Obsidian Solar Center ASC Additional Information
Table of Contents

Rule	Exhibit/ Standard	Request	Response
OAR 345-021-0010(b)(A)(v)	Exhibit B	1. Describe the data acquisition and communication monitoring interface, and how, if at all, it would monitor fire, electrical hazards, or other operability issues at the site. (Exhibit B Facility Information page B-6)	The Facility will have a supervisory control and data acquisition (SCADA) system. Alarming is one of the primary functions of the SCADA. The SCADA HMI software platform will be programmed with various multi-level priority alarms and programming will dictate who receives notice. For a high priority alarm, for example, the software can push a notice through email or SMS (text message) to all operators, operational managers, and asset managers, and perhaps even the Facility owners. Alarms will be provided for electrical hazards, fire, and other operational issues.
OAR 345-021-0010(b)(A)(v)	Exhibit B	2. Describe the type of fire suppression equipment that could be located onsite, and provide the location where equipment would be stored. (ASC Exhibit U Public Services (page U-16/17)	Through its participation in the High Desert RFPA, Applicant will have access to federal excess personal property (FEPP), including excess U.S. Forest Service wildland fire engines and equipment. These are on loan from the federal government for the life of the equipment. Similarly, FFP (fire fighter property) held as excess by the Department of Defense, may be available, potentially modified to suit rangeland needs. Applicant, in consultation with the RFPA and RFPA members near the Facility, will identify a location for the FEPP and FFP such that it is near a main access road and can be easily accessed by Applicant and other RFPA members in the event of fire suppression needs. The most likely location will be at the eastern Facility site access gate just off Oil Dri Road. Alternatively, or perhaps in addition, equipment may be stored just off Connley Lane near the site of the GSU.

OAR 345-021-0010(b)(A)(v)	Exhibit B	3. Describe routine operations and maintenance activities, specific to fire prevention measures, for the solar facility components and the transmission line (i.e. describe routine solar facility and transmission line inspections and purpose of inspections; describe what inspections/factors will be evaluated to determine whether mowing should be employed for vegetative/fuel maintenance).	During Facility operation, the site, including the facility components and transmission line, will be inspected periodically consistent with the SOLV Fire Management Plan. See Attachment 1. Vegetation and electrical equipment will be inspected (visual inspection and infra-red scanning, as appropriate for the particular area) and vegetation will be managed with mowing and spraying as necessary to avoid any hazardous conditions. SOLV is Swinerton Builder's O&M operator. SOLV will also be notified via the SCADA system (as described above), which provides constant electrical equipment monitoring.

OAR 345-021-0010(1)(k)(C)(v)	Exhibit K/ Land Use Standard	4. ASC Exhibit K page K-34 states "The land within the Facility site boundary is of low value for agricultural production given the quality of the underlying soils and the lack of available irrigation water rights. The temporary loss of this land is insignificant when considering the other available agricultural land in Lake County". To support the findings for how the goal exception is justified under this reasoning, please provide evidence or a discussion of the land value and uses within the site boundary. For example, provide evidence or correspondence log from landowners of the existing uses for agriculture (cattle grazing) as compared to the state or county average for similar land.	The Facility is comprised predominately of NRCS nonarable land, specifically nonarable soils Class VI and VIII. There are no water rights within the site boundary. The Fort Rock sub-basin of the Summer Lake Basin has been under a moratorium preventing issuance of new groundwater rights for irrigation by the Oregon Water Resources Department since the mid-1980s.[1] The underlying property owner previously documented the low value of the underlying soil quality and the poor grazing forage such that the land, the landowner's opinion, was inadequate for a viable commercial grazing operation. See Attachment 2.

[1] See NRCS Long Range Strategy, Lake County, Oregon (p 12), available at https://www.nrcs.usda.gov/wps/PA_NRCSConsumption/download?cid=nrcseprd1358495&ext=pdf.

OAR 345-021-0010(i)(C)	Exhibit I/ Exhibit P/ Fish and Wildlife Standard	5. Describe site preparation activities, including methods for pre-construction vegetation clearing, appropriate for 3-7’ tall big sagebrush. (ASC Exhibit I Soils (page I-8); Exhibit P Fish and Wildlife Habitat (page P-30))	While the site boundary is primarily comprised of sagebrush shrubland habitat, only 15-30 percent of the site is big sagebrush with 10-25 percent being green rabbitbrush and 40-60 percent being bare ground. During construction, Applicant will brush beat vegetation leaving root boles in place to the greatest extent possible. Mowing, grading and ground disturbance will be limited. If needed, larger sagebrush will be removed by hand-cutting to minimize soil disturbance, but Applicant will design the Facility to the extent possible to minimize removal. To the extent removal is unavoidable, this vegetation will either be chipped on site or removed and properly disposed of by Applicant.

OAR 345-021-0010(j)(B)	Exhibit J	6. Provide the assumptions of temporary and permanent disturbance activities within Playa 08, 11 and 16 (jurisdictional wetlands); provide area calculations that were used to establish extent of removal/fill within playas. (ASC Exhibit J Table J-1)	Playa 08, 11 and 16, designated as Playa Barrens in the Study Area (see Revised Table E-1 of Appendix J-1 Waters Delineation Report) (revised May 7, 2019), total 4.2 acres and expected volume of fill for these acres is 4.69 cubic yards. The temporary and permanent disturbance activities within these areas were determined based on the assumptions set forth in note (a) to Table J-1. The "area" of the removal/fill calculation, as Applicant understands the request, would be the surface area of the footprint of each I-beam post within the 4.2 acres. Each I-beam post has a surface on the ground area (prior to pounding) of approximately 6.5 inches (based on two 4-inch flanges and one 6-inch web, each with a width of 0.5-inches). <u>Proposed Condition of Approval</u> Within Playa 08, 11, and 16 as shown Figures J-1.1, J-1.2. and J-1.3 in Exhibit J of the ASC, construction activities and permanent facilities will be limited to installation of posts, racks and solar panels, and the permanent impact within these areas will not exceed 50 cubic yards unless Applicant obtains an appropriate removal/fill permit.
OAR 345-021-0010(j)(B)	Exhibit J	7. Describe the parameters applicant will impose to ensure that no disturbance other than posts would occur within delineated area of Playa 08, 11 and 16 (i.e. how will the design ensure that foundations and roads would not be placed on or within playas)?	Applicant proposes a condition of approval to address this RAI. See above.

OAR 345-021-0010(w)(D)	Exhibit W	8. Provide a more detailed description of the individual tasks to be conducted under the categories of estimated costs in Table W-1 and of the assumptions that are included in the tasks and actions identified in the ASC Exhibit W Table W-1 site restoration costs. The information in ASC Exhibit W Table W-1 does not contain sufficient evidence for the Department to recommend to Council that the estimated retirement costs reasonably capture all costs to be incurred in restoring the site to a useful, non-hazardous conditions. The Department provides specific questions on line items provided in the table. (Please see example site restoration costs from approved site certificates, for reference to level of detail considered satisfactory)	See attached revised Table W-1. Attachment 3. Applicant will be presenting an alternative approach to decommissioning in the DPO comment period.

Obsidian Solar Center LLC
Obsidian Solar Center Project
Response to ODOE RAI February 5, 2020

Supplemental ODOE Questions			
		Request	**Response**
1.		Please describe the permanent infrastructure located at the step-up substation, particularly the interconnection from the substation to the 500 kV transmission line.	The Facility will have a step-up substation adjacent to the PGE point of interconnection (POI). The PGE POI will connect with the 500 kV transmission line. No infrastructure located at the Facility step-up substation, and required for interconnection, amounts to a transmission line requiring an analysis under ORS 215.274 or 215.275. The Facility's 115 kV gen-tie line will terminate at the Facility step-up substation where the power will be "stepped up" to 500 kV and transferred to the PGE POI, at which point it will be transferred onto the regional grid. The equipment to transfer the power from the Facility substation to the PGE POI then to the 500 kV line is accessory to the substation, either the step-up or PGE POI, and is not a linear facility within the meaning of ORS 215.274 or 215.275.
2.		Please confirm the extent of the public right-of-way along Connley Lane and confirm the extent of the 115 kV gen-tie line within the public right-of-way.	The County right-of-way on Connley Lane is understood to be 30 feet from the center line. Utilities must be installed at the back edge of the right of way to allow for proper maintenance of ditches. Regardless, Applicant is not relying on the location of the 115 kV gen-tie line within the public right-of-way to demonstrate compliance with ORS 215.274. Rather, Applicant demonstrates compliance under ORS 215.274(3)(a) because the entire length of the proposed associated transmission line corridor is located entirely on NRCS nonarable soils (not located on high-value farmland or arable land).

3.		Visual impacts (zone of visual influence maps/evaluation) for the 115/500 kV step up substation need to be updated for EFSC's Scenic, Recreation, and Protected Areas standards, based on description provided by applicant on Feb 13, or applicant must explain how the assumptions used in ASC to evaluate visual impacts accurately represent the current proposal (ASC assumptions: 4 acre footprint, with structures not exceeding 10 feet in height; current proposal: 35 acre footprint, with structures up to 100 feet in height).	In Applicant's supplemental description for the 115kV/500kV step-up substation, Applicant described the substation area as 35 acres, which refers to the full acreage of what is identified in the Facility site boundary as Area D. This area will include the Facility's step-up substation and the PGE point of interconnection (POI), including PGE's 500 kV substation. Applicant studied the full 35 acres and included it within the Facility site boundary because the specific location of Applicant's step-up substation within the 35 acres has not yet been determined. Within the 35 acres, the Facility step-up substation will occupy about 3 acres (300 x 300 feet), as previously described in Exhibit B of the ASC. Exhibit B also provides that the step-up substation will be about 10 feet in height with lightning protection of up to 40 feet tall. Since Exhibit B was prepared, the Facility design has continued to be refined. The reference to the 10-foot height in Exhibit B was intended to be for the step-up substation main components (transformers and insulators), not the lightning protection or the structural components receiving the power from the 115 kV gen-tie line or the structural components sending the power from the step-up substation to the PGE POI. The structure components receiving and sending power continue to be refined as Applicant works with PGE. The structural components receiving power from the 115 kV gen-tie transmission line will likely be about 65 feet in height (referred to as the "Incoming Line Mast") and the structural components sending the stepped-up power to the PGE POI will likely be up to 100 feet (referred to as the "Outgoing Line

			Mast”). The height of these types of structures vary depending on the voltage of the gen-ties and substations. Wires from the Outgoing Line Mast will cross the fence dividing the Facility step-up substation area from the PGE POI. The “point of change of ownership” is the point where the power lines cross the fence to the PGE POI. The Incoming Line Mast and the Outgoing Line Mast are typically about 3 or 4 feet wide at the base and taper to about 18 inches at the top. There are generally three Incoming Line Masts and three Outgoing Line Masts, each with crossbar supports between them. Applicant conducted a visual analysis, including in the ASC, to demonstrate the Facility’s compliance with EFSC’s Scenic, Recreation, and Protected Areas standards. The assumptions used in ASC to evaluate visual impacts under the EFSC standards still cover the refined step-up substation design and may be relied upon notwithstanding the changes in the step-up substation description (noting that the exact height and dimensions will not be finalized until final design is complete). . The step-up substation structural components with the greatest height (e.g., the Incoming and Outgoing Line Masts) will be co-located with the three existing 500-kV transmission lines (steel lattice towers in excess of 100 feet in height) that run across the valley and are visually predominate in the landscape. The existing 500kV transmission lines and towers were considered in the Facility’s visual analysis and Applicant already demonstrated that the Facility’s gen-tie line and its 70-foot-tall poles were visually subordinate to the existing 500kV transmission structure.

			Applicant's analysis of potential visual impacts in Exhibits L, R and T demonstrate that the potential visual impacts of the substation structural components will be low or negligible and will not rise to the level of significance. The visual analysis detailed in Exhibit L, explains that, in part because the protected areas are a minimum of 4 miles away, the gen-tie transmission line was not included in the viewshed analysis because it is so "unlikely that the transmission line will attract the attention of casual observer away from any of the protected areas." Ex. L, page L-11. This is also true of the substation components, which are just slightly higher than the monopoles of the proposed gen-tie line but are also closer in location to the existing 500-kV transmission line and related infrastructure. Similarly, as described in Exhibit T (Recreational Resource), due to the location of the Facility structures relative to the recreational areas, visual impacts on recreational resources of the Facility will be low to negligible. Ex T., page T-7. The analyses in Exhibits L and T rely in part on the viewshed analysis in Exhibit R. In Exhibit R, Applicant demonstrates that the approximately 70-foot tall steel monopoles of the proposed 115-kV transmission line "will be subordinate in appearance compared to the existing 500 kV transmission lines". Ex. R, page R-11. The substation components will be located closer than the monopoles will be to the existing 500 kV transmission towers and lines and will similarly be visually subordinate or subsumed in the existing visual landscape Therefore, no further analysis or study is necessary to show that the potential visual impacts of the substation components

			will be low or negligible and will not rise to the level of significance

Attachment 1

SOLV, Inc.

Vegetation Management and Fire Prevention Plan

SOLV, Inc.
16798 WEST BERNARDO DRIVE
SAN DIEGO, CA 92127

Vegetation Management and Fire Prevention Plan

General Mowing Procedure for Solar Site

All site personnel should always have an exit strategy when on the site and make themselves aware of all exit points including man gates where available.

Each mower operator has a five-pound fire extinguisher on their mower for potential fire (please refer to Swinerton's internal safety training regarding fire extinguishers, attached). Additionally, technicians have five or ten-pound fire extinguisher on their truck.

SOLV technicians all have access to the National Weather Service mobile application (provided by the National Oceanic and Atmospheric Administration https://www.wrh.noaa.gov/fire2/?wfo=slc) downloaded on their cell phone, which tracks each technician and provides customized push notifications including Red Flag Warning or Fire Watch Alerts, dependent on location.

Each technician or operator will have a pocket card with the following procedure should fire emerge:

- Blow air horn
- Call SOLV's OCC

On site safety should always be prioritized as people, followed by equipment.

SOLV does not expect personnel to act as firefighters. If a fire does break out, refer to fire containment procedure.

Vegetation Management and Fire Prevention Plan for Red Flag Fire Danger Conditions

Before the start of each daily shift, at approximately 07:00 a.m local time, the Technician in charge will check the fire danger posting by the National Weather Service, as described above, for any Red Flag Warnings for that day.

If there is a Red Flag Warning for that day, all mowing activities done with power mowers using metal blades will be halted. The only vegetation mitigation that is allowed during a Red Flag Warning is that done with a string trimmer using nylon string that won't cause sparks. These warnings will be referenced on the daily pre-task plan document.

Vegetation Management and Fire Prevention Plan when there is no Red Flag Issued but Possible Conditions Present

Before the start of each daily shift, at approximately 07:00 a.m local time, the Technician in charge will check the fire danger posting by the National Weather Service, as described above, for any Red Flag Warnings for that day.

If there is no Red Flag Warning, but a Fire Watch Alert is issued based on temperature and wind conditions, mowing activities will proceed with caution. If there is a Fire Watch Alert issued, SOLV will assign one Technician/Operator as a Fire Watch designee during full scale mowing efforts whose sole job will be to scan for emergent fire conditions.

If SOLV is performing light work (eg one to two mowers per site), one operator will be designated to turn off the mower at twenty minute intervals to perform a visual scan of the area mowed, walking approximately 20 yards in each direction and ensuring nothing is burning.

Technicians can use their discretion at any time, if they feel conditions are not safe, to recommend that vegetation abatement be halted.

Fire Containment Procedure

If fire breaks out onsite, refer to your pocket card and call SOLV's OCC, they will directly contact the emergency services in the area. Use air horns or other methods to alert site personnel of danger. After assessing your own personal safety, assess if any countermeasures are safe. For example, use fire extinguisher, if available, and fire is in the incipient period to mitigate small vegetation fire or small equipment fire.

Again, it must be reiterated that personal safety of site personnel is paramount. Do not take any risks to protect site equipment if you feel in danger in any way. Find a way to exit to safety above all else.

Please note: Water should not be sprayed into the arrays as an electrical fire can escalate with water introduced.

SOLV Recommendations

SOLV proposes the following recommendations:

1) Full Time Fire Watch designee during full scale mowing with safety equipment to alert other site personnel in the event a fire did emerge (eg two-way phone, air horn). This option would require scope to be built out for fire watch responsibilities.
2) Defensible space perimeter around each site of 10 feet – requires spraying and discing

While it has been discussed, SOLV *does not* recommend a water buffalo at this time because SOLV personnel are not trained firefighters and if water in that volume is required, the situation is already at a level that is beyond SOLV technician training. Also, fire management techniques on a solar site include special additives to the water to be effective. Finally, spraying into compromised arrays can exacerbate an electrical fire.

Basic Fire Extinguisher Training

Four things must be present at the same time in order to produce fire:

1. Enough **oxygen** to sustain combustion,
2. Enough **heat** to raise the material to its ignition temperature,
3. Some sort of **fuel** or combustible material, and
4. The **chemical, exothermic reaction** that is fire.

Oxygen, heat, and fuel are frequently referred to as the "fire triangle." Add in the fourth element, the chemical reaction, and you actually have a fire "tetrahedron." The important thing to remember is: **take any of these four things away, and you will not have a fire** or **the fire will be extinguished**.

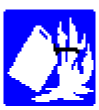
Essentially, fire extinguishers put out fire by taking away one or more elements of the fire triangle/tetrahedron.

Fire safety, at its most basic, is based upon the principle of keeping fuel sources and ignition sources separate.

Not all fires are the same, and they are classified according to the type of fuel that is burning. If you use the wrong type of fire extinguisher on the wrong class of fire, you can, in fact, make matters worse. It is therefore very important to understand the four different fire classifications.

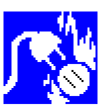
Class A - Wood, paper, cloth, trash, plastics

Solid combustible materials that are not metals. (Class **A** fires generally leave an **A**sh.)



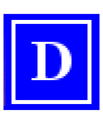
Class B - Flammable liquids: gasoline, oil, grease, acetone

Any non-metal in a liquid state, on fire. This classification also includes flammable gases. (Class **B** fires generally involve materials that **B**oil or **B**ubble.)



Class C - Electrical: energized electrical equipment

As long as it's "plugged in," it would be considered a class C fire. (Class **C** fires generally deal with electrical **C**urrent.)



Class D - Metals: potassium, sodium, aluminum, magnesium

Unless you work in a laboratory or in an industry that uses these materials, it is unlikely you'll have to deal with a Class D fire. It takes special extinguishing agents to fight such a fire.

Most fire extinguishers will have a pictograph label telling you which classifications of fire the extinguisher is designed to fight. For example, a simple water extinguisher might have a label like the one below, indicating that it should only be used on Class A fires.

Fires can be very dangerous and you should always be certain that you will not endanger yourself or others when attempting to put out a fire. For this reason, when a fire is discovered:

- Assist any person in immediate danger to safety, if it can be accomplished without risk to yourself.
- Activate the building fire alarm system or notify the fire department by dialing 911 (or designating someone else to notify them for you). When you activate the building fire alarm system, it will automatically notify the fire department and get help on the way. It will also sound the building alarms to notify other occupants, and it will shut down the air handling units to prevent the spread of smoke throughout the building.
- Only after having done these two things, if the fire is small, you may attempt to use an extinguisher to put it out.

However, before deciding to fight the fire, keep these rules in mind:

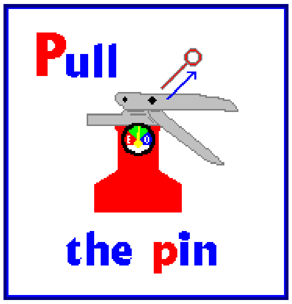
Know what is burning. If you don't know what is burning, you don't know what type of extinguisher to use. Even if you have an ABC extinguisher, there may be something in the fire that is going to explode or produce highly toxic smoke. Chances are, you *will* know what's burning, or at least have a pretty good idea, but if you don't, let the fire department handle it.

The fire is spreading rapidly beyond the spot where it started. The time to use an extinguisher is in the incipient, or beginning, stages of a fire. If the fire is already spreading quickly, it is best to simply evacuate the building, closing doors and windows behind you as you leave.

It's easy to remember how to use a fire extinguisher if you can remember the acronym **PASS**, which stands for **P**ull, **A**im, **S**queeze, and **S**weep.

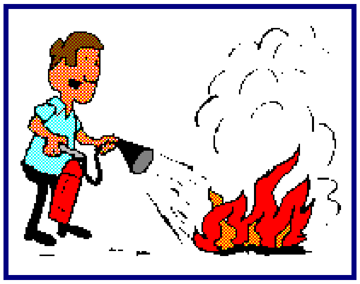
Pull the pin.

This will allow you to discharge the extinguisher.



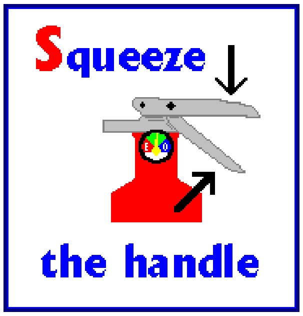
Aim at the base of the fire.

If you aim at the flames (which is frequently the temptation), the extinguishing agent will fly right through and do no good. You want to hit the fuel.



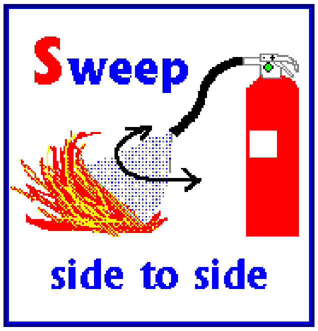
Squeeze the top handle or lever.

This depresses a button that releases the pressurized extinguishing agent in the extinguisher.



Sweep from side to side

until the fire is completely out. Start using the extinguisher from a safe distance away, then move forward. Once the fire is out, keep an eye on the area in case it re-ignites.



Attachment 2

Darwin Johnson, Jr., Director
Lake County Planning Department
513 Center Street
Lakeview, Oregon 97630

August 2 2019

RE: File # 19-028-CUP (Morehouse Solar, LLC)

Mr. Johnson

I am the property owner of land proposed for Morehouse Solar, a solar power generation facility of up to 320 acres (the project). I write this letter in support of the pending Conditional Use Permit Application for the project

My land is zoned Agricultural, but there are no water rights on the property and, due to the water moratorium, no water is available for irrigation. The soil is of variable quality, most of it low value for agricultural production or grazing forage. It is not feasible to establish a commercial agricultural operation on the property, and while I have grazed some cattle on it in the past, the land is inadequate, in my opinion, to support a viable commercial grazing operation.

Sincerely,

Richard Morehouse

Richard Morehouse

Attachment 3

Revised ASC Exhibit W Table W-1

679,603 kw dc - Obsidian Solar Center 08.30.18 rev 02.20.18	**Unit Cost**	**Cost Estimate**	**Assumption**
Cost Estimate Component			
Module Blocks			
Disconnect combiner boxes and ready array for disassembly	$ 0.00410	$ 2,786,372	Based on 679,603 kw dc
Remove panels (1,742,572 modules)	$ 0.00410	$ 2,786,372	Based on 679,603 kw dc
Remove racking and steel posts	$ 0.00500	$ 3,398,015	Based on 679,603 kw dc
Remove inverters and their foundations (per inverter)	$ 8,000	$ 1,280,000	160
Restore site (per acre) (primarily re-seeding disturbed areas)	$ 200	$ 260,000	1300 acres
O&M Facilities			
Remove O&M facility (per building)	$ 40,000	$ 80,000	2 buildings
Remove fences/gates (per foot)	$1.25/ft	$ 118,800	18 miles
Substations			
Remove collector substation(s) (138 kV; Remove high-voltage collector system junction boxes and foundations	$ 1,522,763	$ 3,045,527	2 Collector Subs
Collector Substation Transformer Oil Removal and Disposal	$ 182,250	$ 364,500	2 Transformers
Remove fences/gates at Collector Substation	$ 20,000	$ 40,000	2 Collector Subs
Remove step-up substation	$ 794,140	$ 794,140	
Step-up Substation Transformer Oil Removal and Disposal	$ 121,500	$ 243,000	2 Transformers
Remove fences/gates at Step-up Substation	$1.25/ft	$ 1,500	1,300 feet
Battery System			
Disconnect building and prepare for removal	$ 5,000	$ 670,000	134 buildings
Remove building and foundation (each)	$ 25,000	$ 3,350,000	134 buildings
Restore battery building site	$ 1,500	$ 201,000	134 buildings
Haul and disposal, including removal and recycling of electrolyte fluid	$ 1,000	$ 67,000	67 trips
Transmission Lines			
Remove aboveground transmission line (per mile)	$ 300,000	$ 812,500	2.5 miles
Road Restoration			
Internal service roads (per mile) (decompaction, grading, seeding)	$ 5,000	$ 250,000	50 miles
Restore Additional Areas Distributed by Facility Removal			
Restore and seed temporary disturbance areas	$ 500	$ 12,500	25 acres
Well Abandonment	$ 5,000	$ 10,000	2 wells
General Costs			
Haul charges and disposal fees (per load)	$ 1,000	$ 250,000	250 loads
Permits		$ 10,000	
Subtotal		$20,831,227	
Mobilization and Supervisory		$ 208,497	1%
Subcontractor Bonding/Liability Insurance		$ 260,622	1.25%
General Conditions		$ 260,622	1.25%
Performance Bond		$ 208.497	1%
Administration and Project Mgmt		$ 625,492	3%
Future Developments Contingency		$ 625,492	3%
Total Site Restoration Cost (current dollars)		$ 23,018,505	
Total Site Restoration Cost (rounded to nearest $1,000)	**$ 23,019,000**		

Draft Step-up Substation/Point of Interconnection Description

Applicant: Please review, edit and send back for ODOE evaluation under Div 21/22 requirements

Notes: Highlighted text is information ODOE requests be provided/confirmed; un-highlighted text is information from the ASC

The proposed 115/500 kV step-up substation would consist of electrical equipment needed to operate the step-up substation, a perimeter fence ~~wall~~ with a gate, and an access road to the step-up substation from Connley Lane ~~[VERIFY]~~. The total step-up substation footprint may be up to ~~(area contained within the step-up substation perimeter wall) is~~ approximately 35~~44~~ acres. The step-up substation and related infrastructure would be located within a perimeter fence. There would be a control building as a part of the step-up substation (located within the perimeter fence) for housing control and communication equipment. ~~. The total area of the step-up substation including a buffer area (area outside of the step-up substation perimeter wall) is approximately 20 acres~~. The height of electrical equipment would not exceed 100 feet. ~~Any on-site buildings to store electrical equipment, staff, or other materials such as lubricants?~~

The Facility's proposed 115 kV gen-tie transmission line would interconnect to the step-up substation. The step-up substation would contain input structures, circuit breakers, transformers and output structures, the specific combination of which would be finalized during the final design but for purposes of the ASC are described as one 115 kV input structure, two 115 kV circuit breakers, two 115/500 kV transformers, two 500 kV circuit breakers, and 500 kV output structures. ~~The substation would contain a XX kV switchracks, two 115/500 kV transformers, XX capacitor banks, [DESCRIBE STEP-UP SUBSTATION EQUIPMENT].~~ The transformers would contain approximately 50,000 (total) ~~XX~~ gallons of transformer oil. ~~The proposed 115 kV gen-tie transmission line would interconnect to the step-up substation; a line tap, with xx disconnect switches, on XX transmission structures would integrate the proposed facility's generated energy to PGE's existing 500 kV transmission line [PROVIDE POI DESCRIPTION]. The substation would be equipped with an automation system which includes XXX.~~ Once the power is "stepped up," it would be transferred to the adjacent PGE substation for interconnection with the regional grid. The Facility step-up substation and the PGE substation will share a fence line. Applicant would own the 500 kV output structure until it crosses the shared fence line at which point PGE would own the 500 kV output structure and would control the interconnection point at the PGE substation. All equipment and structures would be electrically grounded in accordance with NESC standards.

