434,520

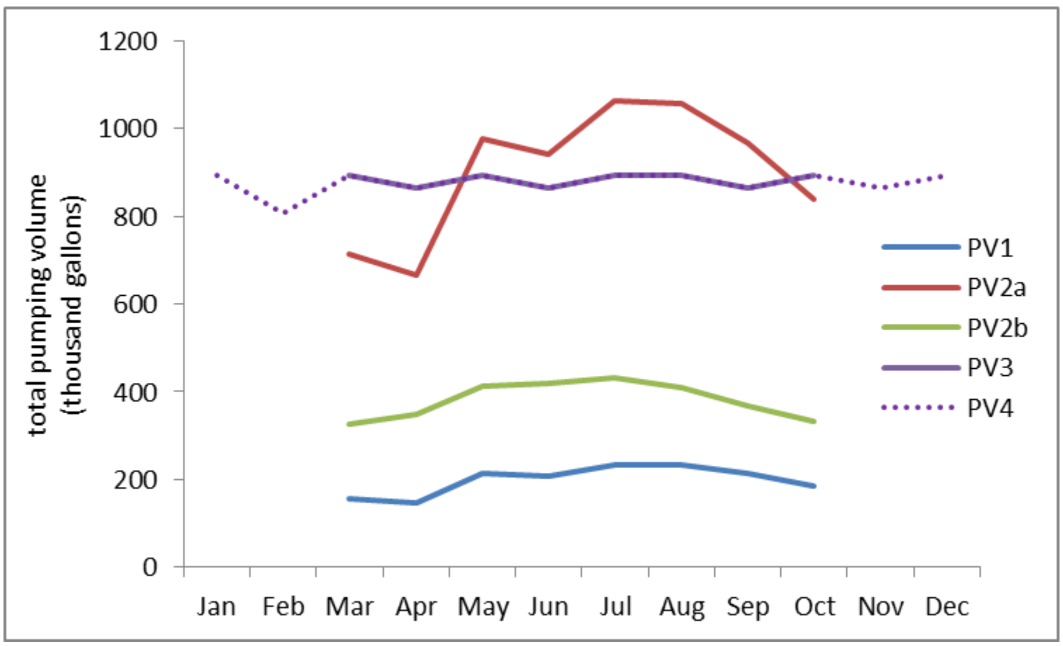

Figure 6.1. Total pumping volumes for each month for the five solar PV alternatives.

6.2 Battery Performance and Health

The designed battery capacity appears to be sufficient for the two energy-storage alternatives. Peak DOD for both systems remains below the maximum recommended value of 50%, and averages for PV3 and 4 are 9% and 5%, respectively. One concern may be the amount of time the batteries are subjected to DODs between 20% and 50%. As discussed in Appendix A, Section A.2, of this report, spending a large period of time in partial state of charge could damage a battery system. The batteries in both systems spend more than 90% of their duty life in states of charge (SOC) greater than 80% (Figure 6.2). Note: SOC = 1 minus DOD. These numbers would suggest the manufacturer-stated duty life of 3,000 discharge-recharge cycles (or about 10 years) might be realized (Appendix A, Figure A.8). However, the lifespan of a lead acid battery is reduced at extremely high temperatures. Local solar PV vendors have mitigated temperature effects using passive ventilation (e.g., louvers), insulation, and placement in the shade created by the PV modules.

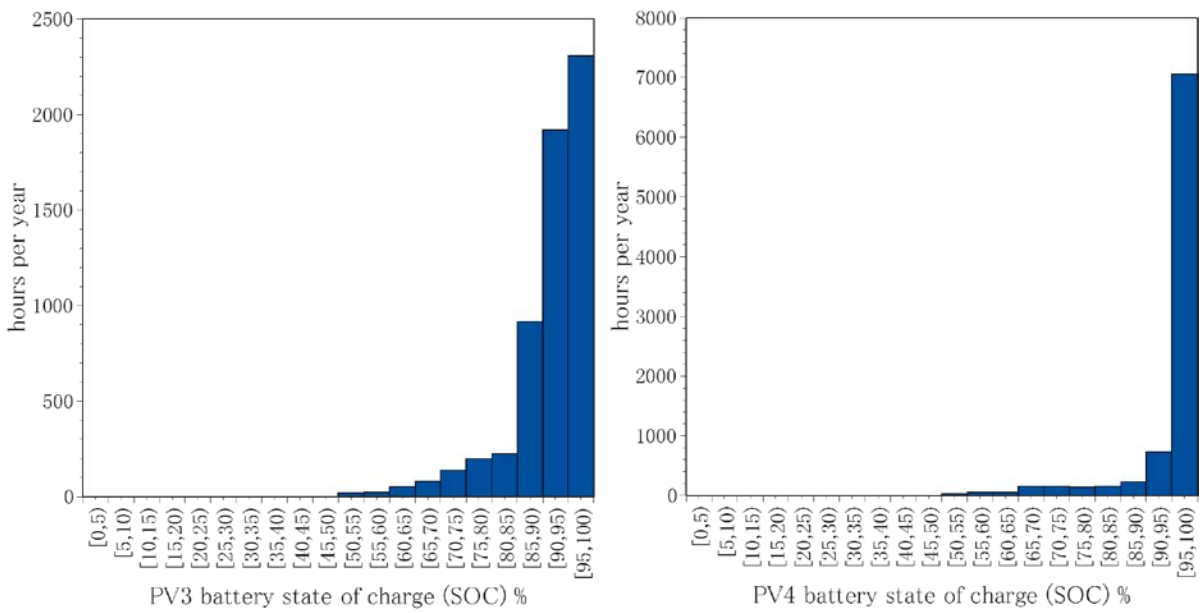

Figure 6.2. Histograms containing the battery state of charge time distributions for the energy storage systems in PV3 (left) and PV4 (right).

6.3 Technical Feasibility Considerations

As discussed previously, the technical feasibility of solar PV as a power source for groundwater extraction system depends on the PV system's compatibility to site conditions, P&T operations, and remedial objectives. This section discusses the ability of the solar PV alternatives to handle some of these operational constraints and technical challenges.

6.3.1 Freezing Conditions

Sub-zero air temperatures during the winter months require the P&T systems to maintain a minimum flow through the water lines to prevent freezing. Non-energy storage solar PV alternatives (e.g., PV1, 2a, and 2b) cannot run at night or during low-solar radiation conditions (snowstorm, heavy clouds, etc.). A three-season pumping schedule involving a March through October operation overcomes this technical challenge by leaving the system in shut-down mode during the winter months. It is unknown if water lines would need to be blown out for winterization using a high-capacity air compressor to prevent damage from freezing, but it is safely assumed that there would be some labor effort associated with placing the system into a safe shutdown mode.

6.3.2 Hydrologic Conditions

The energy and pumping output results described above demonstrate the ability to pump very large volumes of groundwater using solar PV systems. The evaluation scenarios were designed with hydrologic conditions nominally similar to what would be encountered in the 100 Areas. A total head of 100 feet was used; however, these same PV power and energy storage systems could be used at other locations with higher total head conditions. For a given solar PV system, pumping rates would decrease proportionately to the increases in the head according to Eq. 5.1. For example, solar PV alternative system PV2a (5.6 kW_p DC) could provide power for a peak pumping rate of approximately 23 gpm (87 L/min) at an extraction well location on the Central Plateau (200 Areas) having a total head of 400 feet (122 m). Alternatively, the 22.1 kW_p DC solar PV system (not including the energy storage system used) used in PV4 would provide a peak pumping rate of about 90 gpm (341 L/min) at a head of 400 feet. This would result in over 7.2 million gallons of water pumped annually if it were operated during a three-season (March through October) operating schedule.

Pumping groundwater at higher flow rates and from deeper aquifers will require proportionally larger solar PV arrays and energy storage systems. Scaling up the solar PV arrays for the range of hydrologic conditions on the Hanford Site is not a technical limitation. Physical space is abundant on the Hanford Site and solar PV arrays are easily scaled up. However, continuous pumping where energy storage is required could become challenging with scale. For example, a solar PV alternative with sufficient energy output and storage for continuous year-round pumping at a rate of 80 gpm (303 L/min), equal to the nominal pumping rate of 200 West Area extraction wells (Appendix B, Figure B.2), would require a 310 kW_p DC solar PV array with over 13 MWh of energy storage. A solar PV array this large would take up nearly 2,100 m^2 (0.52 acre) and would require 6,000 deep-cycle batteries. This is larger than many utility-scale battery-based energy storage systems.

In summary, intermittent groundwater pumping during three seasons within the range of expected hydrologic conditions on the Hanford Site is well within the technical capabilities of a solar PV system and the preferred mode of operation. However, continuous year-round pumping on the Central Plateau requires excessive energy storage systems that are likely beyond what would be technically reasonable or practical to implement given their physical size.

6.3.3 Remediation Objectives

Preventing groundwater contamination from reaching the Columbia River is a primary objective for many Hanford P&T systems, particularly those in the 100 Areas. Solar PV alternatives where pumping is shut off during the night and winter will likely decrease capture zones (Cortes Di Lena and Elmore 2014). Solar PV systems are not ideal for these locations if containment is the objective. However, if new solar PV extraction wells were installed near existing grid-powered capture wells, hydraulic containment could continue and still achieve additional contaminant mass removal. Target well locations for solar PV extraction systems with intermittent pumping would be wells farther inland from the River Corridor where groundwater flow velocities are lower or the primary objective is to reduce contaminant mass (e.g., 200-DV-1).

6.4 Overall Technical Feasibility Summary

It is technically feasible to implement solar PV groundwater extraction alternatives on the Hanford Site. Implementation of solar PV alternatives would overcome some existing challenges, while at the same time presenting new challenges and constraints. Solar PV alternatives overcome the existing logistical issue of providing power to a remote location. The standalone solar PV option provides a power source directly at the well-head, which eliminates the need to run extensive networks of power cables on the ground. Ideal target locations for solar-powered extraction from a technical perspective are wells farthest from the P&T facility or existing utility power sources.

The general power requirements associated with groundwater pumping on the Hanford Site can be met with solar PV systems similar in scale to residential and commercial systems. PV systems evaluated here provide similar flow rates for 100 Area wells. For wells located on the Central Plateau, where pumping rates are higher and the aquifer is deeper, larger solar PV arrays would be needed to obtain pumping rates comparable to a grid power source.

While PV systems can provide similar flow rates as grid-powered systems, they do not provide similar annual or lifetime volumes unless they also include energy storage. Operating a solar PV alternative on a three-season intermittent pumping schedule does not require energy storage and overcomes the technical challenge of freezing winter conditions. However, pumping rates vary during the day and seasonally as a function of incoming solar conditions, and pumping is shut down during the night and winter. The three non-energy storage systems evaluated here provide only 15% to 29% of the annual pumping volume normally provided by a grid-powered source when a well-yield capacity is taken into account (Table 6.7). Plume capture and hydraulic containment can be maintained with continuously pumping solar PV systems; however, pumping during the night and winter requires very large energy storage and PV arrays. Continuous year-round pumping on the Central Plateau, where flow rates are much higher and the aquifer is significantly deeper, would likely require very large solar PV arrays and battery storage systems similar to small utility-scale systems.

In summary, solar PV extraction alternatives can be implemented in a wide variety of Hanford locations using various design sizes and operation regimes; however, from a technical perspective ideal targets are as follows:

1. Remote wells located a significant distance from an existing grid-power source
2. Wells where the primary remedial objective is contaminant mass reduction and/or lower and intermittent flows are acceptable

Table 6.7. Comparison of annual pumping volumes extracted from solar PV alternatives to the grid-powered option.

	PV1	PV2a	PV2b	PV3	PV4
% of Pumped Groundwater Annual Compared to Grid-Power Option	15%	69%	29%	67%	100%

7.0 Economic Assessment

7.1 Initial Considerations

Because of relatively low electricity prices in the Northwest, solar PV is not economically viable for the site based only on avoided grid electricity considerations. The economic viability of solar PV-powered groundwater pumping on the Hanford Site is driven by several factors. A principal factor is the price of electricity service provided on the Hanford Site. In recent years, this price has been trending upward, and currently it is approximately 10.5 cents/kWh[1], including the cost of electric service from the Bonneville Power Administration and the site contractors' costs for providing and maintaining electrical service infrastructure on the site. This price is relatively low compared to electricity prices in other parts of the country and in areas where the solar resource is significantly better.

Considering avoided maintenance or construction of electric line power to well sites tips the economics in favor of remote, off-grid power solutions such as solar PV. The Hanford Site electric infrastructure, including existing distribution lines and substations, is aging and much of it is the original equipment installed in the 1940s and 50s. Adopting solar PV-powered groundwater pumping stations could reduce the need for line power to be routed to new wells or to be maintained at existing wells. It is estimated that eliminating the need for future power line maintenance avoids approximately $36,000 per mile in annual costs.[2] If new wells could be implemented without line power, the savings could reach $72,000 per mile in avoided construction of new feeder lines. These costs are approximate and depend on the length of the run for new lines and the actual condition of existing lines. These are fully burdened costs representing typically budgeted costs expected to be incurred by the site contractors who build or maintain electrical services. Apart from overhead power distribution lines, the current set of groundwater wells linked to the P&T systems on the site are powered by ground-coupled electrical cable, the costs of which reach well over $100,000 per mile.

There also are benefits that are not purely economic and cannot be directly valued quantitatively, but which have social or political value. These include achieving compliance with mandates assigned to federal agencies by Executive Orders on avoiding greenhouse gas emissions, adopting renewable technologies, and related policy compliance. Though not quantitatively valued, such compliance contributes to DOE's overall goals in these areas and demonstrates goodwill to host communities. In addition, the Hanford Site's current *Infrastructure & Services Alignment Plan* (MSA 2013) calls for both the replacement of aging power infrastructure (especially power poles) and the adoption of alternative energy sources.

All of these considerations are addressed in more detail in the balance of this section.

7.2 Economic Assessment

We performed an economic analysis of the groundwater remediation cases presented in Section 5.3. The economic case is made by comparing benefits and costs using standard economic metrics such as net

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[1] Information provided by Randy Krekel (DOE), 2/6/2015.
[2] Information provided by Tim Haddick (DOE), 2/6/2015.

present value, lifecycle costing, and levelized unit costs and benefits. These metrics allow the individual cases to be put on equal footings such that direct economic comparison can be made between the cases.

Economically viable cases are those for which lifecycle benefits outweigh lifecycle costs. The benefits or savings of economically viable cases would tend to "pay back" their initial investments relatively quickly compared to uneconomic cases, which may not pay back the initial investment within the technology's economic lifetime. The higher the benefit:cost or savings:investment ratio, the faster the case would pay back the initial investment.

Lifecycle analysis relies on economic discounting to consider the time value of money over the economic lifetime of the case being analyzed. When considering the economic value of a stream of benefits and costs accruing over the economic lifetime of the cases presented, those monetary flows happening sooner are valued higher than those flows happening later in the analysis horizon. Economic discounting requires the selection of a discount rate, which represents the economic return expected if the money allotted for the expenses of solar PV-powered groundwater pumping were instead allocated to an alternative investment. For analysis of federal projects, the Office of Management and Budget (OMB) prescribes two rates to be used. A rate of 3% is used for consideration of internal federal government investments designed to reduce agency costs—such as renewable energy projects—and this rate is based on the U.S. Treasury bill current annual constant maturity rate associated with the economic lifetime considered in this analysis (20 years).[3] A rate of 7% is used as a baseline to reflect the marginal pretax rate of return on an average investment in the private sector in recent years (OMB 1992). Using both rates provides some indication of the sensitivity of the cost and benefit estimates to alternative assumptions about expected investment returns.

7.3 Costs

Table 7.1 presents the installed costs of each alternative for providing solar PV powered groundwater pumping. Installed costs include the capital costs for delivery of a mobile power solution to the Hanford Site gate and all related downstream costs to site the product on the Hanford Site and plug it in to the well-stand power infrastructure. These costs would include costs of any permitting, inspection, and commissioning of the equipment.

Table 7.1. Components of annual costs by alternative.

Metric	PV1	PV2a	PV2b	PV3	PV4	Baseline
Installed cost	$26,101	$77,000	$77,000	$197,000	$305,000	$169,736
Annual O&M	$1,305	$3,850	$3,850	$19,700	$30,500	$13,728
Line power annual electricity cost	-	-	-	-	-	$991

Installed costs include the vendor quoted costs (Table 5.2), Hanford-site acquisition overhead charges (assumed to be 20% of the delivered cost), and a flat, fully-burdened $5,000 per site to connect the mobile systems to the established P&T infrastructure including electrical and water lines. Costs do not include any well costs, such as drilling or well site clearing or grading. These costs would be incurred regardless of the pumping technology chosen.

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[3] The use of 3% as of the date of this report reflects a blending of 2014 published updates to OMB Circular A94, Appendix C and current (mid-2015) 20-year Treasury yields.

As described in Section 5.3, we estimate that, for the applications under consideration in this study, each station would require electrical capacity of up to 22.1 kW. From this initial estimate, the question becomes what pump operating regime would provide the greatest return on investment. The alternatives we have developed span a range of battery array options for powering a pump station, from 24-hour, 365-day operation to several variants that offer flexibility in the regime.

Vendor-quoted costs per watt of solar PV for mobile, trailer-mounted applications range between $11 and $15 for systems without battery storage. Note that solar PV costs nationally are declining on a per-watt basis (Barbose and Darghouth 2015); however, the costs of the system design and application considered in this study are driven by the need for portability and the varying sizes of battery arrays needed to support a given operating regime (Figure 7.1). For the range of potential operating regimes considered in this study, the cost of the backup battery array adds over $80,000 to the system cost in the case where a 200-unit battery array would be needed. Thus, the installed cost of the systems being considered ranges from under $14/W to over $21/W, after accounting for the battery backup systems.

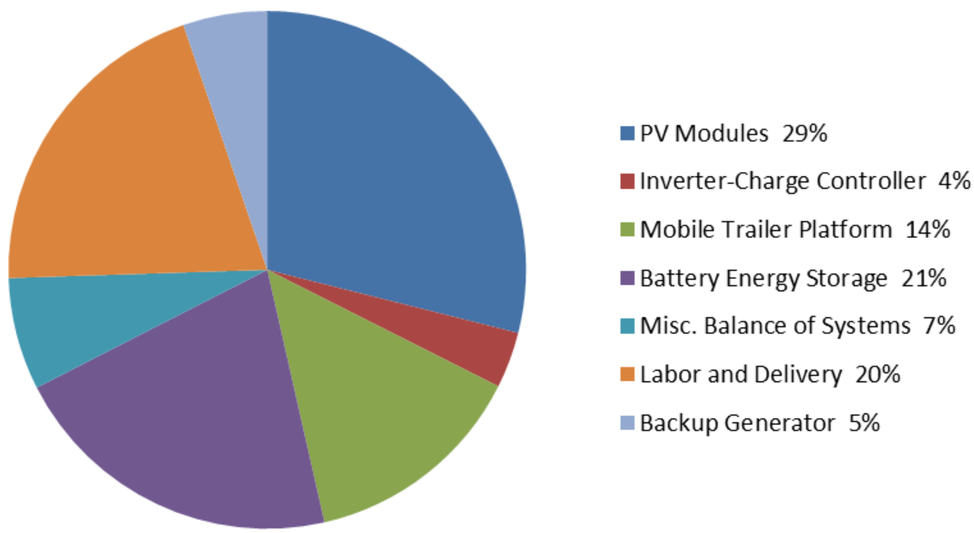

Figure 7.1. Cost element breakdowns for system components included in solar alternative PV4.

To estimate the total lifecycle costs of the alternatives, the stream of annual costs of operations and maintenance/repair activities (O&M) is added to the initial installed costs. Table 7.2 presents the total lifecycle costs of each alternative over the assumed 20-year life of each alternative at the two discount rates. Solar PV panels require maintenance to remain at maximum efficiency. For example, given expected weather patterns on the Hanford Site, the panels will require occasional cleaning to remove dust deposited by wind and rain, occasional snow removal, and regular inspection for these conditions. O&M costs include periodic monitoring, recommissioning as needed, periodic cleaning of the panels, minor repairs, regular maintenance of the battery array, and other actions needed to ensure optimal array performance throughout the year. These costs would be expected to be subject to economies of scale such that as the number of solar PV-powered wells increases, costs per kilowatt of installed capacity would fall, as O&M activities are shared across well sites.

Work by the Electric Power Research Institute (EPRI) investigating O&M activities on utility-scale systems (EPRI 2010) suggests that these costs are highly site dependent and can vary markedly depending on the environment (dry dusty desert vs. areas with periodic significant rainfall). EPRI reported that utility-scale O&M costs are approximately split between the activities discussed above and the need to escrow funds for expected inverter replacement in case of premature failure. This analysis adopted that approach and assumed that half of O&M costs would be required to escrow against inverter failure. We also accounted for escrowing against periodic battery failure and replacement. Thus, the system O&M costs would be expected to be on the higher end of literature estimates.

Examples from several studies suggest that O&M costs can range anywhere from less than 1% of the system installed cost to 10% or more of that cost annually. However, most observations suggest annual O&M expenses should be roughly 1% to 2% of system installed cost. Because of the relatively small-sized systems considered in this study and the relative contribution of Hanford Site factors such as high potential for frequent panel soiling, potential remoteness of the affected well sites, and relatively high labor costs for site contractors, we assumed this expense would be 5% of installed cost annually. Adding the need to escrow for periodic battery replacement, we assumed battery replacement would represent 50% of all maintenance costs over the lifetime for the storage alternatives, and used 10% of installed costs as the O&M expense for those alternatives.

Table 7.2 presents the economic comparison of the costs by alternative using the levelized cost of pumped water (LCOW). Levelized cost places the alternatives considered on an equivalent analytical footing by dividing the total lifecycle cost of each alternative by the lifetime production of pumped water each alternative provides. The alternative having the lowest levelized cost is the most cost-effective of the choices presented.

Table 7.2. Levelized lifecycle costs of pumped groundwater alternatives for 3% and 7% discount rates.

Discount Rate	Costs	PV1	PV2a	PV2b	PV3	PV4	Baseline
3%	LCOW $/kgal	0.105	0.068	0.161	0.264	0.275	0.134
	LCOE $/kWh	0.117	0.076	0.179	0.294	0.306	0.149
7%	LCOW $/kgal	0.120	0.078	0.184	0.285	0.296	0.147
	LCOE $/kWh	0.134	0.087	0.206	0.317	0.330	0.164

Installed costs of the baseline system (line power) are based on establishing new electrical service to an assumed new well site with a need for 1 mile of new power cable. Thus, avoided costs for the alternatives also are based on not needing line power service to be established at the assumed new well site.

The costs for the solar PV systems considered here reflect the small and portable nature of the power sources needed for groundwater pumping on the Hanford Site. Costs depend on the precise design of the power source needed for the pumping stations. Several cost elements would not vary by station design, and would not be compared in our approach to economic lifecycle cost. Only the power source would vary. Thus, grid-based power is the baseline cost and we compare that to the cost of powering the station with solar PV under varying operating regimes.

7.4 Benefits

There are several economic benefits to solar PV technology implementation on the Hanford Site. Most obvious is the avoidance of purchasing electricity from the grid. Another benefit is the potential to power remote sites without extending electrical infrastructure to those sites. Related to that, it also may be possible to avoid replacement of some existing power lines to existing sites. In addition to the purely economic benefits, there are societal benefits including the avoidance of carbon emissions and contributing to federal agency renewable resource goals. Each of these considerations is discussed below.

Replacing grid power with solar PV saves the power costs that would have been accrued had the conversion not occurred. This benefit grows with the amount of grid power avoided. On average, DOE is paying roughly 10.5 cents/kWh for electrical power service on the Hanford Site. At that average rate, Hanford's electricity costs are among the lowest in the nation. Further, for the alternatives discussed in this report, only relatively small amounts of grid power would be avoided, because these ground water pumping systems use relatively small amounts of electricity compared to the other electrical loads on the site. Only after converting or repowering large numbers of these systems would the electricity cost savings start to become significant.

The significant economic benefit for the Hanford Site is the potential to avoid extending and maintaining new grid power infrastructure, or to avoid replacing or maintaining existing and aging grid infrastructure. The estimated cost of maintaining the Hanford Site distribution lines is approximately $36,000 per mile, based on the recent history of distribution line maintenance costs. The cost of establishing new power access to future well sites is expected to surpass $100,000 per mile for ground-coupled electrical cable suitable for groundwater pumps. These avoided costs drive the length of the economic payback period. The more miles of power lines avoided, the shorter the amount of time to recoup the investment in solar PV technology. Case-specific economic benefits are presented in Table 7.3.

Table 7.3. Economic benefits of solar PV groundwater pumping at the Hanford Site at 3% and 7% discount rates.

Discount Rate	Benefits	1	2a	2b	3	4
3%	Benefits $/kgal	0.542	0.124	0.285	0.126	0.087
	Benefits $/kWh	0.605	0.138	0.318	0.141	0.097
	B/C ratio	5.18	1.82	1.77	0.48	0.32
	Simple payback (yr)	2.7	13.5	14.3	-	-
7%	Benefits $/kgal	0.507	0.116	0.266	0.118	0.081
	Benefits $/kWh	0.565	0.129	0.297	0.132	0.090
	B/C ratio	4.21	1.48	1.44	0.41	0.27
	Simple payback (yr)	4.2	28.1	30.6	-	-

In addition to the capital cost of installing electrical cable to a well-site, there are O&M costs that apply to these cables. We could not identify reliable data covering the annual costs to maintain ground-coupled electrical cable. Therefore, we derived a cost based on the expectation that such cables would receive regular walk-downs to visually inspect for any damage or other changes in ground features such as water pooling in the cable path or accumulations of wind-blown vegetation. We also noted the approximation of O&M costs associated with the overhead distribution line maintenance of $36,000 per mile cited earlier. That number was compared to estimated annual O&M cost based on a percentage of cable capital cost (e.g., 10%). If we assume that cable O&M costs would be 10% of capital costs annually, that amounts to over $13,700 per mile to perform recommended maintenance. Compared to the cited cost of overhead line maintenance, that cost is relatively low. It is not certain if these costs would actually lie between the two estimates. In reality on the Hanford Site, cables for several wells may be collocated, running in parallel to on another other, facilitating simultaneous inspection and maintenance. Thus, some economy of scale (lower costs per mile) could be expected, but the costing for this study assumes that recommended maintenance activities would be applied to new wells, and we chose to use the 10% of capital cost approach for costing cable O&M as a conservative estimate of costs that could not be fully quantified.

Clearly, the PV1 alternative is the most economically advantageous, having a benefit-cost ratio above 4 at either the 3% or 7% discount rate, and having a simple payback period of just 2.7 years at a 3% or 4.2 years at a 7% discount rate. The PV2a and 2b alternatives are economic at the 3% discount rate and would pay back within the economic life of the system, but at a7% discount rate, the payback period extends beyond the economic lifetime. Alternatives 3 and 4 would not pay back the initial investment until well past the economic lifetime or not at all. The viability of the PV1 alternative would limit its application to specific well conditions where three-season, variable-flow rate pumping would be desired or useful. Alternatives PV2a of PV2b could be chosen, and would yield more pumped water over their lifetime than Alternative PV1, but it would take much longer to recoup the investment than for PV1.

7.5 Comparing Benefits and Costs

This study uses economic lifecycle costing to compare the present value of the lifetime of benefits to the present value of the lifetime of costs to determine the return on investment. The lifetime considered for the pump station configurations is 20 years. Discount rates of 3% and 7% are used to illustrate the effect of alternative assumptions about expected investment returns. The following discussion is based on the selection of the 3% discount rate as the more appropriate rate in the case of return on internal federal investment.

Figure 7.2 illustrates the levelized benefits and costs of alternative pumping regimes for the case of avoiding just 1 mile of new electric power cabling on the Hanford Site. Figure 7.3 illustrates the effect of halving the amount of avoided power cable in the metrics.

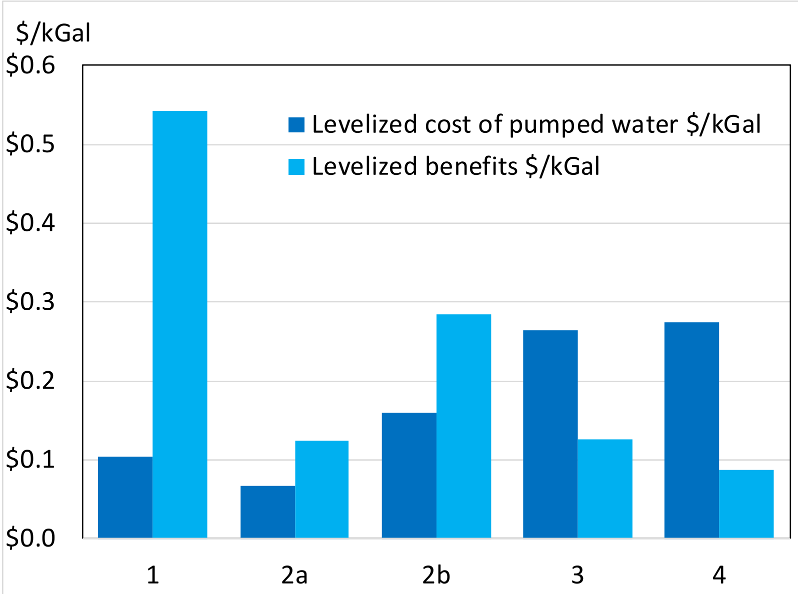

Figure 7.2. Lifecycle benefits and costs per solar PV groundwater pumping station from avoiding 1 mile of new power cable (3% discount rate).