The proposed step-up substation would have access and maintenance lighting. The access light would be low-intensity and controlled by photo sensors. Maintenance lights would be used only when required for maintenance outages and emergency repairs occurring at night. Lights would be directed downward and shielded to reduce glare.

The proposed step-up substation would be enclosed on all four sides by a 7 to ~~minimum~~ 8 foot high chain-link fence. A metal access gate would also be approximately 20 feet wide and be 7 to ~~a minimum of~~ 8 feet high. The ~~All~~ perimeter fence ~~walls~~ and gates would be fitted with barbed wire for increased security.

The substation would be accessed by a 20~~XX~~-foot wide new access road connecting to Connley Lane.

Obsidian Solar Center LLC

Obsidian Solar Center

Habitat Mitigation Plan

February 2020

Obsidian Solar Center LLC

5 Centerpointe Drive, Suite 250
Lake Oswego, Oregon 97035

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ATTACHMENTS

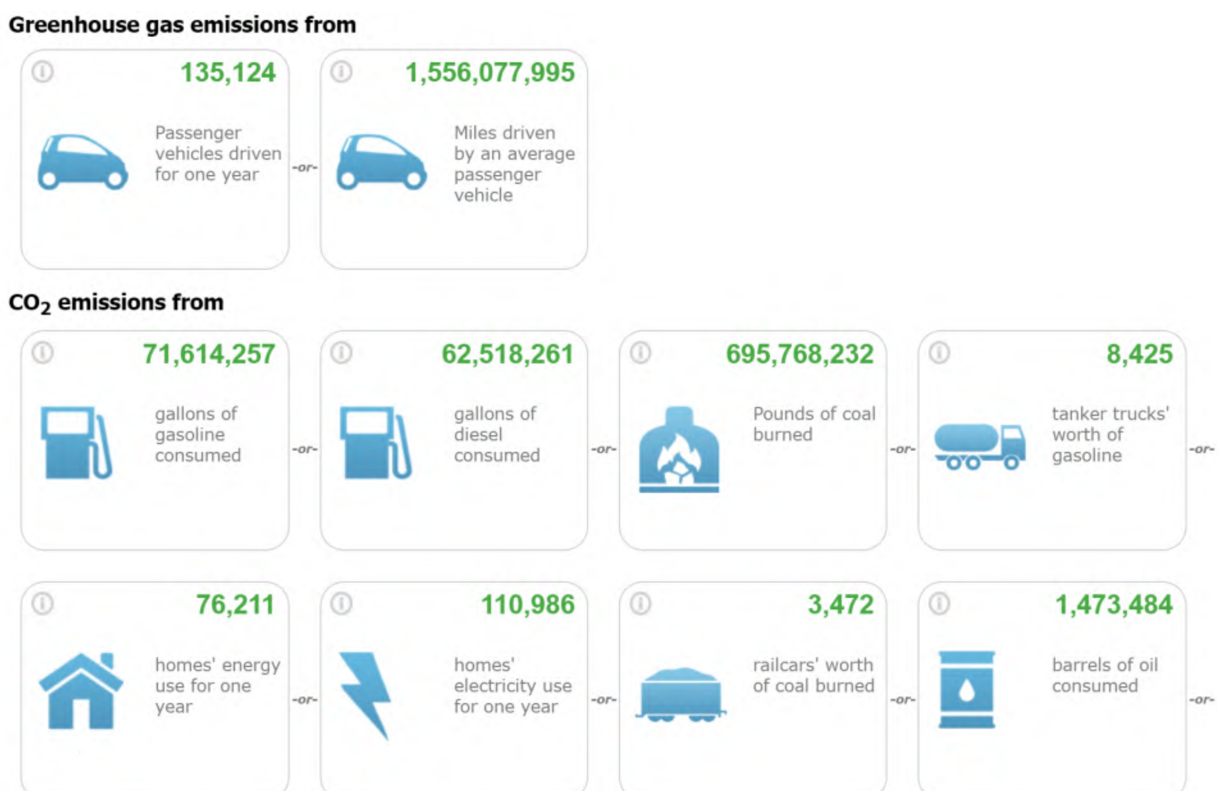
Acronyms and Abbreviations

Applicant	Obsidian Solar Center LLC
ASC	Application for Site Certificate
CWMA	Cooperative Weed Management Area
EFSC or the Council	Energy Facility Siting Council
Facility	Obsidian Solar Center
gen-tie	generation tie
HMP	Habitat Management Plan
MW	megawatts
OAR	Oregon Administrative Rule
ODFW	Oregon Department of Fish and Wildlife
ODOE	Oregon Department of Energy
OHW	ordinary high water
WLIP	Working Lands Improvement Program

1.0 INTRODUCTION

This draft Habitat Mitigation Plan ("HMP") describes how Obsidian Solar Center LLC ("Applicant") will mitigate unavoidable habitat impacts from the Obsidian Solar Center ("Facility") located in Lake County, Oregon. The purpose of the Facility is to generate renewable, clean energy that will replace, in part, energy currently generated by Northwest coal plants scheduled for closure. The Facility will operate about 30 percent of the time on a full-time equivalency basis. Applicant expects the Facility to produce about 900,000-megawatt (MW) hours per year of clean, renewable energy, which would reduce the carbon dioxide emissions equivalent to burning almost 3,500 railcars filled with coal each year (EPA 2018; Figure 1). Clean energy improvements of this kind are crucial for countering climate change, which in turn help conserve wildlife and their habitats on a landscape scale.

Figure 1. Greenhouse Gas and Carbon Dioxide Emissions Reduced Annually by the Proposed Facility



Source: EPA 2018

Habitat loss and degradation are among the greatest threats to many wildlife species around the world. Climate change also is an increasing threat to wildlife and their habitats, including to species of interest for the Facility. Research has indicated that elk (*Cervus canadensis*) (Wang et al. 2002; Sala 2006) and sagebrush habitat (Poore et al. 2009; Bradley 2010; Schrag et al. 2011) are negatively affected by climate change. Exhibit P, Section P.7.2, of the Application for Site Certificate (ASC) identifies several State Sensitive bird species in the

Facility's analysis area that are Climate Threatened or Climate Endangered, according to the National Audubon Society (2015). The Facility is a renewable energy project that will contribute to stemming climate change by reducing carbon dioxide emissions. Although the reduction in carbon emissions that will result from Facility operations may not completely counteract the loss or modification of habitat with the site boundary, it does provide a benefit to wildlife and their habitats.

This draft HMP outlines specific measures Applicant will undertake to satisfy the Oregon Energy Facility Siting Council (EFSC) Fish and Wildlife Habitat standard (Oregon Administrative Rule (OAR) 345-022-0060), which requires that the Facility, with mitigation, demonstrate consistency with the Oregon Department of Fish and Wildlife (ODFW) Habitat Mitigation Policy (OAR 635-415-0025). Applicant proposes three mitigation pathways including (1) ODFW Payment-to-Provide, (2) a Third Party Fee-in-Lieu Program, and (3) Working Lands Improvement Program (in-kind, in-proximity mitigation). In addition, Applicant reserves the right to pursue alternative mitigation pathways if available in the future by pursuing an amendment to this HMP, as provided under Section 6.0 below.

2.0 DESCRIPTION OF THE IMPACTS ADDRESSED BY THE HMP

The Facility is located entirely within the more than 1 million acre-area mapped by ODFW staff as elk winter range and a portion of the Facility is located within the area mapped by ODFW staff as mule deer (*Odocoileus hemionus*) winter range, which overlaps in its entirety with elk winter range (together, referred as "Big Game Winter Range"). ODFW staff has designated acres within Big Game Winter Range as Category 2 (essential and limited) habitat under ODFW's Fish and Wildlife Habitat Mitigation Policy (ODFW 2014, 2016a) ("ODFW Habitat Mitigation Policy"). While Category 2 serves as the habitat category for the entire Facility, the area within the site boundary consists primarily of sagebrush shrubland, with a mosaic of stand cover, plant heights, and levels of disturbance. No acres of sagebrush shrubland habitat were field-characterized as Category 2 habitat, based on vegetation communities observed on-site.

Permanent habitat impacts will be associated primarily with the installation of permanent Facility structures. The solar array areas and related or supporting facilities will be fenced as required by electrical code and safety needs, and ODFW considers all areas inside the fence to be permanently disturbed. Temporary impacts are anticipated from the construction of the gen-tie transmission line (about 1.2 acres). Otherwise, all construction-related activities will occur within the area designated for the Facility's permanent footprint (or the area located within the perimeter fence). Temporary impacts will be fully mitigated through successful implementation of the Revegetation Plan (ASC, Appendix P-3).

The Facility will not have impacts on Category 1 habitat. The Facility will have some temporary and permanent impacts on Category 6 habitat, which do not require compensatory mitigation.[1] For the remaining habitat types, permanent impacts must be mitigated at Category 2 under the ODFW Habitat Mitigation Policy because the impacts area is mapped Big Game Winter Range. Habitat values for Big Game Winter Range can include thermal cover, security from predation and harassment, quality forage, and limited disturbance. The area in the Facility site boundary is primarily sagebrush shrubland, and given the habitat characteristics, its primary habitat value for big game is forage and limited thermal cover.

Table 1: Acres of Temporary and Permanent Impact to Habitat within the Site Boundary

Habitat Category based on Field Habitat Assessment	Habitat Type	Temporary Impact	Permanent Impact	Total
ODFW Designated Category 2 Habitat				
3	Sagebrush Shrubland	0.00	3,419.21	**3,419.21**
3	Playa OHW – Not Wetlands	0.00	16.91	**16.91**
4	Sand Dune	0.03	108.78	**108.81**
4	Non-sagebrush Shrubland	0.15	0.00	**0.15**
5	Non-native Forb	0.05	42.77	**42.82**
Total Category 2 Habitat Impacts to be Mitigated		**0.23**	**3,587.67**	**3,587.90**
6	Agricultural Lands	0.56	1.00	**1.56**
6	Developed	0.21	0.00	**0.21**
	Total Impacts	**1.20**	**3,588.47**	**3,589.67**

Key:

ODFW = Oregon Department of Fish and Wildlife; OHW = Ordinary High Water

The impact analysis presented in the ASC and mitigation outlined in this HMP represents the fully built-out scenario of 400 MW. The Facility will be built as directed by market demands and power sales. For example, if Applicant enters into two separate power purchase agreements, each for 200 MW, Applicant may construct the first 200 MW and then the second 200 MW. In that case, mitigation would follow a corresponding scope and timeline.

[1] Under the ODFW Habitat Mitigation Policy, no compensatory mitigation is required for Category 6 impacts; only minimization of impacts (OAR 635-415-0025(6)).

Table 2 summarizes the habitat characteristics within the Site Boundary, as detailed in the 2018 Habitat Assessment and Biological Resources Field Report (ASC Exhibit P, Appendix P-1). Photo documentation of Area A habitat quality is also provided in photos 1-23b and 53-54 of ASC Exhibit P Appendix P-1, Attachment 1.

Table 2: Habitat Characteristics within Site Boundary

Habitat Category based on Field Habitat Assessment	Habitat Type	Native Shrub Stratum and Ground Cover	Native Herbaceous Stratum and Ground Cover	Bare Ground Cover
ODFW Designated Category 2 Habitat				
3	Sagebrush Shrubland	Big Sagebrush (*Artemisia tridentate)* (*15-30%),* Green rabbitbrush (*Chrysothamnus viscidiflorus*) and Rubber rabbitbrush (*Ericameria nauseosa*) (*10-25%)*	Saltgrass (*Distichlis spicata*), Clasping pepperweed (*Lepidium perfoliatum*), and cheatgrass (*Bromus tectorum*) (≤ 25%)	40 – 60%
3	Playa	Inclusions with Big Sagebrush (≤2*%),* Green rabbitbrush (≤8%), and shadscale saltbrush (*Atriplex confertifolia*) (≤15%)	Usually devoid; or small areas of Saltgrass (*Distichlis spicata*) (≤25%)	≥90%
4	Sand Dune	Big sagebrush and green rabbitbrush (<5%)	Saltgrass (*Distichlis spicata*) (<5%)	

3.0 MITIGATION OPTIONS

Applicant has identified three options for addressing the mitigation obligation where habitat protection and enhancement and/or commensurate funding are feasible and consistent with the EFSC Fish and Wildlife Standard. Based on the information provided on the record of the ASC, Applicant currently may only utilize Option 3, unless ODFW adopts appropriate regulations to support Option 1 or Applicant proposes an HMP amendment to utilize Option 2 that is approved. If other mitigation options become available or are identified, Applicant reserves the right to pursue alternative mitigation pathways by pursuing an amendment to this HMP, as provided under Section 7.0 below.

3.1 Option 1: ODFW Payment-to-Provide

Applicant understands that ODFW is considering a payment-to-provide program that could be used to mitigate habitat impacts related to energy facilities. Applicant recognizes that

Option 1 is not available at the time of ASC review but Applicant reserves the right to use Option 1 through an HMP Amendment should it be an available ODFW program in the future. Applicant, along with other certificate holders and applicants have encouraged ODFW to adopt such a program that could be used to mitigate habitat impacts related to renewable energy projects. Such a program would help further landscape-scale mitigation projects and create greater benefits for rangeland habitat, including Big Game Winter Range habitat.

3.2 Option 2: Third Party Fee-in-Lieu Program

Under this option, Applicant would partner with EFM, Inc., an affiliate of EcoTrust. Applicant and EFM would present to Oregon Department of Energy (ODOE) and ODFW a mitigation plan designed to protect and restore habitat within the Big Game Winter Range on a portion of the about 22,000 contiguous acres west of Fort Rock currently owned and being managed by EFM, including for the benefit of mule deer. The mitigation measures that would be employed on this land are different from those outlined under Option 3 given the enhancement opportunities.

3.3 Option 3: Working Lands Improvement Program (in-kind, in-proximity)

Option 3 involves habitat protection and enhancement measures on lands proximate to the Facility. Specifically, Applicant would secure land in proximity to the Facility and implement a Working Lands Improvement Program (WLIP). The WLIP is twofold: it ensures that (1) there is no net loss in quantity or quality of habitat for the life of the Facility, and (2) there is a net benefit of habitat quality for the life of the Facility. Applicant will carry out the WLIP on suitable land located two to 20 miles from the Facility and within the ODFW-mapped Big Game Winter Range. These sites are considered “in-proximity” to the Facility because the identified acres are within the home range of elk and mule deer that may also use the land within the Facility site boundary.

The WLIP is a western juniper (*Juniperus occidentalis)* treatment and management program on working rangeland. The juniper program includes juniper removal and thinning, which is consistent with the Oregon Conservation Strategy’s recommended approaches for conservation of sagebrush habitats. The treatment includes controlling encroaching junipers by chipping or cutting for firewood, while maintaining pre-settlement juniper stands and juniper trees with old-age characteristics, which are important nesting habitat for birds and other wildlife (ODFW 2016b). Removal of juniper can, over time, result in redistribution of water budget components in the rangeland due to lack of tree canopy interception, in turn influencing soil moisture and vegetation. In the ODFW-mapped Big Game Winter Range, juniper removal can improve the quality and quantity of sagebrush shrubland forage while preserving effective cover habitat (such as large sagebrush and old age juniper).

Working Lands Easements

Applicant will enter into working land leases with the underlying property owners for land enrolled in Applicant’s WLIP. A template of the working lands lease is included as Attachment 1. The working lands lease is a legally binding agreement, authorizing Applicant to implement the WLIP consistent with this HMP and obligating the property owner to manage and operate the land consistent with the goals of the WLIP. The term of the working lands lease is for the life of the Facility.[2] The terms of the working lands leases will provide for mitigation to achieve a no net loss of habitat quality or quantity. The implementation of the juniper treatment and management program on lands subject to working lands leases will achieve mitigation results in a net benefit of habitat quality. Applicant will provide copies of the executed working lands leases to ODOE prior to construction of the Facility.

WLIP Sites

Applicant performed a juniper phase desktop analysis of about 22,722 acres of land in Big Game Winter Range near the Facility site. The desktop analysis identified juniper woodland succession phases (Phase 1, Phase 2, Phase 3) and provided mapping of the phases as well as areas unsuitable for mitigation (*e.g.*, lava beds or quarries).[3] See Attachment 2. From this information, Applicant identified two property owners with large tracts of land for participation in the WLIP: the Morrison Ranch at about 1,870 acres and the Nine Peaks Ranch at about 4,500 acres, totaling about 6,370 acres. [4] Applicant conducted a preliminary desktop assessment of habitat types and categories on the about 6,370 acres to confirm that the habitat

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[2] "For the life of the Facility" is defined at the point when EFSC terminates the site certificate pursuant to OAR 345-027-0010. Before EFSC terminates a site certificate, the certificate holder must apply to EFSC to terminate the site certificate and provide EFSC with a proposed retirement plan consistent with OAR 345-027-0110(5), which requires, among other things, the information about how certificate holder will address impacts to wildlife and the environment during retirement. Before certificate holder may take action, EFSC must review the proposed final retirement plan, considered comments from the public and reviewing agencies, approved the proposed final requirement plan, and issued an order authorizing the retirement according to the approved final retirement plan, as provided for in OAR 345-027-0010. The approved final retirement plan will require certificate holder to restore the site and ODFW may comment on the retirement plan to ensure that the Facility continues to meet the ODFW Mitigation Policy "for the life of the Facility." EFSC may not terminate the site certificate until EFSC finds that certificate holder has completed retirement according to EFSC order authorizing retirement. See OAR 345-027-0110(8).

[3] The desktop analysis was conducted according to the protocols in the *Western Juniper Field Guide: Asking the Right Questions to Select Appropriate Management Actions: U.S. Geological Circular 1321*, Miller et al. (2007).

[4] The GIS data show the Morrison Ranch and Nine Peaks Ranch mitigation area acreage as slightly larger than the tax lot acres. The GIS data show the Nine Acres Ranch mitigation area at about 4,595 acres and the Morrison Ranch mitigation area at about 1,939 acres, rather than 4,500 and 1,870 acres, respectively.

is of similar structure and function as the habitat within the Facility site boundary. See Attachment 3 for the desktop habitat mapping.

The Morrison Ranch mitigation area is located, at its closest point, about 2 miles north of the Facility site boundary. This mitigation area is within the ODFW-mapped Big Game Winter Range and has about 970 acres of sagebrush shrubland and 960 acres of juniper woodland. The sagebrush shrubland within this mitigation area has similar habitat structure and function to the sagebrush shrubland within the Facility site boundary. Roughly, half of the juniper woodlands in the Morrison Ranch mitigation area are Phase 2 succession and likely support an understory with levels of sagebrush and perennial bunchgrasses that are suitable for restoration or conversion to sagebrush shrubland. The Phase 3 succession areas, which is also about half of the juniper woodland habitat in this mitigation area, may also exhibit restoration potential. The Morrison Ranch mitigation area also provides primary habitat values for big game, such as forage and thermal cover. Therefore, this land represents in-kind habitat for purposes of meeting Applicant's Category 2 habitat mitigation obligations.

The Nine Peaks Ranch mitigation area is located, at its closest point, about 7 miles north of the Facility site boundary. This mitigation area is within the ODFW-mapped Big Game Winter Range and has about 4,225 of sagebrush shrubland and 330 acres of juniper woodland. Sagebrush shrubland at Nine Peaks Ranch would be similar in structure and function as the sagebrush shrubland within the Facility site boundary; however, almost 85 percent of sagebrush shrubland in this mitigation area exhibits Phase 1 juniper encroachment. Phase 1 encroachment areas are in danger, long term, of further juniper succession, and would be great candidates for juniper restoration. The Nine Peaks Ranch mitigation area also provides primary habitat values for big game, such as forage and thermal cover. Therefore, this land represents in-kind habitat for purposes of meeting Applicant's Category 2 habitat mitigation obligations.

Prior to construction of the Facility, Applicant will conduct field-based habitat mapping of the WLIP sites, based on a protocol approved by ODOE, in consultation with ODFW (consistent with the field-based habitat mapping performed for the field surveys conducted as a part of Exhibit P). Applicant will provide the written report of a survey and mapping to ODOE and ODFW to verify that selected mitigation acres within the Morrison Ranch and the Nine Peaks Ranch are "in-kind" habitat to meet the Facility's mitigation obligations under this HMP.

Once ODOE, in consultation with ODFW, has concurred with Applicant's field verifications, Applicant will execute working lands leases with the Morrison Ranch and/or the Nine Peaks Ranch. Land under lease will total 1.1 acres for every 1 acre of habitat impacted by the Facility components.

Implementation of the WLIP

The WLIP includes the following components[5]:

Step 1: Pre-Treatment Juniper Survey

Applicant will conduct a pre-treatment survey to determine the appropriate Juniper Treatment Unit, facilitate preparation of the applicable Juniper Treatment Plan for that Unit, and record pre-treatment conditions (the "Pre-Treatment Survey"). The Pre-Treatment Survey may occur as part of, or concurrently with, the pre-construction field-based habitat assessment of the WLIP sites (as described above). The Pre-Treatment Survey will be conducted in accordance with a protocol, to be submitted and approved by ODFW, based on the methods included in the *Western Juniper Field Guide: Asking the Right Questions to Select Appropriate Management Actions: U.S. Geological Survey Circular 1321* (Miller et al, 2007). The Pre-Treatment Survey will document dominant plant species within each habitat type, including general habitat conditions, such as tree and shrub heights and cover (including presence of pre-settlement junipers), weed species and coverage, and level of disturbance. Applicant shall provide the results of the Pre-Treatment Survey to ODOE and ODFW.

Applicant will use the desktop analysis and field-based habitat/weed surveys, in consultation with its qualified consultants, to identify Juniper Treatment Units within the WLIP sites. The Juniper Treatment Units may vary in size depending on natural landscape divisions, qualities, prior uses, etc. and the treatment schedule for different Juniper Treatment Units may vary.[6]

Step 2: Develop Juniper Treatment Plan

Prior to construction of the Facility, following completion of the Pre-Treatment Habitat/Weed Surveys, Applicant will develop and submit for review and approval to ODOE, in consultation with ODFW, site specific Juniper Treatment Plan(s). A Juniper Treatment Plan, at a minimum, will include the following components:

- Habitat maps identifying boundary of Juniper Treatment Unit within WLIP site and treatment areas.
- A table identifying approximate acres of treatment areas application per treatment plan for the Juniper Treatment Unit (*e.g.*, xx acres for thinning, xx acres for juniper removal, xx acres for protection of juniper stands).

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[6] As stated in the ASC, Applicant will develop the Facility based on market demands and other factors. This means that construction may occur in steps or on a rolling basis. Mitigation for each step of construction or implementation of rolling mitigation would correspond to the rolling construction.

- A protocol establishing methods for documentation of pre- and post-treatment conditions such as through photo documentation; and, field based methods including walking a representative sample of 100-meter random transects to assess soil disturbance and vegetation conditions (plant cover, native herbaceous cover, non-native cover).

- Recommendations for post-treatment monitoring, weed treatment, and juniper re-treatment.

A Juniper Treatment Plan may correspond to one or more designated mitigation units within the WLIP sites. Mitigation work must commence within the same season or year of the correlative Facility construction commencement, based on final Facility design and construction schedule at that time. Following construction completion, Applicant may adjust the mitigation obligation (site size, extent of juniper treatment) if changes in final Facility design during construction occur that reduce the mitigation obligation.

Step 3: Juniper Treatment

Applicant will hire one or more contractors (locally, to the extent possible) to implement the Juniper Treatment Plans. Depending on the local site conditions and the capabilities of the contractor(s), felled juniper may be burned on site or hauled away. If slash burning is to occur, contractor will obtain necessary burn permits and will coordinate with landowners, as applicable. Juniper may also be sorted and decked, delimbed, and any commercial product taken off site. Juniper Treatment Plans will emphasize retaining pre-settlement juniper (or late successional junipers) and removing young juniper encroaching into pre-settlement juniper stands as well as other young juniper within the treatment area. The methods for juniper removal will vary depending in local site conditions. One method would be to hand cut and hand pile the trees. Another would be to pull the mid-sized juniper with a rubber tire tractor or small excavator and hand cut the large and very small post-settlement juniper; all juniper would be mechanically piled. The Juniper Treatment Plan will direct the cutting contractor to minimize impacts to sagebrush in the understory.

Step 4: Weed Monitoring and Treatment

Applicant will engage the Lake County Cooperative Weed Management Area (Lake County CWMA) to monitor the WLIP sites for noxious weeds. Lake County CWMA will monitor noxious weeds within a Juniper Treatment Unit within 12 months and again within the following 12 months after initial juniper treatment and will treat weeds as needed. Thereafter, Lake County CWMA will monitor and treat noxious weeds in the WLIP sites as described below.

Step 5: Monitoring and Reporting

Applicant will hire a qualified contractor to conduct monitoring in the treated areas of each Juniper Treatment Unit and provides reports to ODOE, ODFW, and Lake County as provided for in the applicable Juniper Treatment Plans. The monitoring program will consist of monitoring for noxious weeds as well as monitoring for mitigation success.

Generally, monitoring for mitigation success will begin about 24 months after the initial Juniper Treatment and continue every seven years thereafter for the life of the Facility. Monitoring measures to be documented include:

- Confirm ongoing compliance with WLIP leases;
- Assess changes in vegetation cover (species, structural stage, health), and progress towards meeting success criteria, including the presence or lack of noxious weeds;
- Document environmental factors such as average rainfall, average snowfall, occurrence of wildfire, etc.; and
- Assess juniper encroachment to evaluate whether retreatment may be needed, using the location points identified during the initial Juniper Treatment.

Prior to construction of the Facility, Applicant shall provide a draft report template for review and comment by ODOE, in consultation with ODFW. Based on the agency-reviewed report template, Applicant will provide ODOE and ODFW a report following each monitoring period detailing the observations and results, including the details of any noxious weed treatment and juniper retreatment.

4.0 SUCCESS CRITERIA

Given the Facility's location in ODFW-mapped Big Game Winter Range, Applicant must meet Category 2 mitigation goal of "no net loss of either habitat quantity or quality and to provide a net benefit of habitat quantity or quality." The mitigation measures presented in this draft HMP ensure that the Facility's permanent and temporary impacts will not result in a net loss of habitat quantity or quality and result in a net benefit of habitat quality. Applicant will measure success during its monitoring periods and success will be based on the following indicators:

- Increase in herbaceous cover within the WLIP treatment areas, compared to reference sites, based on soil characteristics, precipitation regimes, native plant association prior to juniper encroachment, historical fire regime, and desired future condition using *Western Juniper Field Guide: Asking the Right Questions to Select Appropriate Management Actions: U.S. Geological Circular 1321*, Miller et al. (2007);
- Maintenance of a specified percent juniper overstory within the Juniper Treatment Areas (to be specified in the applicable Juniper Treatment Plan after the Pre-Treatment Survey has been completed);
- Response of sage brush and/or bitter brush as measured by the leader growth in the cut areas within a Juniper Treatment Unit compared to areas without cutting in the Juniper Treatment Unit; and
- Successful weed control (weed monitoring and treatment) within the WLIP sites for the life of the Facility.

Success criteria may be further refined in the Juniper Treatment Plans depending on Applicant's juniper contractor recommendations, the Pre-Treatment Survey, and other site-specific conditions for the treatment area within the WLIP. Applicant is mitigating primarily for impacts to sagebrush shrubland, which was preliminarily identified as Category 3 habitat based on vegetative characteristics observed during field habitat assessments, but was designated as Category 2 because of the ODFW-mapped Big Game Winter Range overlay. As a result, habitat within the WLIP sites will only need to be enhanced to the extent it provides the quality of habitat impacted by the Facility.

5.0 PRE-CONSTRUCTION COMPLIANCE

The final HMP applies to the entirety of permanent and temporary Category 2 habitat impacts.[7] This draft HMP contains numerous pre-construction requirements to which Applicant must comply. As described throughout this plan, prior to construction of the Facility, Applicant shall:

- Develop and submit a habitat assessment protocol for the Facility site boundary and the WLIP sites for review and approval by ODOE in consultation with ODFW;
- Identify the total number of permanent and temporary habitat acres to be impacted, based on permanent facility components within the perimeter fence line and temporary impacts outside of the fence line, including any important assumptions or calculations;
- Executed WLIP landowner agreements, with an opportunity for review and concurrence by ODOE if agreements contain termination or amendment clauses;
- Draft Juniper Treatment Plan(s) (for the Juniper Treatment Units commensurate in size to the initial construction area), including maps of treatment areas; treatment plans and methods, pre- and post-documentation protocols, monitoring and reporting protocols.

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[7] Applicant began construction in 2019 on two solar projects located on land within the Facility site boundary under Lake County Permit No. 19-027-CUP and Lake County Permit No. 19-028-CUP. Applicant is implementing mitigation measures for each project under the respective CUP approvals. Applicant will terminate Lake County Permit No. 19-027-CUP and Lake County Permit No. 19-028-CUP once Applicant has demonstrated compliance with the Facility site certificate's pre-construction conditions of approval, at which point the solar development previously approved under the County CUPs will become subject to EFSC jurisdiction. Applicant proposes a condition of approval requiring an HMP status report to ODOE prior to construction confirming that mitigation conducted under the two county permits meets and will continue to meet the mitigation requirements under this HMP.

6.0 AMEMDMENTS TO THE HMP

The HMP may be amended from time to time upon approval by EFSC, who may delegate its authority to review and authorize amendments to ODOE. ODOE must notify EFSC of all amendments and EFSC retains the authority to approve, reject, or modify any amendments to this HMP agreed to by ODOE.

7.0 REFERENCES

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Attachment 1

Template Working Lands Easement

[*Submitted Under Separate Cover*]

Attachment 2

Juniper Phase Mapping Technical Memo

Stantec

Memo

To:	Michelle Slater and Laurie Hutchinson Obsidian Solar Center LLC	From:	Ilja Nieuwenhuizen Stantec Consulting Services Inc
File:	obsidian_juniperphasesmemo_01162020	Date:	January 16, 2020

Reference: Preliminary Juniper Woodland Succession Phases

Stantec Consulting Services Inc. (Stantec) prepared a preliminary map of juniper woodland succession phases within the approximately 22,722-acre Working Lands Improvement Program area (WLIP area) for the Obsidian Solar Center Project. Stantec also provided general guidance for selecting a mitigation site within the WLIP area for western juniper (*Juniperus occidentalis*) removal. The map and guidance are based on desktop analysis only; no field visit was conducted as part of this effort.

Stantec used aerial imagery and guidance provided in *Western Juniper Field Guide: Asking the Right Questions to Select Appropriate Management Actions* (Miller et al. 2007) to delineate the program area into three phases of juniper succession. The delineations are estimates based on a review of aerial imagery. A summary of the phase characteristics is provided below and a figure showing the WLIP area and the three phases is attached to this letter.

> **Phase 1 (13,554 acres)**: Early woodland succession, with the tree canopy open and actively expanding. The tree canopy cover is less than 10 percent and the shrub layer is intact.
>
> **Phase 2 (3,935 acres)**: Mid woodland succession, with the tree canopy actively expanding. The tree canopy cover is 10 to 30 percent, and the shrub layer is nearly intact to significant thinning.
>
> **Phase 3 (3,905 acres):** Late woodland succession, with the tree canopy expansion nearly stable. The tree canopy cover is more than 30 percent and the shrub layer is more than 75% dead or absent.

A 1,328-acre portion of the WLIP area does not occur in the three juniper succession phases because juniper trees are not present or present only in very small numbers or the area is unsuitable for juniper mitigation. Sagebrush shrubland habitat totals 1,168 acres in the WLIP area. Stantec classified this habitat based on aerial photography review and our familiarity with the landscape. We presume big sagebrush (*Artemisia tridentata* ssp. *tridentata*) is a major component of the sagebrush shrubland, as well as other shrubs commonly associated with big sagebrush, including other sagebrush species, rubber rabbitbrush (*Ericameria nauseosa*), and antelope brush (*Purshia tridentata*). Based on aerial imagery review, it appears no juniper trees are present in the mapped sagebrush shrubland habitat; however, a field review would be required to confirm their absence.

Lava beds compose 148 acres of the WILP area and are likely not suitable for mitigation purposes because of the low percent cover of understory species and the rocky substrate. According to Miller et al. (2007), sites with low percent cover of understory species typically do not respond well to juniper removal and are not prime sites for mitigation. A small quarry (approximately 12 acres) is also present in the WLIP area, as seen on aerial photography.

Reference: Preliminary Juniper Woodland Succession Phases

Stantec Consulting Services Inc.

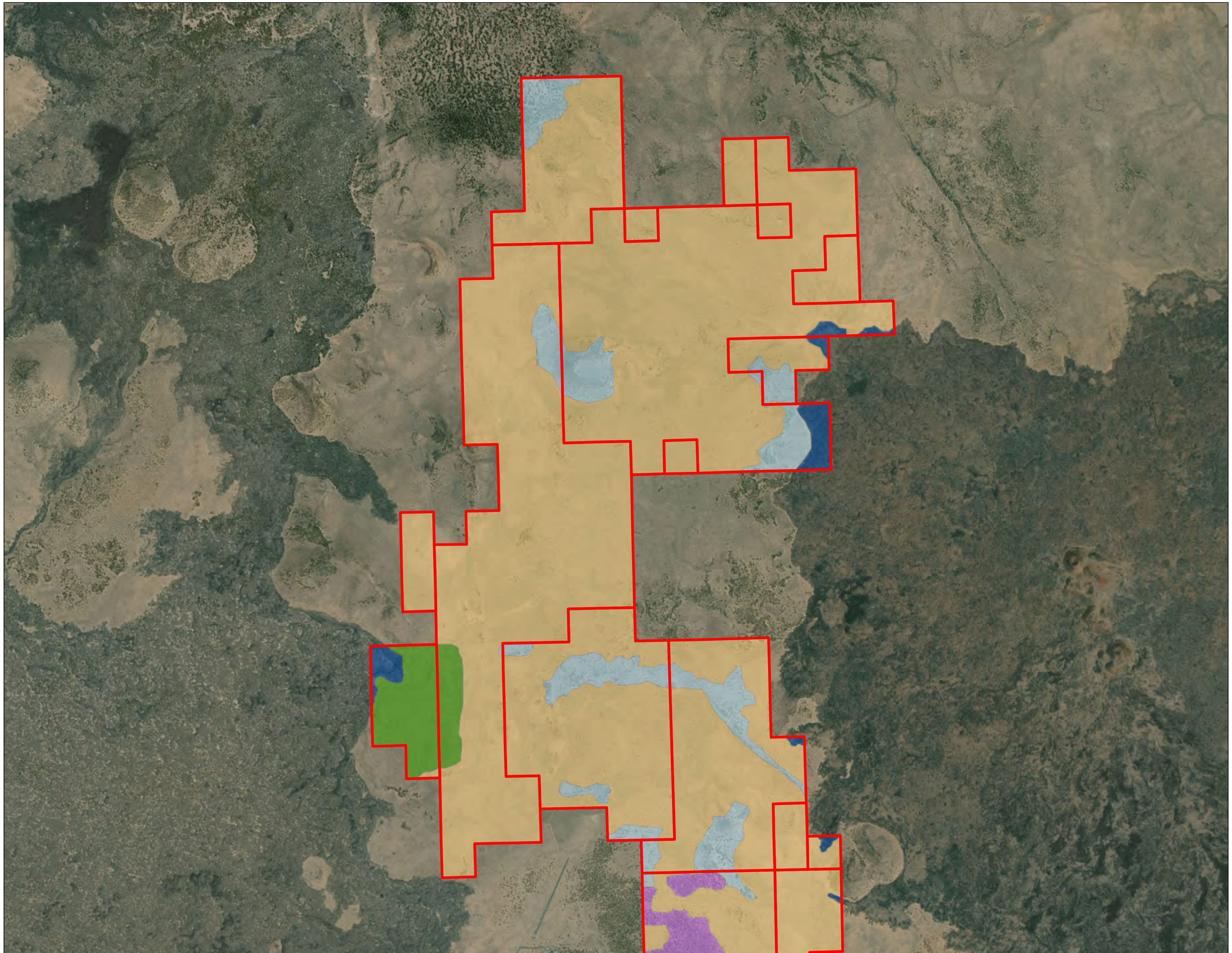
Sarah Tona

Sarah Tona
Associate Biologist
Phone: 530 222 5347 x136
sarah.tona@stantec.com

Attachment: Preliminary Juniper Woodland Succession Phases Map.

Reference

Miller, R.F., J.D. Bates, T.J. Svejcar, F.B. Pierson, and L.E. Eddleman. 2007. Western Juniper Field Guide: Asking the Right Questions to Select Appropriate Management Actions: U.S. Geological Circular 1321, 61 p.



Stantec

Working Lands Improvement Program (WLIP) Area
Non-WLIP Area
Lava Bed
Quarry
Sagebrush Shrubland

Juniper Woodland Succession Phases

Phase 1 (Juniper Subordinate)
Phase 2 (Juniper and Shrubs Co-Dominant)
Phase 3 (Juniper Dominant)

Note: mapping based on desktop interpretation of aerial imagery

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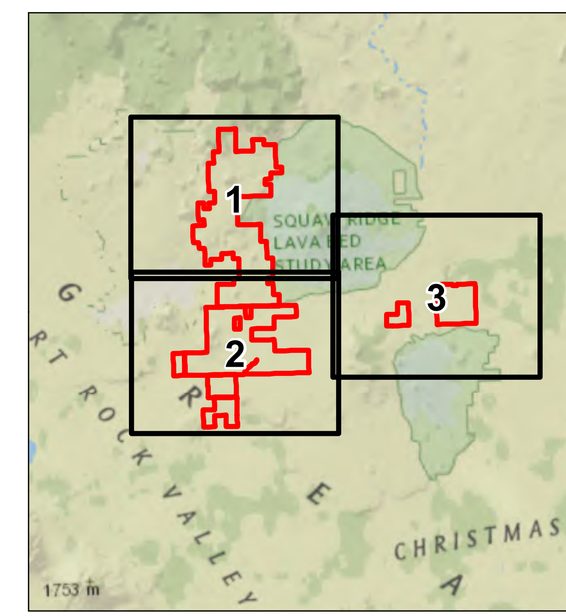
Notes
1. Coordinate System: NAD 1983 UTM Zone 10N
2. ESRI Digital Globe: 8/15/2017
3. Woodland succession phases follow guidance provided in "Western Juniper Field Guide: Asking the Right Questions to Select Appropriate Management Actions" (Miller et al. 2007).



Project Location
Lake County, Oregon

Prepared by SNT on 2020-01-16
TR by DW on 2020-01-16

Client/Project
185704572 REVA

Obsidian Solar LLC
Obsidian Solar Center

Title
Preliminary Juniper Woodland Succession Phases

Page 1 of 3

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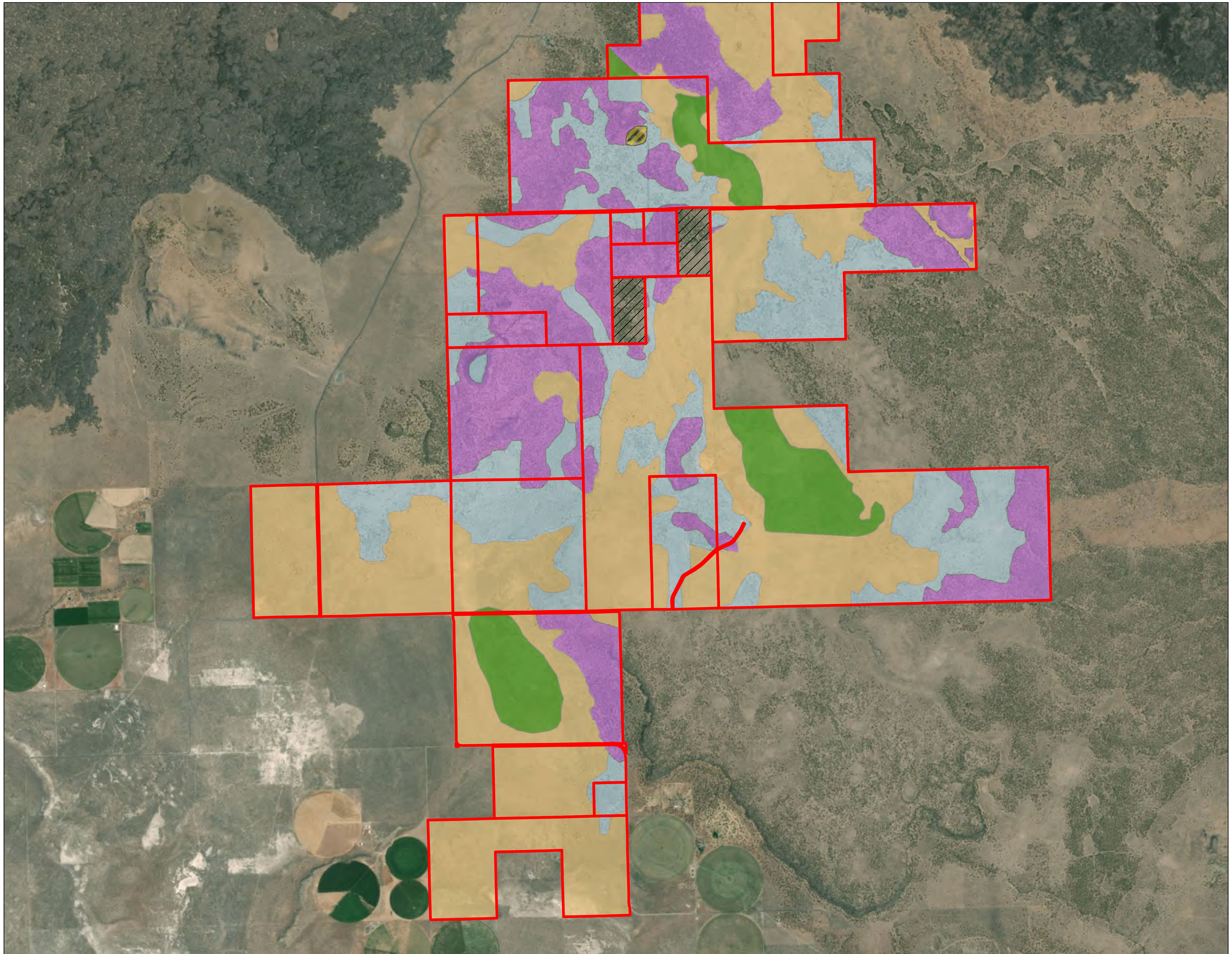
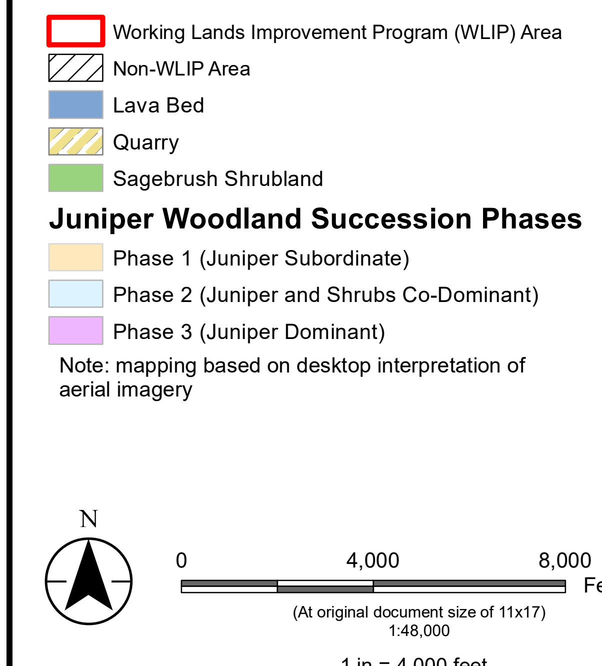
Disclaimer: This document has been prepared based on information provided by others as cited in the Notes section. Stantec has not verified the accuracy and/or completeness of this information and shall not be responsible for any errors or omissions which may be incorporated herein as a result. Stantec assumes no responsibility for data supplied in electronic format, and the recipient accepts full responsibility for verifying the accuracy and completeness of the data.





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1. Coordinate System: NAD 1983 UTM Zone 10N
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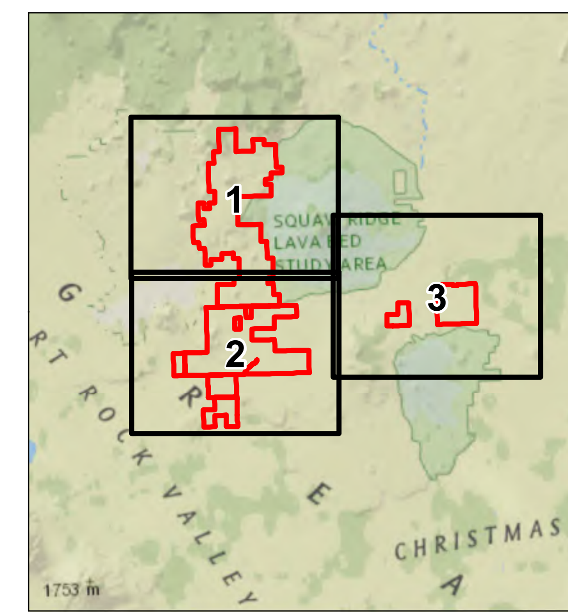

Project Location
Lake County, Oregon

Prepared by SNT on 2020-01-16
TR by DW on 2020-01-16

Client/Project
185704572 REVA

Obsidian Solar LLC
Obsidian Solar Center

Title
Preliminary Juniper Woodland Succession Phases

Page 2 of 3

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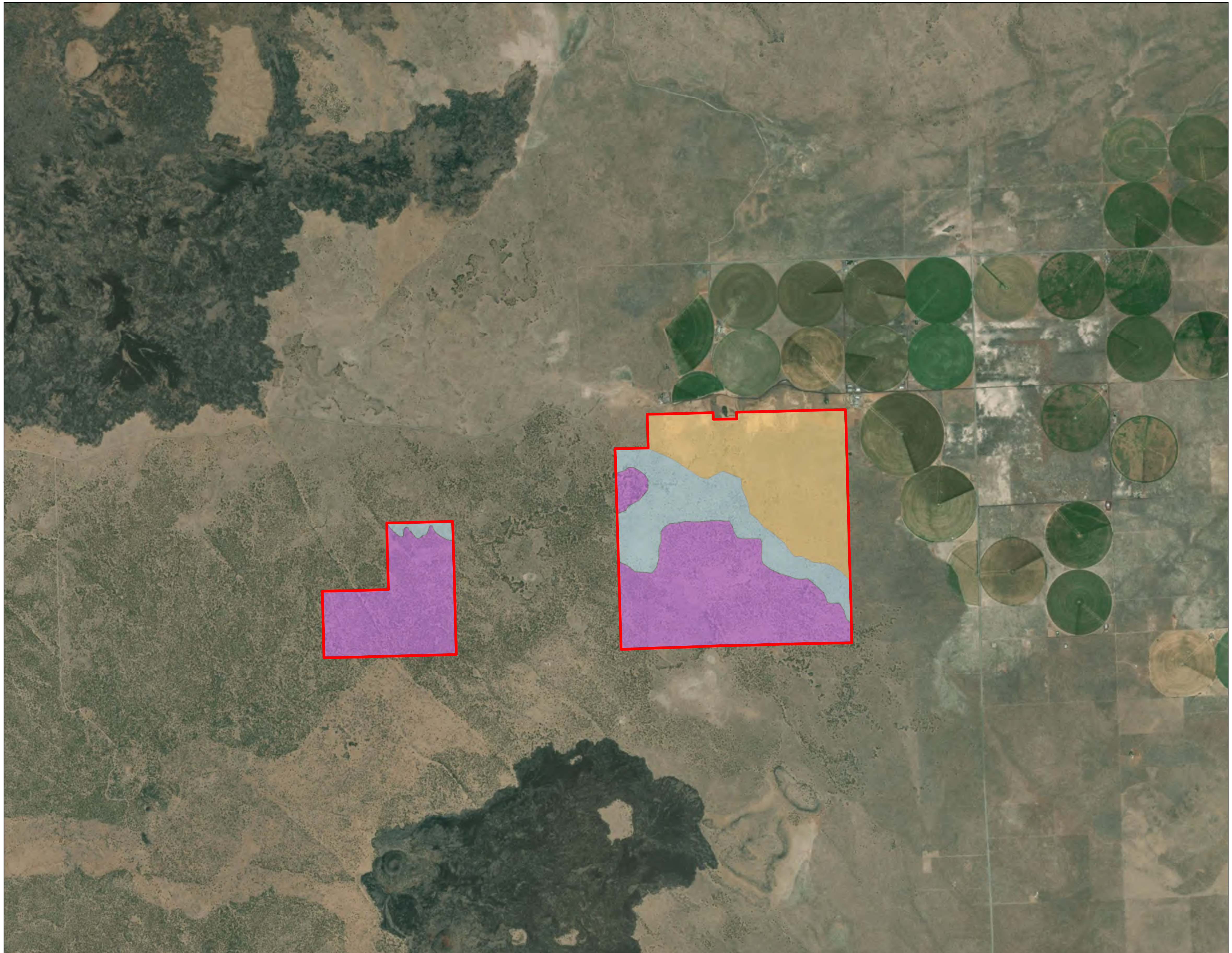

Stantec

Working Lands Improvement Program (WLIP) Area
Non-WLIP Area
Lava Bed
Quarry
Sagebrush Shrubland

Juniper Woodland Succession Phases

Phase 1 (Juniper Subordinate)
Phase 2 (Juniper and Shrubs Co-Dominant)
Phase 3 (Juniper Dominant)

Note: mapping based on desktop interpretation of aerial imagery

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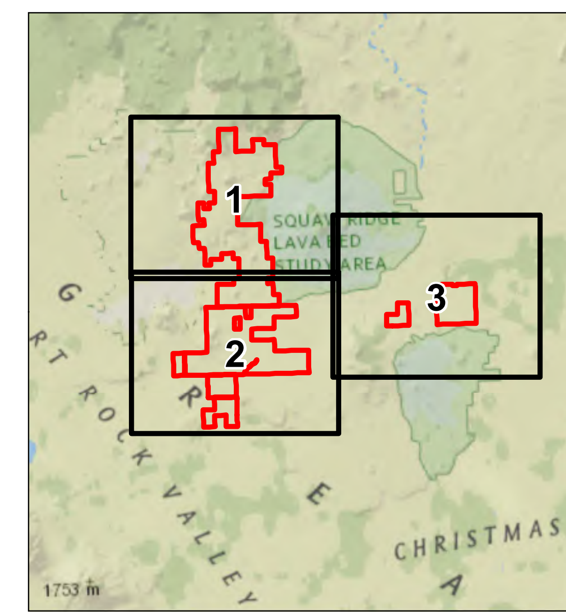


Project Location
Lake County, Oregon

Prepared by SNT on 2020-01-16
TR by DW on 2020-01-16

Client/Project
185704572 REVA

Obsidian Solar LLC
Obsidian Solar Center

Title
Preliminary Juniper Woodland Succession Phases

Attachment 3

Desktop Habitat Mapping Technical Memorandum

Stantec

Memo

To:	Michelle Slater and Laurie Hutchinson	From:	Ilja Nieuwenhuizen
	Obsidian Solar Center LLC		Stantec Consulting Services Inc
Reference:	Habitat Assessment of the Obsidian Solar Center Project Potential Mitigation Area	Date:	February 13, 2020

Introduction

Stantec Consulting Services Inc. (Stantec) prepared a desktop-based habitat assessment within approximately 6,534 acres of potential mitigation lands for the Obsidian Solar Center Project (proposed project). This includes all or portions of parcels in two general locations: 1) a northern area on Nine Peaks Ranch owned by Aaron and Rebecca Borror that consists of approximately 4,595 acres (Figure 1A), and 2) a southern area on the Morrison Ranch owned by Morrison Family Revocable Liv Trust that consists of approximately 1,939 acres (Figure 1B).[1] These two mitigation areas are within approximately 2 to 20 miles of the proposed project site. The proposed project site, the Nine Peaks Ranch, and the Morrison Ranch are all located within the Oregon Department of Fish and Wildlife (ODFW)-mapped elk (*Cervus canadensis*) winter range and mule deer (*Odocoileus hemionus*) winter range (referred to as ODFW Big Game Winter Range). The purpose of this habitat assessment is to help inform the suitability of these areas for mitigation, which includes removing western juniper (*Juniperus occidentalis*) trees as habitat mitigation for the proposed project.

Stantec used aerial imagery and general knowledge of the area obtained from past nearby field efforts to delineate and describe habitat types in the potential mitigation areas. Past field efforts include a habitat assessment performed on the proposed project in March and June of 2018 (Ecology and Environment 2018) and a pre-treatment western juniper inventory performed for a 15-acre parcel within the southern area in the potential mitigation area in December 2019 (Stantec 2019).

Stantec used a modified version of the dichotomous key developed for the proposed project's *2018 Habitat Assessment and Biological Resources Field Report* to delineate habitat types in the potential mitigation area (Ecology and Environment 2018). Ecology and Environment, Inc., integrated vegetation characteristics of the region with the Natural Vegetation Classification Standard, Version 2 (Federal Geographic Data Committee 2008) to create the dichotomous key (Ecology and Environment 2018).

Dichotomous Key to Determine Habitat Types

<u>Determining the Vegetation Stratum</u>

1a) Tree canopy cover >10%= Part A: Forest or Woodland, lead 4a

1b) Tree canopy cover <10%, lead 2a.

2a) Shrub canopy cover >10%= Part B: Shrubland, lead 5a.