For 1 mile of avoided electric cabling needed for the line powered baseline alternative, alternatives PV1, PV2a, and PV2b are economic using a 3% discount rate, and their simple payback periods fall within the economic lifetime of the system. Thus, DOE's Hanford Site operations would be better off economically under any of those alternatives. The storage alternatives (PV3 and PV4) are not economic due to heavy reliance on battery arrays, which swamp the capital and O&M costs.

In the case of 2 miles of avoided electric cabling, Figure 7.3 illustrates that alternatives 3 and 4 still are not economic, as lifecycle costs exceed benefits for this level of avoided electrical cabling. Alternatives 2a and 2b remain economic, and their payback periods drop to 2.9 and 3.0 years, respectively. Thus, in this case, the choice would be the alternative that results in the most pumped water over the economic lifetime. Alternative PV2a would be chosen if there were no constraint on the flow rate from the well, otherwise, if the flow rate is capped, alternative 2b would be selected.

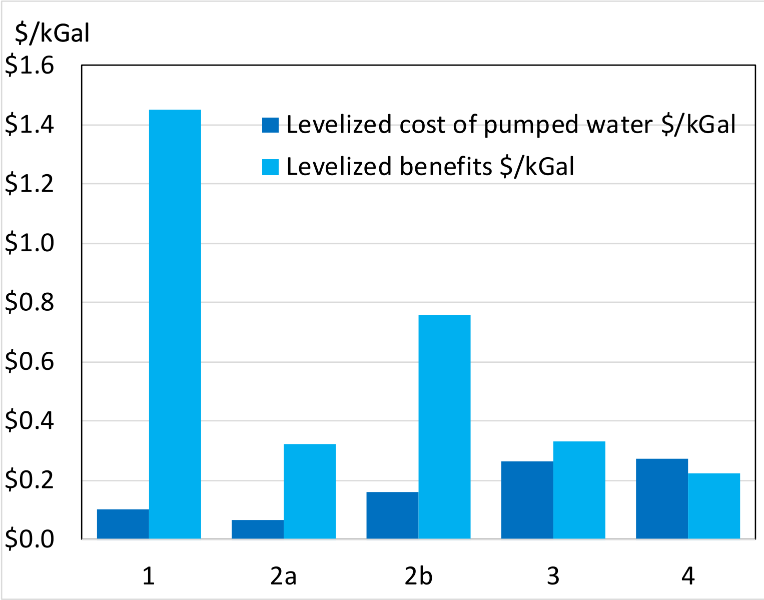

Figure 7.3. Lifecycle benefits and costs per solar PV groundwater pumping station from avoiding 2 miles of new power cable (3% discount rate).

Figure 7.4 illustrates the miles of avoided electric cabling at which each alternative becomes economic using the 3% discount rate. This illustrates that the storage alternative PV3 becomes economic for cable runs beyond 1.6 miles, but PV4 does not approach becoming economic until well after 2 miles of avoided electric cabling. Note that cable pricing becomes speculative after runs of more than 1.4 miles, as the type of cable needed would likely change to account for line voltage losses beyond that distance.

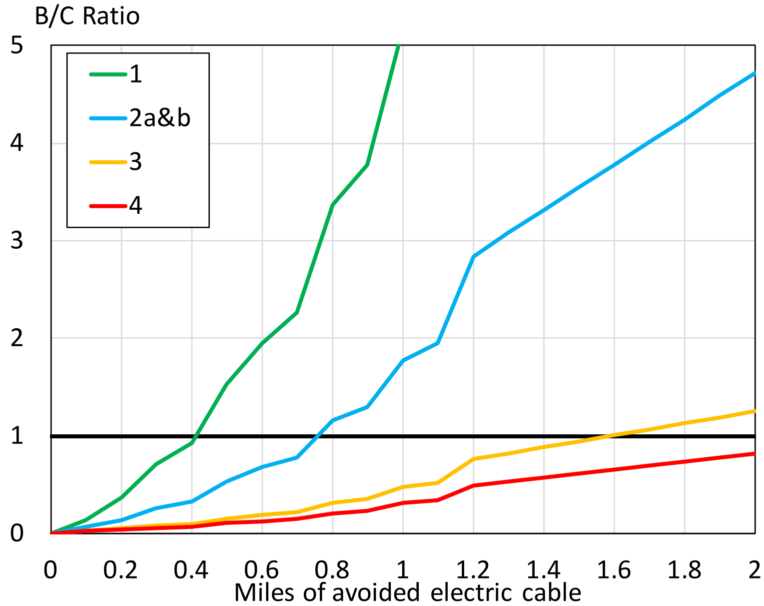

Figure 7.4. Benefit:cost ratio by alternative and by miles of avoided electric cabling at a discount rate of 3%.

7.6 Key Assumptions of the Economic Analysis

The economic analysis is governed by key assumptions that, if altered, could affect the economic viability of the alternatives considered. The principal assumption driving economic viability is the assumed avoidance of electrical cabling or power lines to run power to new well sites. This assumption is based on the observed geographic relationship between exiting P&T facilities on the Hanford Site and the distribution of well sites around them. The economic viability of the alternatives would increase with the remoteness of the well sites.

Alternative designs of the well sites also would affect the economic viability of the alternatives. For example, it may be desirable to cluster future wells, such that a single run of electrical distribution line could power a cluster of wells, rather than running cable a mile or more to each individual well. This would reduce the economic viability of solar PV in comparison to the analysis presented.

Finally, as discussed, the economic viability is driven by the avoidance of electrical infrastructure capital investment and O&M. However, it may be determined that line power is needed to ensure the desired operating regimes of the wells and connected facilities. In this case, none of the alternatives considered would remain economic, because the expense of installing and maintaining electric infrastructure would not be avoided.

8.0 Unquantified Benefits of Solar PV

As discussed earlier, the federal government sets standards or goals for its agencies in renewable energy and greenhouse gas emissions reduction. President Obama recently released Executive Order 13693, *Planning for Federal Sustainability in the Next Decade*. This order replaces previous orders covering similar areas. A portion deals directly with renewable technology adoption in the federal sector. Sec 19 (v) defines “renewable electric energy” as energy produced by solar, wind, biomass, landfill gas, ocean, geothermal, geothermal heat pumps, micro turbines, municipal solid waste, or new hydroelectric generation capacity achieved from increased efficiency or additions of new capacity at an existing hydroelectric project. In Sec 3 (b) the following are the minimum percentages of the total building electric energy and thermal energy that is required to be clean energy (renewable electric energy and alternative energy):

- 10% in fiscal year (FY) 2016 and 2017
- 13% in FY18 and 19
- 16% in FY20 and 21
- 20% in FY22 and 23
- 25% in FY25 and each year thereafter

The following are the minimum percentages of total building electric energy expected to be renewable electric energy:

- 10% in FY16 and 17
- 15% in FY18 and 19
- 20% in FY20 and 21
- 25% in FY22 and 23
- 30% in FY25 and each year thereafter

The following actions are listed in priority order for implementation by federal agencies:

- Installing agency-funded renewable energy on site and retaining corresponding renewable energy credits (RECs) or equal value replacement RECs
- Contracting for the purchase of energy that includes the installation of renewable energy on site or off side and the retention of corresponding RECs or equal value replacement RECs
- Purchasing electricity and corresponding RECs or obtaining equal value replacement RECs
- Purchasing RECs

The other benefits to consider include the contribution to federal agency carbon goals and renewable technology implementation goals, which have some connection to economics, but typically are not pursued for economic reasons. Implementation of solar PV-powered ground water pumping contributes to the DOE Richland Operations Office (DOE-RL) share of the Department’s renewable technology implementation goals, which in turn contributes to the carbon reduction goals of the federal government.

These are strategic rather than economic goals. DOE-RL also purchases RECs from the Western Area Power Administration as another approach to satisfying agency carbon goals. Given the scale of the avoided power consumption we are considering, it is unlikely conversion of grid power to onsite solar PV would alter the number of RECs DOE-RL would purchase in the future. Were the number of RECs purchased to be affected by a wider adoption of solar PV at the Hanford Site, it would be possible to avoid REC consumption at a rate of approximately 2 cents/kWh, based on contract rates for FY2016 (WAPA 2011).

9.0 Solar PV Example for 200-UP-1 Chromium Remediation

This case study looks at the potential use of solar PV to power a submersible well pump and a mobile pump-and-treat (MP&T) system located near the extraction location. Results from Sections 6.0 and 7.0 suggest that solar-powered systems provide a technical and economic alternative to extending grid power (and water piping) to remote locations such as the southwest corner of 200-UP-1, located in the 200 West Area of the Hanford Site (Figure 9.1).

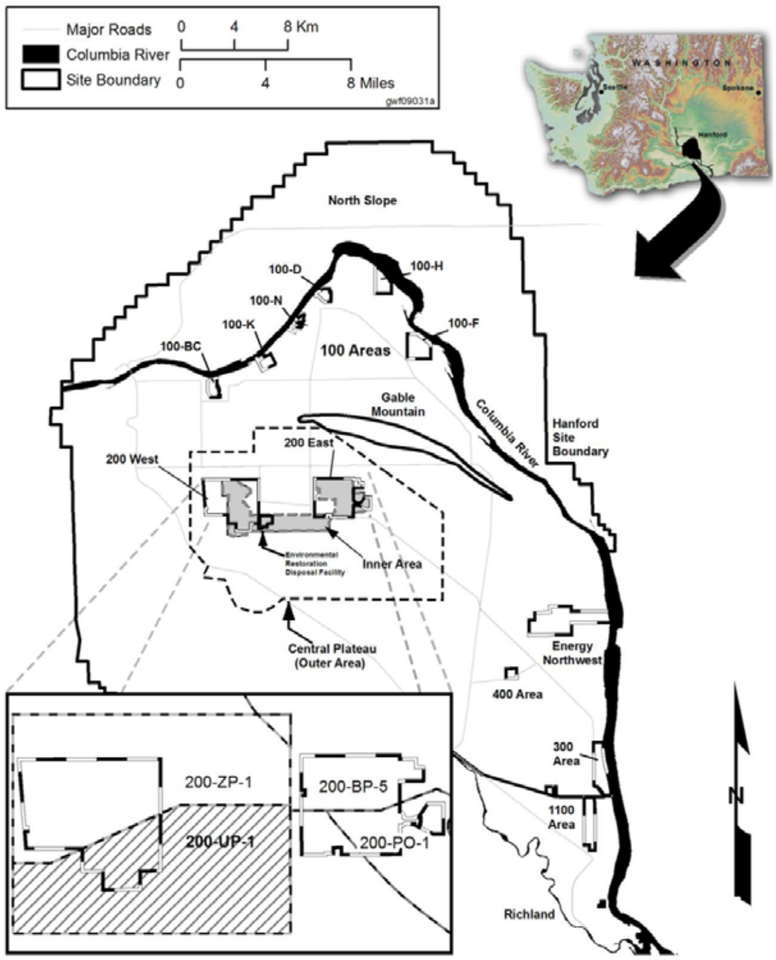

Figure 9.1. Hanford site map showing the inner area and location of 200-UP-1 within the inner area (figure taken from DOE 2012).

Currently, there is no power source at the center of the chromium plume to power extraction pumps or an onsite treatment facility, making it an ideal candidate location for assessing the feasibility of a solar-power alternative. The nearest power grid source from the center of the plume appears to be located a map distance of about 0.75 miles (1.2 km) away (Figure 9.2). The standard practice of extending power to Hanford P&T wells is by running above-ground power cables parallel to roadways (for ease of visual inspection) from the closest power drop to the extraction well (Section 3.5). This would result in a power cable distance of about 1.4 miles (2.3 km) or more. In addition to the long power cable run, the shortest distance for running water lines between the southeast corner of 200-UP-1 and the 200 West P&T facility is 3.2 miles (5.1 km). Realistically, water lines would have to be run much further to be accessible from existing roads and to go around other facilities and waste sites.

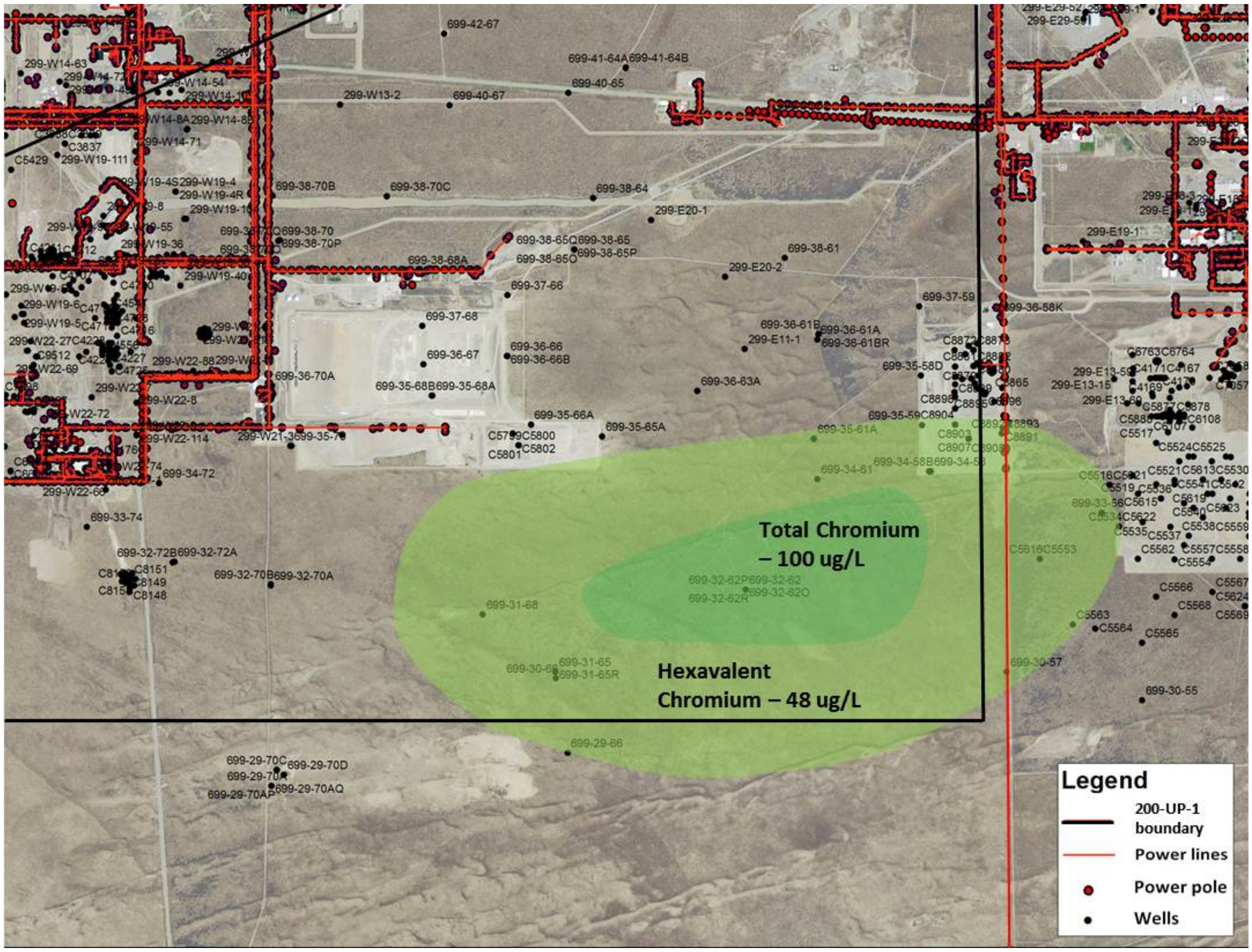

Figure 9.2. Map of the 200-UP-1 chromium plume and its proximity to existing electrical utilities on the Hanford Site.