[1] The GIS data show the mitigation area acreage as slightly larger than the tax lot acres. The GIS data show the Nine Acres Ranch mitigation area at approximately 4,595 acres and the Morrison Ranch mitigation area at approximately 1,939 acres, rather than 4,500 and 1,870 acres, respectively. Stantec disregards this minor acreage discrepancy for purposes of this analysis.

2b) Shrub canopy cover <10%, lead 3a

3a) Herbaceous cover >5%= Part C: Herbaceous Vegetation, lead 6a

3b) Herbaceous cover <5% = **Barren**

Identifying the Habitat Type

Part A: Forest or Woodland

4a) Tree canopy cover dominated by western juniper = **Juniper Woodland**

4b) Tree canopy cover not dominated by western juniper = **Non-juniper Woodland or Forest**

Part B: Shrubland

5a) Shrub cover includes robust sagebrush (*Artemisia* spp.) component = **Sagebrush Shrubland**

5b) Shrub cover does not include robust sagebrush component = **Non-sagebrush Shrubland**

Part C: Herbaceous Vegetation

6a) Graminoids predominantly native species = **Native Grassland**

6b) Graminoids predominantly non-native species = **Non-native Grassland**

Mapped Habitat Types

Stantec mapped the following habitat types in the potential mitigation area: juniper woodland, sagebrush shrubland, and non-native grassland (Figure 1). A quarry approximately 6 acres in size is in the southern mitigation area on the Morrison Ranch and constitutes a lack of habitat due to the absence of vegetation and the disturbed nature of the quarry (Figure 1B).

The text below describes each habitat type in the mitigation areas and their associated juniper succession phase(s), according to Miller et al. (2007). Attachment 1 to this memo describes and evaluates juniper succession phases of land previously evaluated for participation in Obsidian's Working Lands Improvement Program, including the mitigation areas on Nine Peaks Ranch and Morrison Ranch. For all habitat types, the percentage cover of vegetation within each stratum is expected to vary considerably depending on unique characteristics of each location, including aspect, hydrology, soils, and disturbances. The descriptions below are based on the desktop methods described above and will be field verified at a later date (except for the 15-acre parcel that was assessed in the field in December 2019).

Juniper Woodland (1,291 acres): Juniper woodland contains greater than 10 percent cover of western juniper. Western juniper trees and saplings likely range from ground level to about 30 feet tall in the mitigation area. The percentage of mature trees versus new sapling recruitment would vary depending on the location in the mitigation area.

Reference: Habitat Assessment of the Obsidian Solar Center Project Potential Mitigation Areas

In areas with dense juniper, the understory is expected to be minimal to bare. These areas would constitute phase 3 of juniper encroachment, which includes areas where tree canopy expansion is nearly stable, and the shrub layer is more than 75 percent dead or absent (see Attachment 1). Where juniper trees have a lower cover, the understory is expected to be dominated by a variety of shrub species, including big sagebrush (*Artemisia tridentata* ssp*. tridentata*), rubber rabbitbrush (*Ericameria nauseosa*), and yellow rabbitbrush (*Chrysothamnus viscidiflorus*). These areas would constitute phase 2 of juniper encroachment where the tree canopy is actively expanding, and the shrub layer has a varied cover ranging from intact to thinning (Attachment 1). The shrubs likely vary in height and would generally fall between 2 and 7 feet tall. Herbaceous species present may include perennial bunch grasses, including but not limited to crested wheatgrass (*Agropyron cristatum*), bottlebrush (*Elymus elymoides*), and fescues (*Festuca* spp.). Cheatgrass (*Bromus tectorum*), an invasive annual grass, are expected to occur throughout the habitat type at varying percent cover. Other shrub, grass, and forb species may also dominate the habitat type in the mitigation area.

Nine Peaks Ranch Mitigation Area: 330 acres of Juniper Woodland

Morrison Ranch Mitigation Area: 961 acres of Juniper Woodland

Sagebrush Shrubland (5,196 acres): Sagebrush shrubland contains less than 10 percent tree cover, or trees are absent in some areas, and greater than 10 percent shrub cover. Stantec expects that the shrub cover in the potential mitigation areas includes a robust sagebrush component, and we delineated all shrubland areas as sagebrush shrubland. A field-based assessment may determine that other shrubs are dominant in portions of this habitat type, in which case, these areas would need to be mapped as non-sagebrush shrubland.

Areas with no juniper trees present constitute no juniper encroachment, while areas with some juniper trees constitute phase 1 of juniper encroachment (Attachment 1). The shrub layer varies in percentage cover throughout the habitat type and is likely dominated by big sagebrush with rubber rabbitbrush and yellow rabbitbrush occurring to lesser extents. The shrubs likely range between 2 and 7 feet in height. Herbaceous cover also likely varies and may contain perennial bunch grasses, including crested wheatgrass, bottlebrush, and fescues. Cheatgrass is also expected to occur at varying degrees throughout the site. Other shrub, grass, and forb species may also dominate the habitat type in the mitigation area. Bare ground between shrubs is expected to be a major component in a portion of the habitat.

Nine Peaks Ranch Mitigation Area: 4,225 acres of Sagebrush Shrubland

Morrison Ranch Mitigation Area: 971 acres of Sagebrush Shrubland

Non-Native Grassland (41 acres): This habitat type occurs in an area where historical lava flows have resulted in a substrate dominated by coarse volcanic gravel and rock. From aerial imagery interpretation, it appears that shrub and tree cover are both less than 10 percent, making the habitat type herbaceous. Stantec expects that the herbaceous layer is dominated by non-native grasses, including cheatgrass. Non-native grassland does not correspond to a juniper encroachment phase since juniper trees are not expected to be present. All 41 acres of this habitat type occurs on the Nine Peaks Ranch.

Quarry (6 acres): This developed/disturbed area consists of an active rock quarry with little to no vegetation. All six acres of this developed area are on the Morrison Ranch.

Reference: Habitat Assessment of the Obsidian Solar Center Project Potential Mitigation Areas

Comparison of Mitigation and Project Habitat Types

The primary habitat type within the proposed project area is sagebrush shrubland, which is the most common habitat type in the mitigation areas. Based on incidental observations of nearby areas made during the western juniper field inventory of the 15-acre parcel conducted in December 2019 (Stantec 2019), as well as other incidental observations made in this area in the last several years, the sagebrush shrubland habitat in the mitigation areas is similar to the sagebrush shrubland habitat documented in the proposed project area in that it is likely dominated by big sagebrush, rubber rabbitbrush, and yellow rabbitbrush. Mitigation areas also likely have similar dominant herbaceous species to the proposed project area, primarily perennial bunch grasses invasive cheatgrass. The main difference between the mitigation and proposed project areas lies in western juniper cover. There are few western junipers in the proposed project area, while the mitigation areas contain some juniper woodland habitats and the sagebrush shrublands exhibit varying degrees of juniper encroachment. Most of the sagebrush shrubland habitats in the mitigation areas are undergoing some degree of western juniper encroachment or are under threat of encroachment; however, due to the apparent prevalence of big sagebrush and perennial bunch grasses in the understory in most juniper woodland habitats in the mitigation area, the historical habitat type in the mitigation area was likely sagebrush shrubland. Areas with juniper encroachment phases 1 and 2 would be good candidates for western juniper removal to restore to historical sagebrush shrubland conditions, based on the preliminary desktop analysis.

Stantec Consulting Services Inc.

Sarah Tona

Sarah Tona
Associate Biologist
Phone: 530 222 5347 x136
sarah.tona@stantec.com

Attachments: Figures
Preliminary Juniper Woodland Succession Phases – December 2019

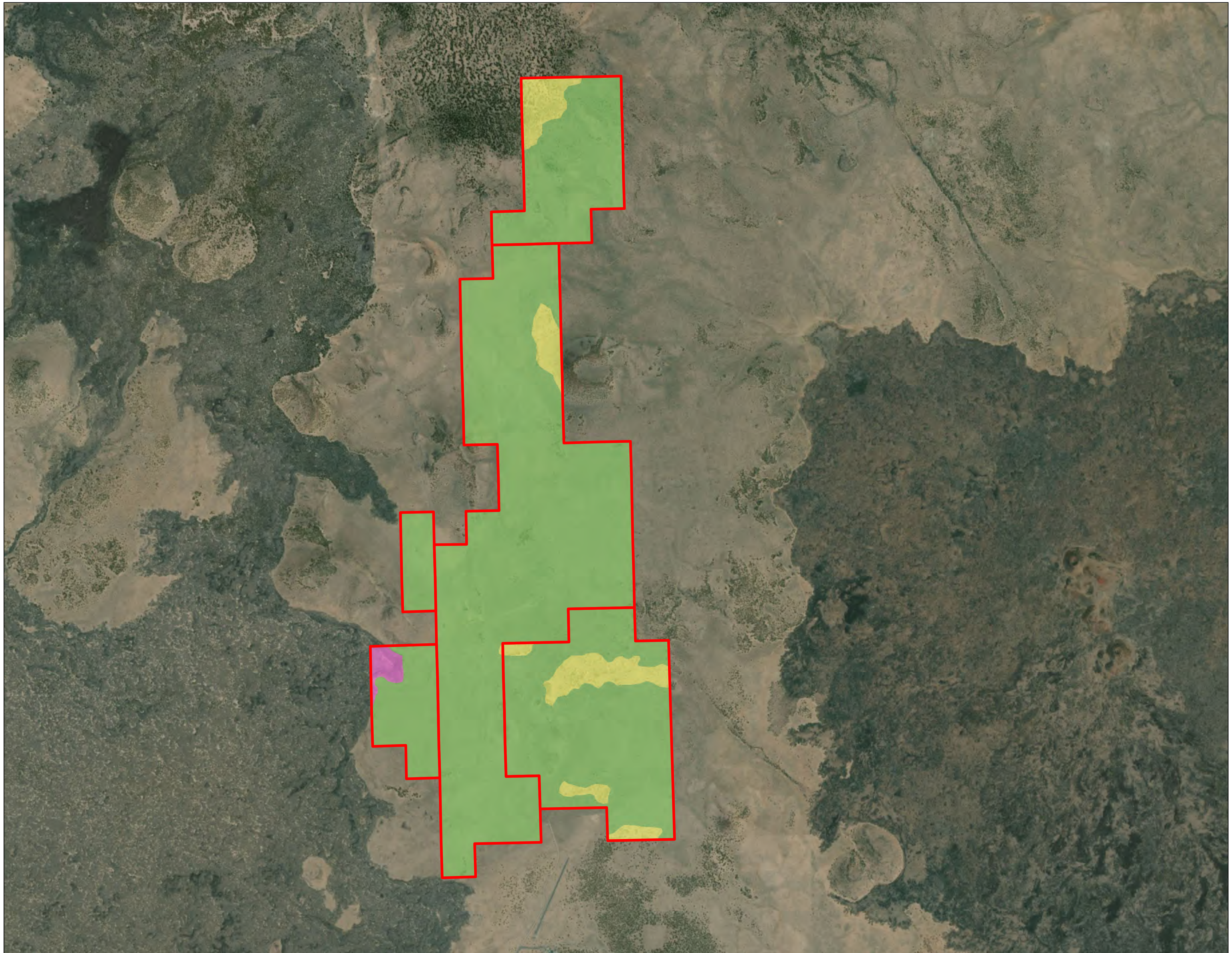
References

Ecology and Environment, Inc. 2018. *Obsidian Solar Center 2018 Habitat Assessment and Biological Resources Field Report. In Application for Site Certificate for Obsidian Solar Center*, October 2019, Exhibit P, Appendix P-1.

Federal Geographic Data Committee. 2008. Natural Vegetation Classification Standard, Version 2. FGDC-STD-005-2008. Federal Geographic Data Committee Secretariat. U.S. Geological Survey. Reston, Virginia. Available at: https://www.fgdc.gov/standards/projects/vegetation/NVCS_V2_FINAL_2008-02.pdf. Accessed: February 10, 2020.

Miller, R.F., J.D. Bates, T.J. Svejcar, F.B. Pierson, and L.E. Eddleman. 2007. Western Juniper Field Guide: Asking the Right Questions to Select Appropriate Management Actions: U.S. Geological Circular 1321, 61 p

Stantec Consulting Services Inc. (Stantec). 2019. Pre-Treatment Inventory for Western Juniper Mitigation. Unpublished technical memorandum prepared for Obsidian Solar Center LLC. December 2019.



Stantec

Mitigation Area
Quarry

Habitat Types

Juniper Woodland
Non-Native Grassland
Sagebrush Shrubland

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1 in = 4,000 feet

Notes
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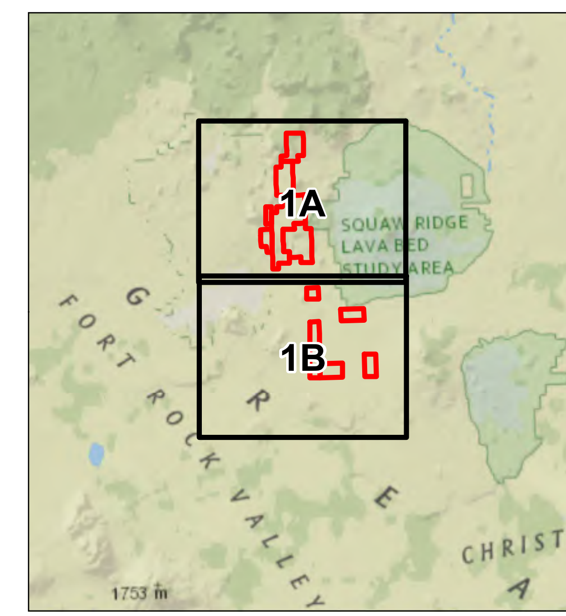
2. ESRI Digital Globe: 8/15/2017



Project Location
Lake County, Oregon

Prepared by SNT on 2020-02-10
TR by DW on 2020-02-11

Client/Project
185704572

Obsidian Solar LLC
Obsidian Solar Center

Title
Figure 1A. Habitat Types in the Mitigation Area on Borror Property

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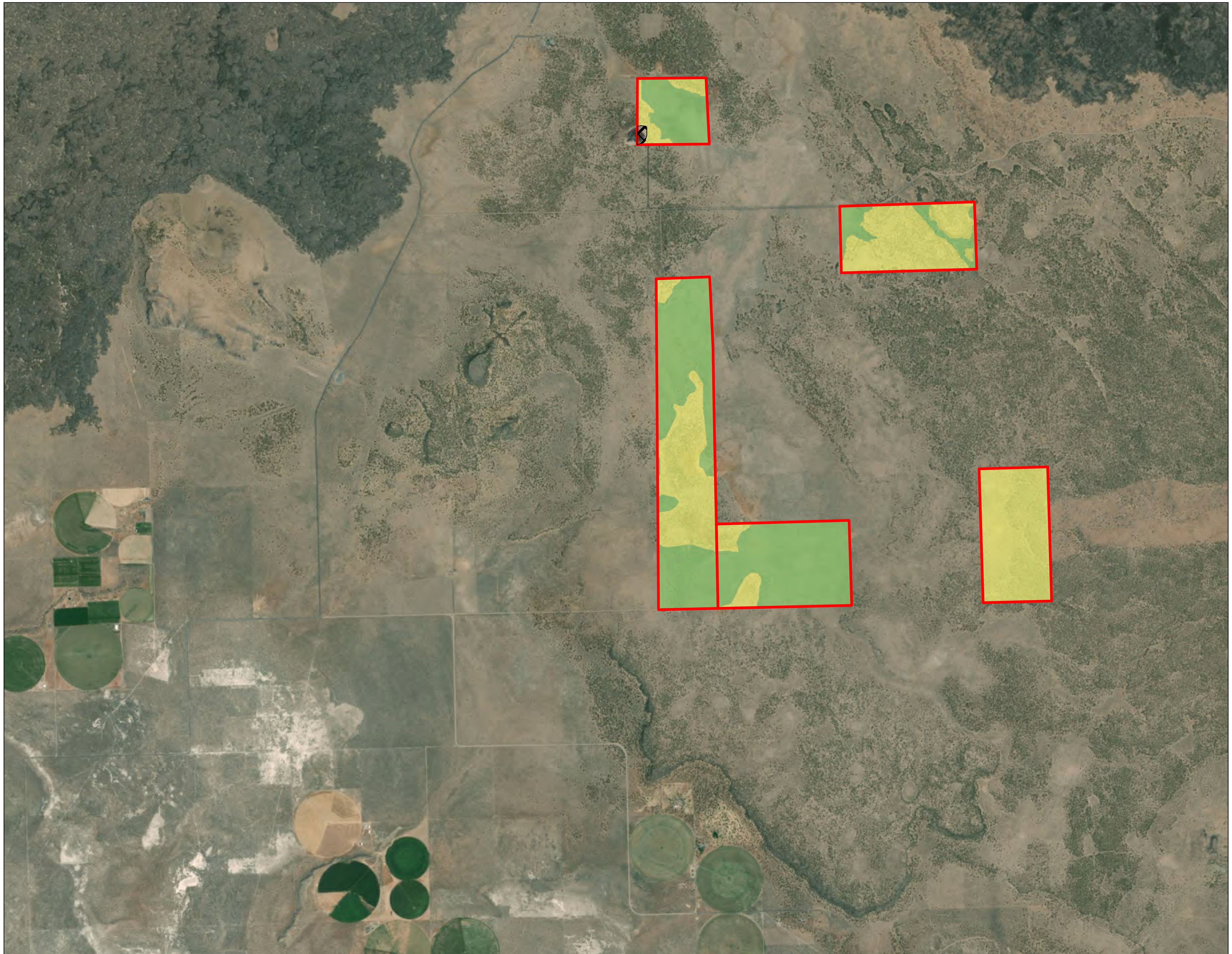

Stantec

Mitigation Area
Quarry

Habitat Types

Juniper Woodland
Non-Native Grassland
Sagebrush Shrubland

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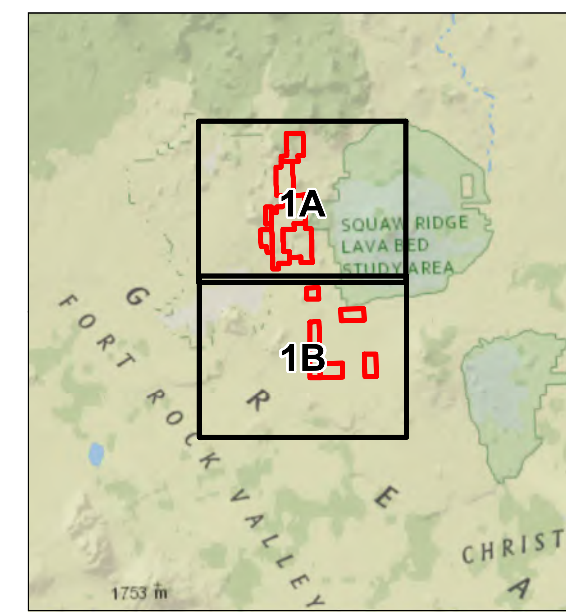

Project Location
Lake County, Oregon

Prepared by SNT on 2020-02-10
TR by DW on 2020-02-11

Client/Project
185704572

Obsidian Solar LLC
Obsidian Solar Center

Title

Figure 1B. Habitat Types in the Mitigation Area on Morrison Property

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Obsidian Solar Center

Wildlife Monitoring Plan

February 2020

Obsidian Solar Center LLC

5 Centerpointe Drive, Suite 250
Lake Oswego, Oregon 97035

TABLE OF CONTENTS

Acronyms and Abbreviations

Applicant	Obsidian Solar Center LLC
ASC	Application for Site Certificate
EFSC or the Council	Energy Facility Siting Council
Facility	Obsidian Solar Center
gen-tie	generation tie
ODFW	Oregon Department of Fish and Wildlife
ODOE	Oregon Department of Energy
PV	photovoltaic
USFWS	U.S. Fish and Wildlife Service
WMP	Wildlife Monitoring Plan

1.0 INTRODUCTION

This draft Wildlife Monitoring Plan ("WMP") describes how Obsidian Solar Center LLC ("Applicant") will avoid or reduce impacts on wildlife from the Obsidian Solar Center ("Facility") located in Lake County, Oregon. This WMP describes the avoidance and minimization measures Applicant undertook in Facility design, the best management practices Applicant will implement during pre-construction and construction, as well as the post-construction monitoring at the Facility.

2.0 AVOIDANCE AND MINIMIZATION MEASURES

Applicant avoided or minimized impacts on wildlife habitat by taking the following Facility siting actions, which reduce the initial development area under consideration from about 7,000 acres to the current design of less than 4,000 acres:

(a) Elimination of Area B from the site boundary (approximately 3,080 acres);

(b) Elimination of Area C from the site boundary (approximately 440 acres);

(c) Avoiding an active pygmy rabbit burrow complex totaling 0.36 acres; and

(d) Avoiding a 10.47-acre area of sagebrush shrubland, dune, and playa habitats that includes two active pygmy rabbit burrow complexes, which will provide connectivity between the complexes and to adjacent sagebrush shrubland habitats on federal lands.

With respect to pygmy rabbits, Applicant removed Area B from consideration for development due, in part, to the large amount of suitable pygmy rabbit habitat (i.e., sagebrush shrubland) within the parcel (refer to Exhibit B of the Application for Site Certificate ("ASC") for further discussion of the removal of Area B from development plans). Applicant will avoid construction in the areas of three active pygmy rabbit burrow complexes (refer to Section P.2.3 and Figure P-1 in Exhibit P of the ASC for burrow complex descriptions and locations). These avoidance areas, in combination with adjacent cultural avoidance areas and other avoidance areas, will maintain habitat connectivity between the two larger of the three burrow complexes. In addition, the smallest, easternmost burrow complex will be outside the eastern site boundary fence and the two larger complexes will be outside the northern site boundary fence and will be connected to sagebrush shrubland habitat outside of the site boundary.

3.0 PRE-CONSTRUCTION AND CONSTRUCTION MEASURES

General Best Management Practices

1. Applicant will conduct environmental awareness training for all Facility personnel and on-site contractors before they begin activities within the site boundary. The training program will discuss State Sensitive Species and other environmental issues related to the Facility, including information about pygmy rabbit identification and reporting procedures.

2. Applicant will clearly demarcate boundaries of environmentally sensitive areas to be avoided during construction to increase visibility to construction crews.

3. Applicant will impose and enforce a speed limit of 15 miles per hour within the site boundary during construction, operation, and retirement phases. In addition to dust control and health and safety benefits, this measure will reduce the risk of vehicle collisions with wildlife.

4. To the extent practicable, Applicant will conduct construction activities on the Facility during daylight hours. If nighttime work is necessary, personnel will shield night lighting downward.

5. Trenching and back-filling construction crews will work proximately to each other to the extent practicable to minimize the number of open trenches at any given time. Applicant will avoid leaving trenches open overnight to the extent practicable. Where trenches remain open overnight, construction crews will construct wildlife escape ramps approximately every 90 meters with slopes of less than 45 degrees. Trenches will be inspected, and any wildlife found removed prior to backfilling.

6. To the extent practicable, Applicant will minimize construction activities on the Facility between December 1 and March 1.

7. Facility personnel will practice good housekeeping. Waste will be disposed of in designated trash bins and removed from Facility work areas regularly.

8. Applicant will implement a *Revegetation and Noxious Weed Control Plan*, which includes measures for revegetating areas of soil disturbance, preventing topsoil loss, and controlling and minimizing the spread of non-native, invasive species and noxious weeds. Applicant will consult with Oregon Department of Fish and Wildlife ("ODFW") wildlife

staff and the Lake County Cooperative Weed Management Area staff in refining the list of plant species used to prevent noxious weed invasion.

Bird-Specific Best Management Practices

1. Applicant shall conduct pre-construction shrub and tree vegetation clearing activities in proposed construction areas prior to the nesting season for migratory birds, to the extent practicable. Vegetation clearing refers to removing trees, shrubs, and tall grasses to stubs, but leaving low grasses, roots, and soil intact until the onset of construction. Applicant will attempt to clear vegetation between September 1 and March 31 for shrubs and trees shorter than 15 feet, and September 1 to January 15 for trees over 15 feet tall. Clearing vegetation prior to the nesting season will discourage most birds from nesting. Applicant will remove vegetation only where necessary, retaining grasses and small plants, to the extent practicable. Applicant will discourage birds from nesting in slash piles by removing vegetation slash material off site to an approved location or chipping slash in place prior to March 31. These measures are consistent with the draft guidance document from U.S. Fish and Wildlife Service ("USFWS") titled *Avian Protection Terms and Conditions* provided to Applicant by USFWS.

2. Because construction activities will occur during the (non-raptor) migratory bird nesting season (April 1 to August 31), a qualified biologist will conduct pre-construction ground surveys for active nests. To the extent Applicant has a right of access, nest surveys for non-raptor species shall be conducted within 50 feet of all proposed disturbance areas, including the gen-tie transmission line and access roads. If the biologist detects active migratory bird nests during pre-construction surveys, Applicant will implement and maintain 30-foot disturbance buffers around the nests in which construction activities are prohibited until the nest has been abandoned/depredated or the eggs hatch and young have fledged. Applicant will consult ODFW for prior approval for exceptions to nest buffers.

3. Because construction activities will occur during the raptor nesting season (February 1 to August 31), a qualified biologist will conduct pre-construction raptor nest surveys within 0.5 mile of proposed Facility disturbance areas (to the extent Applicant has a right of access to such survey areas). Raptor nest surveys shall be conducted no more than two weeks prior to the start of construction activities. If the biologist detects active raptor nests, Applicant will implement and maintain disturbance buffers around the nests in which construction activities are prohibited until the nest has been abandoned/depredated or the eggs hatch and young have fledged. All raptor nests shall have a buffer of 0.25 mile except for golden eagle ([*Aquila chrysaetos*] 0.5 mile) and red-tailed hawk ([*Buteo jamaicensis*] 300 to 500 feet). In cases where smaller buffers or restricted work

authorizations might be appropriate, Applicant will coordinate with ODFW to decrease buffer sizes and/or to allow restricted construction activities. Facility vehicles will be permitted within buffers on public roads. Light traffic by rubber-tired vehicles will be permitted to pass through the buffer on unpaved access roads.

4.0 POST-CONSTRUCTION BIRD AND BAT MORTALITY MONITORING

Applicant will adhere to the following post-construction mortality monitoring and reporting protocols designed to provide information to ODFW regarding the estimated bird and bat fatality rates at the Facility during four seasons in the first year of operations:

- Monitoring Period. Post-construction monitoring will take place beginning after the commencement of operation of the Facility (or, if development in phases, after commencement of at least 200 megawatts alternating current of average generating capacity and will continue for a period of 12 months thereafter.

- Monitoring Frequency. Surveys will be conducted monthly on a statistically valid subset of the total site acres, which is estimated to be 500 acres.

- Distance Sampling. Post-construction monitoring at the Facility will involve standardized distance-sampling based carcass searches. The layout of a photovoltaic (“PV”) solar energy facility is well-suited to a distance sampling approach, which involves searching transect lines and assumes that searcher efficiency decreases as a function of distance from the observer but is ideally suited to situation in which animals (or carcasses) are sparsely distributed across a landscape (Buckland et al. 1993).

- Searcher Qualifications. Searchers will be trained to conduct carcass searches and will be familiar with and able to accurately identify bird and bat species likely to be found in the Facility area. Any unknown birds or bats or suspected state or Endangered Species Act-listed species discovered during carcass searches will be reported to a qualified biologist for positive identification.

- Data Collection. For each carcass found, the following data will be recorded:

    - Photos of the carcass and including a size-referencing object

    - Date and time

    - Initial species identification

    - Global Positioning System location

- Nearest Facility component (PV array, control house, storage unit, other)
- Distance of carcass to nearest PV panel
- Description of substrate/ground cover conditions
- Condition of specimen (alive, no sign of physical trauma, dead and intact, dismembered, feather spot) (at least two or more primary feathers, five or more tail feathers, or 10 or more feathers, injured)
- Carcass condition (fresh/dry, intact/scavenged)

Searchers will not collect or handle carcasses so neither state nor federal collecting/salvaging permits will be acquired for this study.

- Reporting. The monitor will record all observations of bird or bat mortalities along the survey rows and between rows. Applicant will provide a summary report to ODFW within two months of completion of the year-long (four-season) monitoring effort. Incidental observations of bird or bat mortalities (e.g., outside of the abovementioned standardized mortality monitoring efforts) will be documented for the first five years of operations and will be compiled and reported annually. Mortality observations of State Sensitive Species will be reported to ODFW within two weeks of the finding.

5.0 AMENDMENT

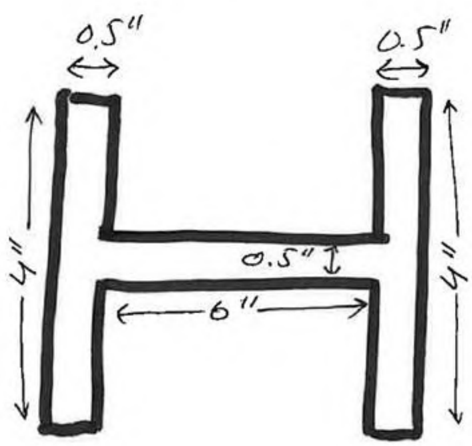
The WMP may be amended from time to time upon approval by Energy Facility Siting Council ("EFSC"), who may delegate its authority to review and authorize amendments to Oregon Department of Energy ("ODOE"). ODOE must notify EFSC of all amendments and EFSC retains the authority to approve, reject, or modify any amendments to this WMP agreed to by ODOE.

6.0 REFERENCES

Buckland, S.T., Anderson, D.R., Burnham, K.P. and Laake, J.L. 1993. *Distance Sampling: Estimating Abundance of Biological Populations*. Chapman and Hall, London. 446pp.

Obsidian Solar Center, 2/28/2020
Description of volume of fill for disturbed plays.

The calculations for volume of fill for each playa assume that the solar array racks will be supported by I-beam posts with an internal “web” that is 4 inches long and 0.5 inch thick, and two outside “flanges” that are each 4 inches long and 0.5 inch thick, resulting in a cross-sectional area of 6 inches^2 (0.04861foot^2). Applicant conservatively assumes that each I-beam post will be 11 feet long below the ordinary high water mark (OHWM) of each playas (i.e., inserted up to 8 feet deep into the ground, with 3 additional feet to account for all OHWMs, which are actually all 2 feet or less). Based on these dimensions, the fill volume of each post will be 0.0198 yards^3. Applicant further assumes that about 56 posts will be required per acre within the solar array. Therefore, volume of fill with in each playa is calculated by multiplying the playa acreage by 56, and then by 0.0198 yards^3. Note that Table J-1 accounts for upland inclusions within the playa mosaics; acreages for upland inclusions are not included in the volume of fill calculations. In addition, portions of playas that fall within project avoidance areas will not have posts or other facility components; therefore, they areas are not included in the volume of fill calculations.

<table>
<tr>
<td rowspan="3">

I-beam Cross Section</td>
<td>Cross Section Area:
0.5 inch X 6 + 2 X 0.5 inch X 4 = 6 inches^2
= 0.04861 feet^2</td>
</tr>
<tr>
<td>Volume per Post (assuming each post is 11 feet long):
0.04861 feet^2 X 11 = 0.53471 feet^3
= 0.0198047 yards^3</td>
</tr>
<tr>
<td>Volume per Playa Calculations (assuming there are 56 posts per acre):
Playa fill = Playa Acres X 0.0198047 yards^3 X 56</td>
</tr>
<tr>
<td colspan="2">Figure 1 Playa Fill Calculation Details</td>
</tr>
</table>

Obsidian Solar Center - Playa Fill Calculations

	Playa Acres	X 0.0198047 Yard^3	X 56 (number of posts/acre)	Comment*
Playa Barrens				
Playa-08	0.74	0.014655	0.82	
Playa-11	3.40	0.067336	3.77	
Playa-16	0.09	0.001782	0.10	
Playa Mosaics				
Playa-09	0.62	0.012279	0.69	
Playa-10	0.83	0.016438	0.92	
Playa-12	0.25	0.004951	0.28	
Playa-13	0.17	0.003367	0.19	
Playa-14	0.76	0.015052	0.84	
Playa-15	1.57	0.031093	1.74	
Playa-24	0.17	0.003367	0.19	
Playa-25	0.10	0.001980	0.11	
Playa-26	0.08	0.001584	0.09	
Playa-27	0.06	0.001188	0.07	
Playa-28	0.04	0.000792	0.04	
Playa-29	0.02	0.000396	0.02	
Playa-30	0.03	0.000594	0.03	
Playa-31	0.02	0.000396	0.02	
Playa-32	0.03	0.000594	0.03	
Playa-33	0.79	0.015646	0.88	
Playa-34	0.03	0.000594	0.03	
Playa-35	0.02	0.000396	0.02	
Playa-36	0.01	0.000198	0.01	
Playa-37	0.02	0.000396	0.02	
Playa-38	0.01	0.000198	0.01	
Playa-39*	0.12	0.002377	0.00	Playa falls within a project avoidance area (0.12 acres omitted from fill calculation)
Playa-40	0.12	0.002377	0.13	
Playa-41	0.07	0.001386	0.08	
Playa-42	0.04	0.000792	0.04	
Playa-43*	0.13	0.002575	0.01	Playa falls mostly within a project avoidance area (0.12 acres omitted from fill calculation)
Playa-44	0.09	0.001782	0.10	
Playa-45*	0.10	0.001980	0.11	A small part of playa falls within project avoidance area (0.01 acres omitted from fill calculation)
Playa-46	1.35	0.026736	1.50	
Playa-47	0.09	0.001782	0.10	
Playa-48	0.95	0.018814	1.05	
Playa-49	0.69	0.013665	0.77	


DSP


1 ft 2 3 4 5 6 7 8 9 10 11 12

From: HARRINGTON Bethany <bethany.harrington@state.or.us>
Sent: Friday, May 31, 2019 10:42 AM
To: Michelle Slater <mslater@obsidianrenewables.com>
Subject: RE: WD#2018-0581 Concurrence

Hi Michelle,
Thanks for reaching out. Yes, if the direct impacts are less than 50 cy of removal plus fill cumulatively, then no State permit is needed. If you want a letter stating that a State permit for this project is not required, please fill out a joint permit application and submit it to our Department. It is a 30-day turnaround. Also, please note that a Army Corps of Engineers permit may still be needed as they do not have the 50cy threshold for impacts.

Thank you,

Bethany Harrington
Aquatic Resource Coordinator
Oregon Department of State Lands
1645 NE Forbes Rd, Ste 112, Bend, OR 97702
Desk: 541-388-6142
Cell: 541-325-6171
bethany.harrington@state.or.us
www.oregonstatelands.us

Archaeological Investigations Northwest, Inc.

3510 N.E. 122nd Ave. • Portland, Oregon 97230
Phone (503) 761-6605 • Fax (503) 761-6620

Vancouver Phone (360) 696-7473
E-mail: ainw@ainw.com
Web: www.ainw.com

Obsidian Solar Center

Archeological Testing and Excavation Methodologies Plan

This Archeological Testing and Excavation Methodologies Plan document confirms the testing and excavation methodologies (Methodologies") agreed upon by Obsidian Solar Center LLC ("Obsidian") and the Oregon State Historic Preservation Office ("SHPO") to address archeological permits and mitigation for potential impacts to identified archaeological isolates and sites for the development of solar energy facility in northern Lake County, Oregon on approximately 3,900 acres ("Project").

RECITALS

1. The provisions below are based on currently available information from previous archaeological work associated with the Project.

2. The Klamath Tribes, Burns Paiute Tribe, and Confederated Tribes of Warm Springs have been contacted, and provided the opportunity to comment and participate in Project planning as it relates to tribal cultural interests.

3. The Methodologies treat the recorded archaeological sites and isolates as a district and focuses on Project-related impacts.

4. The Methodologies do not address instances if human remains, burials, sacred objects, or objects of cultural patrimony are encountered (ORS 97.740-760 items). In the event any are encountered at any time, all work must stop, the area must be protected, and the Inadvertent Discovery Plan (IDP) and Tribal Position Paper on the Treatment of Human Remains followed.

Methodologies

1. Archaeological Site Boundaries

Without a full horizontal and vertical understanding of previously recorded archaeological sites in the project area, Oregon SHPO and Obsidian agree to place a 30-meter (m) buffer around each site. The buffer will constitute the archaeological site boundary in terms of assessing Project-related effects. Any previously recorded isolate within a buffered site, will become part of the larger site. In such cases, the buffer will need to be extended out from the isolate. If an additional isolate is within the new buffer, the process will be repeated. Per SHPO Guidelines, testing may still be conducted to determine site boundaries if preferred to determine whether the 30-meter buffer may be removed.

In the event of discoveries that demonstrate a continuous distribution of artifacts (lacking gaps of at least 30 m) between two or more previously recorded archaeological sites, the sites will be combined into a single archaeological site. The site record forms will be revised and submitted to SHPO to document the new site boundaries. If the combined sites are classified in two different categories (High-Density versus Low-Density), then the original separate site areas will be treated according to their original classifications and the intervening newly identified site area will be treated in intermediate fashion. That is, archaeological excavation interval spacing will be 20 m for the original High-Density area, 40 m for the original Low-Density area, and 30 m for the intervening area. This applies to both construction trenching and construction (non-archaeological) excavation in Sections 4 and 5 below.

2. Definitions

Artifact Cluster	A high density of artifacts equivalent to 50 or more per square meter on the ground surface or 200 or more per cubic meter in archaeological excavations using ¼-inch screening or 800 or more per cubic meter in archaeological excavations using 1/8-inch screening.
Excavation	As used herein the term "Excavation" means the use of a backhoe, bulldozer, shovel, excavator, trencher or earthmoving equipment in order to install building foundations or concrete footers; but does not include pile driving, traversing the land, or material or equipment laydown.
Inadvertent Discovery Plan	The plan that that addresses protocols to be used if previously unidentified archaeological resources are found during construction. This document is attached to the Final Order on the Project Site Certificate issued by the Oregon Energy Facility Siting Council and implemented during Project construction.
Half Test Unit (HTU)	Archaeological excavation measuring 50 centimeters by one meter (rectangle)
High-Density Site	A site identified on Exhibit A as a high-density site, generally determined by developer's consultant to be potentially eligible or eligible for listing on the National Register of Historic Places.
Low-Density Site	A site identified on Exhibit A as a low-density site, generally determined by developer's consultant to be likely not eligible for listing on the National Register of Historic Places, an isolate that becomes a site after testing as prescribed in this Methodologies plan.
Monitoring Agreement	An agreement between developer and an interested tribe pursuant to which the tribe has the right to assign one or more cultural monitors to the Project.

Quarter Test Unit (QTU)	Archaeological excavation measuring 50 centimeters by 50 centimeters (square).
Shovel Probe (SP)	Archaeological excavation measuring 30 centimeters in diameter (round).
Test Unit (TU)	Archaeological excavation measuring one meter by one meter (square).
Trenching	Excavation for the purpose of creating trenches in which to place electrical cables connecting the solar panels, collector boxes, inverter skids, and transformers, as applicable.
Tribal Monitor	A person assigned to monitoring the Project under a monitoring agreement entered into between the applicable tribe and the developer or its designee.

3. Archaeological Testing at Isolates

A. Isolates with three or fewer artifacts will require no archaeological testing.

B. Locations where four to nine artifacts have been previously recorded as an isolate and that will be impacted by Project-related Excavation or Trenching will require archaeological investigation.

C. For the purposes of assessing Project effects, isolates that have previously been recorded as having from four to nine artifacts will include a 10 m buffer.

D. At each isolate location with four to nine artifacts that will be impacted by Project Excavation or Trenching (including buffer), a minimum of one 30-centimeter (cm) diameter shovel probe to be excavated, following SHPO Field Guidelines (minimum depth of 50 cm), and terminated after 20 cm of culturally sterile sediments. Sediments will be screened through either 1/4" or 1/8" wire mesh.

   a. If, after the shovel probes, the total number of artifacts at the isolate site is less than ten (including the original isolate total), and a feature is not encountered, no further archaeological work is necessary aside from any agreed upon project construction archaeological monitoring.
   b. If the total number of artifacts is eight or nine, for example, and consists of any combination of chipped stone debitage, tools, groundstone, fire cracked rock (e.g.,), suggesting more than one activity, the archaeologist may choose to excavate an additional probe(s), or decide based on professional opinion, that the isolate constitutes an archaeological site. The archaeologist should also consider whether excavation of a second probe, would produce additional artifacts resulting in a site.
   c. If the excavation of a probe(s) results in ten or more artifacts (including the original total) or a feature, the isolate will be recorded as an archaeological site (on a State of Oregon Archaeological Site Record) and will be treated as a low density site under this Agreement.

E. All archaeological sites recorded as a result of testing at isolates will require the placement of a 30-m buffer.

F. If previously recorded isolates (with a 10-meter diameter buffer) can be avoided by the project, there is no need to excavate any archaeological probes at those locations.

4. Trenching within a Recorded Archaeological Site

Any Trenching that will impact a recorded archaeological site (including 30-m buffer) will require archaeological investigation to assess if features, artifact concentrations, or potential ORS 97.740-760 items exist.

A. Trenching Impacts Buffer Only
   a. If the Trenching would impact only the buffer area and not the area within the existing site boundary, then shovel probes will be used to establish whether archaeological deposits are present within the proposed trench line.
   b. For Low-Density Sites, the shovel probe interval will be 40 m along the proposed trench line within the buffer area. For High-Density Sites, the shovel probe interval will be 20 m along the proposed trench line within the buffer area.
   c. If artifacts are identified in the shovel probes or on the ground surface during the shovel probe excavations, the site boundaries will be extended to include the identified artifacts and the methods described below will be used.

B. Trenching Impacts Low Density Site
   a. Any Trenching within the archaeological sites identified as low-density sites on <u>Exhibit A</u> will require excavation of 50x50 cm quarter test units ("QTUs") (adhering to SHPO Field Guidelines).
      A. The number of QTUs to be excavated at each of these "low density" sites will be calculated on the basis of QTU spacing at 40-m intervals (within the trenching corridor through the site, excluding the buffer). At least one QTU will be excavated. The archaeologist directing the fieldwork will be allowed to place the calculated number of QTUs at locations outside of the trench line or at irregular intervals along the trench line in order to sample locations judged to be most productive for site evaluation. The rationale for placement of QTUs will be included in the subsequent archaeological report.
      B. If as a result of QTU excavations at the "low density" sites, a feature or Artifact Cluster is encountered, the QTU will be expanded to a 0.5 x 1 m half test unit (HTU).

C. Trenching Impacts High-Density Site
   a. Any Trenching within the following archaeological sites identified as high-density sites on <u>Exhibit A</u> will involve excavation of 50x50 cm QTUs (adhering to SHPO Field Guidelines).
      A. One QTU per every 20 meters (rounding down as necessary) of the high-density site that will be trenched (e.g., if 100 m will be trenched, then five QTUs; if 33 m will be trenched, then one QTU).
      B. Additional QTUs may be necessary near or as an expansion to an excavated QTU, if a feature or Artifact Cluster is encountered.

b. Placement of QTUs will be at the discretion of the archaeologist in the field. Placement does not need to be within the area to be trenched, but wherever the archaeologist feels important information about the site can be obtained. The rationale for placement of QTUs will be included in the subsequent archaeological report.
c. If archaeological sites are avoided by project trenching, additional excavation is not necessary, aside from excavations that may need to be conducted with respect to monitoring and inadvertent discoveries.

D. Monitoring Trenching. All Trenching within recorded archaeological sites (including buffers) will be monitored by one or more tribal monitors. If during monitoring, a feature or Artifact Cluster is encountered, project work will stop and a QTU, HTU, or TU (depending on the size and configuration of the artifact cluster or feature) will be excavated within the feature or cluster (inside or outside the trench) according to SHPO Field Guidelines to collect information on the feature/cluster.
  a. Non-diagnostic isolated artifacts identified during monitoring will not require work stoppages.
  b. Diagnostic artifacts identified during monitoring may be collected and turned over to the Klamath Tribes for curation (except for those found on Department of State Lands property) or other appropriate treatment as the Tribes determine, at the discretion of the monitors and archaeological field director.

5. Testing at Project Related (non-archaeological) Excavation

Any Project related non-archaeological Excavation within a site will first require archaeological investigation.

A. Excavation Impacting Low-Density Sites. Any Project-related Excavation within a Low-Density Site will involve archaeological excavation of QTUs.
  a. The number of QTUs to be excavated at each impacted Low-Density Site will be determined by overlying a 40-m grid within the Excavation area, excluding the site buffer, and counting the number of grid line intersections that occur.
  b. If the Excavation area within the site is smaller than 40 m square, at least one QTU will be excavated.
  c. The archaeological field director will determine placement of the required number of QTUs in order to sample locations judged by her or him to be most productive for site evaluation. Locations outside of the Excavation area or irregular spacing may be used at the discretion of the archaeological field director. The rationale for placement of QTUs will be included in the subsequent archaeological report.
  d. Additional QTUs may be excavated at the discretion of the archaeologist.
  e. If as a result of QTU excavations, a feature or Artifact Cluster is encountered the QTU may be expanded to an HTU if needed to recover important information contained within the archaeological deposit.

B. Excavation Impacting High-Density Sites. Any Project-related Excavation within a High-Density Site will involve archaeological excavation of QTUs (adhering to SHPO Field Guidelines).
  a. The number of QTUs to be excavated at each impacted High-Density Site will be determined by overlying a 20-m grid within the Excavation area, excluding the site buffer, and counting the number of grid line intersections that occur.
  b. If the Excavation area within the site is smaller than 20 m square, at least one QTU will be excavated.

c. The archaeological field director will determine placement of the required number of QTUs in order to sample locations judged by her or him to be most productive for site evaluation. Locations outside of the Excavation area or irregular spacing may be used at the discretion of the archaeological field director. The rationale for placement of QTUs will be included in the subsequent archaeological report.
d. Additional QTUs, HTUs, or TUs may be excavated at the discretion of the archaeologist.
e. If as a result of QTU excavations, a feature or Artifact Cluster is encountered the QTU will be expanded to an HTU if needed to recover important information contained within the archaeological deposit.

C. All Project-related Excavation will be monitored by one or more tribal monitors will be available as a tribal archaeologist as needed.

6. Historical and Multicomponent Archaeological Sites

A. Historical archaeological sites (FRA H1, FRA-H2, FRA-H3, FRA-H4, FRA-H5, FRA-H6, FRA-H8, FRA-H10, FRA-H11, FRA-H12, and FRA-H13) that are impacted by Project-related Excavation will require additional archaeological investigations.

B. For multi component sites (historic and precontact assemblages, FRA-P/H1, FRA-P/H2, FRA-P/H3, FRA-P/H4, FRA-P/H5) impacted historical components will be addressed based on the information below, and precontact components based on the information in previous sections above.

C. For historical sites and components impacted by Project-related Excavation or Trenching, the following shall occur:
a. Direct sensing using a push rod at homesteads (FRA-H1, FRA-H3, FRA-H13, FRA-P/H3[P52/H7], FRA-P/H4[H9], and FRA-P/H5[H14]) to locate privies (with one QTU archaeological testing at any anomaly).
b. Additional background research to more fully establish historic context (e.g., review *The Oregon Desert* (E. R. Jackman and R. A Long 1965) for information on Loma Vista and like towns of the same time period.
c. More description of artifact types (e.g., barbed wire, vent hole cans (measurements), (if not in site forms).
d. Excavation of at least one QTU within root cellars or other subterranean structures.
e. Construction/building debris (such as brick, wood, window glass, etc.), that is non-diagnostic and redundant may be noted but not collected.

D. Following completion of the work described in this Section 6(A)-(C) for the historical and multicomponent archeological sites, no further mitigation or testing of these sites will be required prior to disturbance.

7. Artifact Analysis

Certain analyses on artifacts recovered during the above-mentioned testing and from previous surface recording will assist with understanding patterns of human land use in the Fort Rock Basin. Specifically, obsidian source characterization, obsidian hydration, and residue analyses on certain artifacts will provide data that can relate to travel or trade networks, temporal affiliation, and diet. The information obtained will also address a portion of mitigation requirements.

A. A total of 51 obsidian artifacts will be selected for source characterization and hydration analysis.

B. A total of 10 artifacts will be selected for residue analysis using the cross-over immunoelectrophoresis method.

C. The specific artifacts to sample for these analyses will be selected by an archaeologist in order to maximize the efficacy of the results for interpreting the significance of archaeological deposits studied according to this plan.

D. Representative samples of lithic tools and debitage recovered from the excavations described in this plan will be analyzed for information on lithic reduction technologies in order to characterize the stone tool manufacturing and use activities represented by these materials.

8. Reporting

Following completion of the Project, a supplemental report will be submitted to SHPO with any added background research, methods, analyses and results based on the information provided in this Methodologies plan.

9. Archaeological Permit

This Methodologies plan provides the research design to support issuance of the requested archeological permit for the Project. This Methodologies plan also provides all of the mitigation for impacts to archaeological resources planned for the Project. Once the archaeological treatments identified herein are completed, further consideration of cultural resources is not needed, with the exception of tribal monitoring during construction and barring discovery of human remains, burials, or funerary objects. The latter are further addressed in the Inadvertent Discovery Plan. If exceptionally important archaeological materials or deposits, unlike those found to-date, are identified, the project archaeologist will recommend additional consideration or mitigation. Exceptionally important archaeological materials or deposits might include a pre-contact house pit or intact storage feature, Pleistocene-age diagnostic artifacts, a biface cache, or other rare and unusual artifacts or features.

- The maximum number of shovel probes to be excavated under this permit is 500.
- The maximum area of square unit excavations (QTUs, HTUs, and TUs) is 100 square meters.
- Sediments from archaeological excavations will be screened through nested screens with mesh size of ¼ inch on top and ⅛ inch below.
- All archaeological excavations will be terminated after 20 centimeters of sterile (non-artifact bearing) deposits.
- Surface collections are not anticipated but will be made when artifacts are found that would contribute to the analyses identified in this plan.
- The private landowners plan to donate artifact collections to the Klamath Tribes.

Exhibit A

Low -Density Sites:

FRA-P3, FRA-P6, FRA-P7, FRA-P8, FRA-P9, FRA-P12, FRA-P14, FRA-P15, FRA-P16, FRA-P17, FRA-P18, FRA-P19, FRA-P20, FRA-P21, FRA-P 22, FRA-P 23, FRA-P 24, FRA-P 25, FRA-P 29, FRA-P 31, FRA-P 32, FRA-P 33, FRA-P 34, FRA-P 35, FRA-P 36, FRA-P 37, FRA-P 38, FRA-P 39, FRA-P 40, FRA-P-41, FRA-P42, FRA-P43, FRA-P44, FRA-P45, FRA-P46, FRA-P47, FRA-P50, FRA-P51, FRA-P54, FRA-P56, FRA-P58, FRA-P 62, FRA-P 63, FRA-P 64, FRA-P 65, FRA-P 66, FRA-P 67, FRA-P 69, FRA-P 70, FRA-P 72, FRA-P 74, FRA-P 75, FRA-P 76, FRA-P 77, FRA-P 80, FRA-P 81, FRA-P 83, FRA-P 84, FRA-P 85, FRA-P 87, FRA-P 89, FRA-P 93, FRA-P 95, FRA-P 96, FRA-P 97, FRA-P 98, FRA-P 99, FRA-P101, FRA-P102, and FRA-P/H2, including any former isolate that has been probed and documented as a site

High Density Sites:

FRA-P1, FRA-P2, FRA-P10, FRA-P11, FRA-P13, FRA-P26, FRA-P27, FRA-P28, FRA-P30, FRA-P48, FRA-P49, FRA-P53, FRA-P55, FRA-P57, FRA-P59, FRA-P60, FRA-P61, FRA-P68, FRA-P71, FRA-P73/90, FRA-P78, FRA-P79, FRA-P82, FRA-P86, FRA-P88, FRA-P91, FRA-P92, FRA-P94, FRA-P100, FRA-P/H1, FRA-P/H3, FRA-P/H4, and FRA-P/H5

Department of State Lands Archaeological Sites

Historic: H6, H8, H10
Low Density Precontact: P43, P46, P54, P56, P58, P62, P63, P65, P70, P72
High Density Precontact: P53, P59, P60, P71
Avoided under Klamath Tribes agreement: H1, P55, P57, P61, P64, P66, P67, P68, P69, PH3, PH4

Updated on 2/12/2020, using Lake County tax information provided on http://apps.lanecounty.org/PropertyAssessmentTaxationSearch/lake