9.1 Background

Groundwater in 200-UP-1 is contaminated with carbon tetrachloride, uranium, nitrate, chromium (both tri- and hexavalent), I-129, Tc-99, and tritium (Figure 9.3). The most remote plume is chromium contamination in the southeast corner of 200-UP-1. This widely dispersed chromium plume originated from the S Plant crib and migrated eastward via groundwater movement (EPA 2012). The mass of chromium contamination in this plume is estimated to be approximately 2 metric tons (EPA 2012). Three quarters of the chromium mass is hexavalent chromium, which over long-term exposure can cause lung cancer, nasal septum ulcerations and perforations, skin ulcerations, and allergic and irritant contact dermatitis (EPA 2012). The federal drinking water standard for total chromium is 100 µg/L; however, there is no such standard for hexavalent chromium, which instead is regulated by the Washington State Department of Ecology to 50 µg/L total chromium if chromium (VI) is present. Based on the federal and state regulations, the preliminary remediation goals are to reduce total chromium contamination to 100 µg/L and chromium (VI) to 48 µg/L (DOE 2010). To meet these goals, groundwater in the southeast corner of 200-UP-1 may be remediated using one of the various chemical or biological treatments to remove chromium.

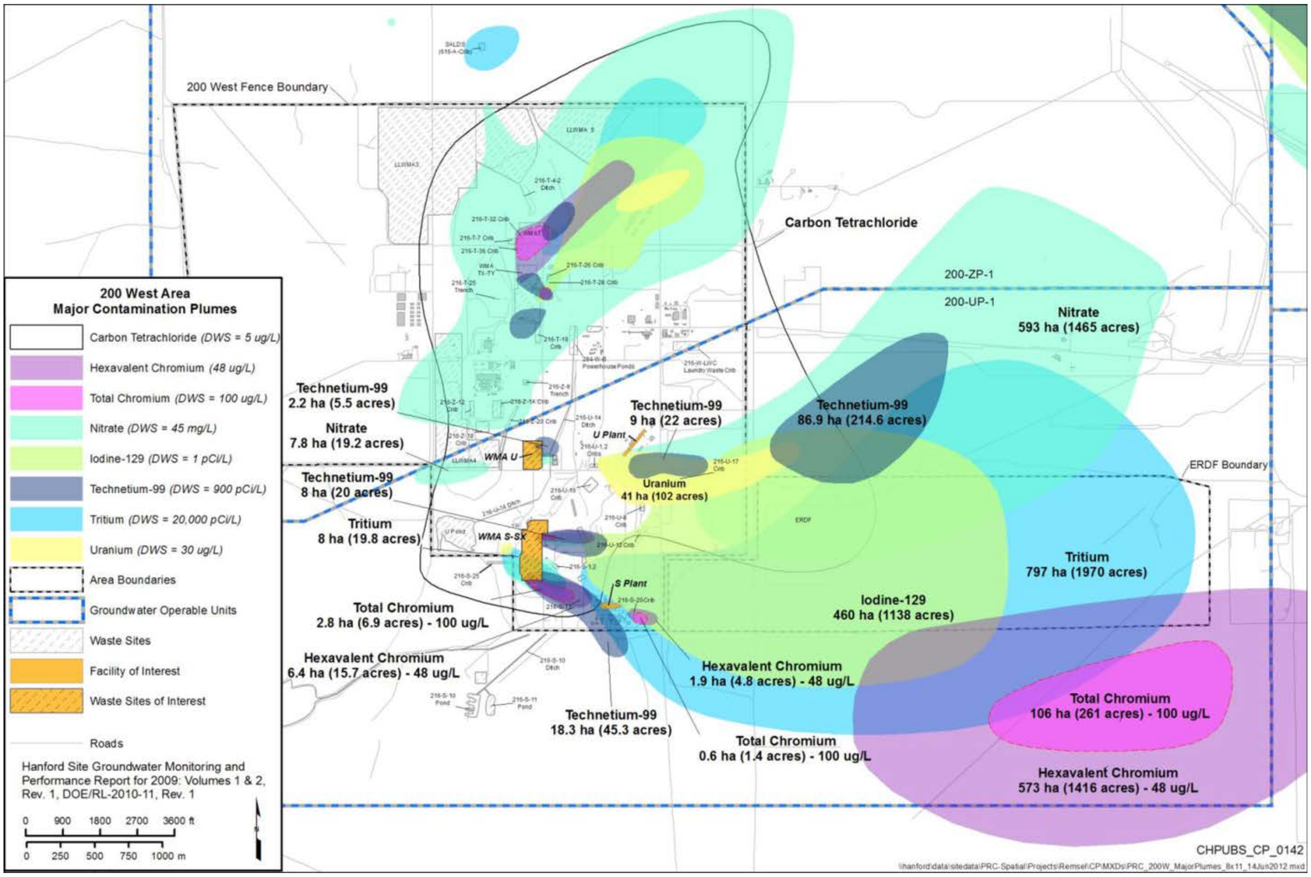

Figure 9.3. Contaminant plumes in 200-UP-1 (figure from EPA 2012).

9.2 Hexavalent Chromium Remediation at 200-UP-1

This section briefly looks at the various treatment methods used for chromium (VI) and describes the method currently being used at the 100-DX and -HX treatment plants. This section also looks at two MP&T systems for remediation of 200-UP-1 groundwater.

9.2.1 Chromium Treatment Methods

Chromium (VI) can be treated in three different ways: reduction in toxicity, removal, or hydraulic containment (Hawley et al. 2005). Although reduction in toxicity may convert Cr (VI) to Cr (III), DOE's goal to remove total Cr may not be met. Also, the process of chemically reducing Cr (VI) to Cr (III) in situ is potentially reversible. Likewise, containment does not meet DOE's goals. Biological reduction of chromium is a viable mechanism for immobilizing Cr in situ, as this process is not reversible; however there are costs with infrastructure that would have to be considered for this to be a potential remedy. Removal appears to be the most viable option for meeting DOE groundwater standards and goals while mitigating infrastructure and remediation costs, with the current technologies available.

9.2.2 Current Chromium Treatment at the Hanford site

Currently Cr (VI) is being removed at the DX and HX P&T facilities (see Figure 9.4) using a weak base anion (WBA) resin (SIR-700), which requires a pH adjustment below 6.5 to efficiently remove Cr (VI). The storage capacity of this type of WBA resin is greatly increased because it also reduces Cr (VI) as its removed, lessening the amount of equivalents filled. Originally, a strong base anion (SBA) resin was used (Dowex 21k), which could be regenerated. However, at the DX P&T facility it proved to be less efficient to regenerate Dowex 21k than to use a disposable resin such as ResinTech's SIR-700 (Neshem and Riddelle 2012). SIR-700 also allowed for more flow capacity without adding more resin beds (also called "ion exchange trains," seen in Figure 9.4).

Figure 9.4. Ion exchange trains at 100-DX water treatment facility (from Neshem et al. 2014).

9.2.3 Chromium Treatment at 200-UP-1

A WBA ion exchange resin (SIR700), as is currently being used in the DX and HX water treatment facilities, can potentially remove more chromium than a strong base anion resin. However, the process of using a SBA ion exchange resin (Dowex 21k) minimizes the complexity and potential hazard of adjusting the pH using a strong acid such as hydrochloric or sulfuric acid. For this reason, the standalone solar-powered P&T systems assessed here look at the use of both WBA and SBA resins. Although storage is much less, pilot studies have shown that SBA resins can remove as much as 1.6 g of chromium (VI) per liter of resin (WRF 2014; Neshem and Riddelle 2012). Also for this case study, regeneration of the ion exchange resin will not be used due to the cost of the process of regeneration and the cost of dealing with the toxic waste it produces.

9.2.4 Treatment Facility Design Parameters

According to DOE (2014b), the average flow rate of extraction wells in the 200 West Area during CY2013 was about 80 gpm, with a maximum flow rate of 135 gpm. Of these 18 wells, 3 are located more centrally within the 200-UP-1 OU and had an average flow rate about 30 gpm with a maximum flow rate of 35 gpm in CY2013. Based on these extraction flow rates and the space restrictions of a standard trailer, a design flow rate of 30 gpm was chosen for the MP&T design at 200-UP-1.

A solar PV extraction system designed and operated similarly to alternative PV2a (Section 5.3), but with a slightly larger solar PV array (7.4 kW_p DC), would provide three-season intermittent pumping at a peak rate of 30 gpm (114 L/min) at an assumed total head of 350 feet (106.7 m). This total head condition is based on the nominal depth to water of 300 feet (90.4 m) plus an additional 100 feet (15.2 m) for assumed system and line losses.

In addition to flow rate, the two MP&T systems were designed: one using SBA and one and using WBA. The MP&T facility using SBA will need to have the resin changed out more frequently because of the limited capacity of this resin. If a run uses the three-season intermittent pumping schedule described above, with a non-energy storage solar PV system having a peak output of (e.g., PV1 or 2a) capable of a 30-gpm peak flow rate, the SBA resin in this facility may last up to 12 weeks. This was calculated using an assumed Cr (VI) concentration of 121 µg/L and breakthrough times reported in WRF 2014 and Neshem and Riddelle 2012. Note that 121 µg/L was the last Cr (VI) concentration measured in well 699-32-62 that is in the center of the chromium plume in 200-UP-1.

The MP&T system using WBA will need to adjust the pH to 5 using 25% hydrochloric acid and adjust the pH back up to 7 using 25% sodium hydroxide, which will add to the initial and long-term cost and complexity. However, the WBA resin will reduce the frequency of resin replacement and the time spent on changing out the resin to once every 11 years based on calculated breakthrough times in Neshem and Riddelle 2012. However, since no literature was found on treating water with the WBA resin for more than 4 months, there could be other reasons to change the resin more frequently. As stated earlier, the peak flow rate is limited by the size and weight limits of a trailer. Higher flow rates would require more bed volume and more resin canisters. Higher flow rates above 30 gpm could be accommodated by adding two or more MP&T systems. However, the higher energy demands would also require a larger solar PV system.

9.3 Facility Design

This section discusses the two MP&T system designs in more detail and how they would conceivably operate to remediate Cr (VI) water pumped from near the center of the chromium plume in 200-UP-1. It discusses the operational parameters governing the design, the estimated capital cost of each design, and the estimated annual cost of each design. Note that these costs are based on current-value approximations and were not developed using any rigorous economic analyses similar to Section 7.0.

The SBA MP&T design has only two system components (Figure 9.5): the water treatment system and the monitoring and controls system. The WBA MP&T design has a third system: the acid and base pH adjustment system (Figure 9.6). These systems are designed to fit in a cargo trailer for transport around the 200-UP-1 site. The SBA MP&T design fits in a 12 x 6 foot cargo trailer and the WBA MP&T design fits in a 14 x 6 foot cargo trailer.

The starting point for each design was the water treatment system. The size of the water treatment system depends on the ion exchange resin's minimum bed depth and the maximum recommended flow rate per bed volume, which for both resin types are generally 2 feet and 4 gallons per minute per cubic foot for the SBA resin and 2 gallons per minute per cubic foot for the WBA resin (ResinTech 2005a, b; and Purolite 2012). To accommodate the flow rate of 30 gpm, four canisters are needed for the SBA resin and six canisters are needed for the WBA resin that are at least 12 inches (30 cm) in diameter and 42 inches (107 cm) tall (Figure 9.7). These canisters are the lead canisters. Smaller canisters could be used, but more of them would be required. Each lead canister needs one lag canister to catch any chromium leakage from the lead canisters. Once the resin capacity is used up in the lead canisters, the resin can be replaced and the lag canisters will be switched to the lead. The canisters with the fresh resin will be set up as lag canisters. The lead and lag process of resin canisters is used in this design to maximize the efficient use of the resin capacity. This lead and lag process is also used in 100-DX and -HX facilities (Neshem and Riddelle 2012). If only the lead were used, the resin would have to be changed out before all of it had reached full capacity of chromium uptake.

The monitoring and control system consists of a CR-1000 Campbell Scientific datalogger with cellular communication, which would be used to monitor the flow rate, the pressure of both the inlet and the outlet of the system, and the water temperature. The flow rate, the differential pressure of the inlet and outlet, and the water temperature could be used to identify a leak or a clog in the system. Also using the CR1000, parameters such as the power supplied to the pump and the amount of water treated could be monitored. The CR1000's communication could also be used to shut down the pump during an emergency. This monitoring and control system would have full-time continuous power from two deep-cycle batteries recharged by the solar PV array.