Map and Tax Lot	Owner Name	Owner Address	City	State	ZIP	Intersects Parcel with a Facility Component, or only with 500 feet of Parcels with a Facility Component?
26S15E000000502	DINSDALE SAMUEL C & ALICE J	57673 FORT ROCK ROAD	SILVER LAKE	OR	97638	500-foot Buffer only
26S15E000000503	U S A	TOM VIBBER, ND #DO5.32 700 W MINERAL AVENUE	LITTLETON	CO	80120	500-foot Buffer only
26S15E000001700	DINSDALE SAMUEL C & ALICE J	57673 FORT ROCK ROAD	SILVER LAKE	OR	97638	500-foot Buffer only
26S15E000001800	DINSDALE SAMUEL C & ALICE J	57673 FORT ROCK ROAD	SILVER LAKE	OR	97638	Facility & Gen-tie
26S15E000001900	LA FRANCHI RON	580 N CENTRAL	COQUILLE	OR	97423	500-foot Buffer only
26S15E000001900 (1)	TIAHRT THEODORE R & JOYCE M	C/O - RON LAFRANCHI 580 NORTH CENTRAL	COQUILLE	OR	97423	N/A
26S15E000003000	LA FRANCHI RON	580 N CENTRAL	COQUILLE	OR	97423	500-foot Buffer only
26S15E000003200	FINE TROY D & ROBERTA K	83394 CONNLEY LANE	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000001100	RUNELS SCOTT L & MARGIE B	PO BOX 39	FORT ROCK	OR	97735	500-foot Buffer only
26S16E000001800	KITTREDGE DORIS H	GENERAL DELIVERY	FORT ROCK	OR	97735	500-foot Buffer only
26S16E000001801	STEVENSON JOHN B & JOYCE	P O BOX 437	CHRISTMAS VALLEY	OR	97641	500-foot Buffer only
26S16E000001900	FINE HAROLD L & JUDY E	83391 CONNLEY LN	SILVER LAKE	OR	97638	Facility
26S16E000002400	FINE HAROLD L & JUDY E	83391 CONNLEY LN.	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000002500	O'LEARY JOHN K	PO BOX 7232	BEND	OR	97708	500-foot Buffer only
26S16E000002600	FORT ROCK HAY RANCH, LLC	5801 SE BANSEN LANE	DAYTON	OR	97114	500-foot Buffer only
26S16E000002700	COIT FAMILY TRUST	2578 S LYON AVE	MENDOTA	CA	93640	Facility
26S16E000002701	HORTON LEE ROY & NANCY B	PO BOX 784	CHRISTMAS VALLEY	OR	97641	500-foot Buffer only
26S16E000002702	MOREHOUSE RICHARD & VIRGINIA	80429 CONNLEY LN	SILVER LAKE	OR	97638	Facility
26S16E000002705	HORTON TRUST	PO BOX 784	CHRISTMAS VALLEY	OR	97641	500-foot Buffer only
26S16E000002707	RUNELS SCOTT L & MARGIE B	PO BOX 39	FORT ROCK	OR	97735	500-foot Buffer only
26S16E000002708	MOREHOUSE RICHARD & VIRGINIA	80429 CONNLEY LN	SILVER LAKE	OR	97638	Facility
26S16E000002800	U S A	TOM VIBBER, ND #DO5.32 700 W MINERAL AVENUE	LITTLETON	CO	80120	500-foot Buffer only
26S16E000003300	RUNELS SCOTT L & MARGIE B	PO BOX 39	FORT ROCK	OR	97735	500-foot Buffer only
26S16E000003400	MAUNEY DENNIS & PAMELA	PO BOX 1031	FERNDALE	CA	95536	500-foot Buffer only
26S16E000004200	HOGAN DAVID L & RITA F	2614 1ST STR	TILLAMOOK	OR	97141	500-foot Buffer only
26S16E000004400	HOGAN DAVID L & RITA F	2614 1ST STR	TILLAMOOK	OR	97141	500-foot Buffer only
26S16E000004400 (1)	KRABILL LUCAS ALAN & KATHERINE ELIZABETH	PO BOX 792	CHRISTMAS VALLEY	OR	97641	N/A
26S16E000004500	HOGAN DAVID L & RITA F	2614 1ST STR	TILLAMOOK	OR	97141	500-foot Buffer only
26S16E000004600	STATE OF OREGON DEPT OF STATE LANDS	775 SUMMER ST NE STE 100	SALEM	OR	97301	Facility
26S16E000004700	FINE HAROLD L & JUDY E	83391 CONNLEY LN	SILVER LAKE	OR	97638	Gen-tie
26S16E000005300	FINE HAROLD L & JUDY	83391 CONNLEY LN	SILVER LAKE	OR	97638	Gen-tie
26S16E000005400	FINE HAROLD L & JUDY E	83391 CONNLEY LN	SILVER LAKE	OR	97638	Gen-tie
26S16E000005500	FORMAN SHANE & JACEY	83136 CONNLEY LANE	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000005500 (1)	FORMAN SHANE LOUIS	83136 CONNLEY LANE	SILVER LAKE	OR	97638	N/A
26S16E000005601	FORMAN SHANE & JACEY	83136 CONNLEY LANE	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000005700	FINE TROY D & ROBERTA K	83394 CONNLEY LANE	SILVER LAKE	OR	97638	Gen-tie
26S16E000005800	G & J HANSON FARMS LLC	PO BOX 69	FORT ROCK	OR	97735	500-foot Buffer only
26S16E000005900	FORMAN SHANE & JACEY	83136 CONNLEY LANE	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000006000	HORTON FAMILY TRUST 1/25/2002	PO BOX 784	CHRISTMAS VALLEY	OR	97641	500-foot Buffer only
26S16E000006200	HOGAN DAVID L & RITA F	2614 FIRST STREET	TILLAMOOK	OR	97141	500-foot Buffer only
26S16E000006300	HOGAN DAVID L & RITA F	2614 FIRST STREET	TILLAMOOK	OR	97141	500-foot Buffer only
26S16E000006400	HOGAN DAVID L & RITA F	2614 FIRST STREET	TILLAMOOK	OR	97141	500-foot Buffer only
26S16E000002300	USA	TOM VIBBER, ND #DO5.32 700 W MINERAL AVENUE	LITTLETON	CO	80120	500-foot Buffer only
26S16E000004800	FINE HAROLD L & JUDY	83391 CONNLEY LN	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000005200	FINE HAROLD L & JUDY	83391 CONNLEY LN	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000005100	FINE HAROLD L & JUDY	83391 CONNLEY LN	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000005000	FINE HAROLD L & JUDY	83391 CONNLEY LN	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000005600	FORMAN SHANE & JACEY	83136 CONNLEY LANE	SILVER LAKE	OR	97638	500-foot Buffer only
26S16E000005701	FORMAN FAMILY TRUST	83386 CONNLEY LN	SILVER LAKE	OR	97638	500-foot Buffer only

Notes:

(1) The Lake County Assessor's Office provided duplicate records for the indicated tax lots. Based on discussion with Walt Lawton, Chief Appraiser with Lake County, Oregon, these properties include parcels for mobile home inclusions on a portion of the property. None of these mobile homes are within the 500-foot boundary. Regardless, Obsidian will send notification letters to all properties listed in table.

TARDAEWETHER Kellen * ODOE

From:	Michelle Slater <mslater@obsidianrenewables.com>
Sent:	Thursday, March 5, 2020 12:59 PM
To:	TARDAEWETHER Kellen * ODOE
Cc:	ElaineAlbrich@dwt.com; David Brown; WOODS Maxwell * ODOE; ESTERSON Sarah * ODOE
Subject:	Exhibit W, Table W-1 (Revised); Decommissioning
Attachments:	Exhibit W Table - Decommissioning 3.4.2020.xlsx

Kellen,

Exhibit W RAI

On February 5, 2020, ODOE sent us an RAI regarding Exhibit W, with this explanation:

"we have many questions regarding the assumptions/explanations for how Obsidian arrived at the retirement costs in ASC Exhibit W, Table W-1. Our DOJ believes these, and the other information requests, are necessary information to be able to support the Council's Retirement and Financial Assurance, and other Council standards."

REVISED TABLE W-1

Applicant subsequently revised and re-submitted Table W-1, but questions remained, and Applicant and ODOE discussed those in some detail last Thursday. I have sharpened my pencil, enlisted many helping hands, and added significant detail to the Table in an effort to be fully responsive and provide ODOE with sufficient information to support a finding of compliance with the Council's Retirement and Financial Assurance Standard. You will note that Applicant has not included a cost for well abandonment, and would like to remove that action from the description of decommissioning in Exhibit W. The wells will remain in use, most likely for exempt or agricultural purposes. Additionally, although included in the decommissioning estimates, the perimeter fence, the internal roads, and perhaps even some structures, would likely remain in use as these improvements could have multiple uses, including future agricultural uses following decommissioning.

SALVAGE AND SCRAP VALUE

The new total projected restoration cost in the Table is $23,955.377] million. Applicant believes this cost would be decreased by as much as 35% taking into account the value of salvage and scrap. ODOE has received a significant amount of evidence and information from other recent applicants, for example Avangrid pertaining to Bakeoven Solar Project, to support the argument that scrap value should be considered in determining the amount of required decommissioning security. Rather than collect additional and likely redundant evidence to be disregarded, Applicant asks that ODOE take note of the evidence submitted by Avangrid and consider it in its evaluation of the ASC. Applicant will submit independent evidence of salvage and scrap value at a later date to be considered with a request to amend the bond amount.

ADDITIONAL PERCENTAGES

Like Avangrid, Obsidian does not think that ODOE's typical add-on of 10% for project management and administration and another 10-20% for future uncertainty can be defended, nor are they necessary. The decommissioning costs already include full on-site management of the decommissioning project. If ODOE were to be in the position somehow of needing to take on the job of decommissioning a project, how could there be such a significant and expensive management role for ODOE if it has selected an appropriate contractor? With respect to future uncertainty, we would submit that there is far greater certainty that, once built, the project will operated for the duration of the applicable power purchase agreement, and then repurposed or repowered in some manner as to continue to generate revenue and utilize the step up substation and interconnection infrastructure. Portland General Electric will have built its own step-up substation for the project as well, which it would not simply abandon or decommission. The underlying real estate will be largely privately owned, and the landowner will have certain remedies in the event the facility is "abandoned", as would Lake County (in the event of a failure to pay taxes, for example). ODOE takes into account future uncertainty about regulatory or legal constraints that may impact the cost of decommissioning but does not take into account how very remote and unlikely is the scenario where ODOE would even be at risk. At the very least, Applicant submits that no contingency or management add-on is appropriate after the facility reaches COD and until there is no longer a power purchase agreement in place, absent some evidence during operation of financial instability of the owner/operator.

<u>POLICY</u>
As we have discussed and represented many times, we think it is poor policy to think that a utility scale solar facility site would ever be decommissioned completely at the end of its expected useful life. It seems extremely unlikely that such destruction would ever be the right decision at the end of a facility's useful life when that site would be the best candidate for the next utility scale solar farm, given that the very expensive infrastructure for interconnection (for example) would still remain in place. It is also hard to imagine that in 40 years we will have no further need for solar sites. Coal plants are shutting down; we are not going to be done with solar. To repurpose or repower an aged solar facility on the same site at the end of its useful life – using the existing components and infrastructure to a great extent – is good wildlife policy, good land management policy, good agricultural policy, and good economic policy. The exercise of predicting complete decommissioning, assigning gross costs to each act involved, and then burdening the project with that cost promotes a strange fiction that is divorced from reality. This needs to be reconsidered.

<u>FINANCIAL ASSURANCE</u>
As we separately discussed, the financial assurance that we provided in our ASC is a letter from Heffernan Insurance, which Applicant understands is not evidence ODOE typically receives as part of Exhibit W. ODOE reported that, more typically, an applicant submits a letter from a financial institution of some sort. Obsidian Solar Center is a small developer with finite capital. The financial assurance evidence included in the ASC is sufficient to demonstrate that Obsidian "has a reasonable likelihood" of obtaining any required decommissioning financial security. The standard does not require more than a showing of "reasonable likelihood." Further, as discussed on the phone, as the project moves into pre-construction, Obsidian will be bringing in a financial partner, which will further ensure Obsidian's ability to obtain the required decommissioning financial security.

<u>SITE CERTIFICATE CONDITIONS</u>
Consistent with the approach proposed by Avangrid in its February 25, 2020 comments to the Bakeoven Solar Draft Proposed Order, Obsidian also proposes that a condition 5b (page 133) from those comments be incorporated into the Obsidian Solar Center Draft Proposed Order. Applicant will provide further comments and condition language in its comments to the DPO.

Thank you for your consideration,

Michelle

SUPPLEMENT TO EXHIBIT W – Application for Site Certificate

FACILITY RETIREMENT
OAR 345-021-0010(1)(w)

To issue a site certificate, OAR 345-022-0050(1) requires the Council to find that the site of the proposed facility, "taking into account mitigation, can be restored adequately to a useful, non-hazardous condition following permanent cessation of construction or operation of the facility."

Certain mandatory conditions will be set forth in the site certificate in accordance with OAR 345-025-0006. Applicant includes in this Supplement to Exhibit W and seeks approval of proposals for satisfying those conditions as follows:

Mandatory Condition:

(8) "Before beginning construction of the facility, the certificate holder must submit to the State of Oregon, through the Council, a bond or letter of credit in a form and amount satisfactory to the Council to restore the site to a useful, non-hazardous condition. The certificate holder must maintain a bond or letter of credit in effect at all times until the facility has been retired. The Council may specify different amounts for the bond or letter of credit during construction and during operation of the facility."

Mandatory Condition:

(9) The certificate holder must retire the facility if the certificate holder permanently ceases construction or operation of the facility. The certificate holder must retire the facility according to a final retirement plan approved by the Council, as described in OAR 345-027-0410. The certificate holder must pay the actual cost to restore the site to a useful, non-hazardous condition at the time of retirement, notwithstanding the Council's approval in the site certificate of an estimated amount required to restore the site.

Proposed Approach:

1. Certificate holder will provide a bond or letter of credit in an amount equal to the sum of (a) $23,955,000, that being the total decommissioning cost set forth on Revised Table W-1 attached hereto, plus (b) $718,661, that being 3 percent of the total decommissioning cost and attributable to a project management/administration charge for the Oregon Department of Energy, plus (c) $718,661, that being 3 percent of the total decommissioning cost, for a future development contingency; for a total of $25,392,699.

Support:

It is more typical for the Council to add 10 percent to the Applicant's decommissioning cost estimate for ODOE project management and administration, and another 10 percent or up to 20 percent for the future development contingency. However, Applicant maintains that 3 percent for each add-on provides the Council with adequate cushion should it ever be in the unlikely position of overseeing facility decommissioning. Applicant provides the following reasons.

ODOE's role in overseeing facility decommissioning would entail converting Table W-1 into a scope of work for bids, identifying and retaining one or more contractors, legal review and costs associated with contracting, reviewing progress reports on decommissioning and relaying information to Lake County and one underlying landowner (the Department of State Lands) with whom Applicant has a land use (all other land is owned fee title by an affiliate of Applicant). Actual on the ground, day-to-day project management and administration, including permitting for the decommissioning activities, would be conducted by the decommissioning contractor and there is already a 3 percent add-on in the decommissioning amount for that management work. There is no evidence that ODOE will incur more costs for managing decommissioning than will the contractor actually overseeing the work. There is only evidence that EFSC has a 10 percent project management mark-up in the past, but no evidence that EFSC has ever needed or used that financial cushion. In fact, there is no evidence of an EFSC project being abandoned in the history of EFSC projects.

With respect to future development contingency, Applicant has included a 3 percent future development contingency in its decommissioning estimate. In addition to that, Applicant proposes that the Council add another 3 percent future development contingency. This would bring the total financial cushion to account for future uncertainties to $1,437,323 (over and above the add-on for project administration and management). The intention of this future contingency add-on is to provide for the potential for regulatory and environmental changes and changes in costs at a rate that exceeds the standard inflation adjustment. Rather than adjust this amount annually during the life of the project, when there is a PPA in place and little risk of actual decommissioning, Applicant proposes that the Council approve annual adjustments to the amount(s) beginning closer to when the project might actually be decommissioned. Specifically:

<u>Construction to COD:</u>

From the beginning of construction to the date of commencement of operations (COD), there is very little risk of changes that would severely impact that accuracy of the cost estimates, particularly because construction is required to be completed within the relatively short time frame set forth in the site certificate. For this period, Applicant proposes to provide financial security in the full amount of $25,3933,000.

<u>COD to 3 Years Left in PPA</u>

Once the facility has reach COD, Applicant proposes to reduce the amount of the bond or letter of credit to $1.00 and maintain it at that level until the year(s) that is three years prior to the expiration of the facility's power purchase agreement(s) (PPA). During the fourth year before the expiration of the PPA, certificate holder would update the estimates reflected in Table W-1 based on current data and information and use that revised amount, with the approval of ODOE, for the financial security for the remaining life of the facility. For example, if the facility reaches COD in 2024 and has a 20 year PPA beginning in 2024, the financial security required for years 2024 through 2041 would be $1.00 and the required financial security beginning in 2042 would be the newly calculated decommissioning total determined in year 2040.

While there is a PPA in place for the facility, the facility will not be decommissioned. Applicant provides in Attachment 1 several PPAs to illustrate the terms, conditions, contingencies, and obligations of the PPA, which all ensure that the facility will remain in operation during the term of the PPA. In the event that certificate holder were to become unable to fulfill its future obligation to complete facility decommissioning and it became apparent while the PPA was still in place, the counterparty to the PPA would have rights and remedies to assume operation of the facility and with that, assume the liability of decommissioning (e.g., the counterparty or another third party would take over ownership of the facility from the certificate holder and the obligations of the certificate holder under the site certificate would be transferred to a financial stable party.) In most cases, in addition to other remedies, the PPA requires the facility owner to provide financial security tied to the successful development and operation of the facility. This includes development security, to allow the power purchaser to recover costs if the facility is not built or COD is delayed, as well as operation security, which allows the power purchaser to purchase energy elsewhere if the project fails to deliver it. Both the offtaker and the project owner are highly incentivized to keep the project viable and operating, and to ensure that the operator of the project is financially stable. While the PPA is in place, the Department's risks relative to decommissioning are extremely low.

Recalculation and Adjustment 4 Years Prior to End of PPA

By recalculating the bond or letter of credit amount 4 years prior to the end of the PPA, better information on current costs and decommissioning practices will be available and can be used to more accurately predict what the Department should require for financial assurance. At the time of this adjustment, certificate holder will have access to updated labor costs, permitting needs in light of then-current environmental requirements, advances in technology for recycling or repurposing component parts of solar photovoltaic facilities, possible precedent in the event additional utility scale solar facilities have actually been decommissioned. Rather than burden the project with the cost of a very expensive bond, plus a 10 to 20 percent add on for the unknown, for every year of facility operation in order to address a very remote risk, it is far better policy and allocation of resources to take a more comprehensive view of the market conditions and realities at the time construction begins, during operation of the facility under a PPA, and toward the end of the contractual term of the PPA.

Consideration of Scrap Value

Applicant proposes that, at the time of recalculation and adjustment 4 years prior to the end of the PPA term, the Council permit inclusion of projected scrap value in the decommissioning estimate. As explained in the attached report (Attachment 2) prepared by Resources for the Future in October

2017, Decommissioning US Power Plants: *Decision, Costs and Key Issues* (Daniel Raimi), "decommissioning costs for solar PV projects are substantially affected by the potential recycle or sell equipment and scrap metal." Page 36. In fact, as shown on Table 9 on Page 36 of that report, in some cases taking into account the potential to recycle or sell equipment or scrap from the project can cause the net cost of the decommissioning to be negative (projects such as Apple One in North Carolina decommissioned for ($88,076) per megawatt where scrap and recycling value is considered; compared to a similarly-sized project in California where scrap was not considered and the per-megawatt cost reflected on Table 9 is $73,333 per megawatt). See also, Table 1 on page 3, showing that (in 2016 dollars), for solar PV salvage value of plant materials can exceed decommissioning costs. There is risk that over optimistic assumptions about recycling and resale value could lead to inadequate financial preparation for decommissioning.

For this reason, applicant does not suggest that scrap value be considered in determining the financial security amount for the period between the start of construction and COD. Rather, applicant seeks approval to include scrap value (e.g., recycling, resale of equipment, salvage and scrap value, as applicable) for the adjustment performed 4 years prior to the end of the PPA, when it is significantly closer in time to the end of the projected useful life of the facility and therefore more accurate information on net costs should be available. There is significant information available demonstrating that facility components will continue to have significant value at the end of the projected useful life. See, for example, the analysis contained in the Memorandum dated February 21, 2020, prepared by Tetra Tech in connection with the Bakeoven Solar Project (Attachment 3), concluding that the market for scrap is "mature and established" and suggesting that it is likely that a salvage market (e.g., a market for the re-sale of solar modules that are still more than 80 percent efficient at the end of the project's lifespan) will develop.

Table W-1, Revised March 9, 2020

Obsidian Solar Center - Decommissioning Estimates Cost Estimate Component	Quantity	Unit	Per Unit Cost	Cost Estimate	Assumption
SWPPP & Dust Control Measures					
Stabilized Construction Entrances	1	Each	$ 3,287	$ 3,287	
Perimter Silt Fencing	95,040	Linear Ft	$ 0.74	$ 70,330	
Spill Kits (Emergency Equipment Cleanup)	2	Each	$ 324	$ 648	
Dust Control Watering (Water Truck)	250	Day	$ 787	$ 196,750	250 works days for decommissioning
				$ 271,015	
500 kV Step-Up Substation and Transmission Line					
Substation Step-up Transformer Removal	2	Each	$ 40,205	$ 80,410	
Haul and Recycle/Dispose of Transformer Oil	2	Each	$ 48,207	$ 96,414	50,000 gallons
Substation Circuit Breaker Removal	2	Each	$ 40,205	$ 80,410	500kv breakers
Remove and Recycle/Disponse of Fencing	1,200	Linear Ft	$ 2.50	$ 3,000	1,200 ft; 8 ft tall barbed chain link
Remove and Recycle Gate	28	Linear Ft	$ 6.75	$ 189	one metal access gate 8 ft by 20 ft
Remove and Recycle Access and Maintenance Lighting	1	Day	$ 1,051	$ 1,051	
Remove and Recycle Control Building Structure	1	Each	$ 2,432	$ 2,432	
Remove and Recycle Control/Communications Equipment	1	Each	$ 1,051	$ 1,051	
Remove and Recycle HV Above Ground Transmission Line	10,560	Feet	$ 36.61	$ 386,602	
Remove Gentie Foundations to Subgrade	37	Each	$ 15,333	$ 567,321	
				$ 1,218,880	
Four Collector Substations					
Remove and Recycle Collector Cables	60	Days	$ 4,000	$ 240,000	4 person crew, 60 days, $4,000/day
Remove Step up Transformers and Oil	4	Each	$ 172,250	$ 689,000	
Haul and Recycle/Dispose of Transformer Oil	20	Trips	$ 1,000	$ 20,000	
Remove Foundations to Subgrade	4	Each	$ 25,000	$ 100,000	
Remove Substation Junction Boxes and Foundations	4	Each	$ 212,500	$ 212,500	
				$ 1,261,500	
Solar Array					
Remove and Recycle Photovoltaic Modules	1,742,572	Panels	$ 3.98	$ 6,935,437	
Hauling and Disposal of Modules	34,851	Ton	$ 30	$ 1,045,543	
Remove Racking	22,689	Each	$ 47	$ 1,072,055	$105/row@22,689 module rows; 45%
Hauling and Disposal of Racking	22,689	Ton	$ 58	$ 1,310,290	removal and 55% hauling and disposal
Remove Posts	246,444	Each	$ 4.50	$ 1,108,998	$10/post@246,444 posts; 45%
Hauling and Disposal of Posts	246,444	Each	$ 6	$ 1,355,442	removal and 55% hauling and disposal
Remove and Recycle Inverters and Transformers	160	Each	$ 1,200	$ 192,000	
Dispose of Inverters and Transformers	3,040	Ton	$ 30	$ 91,200	
Disconnect and Remove Combiner Boxes and Switches	2,240	Each	$ 1,100	$ 2,464,000	14 combiner boxes for each inverter
Remove SCADA and Met Stations	1	Each	$ 1,051	$ 1,051	
Remove Fences/Gates	95,040	Linear Ft	$ 2.50	$ 237,600	18 miles
Restore Site (Primarily Re-Seeding Disturbed Areas)	1,300	Acres	$ 200	$ 260,000	
				$ 16,073,616	
O&M Facilities					
Remove O&M facility (per building)	2	Each	$ 40,000	$ 80,000	2 buildings
				$ 80,000	
Battery System					
Disconnect battery and prepare for removal	134	Each	$ 4,000	$ 536,000	134 buildings
Remove Buildings and Foundations (Demolition and Hauling)	134	Each	$ 1,000	$ 134,000	134 buildings
Haul Batteries Containing Electrolyte Fluid	67	Trips	$ 1,000	$ 67,000	2 buildings per trip
Dispose of Electrolyte Fluid	50	MW	$ 100	$ 5,000	14,000 gallons per MW
Disposal of Battery System Inverters and Switchyard	70	Each	$ 4,100	$ 287,000	
Disposal of Battery System Switchyard	1	Each	$ 9,100	$ 9,100	
Restore Battery Building Site	25	Acres	$ 2,600	$ 65,000	includes application of manure,scarifying , and blending
Hauling and Disposal	67	Trips	$ 1,000	$ 67,000	67 trips
				$ 1,170,100	
Road Restoration					
Remove Service Roads	3,696,000	SF	$ 0.08	$ 295,680	50 miles
				$ 295,680	
Restore Additional Areas Distributed by Facility Removal					

Obsidian Solar Center - Decommissioning Estimates **Cost Estimate Component**	**Quantity**	**Unit**	**Per Unit Cost**	**Cost Estimate**	**Assumption**
Restore and seed temporary disturbance areas	25	Acres	$ 2,600	$ 65,000	includes application of manure, scarifying, and blending
				$ 65,000	
General Costs					
Haul charges and disposal fees (per load)	250	Trips	$ 1,000	$ 250,000	250 loads
Permits, Inspections and Fees				$ 10,000	
				$ 260,000	
Subtotal				$ 20,695,790	
Mobilization and Supervisory				$ 206,958	1%
Subcontractor Bonding/Liability Insurance				$ 310,437	1.50%
General Conditions				$ 258,697	1.25%
Performance Bond				$ 206,958	1%
Administration and Project Mgmt				$ 620,874	3%
General Overhead and Profit				$ 1,034,789	5%
Future Developments Contingency				$ 620,874	3%
Total Site Restoration Cost (current dollars)				$ 23,955,377	
Total Site Restoration Cost (rounded to nearest $1,000)				**$ 23,955,000**	
ODOE Project Management and Administration				$ 718,661	3%
ODOE Future Developments Contingency				$ 718,661	3%
Subtotal ODOE Add-ons				$ 1,437,323	
Total Site Restoration Cost				**$ 25,392,699**	
Proposed Bond or Letter of Credit Amount until COD				**$ 25,393,000**	

Rule: 17.86.106

Prev Up Next

Rule Title: DETERMINATION OF BOND AMOUNT

Department: ENVIRONMENTAL QUALITY
Chapter: ENERGY
Subchapter: Wind Generation Facility Decommissioning and Bonding

Latest version of the adopted rule presented in Administrative Rules of Montana (ARM):

Printer Friendly Version

17.86.106 DETERMINATION OF BOND AMOUNT

(1) The department shall set the bond amount at the estimated amount for the department to perform the decommissioning and reclamation work required of an owner.

(2) The bond amount must be based on:

(a) estimated costs submitted by the owner in accordance with ARM 17.86.105 with such costs estimated by using current machinery production handbooks and publications or other documented or substantiated cost estimates acceptable to the department;

(b) estimated costs to the department that may arise from applicable public contracting requirements or the need to bring personnel and equipment to the facility after its abandonment by the owner to perform decommissioning and reclamation work;

(c) estimated costs to the department that may arise from management and maintenance of the facility upon owner insolvency or abandonment, until full bond liquidation can be effected; and

(d) other cost information as may be required by or available to the department.

(3) In determining the amount of a bond required in accordance with ARM 17.86.107, the department shall provide the owner with a preliminary bond determination, consult with the owner, and consider:

(a) the character and nature of the site where the facility is located; and

(b) the current market salvage value of the wind generation facility, as determined by an evaluator who is not an employee of the owner.

(4) The line items in the bond calculations are estimates only and are not limits on spending of any part of the bond to complete any particular task subsequent to forfeiture of the bond or settlement in the context of bond forfeiture proceedings.

History: 75-26-310, MCA; IMP, 75-26-304, MCA; NEW, 2018 MAR p. 94, Eff. 1/13/18.

MAR Notices	Effective From	Effective To	History Notes
17-394	1/13/2018	Current	History: 75-26-310, MCA; IMP, 75-26-304, MCA; NEW, 2018 MAR p. 94, Eff. 1/13/18.