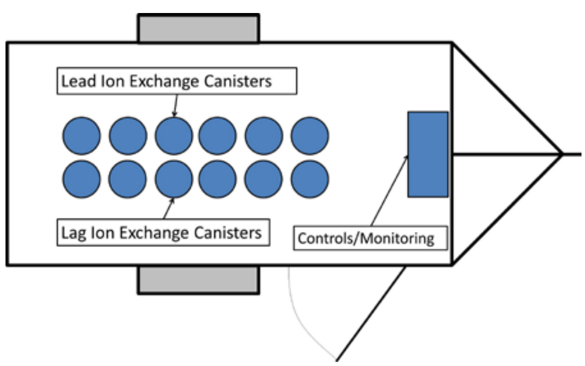

Figure 9.5. Layout of an MP&T system using SBA resin.

The WBA design includes acid and base metering pumps, which are controlled by pH sensors in the influent water for the acid and the effluent water for the base. Each metering pump is designed to adjust the pH to the desired level. The 60-liter acid reservoir was added to the front of the MP&T near the inlet and the 60-liter base reservoir was added to the back of the MP&T near the outlet. The acid and the base reservoirs would be located on opposite ends of the trailer for added safety. The additional energy demand of the metering pumps can be met with the same deep-cycle battery used for the monitoring and control system.

Treated effluent water from the MP&T systems would be conveyed in HDPE flexible pipe (Section 3.5) to far margins of the UP-1 chromium plume (approximately 6,600 feet), and injected back into the aquifer in one or more injection wells.

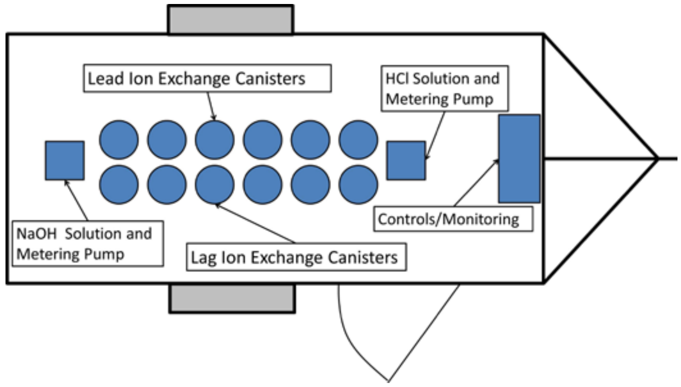

Figure 9.6. WBA pump-and-treat facility layout.

Figure 9.7. Fiberglass resin canister (photo courtesy of ResinTech Inc.).

9.4 MP&T System Cost Estimates

As shown in Table 9.1 and Table 9.2, the cost of the MP&T using SBA resin is about 2/3 of the cost of the WBA resin option. The largest factor in the variation is the cost of the resin itself. The estimated price of WBA resin is $360 per cubic foot (SIR – 700), where SBA resin is $185 per cubic foot (Purolite PSA600). However, the annual operational costs for the SBA design are higher (Table 9.3 and Table 9.4). This higher annual cost is attributed to a higher frequency of resin replacement. After 22 months, the total cost of purchasing and operating both designs is about the same. Note that these cost estimates do not include costs associated with well drilling or the extraction pump.

Table 9.1. The price list used to estimate the total cost of the SBA MP&T facility designed for use in 200-UP-1.

Price List	Price
7.4 kW_p solar PV extraction system	$80,000
Cargo trailer	$4,600
CR1000	$1,500
Thermistors	$300
Communication	$700
Pressure sensors	$400
Flowmeter	$1,000
Batteries	$400
Charging system	$250
Canisters	$2,400
Ion exchange resin	$3,600
3-inch PE pipe (6600ft)	$13,600
Other miscellaneous items	$3,000
Setup cost (200 hours)	$30,000
Total	$141,800

Table 9.2. The price list used to estimate the total cost of the WBA MP&T facility designed for use in 200-UP-1.

Price List	Price
7.4 kW_p solar PV extraction system	$80,000
Cargo trailer	$5,600
CR1000	$1,500
Thermistors	$300
Communication	$700
Pressure sensors	$400
Flowmeter	$1,000
Batteries	$700
Charging system	$250
Canisters	$3,600
HCl @ 25%	$100
Acid metering pump	$900
Acid feed tank	$100
NaOH @ 25%	$ 100
Base metering pump	$900
Base feed tank	$100
Ion exchange resin	$10,400
3-inch PE pipe (6600ft)	$13,600
Other miscellaneous items	$4,000
Setup cost (360 hours)	$54,000
Total	$178,300

Most of the items in Table 9.1 and Table 9.2 were priced either online or through vendor quotes. The "Setup cost" category could be highly variable depending on the laborers. For this cost estimation, 200 hours was used at a rate of $150 per hour for the setup of SBA facility. Also, 360 hours was used at the same rate of $150 per hour for the setup of the WBA facility, which is mainly because of the added complexities of the acid and base pH adjustment systems.

The “Number of resin changes per year” in Table 9.3 and Table 9.4 is calculated based on the reported amount of bed volumes of SIR-700 and Purolite A600 run during testing by WRF (2014), Neshem and Riddelle (2012), and Neshem et al. (2014), and the corresponding Cr (IV) concentration associated with each test. Note that other ions in solution do play a role in the capacity of each resin during testing. The “Change resin” category in Table 9.3 and Table 9.4 is calculated as the product of the number of resin changes and estimated labor hours and costs associated with a changeout. A labor cost of $150 per hour is assumed in all labor cost calculations. For the SBA design, the resin would need to be changed in four of the eight canisters every 12 weeks. Although a value is given in Table 9.4 for the number of resin changes per year with associated cost per year below, using data from previous studies, WBA resin was calculated to last about 11 years. Note that there is no literature that tests WBA resin for use over 11 years and there may be other complications with using resin this long.

In Table 9.3 and Table 9.4, the “Operational maintenance” assumes that the site will be visited by a pair of staff members once a week for 4 hours per trip to inspect the system for leaks, sample effluent of the lead canisters, and/or refill acid and base tanks. An extra 40 working hours is added for winterizing the facility during the fall.

As noted earlier, no attempt was made to perform a detailed lifecycle cost assessment on the two systems compared to each other and the grid-power option. However, the cost estimates do indicate that after the second year of operation, the WBA system would be the least-expensive option. Disposal costs are not included in these system cost estimates, but if they were, the more-frequent resin changeout associated with the SBA system would further favor the WBA system economically.

Table 9.3. The annual cost estimates for operation of the SBA MP&T facility designed for use in 200-UP-1.

SBA design	Scenario 1
Number of resin changes per year	3.91
Change resin (24 hours per change)	$14,100
Operational maintenance (40+208 hours)	$37,200
Resin	$7,000
Total	$58,300

Table 9.4. The annual cost estimates for operation of the WBA MP&T facility designed for use in 200-UP-1.

WBA design	Scenario 1
Number of resin changes per year	0.09
Change resin (32 hours per change)	$500
Operational maintenance (40+208 hours)	$37,200
Resin	$500
HCl @ 25%	$100
NaOH @ 25%	$100
Total	$38,400

9.5 200-UP-1 Mobile Pump-and-Treat Facility Performance

The SBA and WBA versions would have similar remediation performance in terms of chromium removal; therefore, this section looks briefly at how much water and chromium can be treated using the solar PV powered MP&T as compared to the grid-powered case. This three-season MP&T system would operate on an intermittent pumping schedule involving daytime-only pumping from March 1 through October 31 each year. The system would be shut down and winterized the other months of the year to avoid freezing issues.

The MP&T system would treat 2.38 million gallons (9.0 million liters) of groundwater per year. The average and peak flow rates through the system during operation hours would be 11 and 30 gpm (41.6 and 113.6 L/min), respectively. Instantaneous flow rates vary with solar conditions and monthly total groundwater volumes vary from about 220 to 350 thousand gallons (0.83 to 1.3 million liters) during the three-season operating schedule (Figure 9.8).

The inherent intermittency of the solar PV system results in annual volume that is 15% of the volume possible with a grid-powered system that operates continuously during the year both day and night. However, the solar PV system provides a remediation option that avoids running costly power and water lines large distances to the central part of the 200-UP-1 chromium plume. Additional economic feasibility analysis is required to fully quantify the economic feasibility, but initial cost estimates suggest a solar-powered MP&T system may be a viable option given the site's remoteness.

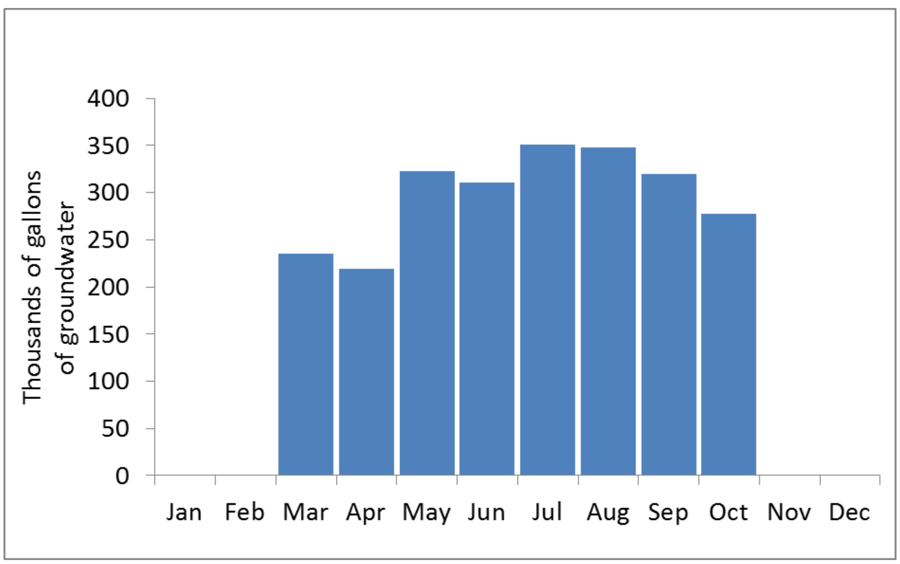

Figure 9.8. Monthly total volume of groundwater processed through an MP&T powered by a 7.4 kW_p solar PV system at 200-UP-1.

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10.0 Conclusions

Solar photovoltaic (PV) alternatives for Hanford groundwater extraction were evaluated for their technical and economic feasibility. Solar PV alternatives ranging in size from 1.2 to 22.1 kW_p DC were designed as evaluation test cases to compare against traditional grid-powered systems. The results of the technical and economic feasibility assessments suggest that solar PV can be successfully implemented on the Hanford Site given the following conditions and considerations:

1. Remote or distant well locations are the most economic targets for implementing solar PV alternatives. Standalone solar PV systems provide an energy source at the well location and avoid the costs and logistics associated with running long lengths of power cable from the P&T facility to the well-head. The degree to which solar PV alternatives are economic is mainly a function of the distance of avoided power cable costs and the inclusion of an energy storage component. Additionally, on-site solar PV systems may help reduce the long-term costs and environmental footprint associated with operating and maintaining the 75-year old electrical infrastructure system on the Hanford Site.

2. The size and operation mode of a solar PV alternative varies based on energy demands and is driven primarily by the hydrologic conditions and remedial objectives of the extraction well. Wells in the River Corridor with a shallower water table and lower flow rates require less energy than those on the Central Plateau. Solar PV systems can meet nominal energy demands for both locations when three-season intermittent pumping is acceptable. When the primary remedial objective is hydraulic containment and continuous year-round pumping is necessary to maintain capture zones, the solar PV system must have a larger solar PV array and incorporate sufficient energy storage. Year-round pumping would be technically feasible for typical extraction wells in the 100 Areas or for low-yield wells on the Central Plateau. However, due to the high cost premium of the energy storage component, a fully solar-powered solution could not provide an economic direct replacement for line-powered pumping systems.

3. A location where the remedial objective is contaminant mass removal makes intermittent pumping permissible. In fact, cyclical or intermittent pumping is the current mode of extraction in locations such as the perched water extraction wells in 200-DV-1. Solar PV alternatives that pump intermittently could provide an economic solution in these cases, particularly in situations where they would avoid the costs of conveying power more considerable distances.

4. The cold weather conditions of the Hanford Site dictate that intermittently pumping solar PV systems be shut down during the winter to avoid freezing of the lines at night or during low-light conditions in the winter months. While PV alternatives can provide similar peak *flow rates*, they are unlikely to provide comparable annual or lifetime *extraction volumes* unless they contain large and expensive energy storage components that allow pumps to run continuously. Accordingly, solar PV systems are better suited to locations having longer-term cleanup goals.

5. A solar powered mobile pump-and-treat (MP&T) system for remediation of hexavalent chromium in 200-UP-1 groundwater appears to be a viable alternative given the extreme remoteness of the site relative to available grid power sources and the existing 200 West P&T facility.

6. There are environmental and political benefits to adopting on-site renewable energy such as solar PV. While difficult to quantify, they have societal value. These include achieving compliance with mandates assigned to federal agencies by Executive Orders on avoiding greenhouse gas emissions, adopting renewable technologies, and related policy compliance. Solar PV-powered systems will contribute to the DOE Richland Operations Office (DOE-RL) share of the Department's renewable technology implementation goals, which in turn contributes to the carbon reduction goals of the federal government.

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Appendix A

Solar PV System Technology and Components

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Solar PV System Technology and Components

A.1 Overview

Photovoltaic (PV) gets its name from the process of converting light (photons) to electricity (voltage), which is called the PV effect. This technology has been used for decades to power satellites, homes, businesses, and other off-grid or remote facilities or equipment.

PV cells, commonly known as solar cells, are electricity-producing devices made of semiconductor materials that convert sunlight into electricity. Sunlight absorbed on the surface of a PV cell is transferred to electrons in the atoms of the PV cell semiconductor material. The electrons form an electrical flow or current, providing the force, or voltage, needed to drive the current through an external load (EERE 2015).

PV cells range in size from a postage stamp to several inches across. PV cells are connected to form PV modules that may be up to several feet long and a few feet wide (Figure A.1). The larger the PV module, the more electricity it can generate. PV modules are typically characterized in terms of their peak power rating (W_p). The W_p rating is the maximum power rating that PV module can provide under the most ideal conditions and is determined under standard test conditions of 1000 W/m^2 and 25°C. PV modules are then combined to form PV arrays sized to meet the desired power load. Solar modules for typical residential and commercial installations contain 60 cells (wired in series-parallel) and produce 250 to 285 watts each, although 72-cell modules with output over 300 watts are also common.

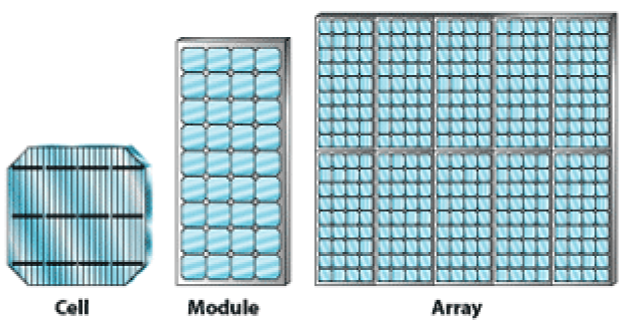

Figure A.1. Illustration showing individual PV cells, which are combined into modules, and then in turn to connected to form arrays (from NREL; http://energy.gov/eere/energybasics/articles/photovoltaic-system-basics).

A.2 System Components

Solar PV systems consist of multiple key components that capture, condition, store (in some cases), and distribute energy in a usable form (Figure A.2). The typical PV system can be broken down into three subsystems:

1. The source side of the system, consisting of PV devices (cells, modules, and arrays) that convert sunlight to DC electricity.
2. The load side of the system, which involves the application or use of the PV electricity.
3. A third subsystem between the source and load that enables the PV-generated electricity to be properly *balanced* to the load; this is often called the balance of system (BOS).

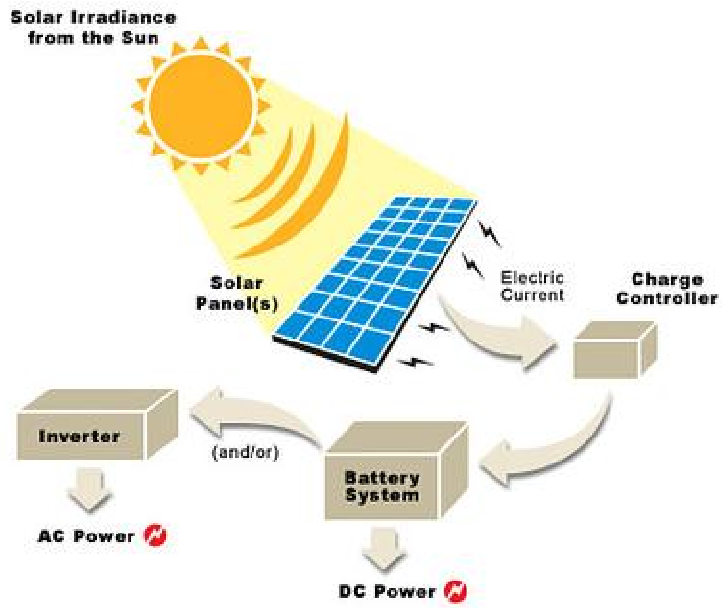

Figure A.2. Typical elements of a solar PV system, including solar panels (flat-plate modules), charge controller, battery storage, and DC-to-AC inverter.

The specific components included in the BOS category can vary by installation type, application, and system configuration. In general, however, the BOS would include mounting structures for the PV modules, charge controllers and regulators, DC-to-AC inverters, and electrical wiring. The BOS could include battery storage, PV system monitoring instrumentation, and weather sensors in some installations. Additional components and hardware for specialized applications such as groundwater extraction would include flatbed trailers for a mounting platform for the PV modules. Reported costs for solar PV systems typically do not include system monitoring and weather instrumentation, trailer-mounted PV arrays, or energy storage. It is critical to know which components are (and are not) included in the BOS associated with any reported costs.

Solar PV modules, BOS components, and other system components relevant to Hanford groundwater remediation and monitoring are discussed below from a technology and operational and maintenance perspective.

A.2.1 PV Modules

The PV cells in modules can be made from a variety of materials, but silicon-based modules are the most common (NREL 2015). Crystalline silicon modules come in the form of mono- or polycrystalline silicon and have an efficiency ranging from about 15% to 19% (Singh 2013). Monocrystalline panels typically have slightly higher efficiencies (take up less space) but cost more. Crystalline silicon modules of both types have been used for over 30 years successfully (Kiatreungwattana et al. 2013).

PV modules have an expected lifespan of 20 to 30 years. Manufacturers typically offer a 10-year product warranty against product defects and premature failure and offer 25-year performance warranty for 80% to 85% of the original stated power output. Field and analytical studies show PV module performance typically degrades at a rate of about 1% per year due to long-term exposure, with some of the newer U.S.-made modules losing only 0.5% per year (Chandel et al. 2015).

A.2.2 Balance of System

As noted above, the integrated system components that help to balance the power source (solar PV modules) to the electrical load are collectively known as the balance of system, or BOS. BOS components vary by system, but may include the following:

- mounting structures for the PV modules (including trailers)
- DC-to-AC inverters
- charge controllers and regulators
- battery storage
- electrical wiring
- weather sensors
- electrical protection devices

A.2.2.1 Module Mounting Structures

Common PV arrays mounting platforms include ground (Figure A.3), rooftop (Figure A.4), and trailer (Figure A.5). All mounting options must offer structural protection to withstand heavy wind loading (90 to 120 mph), snow accumulation, and ground surface instability. Key advantages, benefits, weakness, limitations, and constraints of each of these mounting platforms are summarized in Table A.1.

Figure A.3. Ground-mounted solar PV installations with (a) subsurface penetration using concrete footers (photo courtesy of Schletter Inc.), and (b) surface installation using concrete ballasts (photo courtesy Patriot Solar Group).

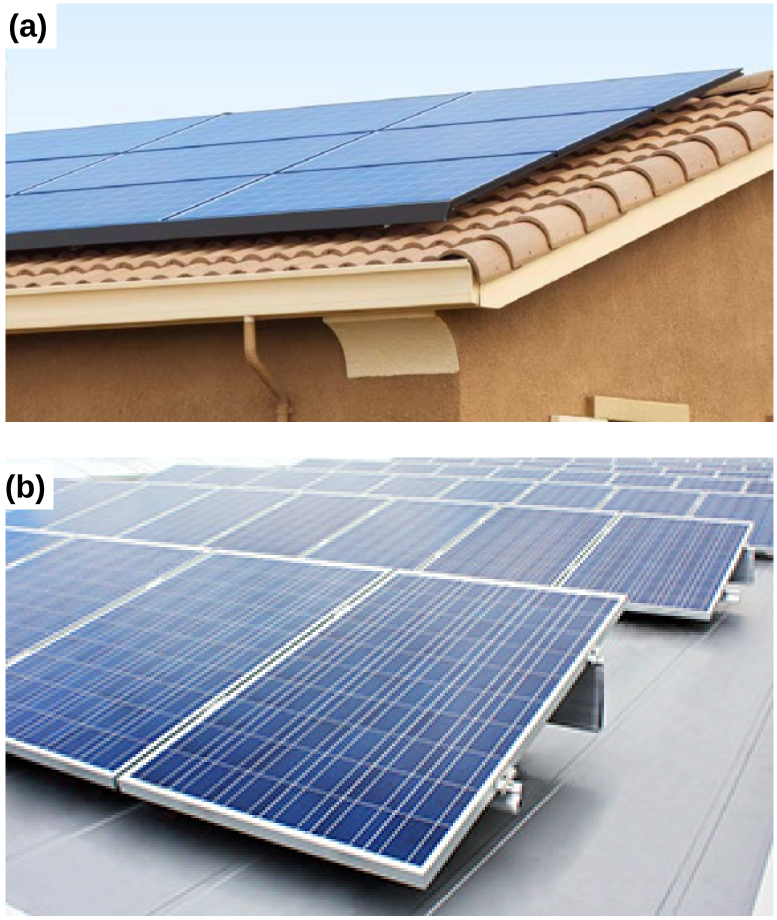

Figure A.4. Roof-top solar PV installations with (a) sloped (photo courtesy of SolarCity) and (b) level roof (photo courtesy Schletter, Inc.).

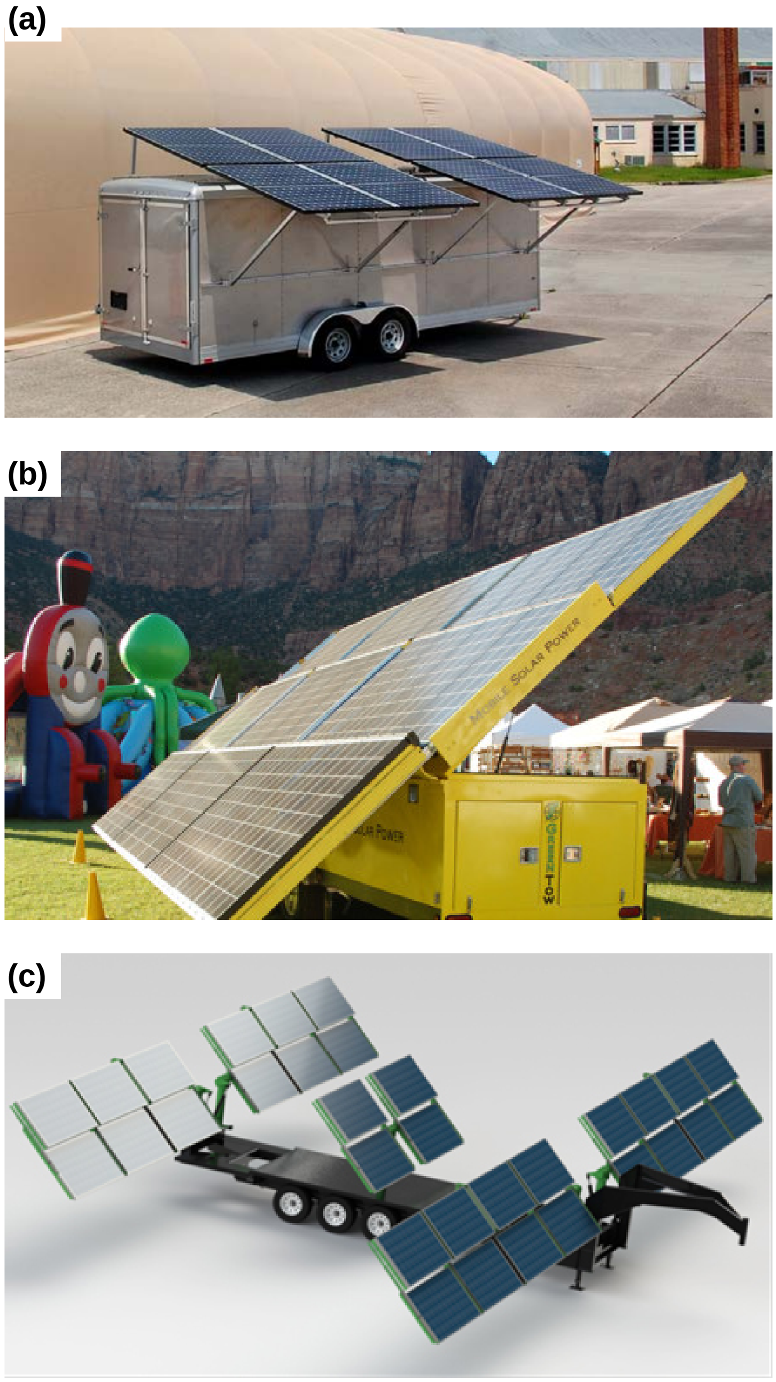

Figure A.5. Mobile solar PV systems mounted on (a) an enclosed trailer (photo courtesy of Renewables West), (b) a custom-engineered trailer (photo courtesy of GreenTow), and (c) a flatbed trailer (photo courtesy of Pearsala Group).

Table A.1. Summary of ground, rooftop, and trailer mounting platforms for solar PV module systems.

Mounting Option	Strengths, Advantages, and Benefits	Weakness, Limitations, and Constraints
Ground	Generally more land space is available, allowing larger PV array, orientations and angles can be adjusted and optimized, easy to install away from shaded areas, no upgrades or changes to rooftops needed, can be ballasted to avoid ground penetration, better for tracking systems that require more space or pole-mount option	Requires sufficient land space, requires ground penetration in some cases, installations may require more time, cultural and environmental reviews and permitting may be required
Roof-top	Streamlined appearance, uses existing roof space, avoids ground penetration and excavation, easier/faster installation	Roofs may lack sufficient space, shade from nearby trees can create shadows, less flexibility on orientation, works best with south-facing roofs, creates a semi-permanent construction change to a building, temperatures may be higher on top of roof, the structural load capacity of the roof must be determined and modified if necessary
Trailer	Mobile, ideal for temporary projects, avoids on-site construction and permitting, can be purchased commercial-off-the-shelf	Requires additional engineering design and fabrication, trailer space is limited

Ballasted ground- or trailer-mounted solar PV systems would be preferable for remote field locations on the Hanford Site since they can be installed quickly with minimal ground disturbance and buildings aren't always nearby. Trailer-mounted solar systems offer the advantage of being mobile and built-to-order with easy electrical tie-ins. Rooftop solar, on the other hand, would require buildings to be located near the groundwater wells or require long runs of heavy and expensive power cord between the building and the well site, similar to how it is currently done.

A.2.2.2 Fixed-Angle and Solar Tracking Systems

Regardless of which PV module mounting option is used, the tilt of the modules is generally set to an angle that optimizes the reception of incoming direct-beam solar radiation (Figure A.6). The angle of the sun varies by latitude and season, so the tilt angle of solar modules will also vary by location and the desired time of the year when maximal solar yield is desired. Seasonal solar variations and site-specific tilt-angles for the Hanford Site are discussed in Section 4.0 of the main report. Modules can be mounted in fixed-angle or solar tracking mounting devices.

In fixed-angle systems, the PV modules are manually set to the desired angle. Some fixed-angle mounting systems do not allow angles to be adjusted after initial installation; however, others do allow manual adjustment of the angle by system operators. This allows adjustment of the module tilt angles to match changing seasonal solar conditions for a given site (e.g., shallower angles for summer months and steeper angles for winter months) or new site conditions for mobile trailer-mounted systems. Rooftop solar arrays are almost exclusively fixed-angle systems due to additional space, shading, structural, and aesthetic constraints of tracking systems. Solar tracking is also not very feasible for trailer-mounted systems due to similar space restrictions.