Rule: 17.86.107

Prev Up Next

Rule Title: BONDING DEADLINE

Department: ENVIRONMENTAL QUALITY
Chapter: ENERGY
Subchapter: Wind Generation Facility Decommissioning and Bonding

Add to Favorites

Latest version of the adopted rule presented in Administrative Rules of Montana (ARM):

Printer Friendly Version

17.86.107 BONDING DEADLINE

(1) Except as provided in (3) and (4), and in accordance with ARM 17.86.110, the owner shall submit to the department a bond payable to the state of Montana in a form acceptable by the department as provided in ARM 17.86.115 and in a sum determined by the department in accordance with ARM 17.86.106, conditioned on the faithful decommissioning of the facility.

(2) Except as provided in (3) and (4):

(a) if a wind generation facility commenced commercial operation on or before January 1, 2007, the owner shall submit the decommissioning bond to the department prior to the conclusion of the 16th year after commencing commercial operation; or

(b) if a wind generation facility commenced commercial operation after January 1, 2007, the owner shall submit the decommissioning bond to the department prior to the conclusion of the 15th year of commencing commercial operation.

(3) If a wind generation facility is repurposed, as determined by the department in consultation with the owner, the owner is not required to provide a bond and any existing bond must be released until the repurposed facility reaches its fifth year of operation. The owner shall submit all revised information required in ARM 17.86.102(4)(b) within six months of finishing repurposing activities. Within five years of repurposing a facility, the facility shall submit to the department a bond payable to the state of Montana in a form acceptable by the department as provided in ARM 17.86.115 and in a sum determined by the department in accordance with ARM 17.86.106, conditioned on the faithful decommissioning of the facility.

(4) The owner is exempt from the requirements of this rule if:

(a) the owner posts a bond with a federal agency, with a state agency for the lease of state land, or with a tribal, county, or local government; or

(b) a private landowner on whose land the wind generation facility is located owns a 10 percent or greater share of the wind generation facility, as determined by the department.

History: 75-26-310, MCA; IMP, 75-26-304, MCA; NEW, 2018 MAR p. 94, Eff. 1/13/18.

MAR Notices	Effective From	Effective To	History Notes
17-394	1/13/2018	Current	History: 75-26-310, MCA; IMP, 75-26-304, MCA; NEW, 2018 MAR p. 94, Eff. 1/13/18.

Execution Version

POWER PURCHASE AGREEMENT
FOR RENEWABLE-DISPATCHABLE GENERATING FACILITY

BETWEEN

NEVADA POWER COMPANY D/B/A NV ENERGY

AND

SOLAR PARTNERS XI, LLC

Gemini Solar
Clark County, Nevada

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EXHIBITS

POWER PURCHASE AGREEMENT FOR A RENEWABLE-DISPATCHABLE GENERATING FACILITY

This Power Purchase Agreement for a Renewable-Dispatchable Generating Facility (this "Agreement") is made and entered into as of May 1, 2019 (the "Effective Date") by and between **NEVADA POWER COMPANY,** a Nevada corporation, d/b/a NV Energy acting in its merchant function capacity ("Buyer"), and **SOLAR PARTNERS XI, LLC**, a Delaware limited liability company ("Supplier"). Buyer and Supplier are sometimes referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Buyer is an operating electric public utility, subject to the applicable rules and regulations of the PUCN and FERC (as such terms are defined below);

WHEREAS, Buyer seeks the ability to dispatch renewable energy at a fixed price in order to reduce its reliance on fossil fuels, to meet peak energy demand and obtain Ancillary Services (as such term is defined below);

WHEREAS, Buyer intends to construct or cause to be constructed the Facility (as such term is defined below) upon the terms and conditions set forth herein; and

WHEREAS, Supplier desires to sell to Buyer, and Buyer desires to purchase from Supplier, Product (as such term is defined below) from the Facility upon the terms and conditions set forth herein.

NOW, THEREFORE, in consideration of the premises and the covenants and conditions contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Buyer and Supplier, intending to be legally bound, hereby agree as follows:

1. DEFINITIONS

As used in this Agreement, the following terms shall have the meanings set forth below:

1.1 "Accepted Compliance Costs" is defined in Section 3.5.

1.2 "Affiliate" means, with respect to any Person, each Person that directly or indirectly, controls or is controlled by or is under common control with such Person. For the purposes of this definition, "control" (including, with correlative meanings, the terms "controlled by" and "under common control with"), as used with respect to any Person, shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities or by contract or otherwise. Notwithstanding the foregoing, with respect to Buyer, unless Buyer assigns this Agreement or there is a change of control of Buyer, Affiliate shall only include Berkshire Hathaway Energy Company and its direct and indirect, wholly owned subsidiaries.

1.3 "AGC" or "Automatic Generation Control" means Supplier's Automatic Generation Control for the Generating Facility which shall be compatible with Buyer's Energy Management System.

1.4 "Agreement" means this Long-Term Renewable Power Purchase Agreement together with the Exhibits attached hereto, as amended from time to time.

1.5 "ALTA Survey" means a land survey prepared and certified in accordance with the standards jointly promulgated by the American Land Title Association and the American Congress on Surveying and Mapping.

1.6 "Ancillary Services" means those services necessary to support the transmission of electric power from Supplier to Buyer and to maintain reliable operations of the Transmission System, including but not limited to: voltage control, operating reserve, spinning reserve, and reactive power.

1.7 "Annual Charging-Only Energy Amount" means, with respect to each Contract Year, 115,000 MWh.

1.8 "ASC" is defined in Section 12.7.

1.9 "Availability Backcast Amount" means an amount determined by a backcasting analysis that takes into account both resource conditions and availability of the Generating Facility. The backcasting analysis will be performed by Supplier using a tool which will be mutually agreed upon by Buyer and Supplier in accordance with Exhibit 27 no later than ninety (90) days prior to the Project Milestone described in Section 2(G) of Exhibit 6. Supplier shall provide Buyer its calculations and include all relevant back-up data and other information reasonably requested by Buyer. If the Parties disagree on the calculation of the Availability Backcast Amount, then the Availability Backcast Amount will be determined through the Dispute resolution provisions of Article 21.

1.10 "Availability Liquidated Damages" is defined in Exhibit 26.

1.11 "Availability Notice" means a notice delivered by Supplier to Buyer pursuant to Section 14.1 notifying Buyer of the availability of the Facility.

1.12 "Balancing Authority Area" is defined in the OATT (as may be modified from time to time) of the Balancing Authority Area Operator.

1.13 "Balancing Authority Area Operator" means a Person, and its agents and any successors thereto, that is responsible for the operation of the electric transmission system and for maintaining reliability of the electric transmission system, including the Transmission System, within the Balancing Authority Area where the Facility is located. As of the Effective Date, the Balancing Authority Area Operator is the Transmission Provider.

1.14 "Billing Period" is defined in Section 7.2.1.

1.15 "Business Day" means any day other than Saturday, Sunday and any day that is a holiday observed by Buyer.

1.16 "Buyer" is defined in the preamble of this Agreement and includes such Person's permitted successors and assigns.

1.17 "Buyer ROFO Notice" is defined in Section 6.1.1.

1.18 "Buyer's Charging Energy" means all Energy produced by the Generating Facility, net of transformation and transmission losses, if any, measured at the Storage Facility Metering Points that is a result of a Charging Notice given by Buyer. All Buyer's Charging Energy shall be used for Buyer's benefit in accordance with Charging Notices and Discharging Notices given by Buyer. Buyer's payment for Buyer's Charging Energy shall not be for more than the amount of Energy flowing through, and delivered at, the Storage Facility Metering Points and, in any event, not greater than the amount of Buyer's Charging Energy included in the applicable Charging Notice.

1.19 "Buyer's PC Account" means the account maintained by the PC Administrator for the purpose of tracking the production, sale, transfer, purchase and retirement of PCs by Buyer, or such other account, including a WREGIS account, as Buyer may designate from time to time.

1.20 "Buyer's Required Regulatory Approvals" means the approvals, consents, authorizations or permits of, or filing with, or notification to the Governmental Authorities listed on Exhibit 9, and such others as are deemed by Buyer to be necessary or desirable from time to time.

1.21 "CAMD" means the Clean Air Markets Division of the Environmental Protection Agency or successor administrator, or any state or federal Governmental Authority given jurisdiction over a program involving transferability of Renewable Energy Benefits or any part thereof.

1.22 "Capacity Rights" means any current or future defined characteristic, certificate, tag, credit, ancillary service or attribute thereof, or accounting construct, including any of the same counted towards any current or future resource adequacy or reserve requirements, associated with the electric generation capability and capacity of the Facility or the Facility's capability and ability to produce energy. Capacity Rights are measured in MW and do not include any Tax incentives of any kind existing now or in the future associated with the construction, ownership or operation of the Facility.

1.23 "Certified Nameplate Capacity Rating" is defined in Section 8.3.2.2.

1.24 "Charging Energy" means Buyer's Charging Energy and Supplier's Charging Energy.

1.25 "Charging Notice" means the operating instruction, and any subsequent updates, given by Buyer to Supplier, directing delivery of Buyer's Charging Energy to the Storage Facility to charge it at a specific MW rate to a specified Stored Energy Level, provided that any operating instruction shall be in accordance with the Storage Operating Procedures. Charging Notices may be communicated electronically, via facsimile, telephonically or other verbal means, provided that telephonic or other verbal communications shall be documented (either recorded by tape, electronically or in writing), and such recordings shall be made available to both Buyer and Supplier upon request for settlement purposes. For the avoidance of doubt, any Buyer request to initiate a Storage Capacity Test shall not be considered a Charging Notice.

1.26 "Charging-Only Energy" means, for any Delivery Hour during the Dispatch Availability Months, Energy that the Generating Facility is capable of generating in such Delivery Hour that is in excess of the Delivery Points Maximum Amount.

1.27 "Commercial Operation" means that: (a) the Generating Facility is fully operational, reliable and interconnected, fully integrated and synchronized with the Transmission System, and that the Storage Facility is fully capable of charging, storing and discharging energy up to the Storage Contract Capacity; (b) Supplier shall have received or obtained all Required Facility Documents; and (c) which occurs when all of the requirements set forth in Sections 8.1, 8.3 and 17.2 and Exhibits 6 and 7 (i) have occurred, and (ii) remain simultaneously true and accurate: (A) as of the date and time Supplier gives Buyer notice that Commercial Operation has occurred; and (B) for the period Buyer has to review Supplier's notice of Commercial Operation pursuant to Section 8.2.1.

1.28 "Commercial Operation Date" means the date on which Commercial Operation occurs.

1.29 "Commercial Operation Deadline" means the date specified in Exhibit 6 by which the Commercial Operation Date must occur, as such date may be extended if and to the extent Supplier fails to achieve the Commercial Operation Date as a result of Force Majeure.

1.30 "Compliance Cost Cap" is defined in Section 3.5.

1.31 "Construction Contract" means one or more construction and equipment supply agreements, in each case, between a Construction Contractor and Supplier (or one of its Affiliates), pursuant to which, in the aggregate, the Facility will be designed, engineered, constructed, tested and commissioned.

1.32 "Construction Contractor" with respect to a Construction Contract, means the construction contractor and/or equipment supplier that is party to such Construction Contract.

1.33 "Contract Representative" of a Party, means the individual designated by that Party in Exhibit 4 as responsible for ensuring effective communication, coordination and cooperation between the Parties. A Party may change its Contract Representative by providing notice of such change to the other Party in accordance with the procedures set forth in Section 29.1.

1.34 "Contract Year" means each year during the Term beginning on January 1 and ending on December 31 of the year following the Commercial Operation Date (or commencing on the Commercial Operation Date if the Commercial Operation Date is January 1).

1.35 "Controlling Interest" with respect to a Person, means more than fifty percent (50%) of the outstanding ownership interest of such Person, or the power to vote such percentage of ownership interest.

1.36 "Credit Rating" of a Person means the credit rating then assigned by a Relevant Rating Agency to the long-term, senior, unsecured, non-credit-enhanced indebtedness of that Person.

1.37 "Critical Project Milestone" means a Project Milestone designated as a Critical Project Milestone on Exhibit 6.

1.38 "Cure Period" is defined in Section 24.3.

1.39 "Curtailed Product" is defined in Section 10.1.1.

1.40 "Daily Delay Damages" means an amount equal to: (a) with respect to the first (1st) through and including the sixtieth (60th) day subsequent to the Commercial Operation Deadline, three hundred one dollars and fifty three cents ($301.53) per MW of Expected Nameplate Capacity Rating per day; (b) with respect to the sixty-first (61st) through and including the one-hundred-twentieth (120th) day subsequent to the Commercial Operation Deadline, six hundred three dollars and six cents ($603.06) per MW of Expected Nameplate Capacity Rating per day; and (c) with respect to the one-hundred-twenty-first (121st) through and including the one hundred and eightieth (180th) day subsequent to the Commercial Operation Deadline, nine hundred four dollars and fifty nine cents ($904.59) per MW of Expected Nameplate Capacity Rating per day.

1.41 "Defaulting Party" is defined in Section 24.1.

1.42 "Deficit Damages" is defined in Section 8.6.1.

1.43 "Deficit Damages Rate" means two hundred thousand dollars ($200,000) per MW.

1.44 "Delivered Amount" means, with respect to any Delivery Hour or period, the actual amount of Net Energy delivered by Supplier and accepted by Buyer at the Delivery Points during such Delivery Hour or period, and, if applicable, Buyer's Charging Energy delivered by Supplier to the Storage Facility Metering Points during such Delivery Hour or period.

1.45 "Delivered PCs" means PCs that have been delivered by Supplier and awarded to Buyer pursuant to the terms of this Agreement, in accordance with the Portfolio Standard and which have been properly delivered and recorded to Buyer's PC Account.

1.46 "Delivery Hour" means each hour.

1.47 "Delivery Points" means, with respect to Net Energy (other than Buyer's Charging Energy) and Discharging Energy, the delivery points on the Transmission System set forth in Exhibit 5.

1.48 "Delivery Points Maximum Amount" means, with respect to a Delivery Hour, the amount defined in Section 5(b)(iv) of Exhibit 1 (in MW) multiplied by one (1) hour.

1.49 "Derating" means a condition of the Generating Facility as a result of which the actual available generating capacity of the Generating Facility is less than the Certified Nameplate Capacity Rating.

1.50 "Development Security" is defined in Section 17.1.

1.51 "Deviation Amount" is defined in Section 3.6.2.1.

1.52 "Discharging Energy" means all Energy discharged by the Storage Facility, less inverter, transformation and transmission losses, if any, and delivered to the Delivery Points.

1.53 "Discharging Notice" means the operating instruction, and any subsequent updates, given by Buyer to Supplier, directing the Storage Facility to discharge Discharging Energy at a specific MW rate to a specified Stored Energy Level, provided that any operating instruction shall be in accordance with the Storage Operating Procedures. Discharging Notices may be communicated electronically, via facsimile, telephonically or other verbal means, provided that telephonic or other verbal communications shall be documented (either recorded by tape, electronically or in writing), and such recordings shall be made available to both Buyer and Supplier upon request for settlement purposes.

1.54 "Dispatch Availability Amount" means, with respect to any Delivery Hour, the amount of Energy stated in Exhibit 13A for such Delivery Hour.

1.55 "Dispatch Availability Month" is defined in Section 3.4.10.1.

1.56 "Dispatch Availability Shortfall" is defined in Section 3.6.1.1.

1.57 "Dispatch Availability Shortfall Amount" is defined in Section 3.6.1.1.

1.58 "Dispatchable Accuracy Rate" or "DAR" means a measure of the ability of the Generating Facility (and the AGC, as applicable) to follow Buyer's Energy Management System signals as calculated pursuant to Exhibit 16.

1.59 "Dispatchable Accuracy Rate Threshold" or "DAR Threshold" is defined in Section 3.6.2.1.

1.60 "Dispatchable Period" the period in the Stub Period or a Contract Year, as applicable, outside of the Full Requirements Period, consisting of January through May, and September through December, for all hours, and for the months of June through August, hour ending 0100 through 1600, and hour ending 2200 through 2400 as identified in Exhibit 13B.

1.61 "Dispatchable Period Product Rate" means the Product Rate identified in Exhibit 2A as the Dispatchable Period Product Rate.

1.62 "Dispatchable Period Replacement Costs" is defined in Section 3.6.1.2.

1.63 "Dispatched Amount" is defined in Section 3.4.7.

1.64 "Dispute" is defined in Section 21.1.

1.65 "Early Purchase Option" is defined in Section 6.2.1.

1.66 "Effective Date" is defined in the preamble of this Agreement.

1.67 "Electric System Authority" means each of NERC, WECC, WREGIS, Balancing Authority Area Operator, Market Operator, a Regional Transmission Organization, a regional or sub-regional reliability council or authority, and any other similar council, corporation, organization or body of recognized standing with respect to the operations of the electric system in the WECC region.

1.68 "Emergency" means any circumstance or combination of circumstances or any condition of the Facility, the Transmission System or the transmission system of other transmission operators, which is determined or reported by Supplier, the Transmission Provider or any Electric System Authority, whether planned or unplanned, to be: (a) reasonably likely to endanger life or property and necessitates immediate action to avert injury to persons or serious damage to property or (b) reasonably likely to adversely affect, degrade or impair Transmission System reliability or transmission system reliability of the transmission system of other electric utilities.

1.69 "EMS" or "Energy Management System" means Buyer's equipment and software used to monitor, control and optimize the performance of Buyer's generating system.

1.70 "Energy" means all energy that is generated by the Generating Facility.

1.71 "Energy Imbalance Market" means generation facilities electrically located within the Balancing Authority Area that are, from time to time, bid into or otherwise subject to dispatch instructions issued or originating from the Market Operator.

1.72 "Environmental Contamination" means the introduction or presence of Hazardous Substances at such levels, quantities or location, or of such form or character, as to constitute a violation of Laws and present a material risk under Laws that the Project Site will not be available or usable for the purposes contemplated by this Agreement.

1.73 "Environmental Law" shall mean any Law relating to the protection, preservation or restoration of human health, the environment, or natural resources, including any Law relating to the releases or threatened releases of Hazardous Substances into any medium (including ambient air, surface water, groundwater, land, surface and subsurface strata) or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, release, transport and handling of Hazardous Substances.

1.74 "Event of Default" is defined in Section 24.1.

1.75 "EWG" means an "exempt wholesale generator" as defined in the Public Utility Holding Company Act of 2005 and in implementing regulations issued thereunder.

1.76 "Excess Charging Energy" is defined in Section 3.4.8.3.

1.77 "Excess Energy" means for the Dispatchable Period, (a) with respect to the Stub Period, the portion of the Delivered Amount plus any Un-Dispatched Amount for the Stub Period, if any, that exceeds one hundred percent (100%) of the Maximum Amount for the Stub Period, and (b) with respect to a Contract Year, the portion of the Delivered Amount plus any Un-Dispatched Amount for such Contract Year, if any, that exceeds one hundred percent (100%) of the Maximum Amount for such Contract Year; provided, however, that Delivered Amount plus Un-Dispatched Amount in excess of the Delivery Points Maximum Amount for any Delivery Hour shall be excluded for purposes of determining Excess Energy.

1.78 "Excused Product" is defined in Section 3.6.6.

1.79 "Expected Nameplate Capacity Rating" is defined in Exhibit 1.

1.80 "Facility" means the Generating Facility and the Storage Facility.

1.81 "Fair Market Value" means the price which a willing buyer would pay for the Facility in an arm's-length transaction to a willing seller under no compulsion to sell, as such price shall be determined by mutual agreement of the Parties or, absent mutual agreement of the Parties, pursuant to Section 6.6.

1.82 "FERC" means the Federal Energy Regulatory Commission and any successor.

1.83 "Final Purchase Option" is defined in Section 6.3.

1.84 "FRP Deemed Delivered Energy" is defined in Section 14.3.2.

1.85 "Full Requirements Capacity Shortfall" is defined in Section 3.6.4.1

1.86 "Full Requirements Capacity Shortfall Amount" is defined in Section 3.6.4.1.

1.87 "Full Requirements Period" means hours ending 1700-2100 for the months of June, July and August, as identified in Exhibit 13B, in the Stub Period or a Contract Year, as applicable.

1.88 "Full Requirements Period Capacity Factor" means the percentage stated in Exhibit 1, Section 5(b)(v).

1.89 "Full Requirements Period Charging Energy" means all Energy produced by the Generating Facility, less transformation and transmission losses, if any, delivered to the Storage Facility Metering Points during the months of June, July or August.

1.90 "Full Requirements Period Product" is the amount of Product, as measured by Net Energy, required to be delivered during the Full Requirements Period, which is equal to the product of (a) the Full Requirements Period Capacity Factor, times (b) the Certified Nameplate Capacity Rating, times (c) four hundred sixty (460) hours.

1.91 "Full Requirements Period Product Rate" means the Product Rate identified in Exhibit 2A as the Full Requirements Period Product Rate.

1.92 "Full Requirements Period Replacement Costs" is defined in Section 3.6.4.1.

1.93 "Force Majeure" is defined in Section 20.2.

1.94 "Generating Facility" means Supplier's generating power plant as described in Exhibit 1, located at the Project Site as identified in Exhibit 3A and 3B and including mechanical equipment and associated facilities and equipment required to deliver Net Energy to the Delivery Points and Storage Facility Metering Points, including items as further described in Exhibits 1, 3A, 3B, 5 and 14, and as such generating power plant may be modified from time to time in accordance with the terms hereof.

1.95 "Good Utility Practice" means (a) the applicable practices, methods and acts required by or consistent with applicable Laws and reliability criteria, whether or not the Party whose conduct at issue is a member of any relevant organization and otherwise engaged in or approved by a significant portion of the electric utility industry during the relevant time period with respect to grid-interconnected, utility-scale generating facilities with integrated storage in the Western United States, or (b) any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to acceptable practices, methods or acts generally accepted in the industry with respect to grid-interconnected, utility-scale generating facilities with integrated storage in the Western United States. Good Utility Practice shall include compliance with applicable Laws, applicable reliability criteria, and the criteria, rules and standards promulgated in the National Electric Safety Code and the National Electrical Code, as they may be amended or superseded from time to time, including the criteria, rules and standards of any successor organizations.

1.96 "Governmental Approval" means any authorization, approval, consent, license, ruling, permit, tariff, certification, exemption, order, recognition, grant, confirmation, clearance, filing, notification, or registration of, by, with or to any Governmental Authority.

1.97 "Governmental Authority" means, as to any Person, any federal, state, local, or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over such Person or its property or operations, and with respect to Supplier, specifically includes FERC, the PUCN, NERC, WECC and WREGIS.

1.98 "Guaranteed Storage Availability" is defined in Section 3.4.10.1.

1.99 "Guarantee" means a Guarantee substantially in the form of Exhibit 20.

1.100 "Hazardous Substance" means: (a) any petroleum or petroleum products, flammable materials, explosives, radioactive materials, friable asbestos, urea formaldehyde foam insulation and transformers or other equipment that contain dielectric fluid containing polychlorinated biphenyls (PCBs) in regulated concentrations; (b) any chemicals or other materials or substances which are now or hereafter become defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "toxic pollutants," "contaminants," "pollutants" or words of similar import under any Environmental Law; and (c) any other chemical or other material or substance, exposure to which is now or hereafter prohibited, limited or regulated as such under any Environmental Law, including the Resource Conservation and Recovery Act, 42 U.S.C. section 6901 et seq., the Comprehensive Environmental Response Compensation and Liability Act, 42 U.S.C. section 9601 et seq., or any similar state statute.

1.101 "IA" means (a) the Large Generator Interconnection Agreement executed on June 11, 2018, as amended from time to time, between Supplier and the Transmission Provider for the portion of the Facility interconnected at 230 kV ("230 kV IA"), and (b) the Large Generator Interconnection Agreement, as amended from time to time, between Supplier and the Transmission Provider for the portion of the Facility interconnected at 525 kV. This definition may be revised in accordance with Section 8.2.3.

1.102 "IEEE-SA" means the Institute of Electrical and Electronics Engineers Standards Association and any successor entity thereto.

1.103 "Indemnified Party" is defined in Section 18.1.

1.104 "Indemnifying Party" is defined in Section 18.1.

1.105 "Intraday Schedule Change" is defined in Section 14.2.2.

1.106 "Invoice" means the statements described in Section 7.2 setting forth the information required therein, as well as the associated payment due for the Billing Period, the Measurement Period or the Contract Year, as the case may be, in accordance with Exhibits 2B and 2C.

1.107 "ITC" means the investment tax credit established pursuant to Section 48 of the United States Internal Revenue Code of 1986.

1.108 "Law" means any federal, state, local or other law (including any Environmental Laws), common law, treaty, code, rule, ordinance, binding directive, regulation, order, judgment, decree, ruling, determination, permit, certificate, authorization, or approval of a Governmental Authority which is binding on a Party or any of its property.

1.109 "Loss" with respect to a Person means, any and all claims, demands, suits, obligations, payments, liabilities, costs, fines, Regulatory Penalties, sanctions, Taxes, judgments, damages, losses or expenses imposed by a third party upon such Person or incurred in connection with a claim by a third party against such Person.

1.110 "Licensed Professional Engineer" means a person proposed by Supplier and acceptable to Buyer in its reasonable judgment who: (a) is licensed to practice engineering in the appropriate engineering discipline for the required certification being made in Nevada; (b) has training and experience in the engineering disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation or opinion; (c) has no economic relationship, association, or nexus with Supplier and is not an employee of its members or Affiliates, other than with the prior written consent of Buyer, for services previously or currently being rendered to Supplier or its members or Affiliates; and (d) is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility.

1.111 "Market Operator" means, if applicable, the California Independent System Operator Corporation or any other entity performing the market operator function for the Energy Imbalance Market.

1.112 "Market Price" means the simple average of MEAD for the Dispatchable Period or the Full Requirements Period, as applicable.

1.113 "Material Adverse Effect" means, with respect to a Party, a material adverse effect on: (a) the ability of such Party to perform its obligations under this Agreement, individually or in the aggregate; (b) the validity or enforceability of this Agreement or the transaction contemplated hereby; or (c) on the business, assets, operations, property or condition (financial or otherwise) of such Party.

1.114 "Maximum Amount" means (a) for the Stub Period, 100% of the Dispatch Availability Amounts (in MWh) for all hours in the Stub Period, plus the pro-rated portion of the Annual Charging-Only Energy Amount, and (b) for any Contract Year, 100% of the Dispatch Availability Amounts (in MWh) for all hours in such Contract Year, plus the Annual Charging-Only Energy Amount.

1.115 "Mead" means the Hourly Mead Index published by Powerdex.

1.116 "Measurement Period" means each one (1) Contract Year commencing with the first one (1) Contract Year of the Term.

1.117 "Meter" means any of the physical or electronic metering devices, data processing equipment and apparatus associated with the meters required for: (a) accurate determination of the: quantities of Delivered Amounts from the Facility, the quantities of Charging Energy delivered to the Storage Facility Metering Points, the amount of Discharging Energy delivered to the Delivery Points, and for recording other related parameters required for the reporting of data to Supplier: (b) the computation of the payments due from one Party to another under this Agreement; and (c) compliance with requirements of any Electric System Authority, any Governmental Authority or Transmission Provider. Meters do not include any check meters Supplier may elect to install as contemplated by Section 7.1.1.