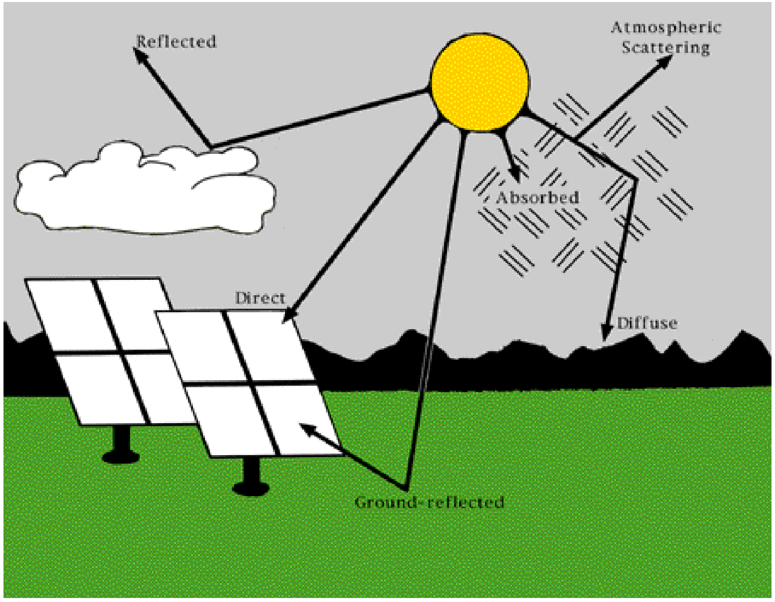

Figure A.6. Direct beam, diffuse, and ground-reflected components of solar radiation that are received by solar PV modules (courtesy of NREL; http://rredc.nrel.gov/solar/pubs/shining/page12_fig.html).

Solar tracking systems are an increasingly popular option for PV systems as the price premium for this feature continues to drop (Barbose and Darghouth 2015). Tracking systems have the potential to increase the annual solar power yield by 30% to 40% (Singh 2013) by controlling the angle of the PV modules relative to the sun through passive or active motion systems. Tracking systems are offered in variations of single- and dual-axis of rotation configurations (Figure A.7). Advances in tracking system technology are making them more reliable and require little to no more maintenance than fixed-angle systems (Bushong 2015). However, they do require more ground space due to shading, particularly the dual-axis systems.

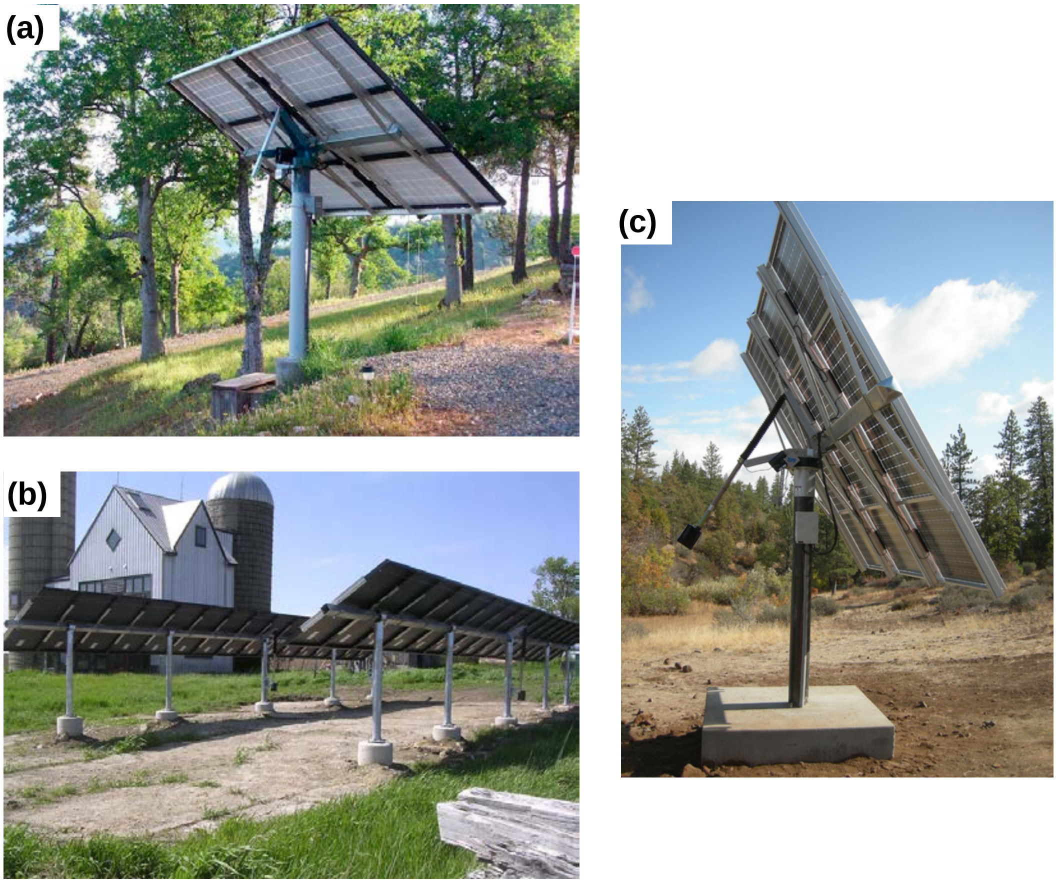

Figure A.7. Solar PV tracking systems with (a) single vertical axis of rotation, (b) single horizontal axis of rotation, and (c) dual-axis rotation (photos courtesy of Array Technologies, Inc.)

A.2.2.3 Inverters

PV modules output DC energy. If the appliances or equipment such as groundwater pumps are powered with AC, an inverter is needed to convert from DC to AC (Figure A.2). For standalone solar PV systems that are not tied back into the electrical grid, there are two main categories of inverters: string and micro-inverters. String inverters are the most common in residential and commercial systems, have been around the longest, and are typically the least expensive option. With string inverters, “strings” of PV modules are combined into an array and the power runs into a single (central) inverter. The drawback of string inverters is that if one or more modules are shaded or fail, the entire string is reduced in power to this level (similar to a plugged water pipe). Micro-inverters, on the other hand, are a newer advancement in technology that places an inverter at the power output side of each of the solar PV modules in the array. Conversion to DC takes place at each module, and there is no need for a central inverter. Shading or failure on one or more modules in a large array is limited to only those affected, eliminating the potential for “bottlenecking” of power. Micro-inverters are typically more expensive. Efficiencies as high as 95% and 98% are typical in newer string and micro-inverters (Fraunhofer 2014); however, these are peak efficiencies realized when the inverter is running near its rated capacity. Accordingly, NREL’s solar PV resource software, PVWatts version 5 (Dobos 2014), uses a nominal default efficiency of 96% based on modeling of inverter performance.

Standard, grid-connected inverters require a signal from the grid to operate, so off-grid power solutions require specialized inverters. Off-grid string inverters that can convert DC energy from PV and/or batteries to AC energy are common. However, micro-inverters are designed for grid-connected operation only, so an off-grid inverter dedicated to the batteries would have to provide the grid signal to the micro-inverters and enable PV power production in an off-grid design.

Inverters are often viewed as the "brains" of the system and are arguably one of the most critical components that determine the success of a solar PV system (Andorka 2013). They have lifetimes ranging from 10 to 15 years. Manufacturers typically offer 10-year product warranties. Careful emphasis should be placed on the inverter selection (type, size, enclosures, efficiency, etc.) in the design and planning stages of any solar PV project.

A.2.2.4 Charge Controllers

A charge controller is a device that is installed between the power output side of the PV modules and the batteries (Figure A.2). Charge controllers constantly monitor the PV module power output and battery, and control the current and voltage levels going from the PV modules to the batteries using various technologies (e.g., pulse-width modulation or maximum power point tracking). They can be standalone, but are often integrated into the inverter in off-grid applications. They typically have 5- to 10- year product warranties. A current market review of standalone charge controllers revealed that efficiencies are 93% to 98%. Total overall system efficiency of integrated inverter/chargers is 90% to 95%.

A.2.2.5 Batteries

Multiple battery technologies are used in the storage of solar-generated power. The most commonly used are flooded and sealed-lead acid batteries. Lithium-ion (Li-ion) batteries are also used due to their higher efficiency, improved ability to handle partial state of charge (PSOC) conditions, and longer lifespan in the solar PV applications (Solanki 2013). Batteries in some solar PV storage systems can spend a large portion of their lifespan in a PSOC due to the inherent intermittency of solar PV. This can damage the batteries and significantly reduce their efficiency and lifespan. Manufacturers rate batteries with an expected effective lifespan expressed as number of discharge cycles based on the depth of discharge (DOD; Figure A.8). Although they can tolerate deep discharges, it is recommended that DOD's for lead-acid and Li-ion batteries be less than 50% and 80%, respectively (Solanki 2013). The energy stored and discharged in a battery is always less than the required charging energy due to the battery's internal resistance. Lead-acid batteries are typically 80% to 90% efficient in transferring charged energy (Solanki 2013).

Temperature also significantly affects battery performance. Battery capacities are rated at 25°C, and as temperature drops, battery capacity is reduced (Figure A.9). Extreme heat can also damage lead-acid batteries and decrease their cycle lifespan (Hutchinson 2004). Li-ion batteries are reduced less in cold-temperatures and are far less susceptible to high-temperature damage. The major drawback to Li-ion batteries is the increased cost.

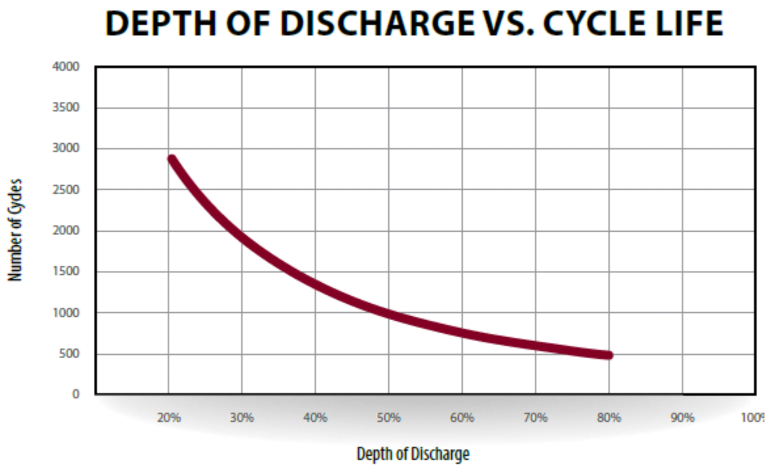

Figure A.8. Relationship between battery lifespan expressed in terms of discharge cycles as a function of depth of discharge for a deep-cycle sealed-lead acid battery (Trojan Reliant L16-AGM).

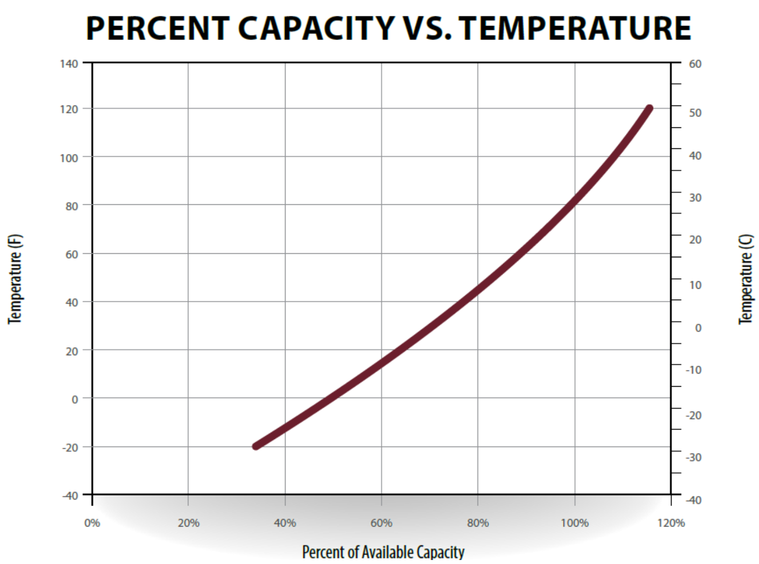

Figure A.9. Relationship between battery capacity and temperature for a deep-cycle sealed-lead acid battery (Trojan Reliant L16-AGM).

A.2.2.6 Electrical Wiring and Protection

Wires connect each solar PV component in the system and protection devices ensure the safe operation of the system; both are integral parts of the solar PV BOS. The wire and coating material type, diameter, length, temperature, and electrical load (e.g., voltages and amperages), and current type (AC vs DC) system need to be factored into the design of the system to reduce system losses, ensure safety, and maintain reliability. Solanki (2013) thoroughly discusses solar PV system wiring criteria and design. Voltage losses from wiring components for solar systems should be in the 2% to 3% range or less (Solanki 2013). PVwatts uses a 2% wiring loss value in its output model (Dobos 2014).

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Appendix B

Groundwater Extraction Pumps

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Groundwater Extraction Pumps

Many types and models of groundwater extraction pumps and drivers (motors) are commercially available. The most common type of groundwater extraction pump used on the Hanford Site and many other locations is the submersible centrifugal pump and motor (Figure B.1). For groundwater sampling and pump-and-treat (P&T) extraction wells, the submersible pumps are often powered by an AC electrical power source in combination with a variable frequency drive (VFD)[1] to maintain desired flow and head conditions. Other groundwater pump technologies exist (e.g., surface-mounted centrifugal, vertical lineshaft turbine, jet, and electric/pneumatic piston pumps); however, the electric submersible centrifugal pump was selected as the single candidate and focus for application in the solar photovoltaic (PV) groundwater extraction assessment based on the near-exclusive use of this pump type currently in Hanford wells. For a review and comparison of various pump technologies for solar-powered groundwater extraction, see Sinton et al. (2015). The main components of a submersible pump are the pump body itself, a screened inlet, the attached motor that mechanically drives the pump, and a power cable (Figure B.1). Submersible well pumps come with a 1- to 2-year product warranty and have a typical life expectancy under normal operating conditions of about 10 years.

The types, power requirements, efficiencies, and features of AC-powered submersible pumps currently in use at Hanford and DC-powered submersibles for solar PV power applications are discussed below. The energy efficiency differences of AC and DC pumps are also discussed.

[1] A VFD is also known as an adjustable-frequency drive (AFD). AFD is the term commonly used on the Hanford Site. VFD is the term most often used in the groundwater pump industry and literature and is preferred by the authors for use here

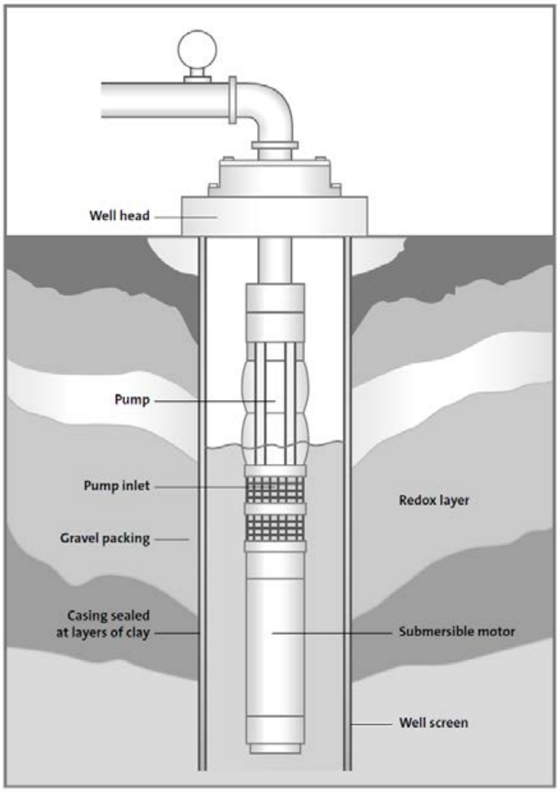


Figure B.1. Example of a submersible pump and motor installed in a groundwater well (courtesy of Grundfos Pumps Corporation).

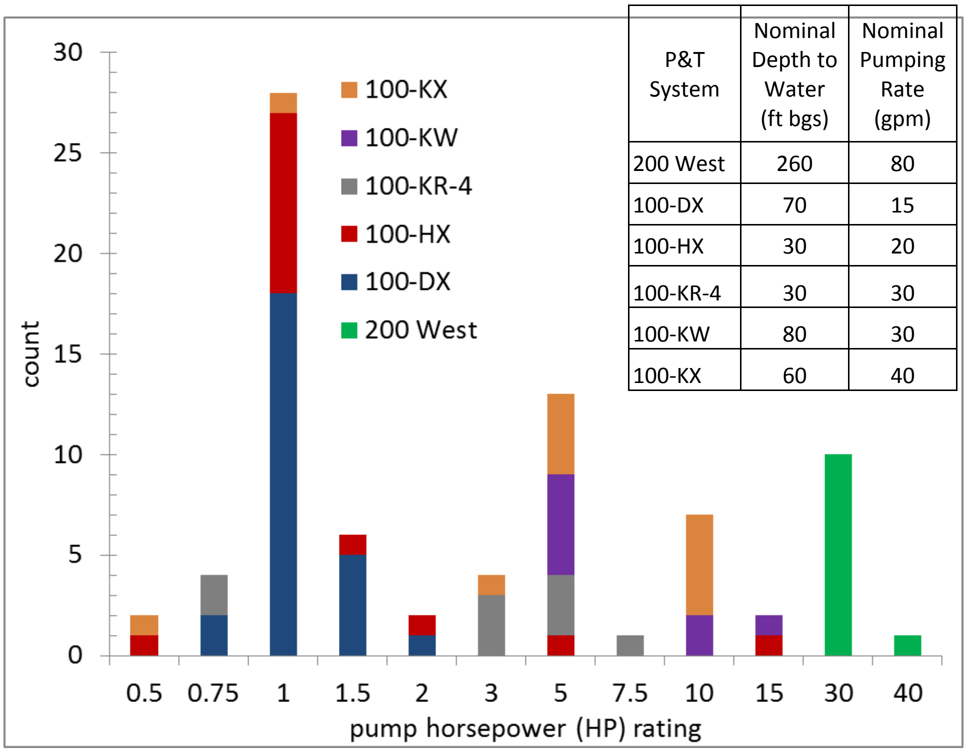
B.1 AC Submersible Groundwater Pumps at Hanford

Groundwater is pumped in Hanford extraction wells using "downhole" submersible pumps powered by AC electricity. Flow rates are controlled according to well yield and facility design and operational constraints using a VFD installed with other system control and monitoring instrumentation on a skid adjacent the wells (Figure 3.4 in the main report). The VFD controls the AC motor speed (rpm) and torque by varying the input frequency and voltage to the motor. The VFD can be controlled remotely from a process and control system in the P&T facilities where flow, pressure, and other information (e.g., pump rpm and load) are monitored.

Figure B.2 graphically summarizes the distribution of HP ratings for pumps installed in extraction wells connected to Hanford P&T systems. A total of 80 of the 171 extraction wells listed in the 2014 annual P&T reports (DOE 2014a and 2014b) had pump horsepower information listed in the well information tables in the Hanford Environmental Information System. In all wells, the pumps are listed as submersible pumps with AC-powered motors. Nominal depth to water (DTW) and extraction rates are also included in Figure B.2. Extraction wells in the 200 West P&T system have pumps fitted with 30 to 40 HP motors to sustain ~80 gallon per minute (gpm) pumping rates from a deep (average DTW before pumping = 260 ft below ground surface [bgs]) and highly transmissive aquifer. The majority (86%) of the extraction wells in the 100 Areas have five HP pumps or fewer, with one HP pump being the most common (41%). These smaller pumps and motors are sized for extraction rates that average between 15 and 40 gpm from wells with pre-pumping DTWs of 30 to 80 ft bgs.

B.2 DC Submersible Pumps for Solar Applications

Solar PV technology has been used to directly power groundwater pumps for decades in the off-grid agricultural/ranching and urban drinking water applications in developing countries. Many of these systems use submersible pumps that have DC motors. AC- and DC-powered pumps are similar in pump design and manufacturers commonly offer their pumps in either option. The primary benefit of the DC motors is that they increase the overall system efficiency and decrease costs by avoiding the need for a DC-AC power inverter (see Appendix A, Section A.2.2.3, for a discussion on inverters). These DC pumps specifically designed and marketed for solar PV application also tend to have more efficient pumps and motors and require a lower starting torque.



P&T System	Nominal Depth to Water (ft bgs)	Nominal Pumping Rate (gpm)
200 West	260	80
100-DX	70	15
100-HX	30	20
100-KR-4	30	30
100-KW	80	30
100-KX	60	40

Figure B.2. Extraction well and pump information for Hanford P&T extraction wells. Pumping rates are approximate averages for calendar year 2013 and come from the same 2014 P&T reports.

B.3 Submersible Pump and Motor Efficiencies

Submersible groundwater pumps and motors have efficiencies that vary by model, size, motor type (DC vs. AC), and how they are operated within their intended design window. The overall “wire to water” efficiency of a pump-motor combination is the ratio of input energy and the amount of groundwater delivered for a given pumping head (feet) according to:

$$wire\ to\ water\ pump\ \&\ motor\ efficiency\ \% = \frac{HP_{water}}{HP_{input}} * 100 \tag{B.1}$$

Where:

$$HP_{water} = \text{output HP of the pump } = \frac{GPM * Total\ head}{3{,}960}$$

3,960 = 33,000 ft-lb/min/HP ÷ 8.33 lb/gal

HP_{input} = input HP to pump motor = electrical power input in kW $*$ 1.34

Total head (ft) = pumping water level + discharge head

Discharge head (ft) = discharge pressure in PSI $*$ 2.31 ft/PSI

The pump and motor have their own respective levels of efficiency and can be separated into their individual components for analysis and optimization; however, this study is interested in the overall efficiency of the pump-motor combination (wire to water efficiency). For a given pump-motor combination, the peak efficiency occurs at some designed flow, head, and power load condition . As noted above, VFDs control the flow rate and energy consumption of AC pumps. Figure B.3 shows an example of performance and efficiency curves supplied by a manufacturer for an AC submersible pump that is controlled by a VFD. The figure shows three families of curves: head-flow performance curves, power efficiency curves for the pump body, and overall power (wire to water) efficiency curves for the pump-motor combination. The six curves in each family represent a range of frequencies supplied to the motor by the VFD. The maximum wire-to-water efficiency for this pump-motor combination is about 36%, and it nominally occurs at about 210 ft with a flow of 26 gpm at a supplied 460 VAC power frequency of 60 Hz. At a head of 100 ft and a flow of 20 gpm, the motor requires 42 Hz from the VFD and has a wire-to-water efficiency of about 32%, which is less than the peak efficiency. Thus, matching the size of the pump-motor combination to the intended operational range of the extraction well is key to optimizing energy efficiencies.

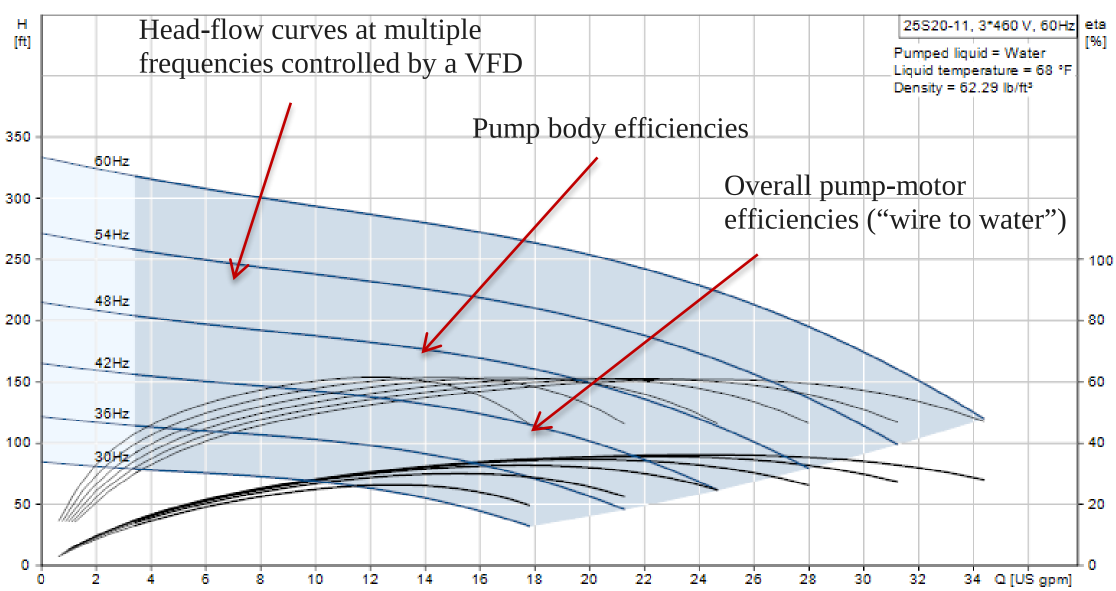


Figure B.3. Manufacturer-supplied performance and efficiency curves for a three-phase 460 VAC submersible pump (Grundfos model 25S20-11) at six different frequencies as controlled by a VFD.

Conlon et al. (1999) published efficiency values for AC-powered water pumps 20 HP and greater, including submersible well pumps, based on thousands of individual performance tests conducted throughout the 1990s. They reported an average wire-to-water efficiency for AC-powered submersible well pumps of about 44%. For comparison, we investigated the peak wire-to-water efficiencies of 20 AC and DC model submersible pumps from three popular manufacturers at total head conditions of 100 ft, consistent with extraction wells in the 100 Area P&T extraction wells (Table B.1). Peak efficiencies for AC pumps ranged from 31% to 45%, with an average of 38%. These values are slightly less than those published by Conlon et al. (1999), but are similar in range. For the DC-powered pumps marketed for solar applications, the efficiencies were noticeably higher. DC pump efficiencies ranged from 41% to 61%, with an average of 50%, which is 26% more efficient than the AC pumps in the same size category. It is also evident that the AC pumps increase in efficiency with size, while the DC pumps do not show a trend related to size. In addition to having higher peak efficiencies for a given head-flow design window, DC pumps perform at higher efficiencies throughout their intended range of pumping rates (Figure B.4).

Table B.1. Peak wire to water efficiencies for various AC and DC-powered submersible pumps at the prescribed total head condition of 100 feet based on pump performance and efficiency curves produced by the manufacturer.

Type	Pump Manufacturer	Pump Model	Pumping Rate Range (gpm)	Peak Wire to Water Efficiency (%)
AC	Grundfos	25S15-9	1-30	31
AC	Grundfos	25S20-11	1-25	32
AC	Grundfos	40S20-7	1-54	35
AC	Grundfos	40S50-12	1-42	40
AC	Grundfos	40S50-15	7-37	41
AC	Grundfos	60S50-7	1-78	45
AC	Grundfos	60S50-9	1-80	44
AC	Grundfos	75S50-8	1-90	45
			Average	38
DC	Grundfos	11 SQF-2	2-12	55
DC	Grundfos	16 SQF-10	1-21	41
DC	Grundfos	25 SQF-7	2-28	43
DC	Grundfos	3 SQF-2	1-6	41
DC	Grundfos	40 SQF-5	5-30	43
DC	Lorentz	PS1200 C-SJ5-8	2-26	49
DC	Lorentz	PS1800 C-SJ8-7	5-38	49
DC	Lorentz	PS200 HR-04	0.3-3	47
DC	Lorentz	PS4000 C-SJ8-15	4-62	61
DC	Lorentz	PS600 C-SJ5-8	2-18	50
DC	SunPumps	SCS 30-130-120 BL	13-36	48
DC	SunPumps	SCS 45-116-180 BL	10-50	49
			Average	50

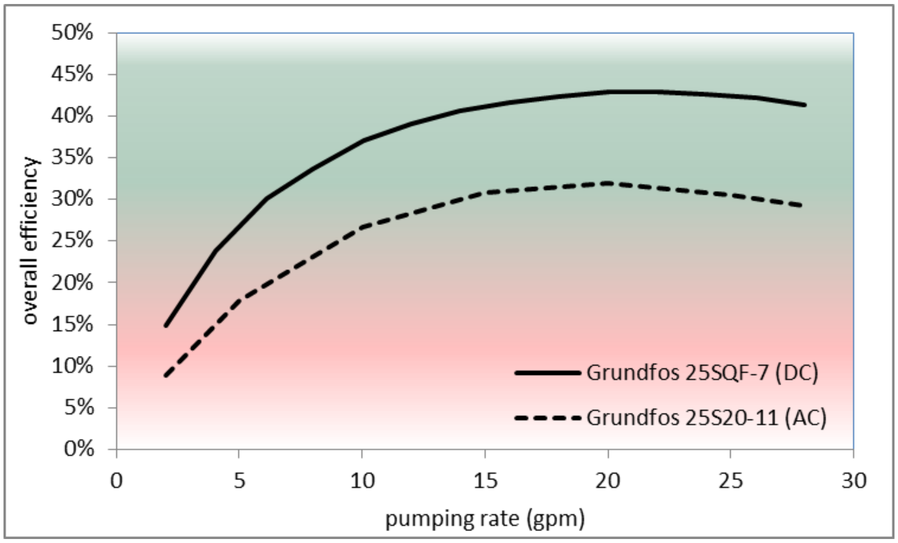


Figure B.4. Wire to water efficiencies across the designed pumping rate range for AC (dashed line) and DC (solid line) pumps from the same manufacturer. Both pumps have similar design operation ranges and are running at a total head of 100 feet.

B.4 References

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