1.118 "Minimum Credit Rating" of a Person means that the Credit Rating of that Person is at least (a) BBB- (or its equivalent) as determined by Standard & Poor's and (b) Baa3 (or its equivalent) as determined by Moody's.

1.119 "Monthly Storage Availability" is defined in Exhibit 26.

1.120 "Moody's" means Moody's Investor Services, Inc. and any successor.

1.121 "MW" means megawatts of electrical power in AC.

1.122 "MWh" and "MWhs" mean a megawatt hour or megawatt hours of electrical energy.

1.123 "NAC" means the Nevada Administrative Code.

1.124 "NERC" means the North American Electric Reliability Corporation and any successor.

1.125 "Net Energy" means: (a) during the Dispatchable Period, all Energy produced by the Generating Facility (including Buyer's Charging Energy, but not Full Requirements Period Charging Energy or Discharging Energy), all of which shall be net of Station Usage, and transformation and transmission losses and other adjustments (e.g., Supplier's load other than Station Usage), if any, and delivered to Buyer at the Delivery Points or the Storage Facility Metering Points, and (b) during the Full Requirements Period, all Energy produced by the Generating Facility and all Discharging Energy delivered to and received by Buyer at the Delivery Points.

1.126 "Network Resource" is defined in the OATT.

1.127 "Non-Defaulting Party" means the Party other than the Defaulting Party.

1.128 "Notice" is defined in Section 29.1.1.

1.129 "Notice to Proceed" means the initial notification by Supplier to its Construction Contractor to commence work under the Construction Contract.

1.130 "NRS" means the Nevada Revised Statutes.

1.131 "OATT" means Transmission Provider's or the Balancing Authority Area Operator's then-effective Open Access Transmission Tariff, which has been accepted for filing by FERC.

1.132 "Offered Interests" is defined in Section 6.1.1.

1.133 "Operating Representative" of a Party means any of the individuals designated by that Party, as set forth in Exhibit 4, to transmit and receive routine operating and Emergency communications required under this Agreement. A Party may change any of its Operating Representatives by providing notice of the change to the other Party in accordance with the notice procedures set forth in Section 29.1.

1.134 "Operating Security" is defined in Section 17.2.

1.135 "Operation Date" means the first date on which the Generating Facility is energized and operates in parallel with the Transmission System and delivers Net Energy to and at the Delivery Points and Storage Facility Metering Points and the Storage Facility is capable of charging, storing and discharging energy in amounts less than or up to the Storage Contract Capacity and receiving instructions to charge, store and discharge energy.

1.136 "Over Delivery Amount" is defined in Section 3.6.3.1.

1.137 "PPT" means Pacific Standard Time or Pacific Daylight Time, whichever is then prevailing in Las Vegas, Nevada.

1.138 "Party" or "Parties" means each entity set forth in the preamble of this Agreement and its permitted successor or assigns.

1.139 "PC" or "Portfolio Energy Credit" means a unit of credit which equals one kilowatt-hour of electricity generated, acquired or saved (or deemed so) by the Facility, all as calculated by the PUCN operations staff and certified by the PC Administrator pursuant to the Renewable Energy Law (or by a successor Governmental Authority pursuant to a successor Law if the Renewable Energy Law is replaced, superseded or preempted by another Law or regulatory regime tasked with enforcement of renewable energy quotas by utility providers in Nevada), and certified by WREGIS.

1.140 "PC Administrator" means the Person appointed by the PUCN to administer the system of Portfolio Energy Credits established pursuant to the Portfolio Standard or a successor Governmental Authority pursuant to a successor law if the Renewable Energy Law is replaced, superseded or preempted by another Law or regulatory regime tasked with enforcement of renewable energy quotas by utility providers in Nevada.

1.141 "PC Replacement Costs" is defined in Section 3.7.1.

1.142 "PC Shortfall" is defined in Section 3.7.1.

1.143 "PC Shortfall Amount" is defined in Section 3.7.1.

1.144 PC Shortfall Threshold" is defined in Section 3.7.1.

1.145 "Permitted Transfer" means any of the following: (a) any foreclosure by Supplier's Lenders pursuant to any financing, including tax equity financing, or other financial arrangements for the Facility; (b) any change of economic and voting rights triggered in Supplier's organizational documents arising from the financing of the Facility and which does not result in the transfer of ownership, economic or voting rights to any entity that had no such rights immediately prior to the change; or (c) the direct or indirect transfer of shares of, or equity interests in, Supplier to Supplier's Lenders as part of a tax equity financing.

1.146 "Person" or "Persons" means any natural person, partnership, limited liability company, joint venture, corporation, trust, unincorporated organization, or Governmental Authority.

1.147 "Planned Outage" is defined in Article 11.1.

1.148 "Portfolio Standard" means the amount of electricity that Buyer must generate, acquire, or save from renewable energy systems or efficiency measures specified by the percentage of the total amount of electricity sold by Buyer to its retail customers in the State of Nevada pursuant to the Renewable Energy Law, as established pursuant to NRS 704.7821, and the regulations, guidance and requirements promulgated thereunder, as may be amended, preempted or superseded from time to time (or pursuant to a successor law if the Renewable

Energy Law is replaced, superseded or preempted by another Law or regulatory regime tasked with enforcement of renewable energy quotas by utility providers in Nevada).

1.149 "Power Quality Standards" means the power quality standards established by NERC, WECC, Buyer, IEEE-SA, National Electric Safety Code, the National Electric Code, or their respective successor organizations or codes, as they may be amended or superseded from time to time, and consistent with Good Utility Practice.

1.150 "Product" means all (a) Net Energy, (b) PCs (and any equivalent rights in any other jurisdiction), (c) Renewable Energy Benefits, (d) Capacity Rights, and (e) Ancillary Services in each case, arising from or relating to the Facility, including Storage Product.

1.151 "Product Rate" means, for any period, the applicable rate set forth in Exhibit 2A for such period.

1.152 "Project Milestone" means each of the milestones listed in Exhibit 6.

1.153 "Project Site" means the site for the Facility, as more particularly described in Exhibit 3A and depicted in Exhibit 3B.

1.154 "Provisional Energy" means Net Energy (but not Test Energy) that is delivered by Supplier to Buyer prior to the Commercial Operation Date and at the request of Buyer in increments of no less than five (5) MW up to an aggregate maximum of six hundred ninety (690) MW.

1.155 "Provisional Product Rate" is defined in Section 4.1.1.2.

1.156 "PUCN" means the Public Utilities Commission of Nevada and any successor.

1.157 "PUCN Approval" is defined in Section 16.2.

1.158 "PUCN Approval Date" means the date the PUCN Approval becomes effective pursuant to NAC §703.790.

1.159 "PUCN Approval Deadline" means December 31, 2019.

1.160 "QF" means a cogeneration or small power production facility that meets the criteria as defined in Title 18, Code of Federal Regulations, §§ 292.201 through 292.207.

1.161 "Qualified Financial Institution" means a financial institution having an office in the United States, with a total tangible net worth of at least ten billion dollars ($10,000,000,000) U.S. and whose Credit Rating is at least "A-" by S&P and "A3" by Moody's.

1.162 "Qualified Guarantor" means (a) Quinbrook Low Carbon Power Parallel Fund (US) LP and Quinbrook Low Carbon Power LP, or (b) an entity, which at the time it provides a Guarantee, either (i) meets Buyer's minimum credit requirements as determined by Buyer in its sole and absolute discretion, or (ii) meets the Minimum Credit Rating.

1.163 "Qualified Operator" means (a) NextEra Energy Operating Services, LLC, or an Affiliate of NextEra Energy Resources, LLC with experience comparable to NextEra Energy Operating Services, LLC, (b) First Solar Electric, LLC, or an Affiliate of First Solar, Inc. with experience comparable to First Solar Electric, LLC, (c) Swinerton Renewable Energy, or (d) a Person that has at least three (3) years of experience operating a generating facility of at least 100 MW and of similar technology to the Generating Facility and at least two (2) years of experience operating a storage facility of at least 10 MW and similar technology to the Storage Facility approved by Buyer in its reasonable discretion.

1.164 "Qualified Transferee" means a Person that is at least as financially and operationally qualified as Supplier as of the Effective Date and, at a minimum, (a) has a tangible net worth of at least thirty million dollars ($30,000,000) or provides replacement Development Security or Operating Security to Buyer, as applicable, and (b) has (or agrees to contract with an operator who has) at least three (3) years of experience operating a generating facility of at least 100 MW and of similar technology to the Generating Facility and at least two (2) years of experience operating a storage facility of at least 10 MW and similar technology to the Storage Facility.

1.165 "Regulatory Penalties" means any penalties, fines, damages, or sanctions attributable to Supplier's failure to perform under this Agreement and actually imposed on Buyer pursuant to an order issued by any Governmental Authority, the Transmission Provider or any Electric System Authority.

1.166 "Relevant Rating Agency" means Moody's or S&P.

1.167 "Renewable Energy Benefits" means any and all renewable and environmental attributes, emissions reductions attributes, Portfolio Energy Credits (and any equivalent rights in any other jurisdictions), credits, offsets, allowances, reporting rights and benefits, howsoever entitled, and includes any and all: (a) available, allocated, assigned, awarded, certified or otherwise transferred or granted to Supplier or Buyer by the PC Administrator or any Governmental Authority in any jurisdiction in connection with the Facility or the generation, transmission or use of the Product, including those related to the Clean Air amendments of 1970 and regulations of the Environmental Protection Agency thereunder; (b) associated with the production of Energy or based in whole or part on the Facility's use of renewable resources for generation or because the Generating Facility constitutes a Renewable Energy System or the like or because the Facility does not produce or produces less greenhouse gasses, regulated emissions or other pollutants, whether any such credits, offsets, allowances or benefits exist now or in the future and whether they arise under existing Law or any future Law or whether such credit, offset, allowance or benefit or any Law, or the nature of such, is foreseeable or unforeseeable; (c) credits, offsets, allowances or benefits attributable to Energy generated and consumed by the Facility, such as Station Usage (parasitic load); (d) claims, credits, benefits, emissions, reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water or generation of the Product, and include : (1) any avoided emissions of pollutants into the air, soil, or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; and (e) the Renewable Energy Benefits Reporting Rights. Renewable Energy Benefits exclude and do not include: (i) any Tax Credits or other Tax incentives existing now or in the future associated with the construction, ownership or operation of the Facility; (ii) matters designated by Buyer as sources of liability; and (iii) adverse wildlife or environmental impacts.

1.168 "Renewable Energy Benefits Reporting Rights" means the exclusive right of a purchaser of Renewable Energy Benefits to report ownership of Renewable Energy Benefits in compliance with any applicable Law, and to Governmental Authorities or other Persons at such purchaser's discretion, and include reporting under: (a) Section 1605(b) of the Energy Policy Act of 1992; (b) the Environmental Protection Agency; (c) the Clean Air Act Amendments Section 111(d) and regulations thereunder; and (d) any present or future domestic, international or foreign emissions trading program or renewable portfolio standard.

1.169 "Renewable Energy Law" means an act of the Nevada Legislature relating to energy that requires certain electric service providers to comply with the portfolio standard for renewable energy, and providing for other matters relating thereto, codified as NRS §§ 704.7801 through 704.7828, inclusive, and the rules and regulations of WREGIS, and the regulations, guidance and other requirements promulgated thereunder, in each case, as such Laws, rules, regulations, guidance and other requirements may be amended, preempted or superseded from time to time.

1.170 "Renewable Energy System" means a generation facility that is both (a) a "renewable energy system" as defined in the Renewable Energy Law and (b) a "renewable Generating Unit" under WREGIS.

1.171 "Replacement Costs" means the Full Requirements Period Replacement Costs or Dispatchable Period Replacement Costs, as applicable.

1.172 "Required Facility Documents" means the Governmental Approvals, rights and agreements now or hereafter necessary for construction, operation and maintenance of the Facility set forth in Exhibit 12. Nothing set forth in Exhibit 12 limits

Supplier's obligation to obtain the Governmental Approvals set forth in Exhibit 12 or otherwise required hereunder or with respect to the Facility.

1.173 "Resource-Adjusted Backcast Amount" means an amount determined for the Dispatchable Period by a backcasting analysis that takes into account weather conditions during the Dispatchable Period, including cloud cover, rain and snow impacting the solar resource, but assumes 100% operational availability of the Generating Facility; provided, however, that the Resource-Adjusted Backcast Amount for the Dispatchable Period of a Contract Year will not be greater than the Dispatch Availability Amounts (in MWh) for all hours in the Dispatchable Period of such Contract Year. The backcasting analysis will be performed by the Supplier using a tool, which will be mutually agreed upon by Buyer and Supplier in accordance with Exhibit 27 no later than ninety (90) days prior to the Project Milestone described in Section 2(G) of Exhibit 6. Supplier shall provide Buyer its calculations and include all relevant back-up data and other information reasonably requested by Buyer. If the Parties disagree on the calculation of the Resource-Adjusted Backcast Amount, then the Resource-Adjusted Backcast Amount will be determined through the Dispute resolution provisions of Article 21.

1.174 "Restricted Period" is defined in Section 24.5.1.

1.175 "Restricted Transaction" is defined in Section 6.1.1.

1.176 "ROFO" is defined in Section 6.1.

1.177 "ROFO Period" is defined in Section 6.1.1.

1.178 "ROFO Seller" is defined in Section 6.1.1.

1.179 "Scheduled Amount" is defined in Section 14.2.1.

1.180 "Seller ROFO Notice" is defined in Section 6.1.1.

1.181 "Shortfall" means the Full Requirements Capacity Shortfall and/or the Dispatch Availability Shortfall, as applicable.

1.182 "Shared Facilities" means the shared permits, fences, access roads, buildings, or other equipment, permits, contract rights, and other assets and property (real or personal), in each case as necessary to enable delivery of Energy from the Facility (which is excluded from Shared Facilities) to the Delivery Points.

1.183 "Shortfall Amount" means the Full Requirements Capacity Shortfall Amount and/or the Dispatch Availability Shortfall Amount, as applicable.

1.184 "Standard and Poor's" or "S&P" means Standard and Poor's Ratings Group, a division of McGraw Hill, Inc., and any successor.

1.185 "Standby Service" means the electric service supplied by Nevada Power Company for Station Usage pursuant to Schedule LSR, Large Standby Service Rider, as such tariff is in effect and as may be amended from time to time.

1.186 "Station Usage" means all Energy used by the Facility with the exception of any energy used to charge the Storage Facility as provided herein.

1.187 "Storage Capacity" means the maximum dependable operating capability (in MWh) of the Storage Facility to store or discharge electric energy, and any other products that may be developed or evolve from time to time during the Term that relate to the maximum dependable operating capability of the Storage Facility to discharge electric energy.

1.188 "Storage Capacity Test" means the testing procedures, requirements and protocols set forth in Section 3.4.9 and Exhibit 25.

1.189 "Storage Contract Capacity" means the total capacity (in MW) of the Storage Facility determined in accordance with Section 3.4.9 and Exhibit 25, as the same may be adjusted from time to time pursuant to Section 3.4.9 and Exhibit 25.

1.190 "Storage Deficit Damages" is defined in Section 8.6.3.

1.191 "Storage Deficit Damages Rate" means six-hundred thousand dollars ($600,000) per MW.

1.192 "Storage Facility" means Supplier's energy storage facility as described in Exhibit 1 (including the operational requirements of the energy storage facility), located at the Project Site as identified in Exhibit 3A and 3B and including mechanical equipment and associated facilities and equipment required to deliver Storage Product, including items as further described in Exhibits 1, 3A, 3B, 5 and 14, and as such storage facility may be expanded or otherwise modified from time to time in accordance with the terms hereof.

1.193 "Storage Facility Metering Points" means, with respect to Charging Energy, the points at the Storage Facility set forth in Exhibit 5.

1.194 "Storage Operating Procedures" is defined in Section 8.8 and set forth in Exhibit 24.

1.195 "Storage Product" means (a) Discharging Energy, (b) PCs (and any equivalent rights in any other jurisdiction), if any, (c) Renewable Energy Benefits, if any, (d) Storage Capacity, and (e) Ancillary Services, in each case arising from or relating to the Storage Facility.

1.196 "Stored Energy Level" means, at a particular time, the amount of energy in the Storage Facility available to Buyer, expressed in MWh.

1.197 "Stub Period" means the period of time commencing on the Commercial Operation Date and ending on December 31 of the year in which the Commercial Operation Date occurs (provided, however, that if the Commercial Operation Date occurs on January 1, then the term "Stub Period" will have no application to this Agreement).

1.198 "Supplier" is defined in the preamble of this Agreement and includes such Person's permitted successors and assigns.

1.199 "Supplier's Charging Energy" means all energy, including Energy produced by the Generating Facility, less transformation and transmission losses, if any, delivered to and measured at the Storage Facility Metering Points that is not Buyer's Charging Energy or Full Requirements Period Charging Energy. Supplier's Charging Energy shall be used as needed to power the Storage Facility's Station Usage and other auxiliary loads.

1.200 "Supplier's Lenders" means any Person other than an Affiliate of Supplier, and its permitted successors and assigns, providing money or credit to Supplier or an Affiliate (but only where and to the extent such Affiliate is receiving such money or credit for the purpose of funding Supplier or the development of the Facility) in connection with any development, bridge, construction, takeout, or permanent debt, tax equity or other financing or refinancing for the Facility, including lease, inverted lease, sale-leaseback, partnership-flip, monetization of tax benefits, back-leverage financing, or credit derivative arrangements.

1.201 "Supplier's Required Regulatory Approvals" means the Governmental Approvals listed on Exhibit 10.

1.202 "Tax" or "Taxes" means any federal, state, local or foreign income, gross receipts, license, payroll, employment, excise, severance, stamp, occupation, premium, windfall profits, environmental, customs duties, capital stock, franchise, profits, withholding, social security (or similar), unemployment, disability, real property (including assessments, fees or other charges based on the use or ownership of real property), personal property, transactional, sales, use, transfer, registration, value added, alternative or add-on minimum, estimated tax, or other tax of any kind whatsoever, or any liability for unclaimed property or escheatment under common law principles, including any interest, penalty or addition thereto, whether disputed or not, including any item for which liability arises as a transferee or successor-in-interest.

1.203 "Tax Credits" means the PTC, ITC and any other state, local and/or federal production tax credit, depreciation benefit, tax deduction and/or investment tax credit specific to the production of renewable energy and/or investments in renewable energy facilities.

1.204 "Term" is defined in Section 2.2.

1.205 "Test Energy" is defined in Section 4.1.1.1.

1.206 "Test Product Rate" is defined in Section 4.1.1.1.

1.207 "Transmission Provider" means Nevada Power Company or any successor operator or owner of the Transmission System.

1.208 "Transmission Provider Instructions" means any instructions, requirements, or demands given by the Transmission Provider to Supplier or Buyer requiring the curtailment of the Facility for the purpose of operating, maintaining, improving or modifying the transmission or distribution system whether planned or unplanned, regardless of the amount advance notice provided to Supplier.

1.209 "Transmission System" means the facilities used for the transmission of electric energy in interstate commerce, including any modifications or upgrades made to such facilities, owned or operated by the Transmission Provider.

1.210 "Un-Dispatched Amount" is defined in Section 10.2.2.

1.211 "Weather Meter" is defined in Section 7.1.8.

1.212 "WECC" means the Western Electric Coordinating Council (formerly Western System Coordinating Council) and any successor.

1.213 "WREGIS" means the Western Renewable Energy Generation Information System and any successor.

1.214 "Yearly PC Amount" means the amount of PCs the Facility is expected to be capable of generating in a Contract Year as stated in Exhibit 18.

2. TERM; TERMINATION AND SURVIVAL OF OBLIGATIONS

2.1 Effective Date. Subject to Article 16, this Agreement shall become effective on the Effective Date.

2.2 Term. Supplier's obligation to deliver Product, and Buyer's obligation to accept and pay for Product, shall commence on the Commercial Operation Date and shall continue for a period of twenty-five (25) Contract Years, subject to earlier termination of this Agreement pursuant to the terms hereof (the "Term"); provided, however, that Buyer's obligations to pay for or accept any Product are conditioned on the receipt of the PUCN Approval in form and substance acceptable to Buyer in its sole discretion. Buyer shall not be obligated to accept or pay for any Product, unless the PUCN Approval is received in form and substance acceptable to Buyer in its sole discretion or Buyer waives its right to terminate this Agreement pursuant to Article 16.

2.3 Termination.

2.3.1 For Cause. Except as provided below in this Section 2.3.1, this Agreement may be terminated at any time by the Non-Defaulting Party upon two (2)

Business Days' prior notice to the Defaulting Party if an Event of Default has occurred and is continuing (after the applicable Cure Period (if any) in Section 24.3 has expired); provided, however, that any purported termination by Supplier shall first require that Supplier deliver Notice to Buyer stating prominently therein in type font no smaller than 14 point all-capital letters that "THIS IS A TERMINATION NOTICE UNDER A RENEWABLE RESOURCE PPA. YOU MUST CURE A DEFAULT, OR THE PPA WILL BE TERMINATED," and shall state therein any amount purported to be owed and wiring instructions. Notwithstanding any provision to the contrary contained in this Agreement, Supplier will not have any right to terminate this Agreement if the Event of Default that gave rise to the termination right is cured within fifteen (15) Business Days after receipt of such notice.

2.3.2 Failed Conditions Precedent. This Agreement may be terminated by Buyer in accordance with Article 16 without payment or penalty or liability of any kind.

2.3.3 Force Majeure. This Agreement may be terminated by Buyer if Supplier's obligations hereunder have been excused by the occurrence of an event of Force Majeure for longer than twelve (12) consecutive months or three hundred sixty (360) days in any five hundred forty (540) day period.

2.4 Effect of Termination - Survival of Obligations. The termination or expiration of this Agreement shall not release either Party from any applicable provisions of this Agreement with respect to:

2.4.1 The payment of any amounts owed to the other Party arising prior to or resulting from termination or breach of this Agreement;

2.4.2 Indemnity obligations contained in this Agreement, including Article 18, which shall survive to the full extent of the statute of limitations period applicable to any third-party claim;

2.4.3 Limitation of liability provisions contained in Article 19;

2.4.4 For a period of two (2) years after the termination date, the right to submit a payment Dispute pursuant to Article 21; or

2.4.5 The resolution of any Dispute submitted pursuant to Article 21 prior to, or resulting from, termination.

3. SUPPLY SERVICE OBLIGATIONS

3.1 Dedication. One hundred percent (100%) of the Product from the Facility shall be dedicated exclusively to Buyer for so long as this Agreement is in force and effect. Subject to Section 24.2, Supplier shall not: (a) sell, divert, grant, transfer or assign Product to any Person other than Buyer; (b) provide Buyer with any Product from any source other than the Facility; or (c) divert, redirect or make available the Facility or any resource therefrom to another generating facility or storage facility or any third party. The Parties agree that remedies at Law may be inadequate in the event of a breach of this Section 3.1, and Supplier agrees that Buyer shall be entitled, without proof of actual damages and without necessity of posting bond or other security, to temporary, preliminary and permanent injunctive relief from any Governmental Authority of competent jurisdiction restraining Supplier from committing or continuing any breach of this Section 3.1.

3.2 Purchase and Sale. For and in consideration of Buyer's payment for the Product, Supplier sells to Buyer, and Buyer purchases from Supplier, all rights, title and interest that Supplier may have in and to the Product, including Capacity Rights, Ancillary Services and Renewable Energy Benefits on all Energy (including Excess Energy and the Un-Dispatched amount as applicable) existing during the Term.

3.3 No Double Sales. Supplier represents that it has not sold, and covenants that during the Term it will not sell or attempt to sell to any other Person, the Product, including the Capacity Rights, if any, and the Renewable Energy Benefits on all Energy (including Excess Energy and the Un-Dispatched Amount, as applicable) existing during the Term, whether Buyer has scheduled Product or not, other than as provided in Section 24.2. During the Term, Supplier shall not report to any person or entity that the Product, including the Capacity Rights, if any, and the Renewable Energy Benefits on all Energy (including Excess Energy) existing during the Term, belong to anyone other than Buyer. Buyer may report to any person that it exclusively owns the Product, including the Capacity Rights, if any, the Ancillary Services and the Renewable Energy Benefits on all Energy (including Excess Energy) existing during the Term. At Buyer's request, the Parties shall execute such documents and instruments as may be reasonably required to effect recognition and transfer of the Capacity Rights, if any, to Buyer.

3.4 Delivery Responsibilities.

3.4.1 Product. Subject to the provisions of this Agreement, commencing on the Commercial Operation Date and throughout the Term, Supplier shall supply and deliver the Product to Buyer at the Delivery Points (other than Buyer's Charging Energy which shall be delivered at the Storage Facility Metering Points).

3.4.2 Delivered Amount. Buyer shall take delivery of the Energy, including any Excess Energy, and Discharging Energy at the Delivery Points in accordance with the terms of this Agreement. Supplier shall be responsible for paying or satisfying when due all costs or charges imposed in connection with the scheduling and delivery of Energy and Discharging Energy up to the Delivery Points, including transmission costs, transmission line losses, any costs or charges imposed in connection with scheduling and delivery of the Charging Energy to the Storage Facility Metering Points and any operation and maintenance charges imposed by the Transmission Provider. Buyer shall be responsible for all costs or charges, if any, imposed in connection with the delivery of Energy and Discharging Energy at and after the Delivery Points, including transmission costs and transmission line losses and imbalance charges. Without limiting the generality of the foregoing, Buyer, in its merchant capacity, shall not bear costs associated with the modifications to the Transmission System (including system upgrades) caused by or related to: (a) the interconnection of the Facility with the Transmission System; and (b) any increase in generating capacity of the Generating Facility. The Parties agree that the terms of the IA shall govern the allocation of costs associated with any modifications or upgrades to the Transmission System. To the extent any terms of this Agreement conflict with the IA, the terms of the IA shall prevail.

3.4.3 Title and Risk of Loss. Title and risk of loss with respect to Energy and Discharging Energy delivered by Supplier shall pass from Supplier to Buyer at the Delivery Points. Supplier shall be deemed in exclusive control of the Energy and Discharging Energy and shall be responsible for any damage or injury caused prior to the Delivery Points. Buyer shall be deemed in exclusive control of the Energy and Discharging Energy and shall be responsible for any damage or injury caused at and after the Delivery Points. Supplier warrants that all Product delivered to Buyer is free and clear of all liens, security interests, claims and encumbrances of any kind.

3.4.4 Provisional Energy Delivery. Buyer may request by written notice to Supplier to deliver Provisional Energy prior to the Commercial Operation Date, in increments as defined in Section 1.154, and on and after a specified date. Supplier may, in its sole discretion, elect to deliver such Provisional Energy to Buyer by delivering written notice thereof to Buyer. Notwithstanding the foregoing, Buyer and Supplier shall mutually agree on the amounts of Provisional Energy to be supplied and the date and time when such Provisional Energy shall be supplied.

3.4.5 Voltage Support. The IA requires the Facility to maintain a composite power delivery at continuous rated power output at the points of interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to the Facility and all generators in the control area on a comparable basis. In addition to the requirements of the IA, the Facility will provide voltage set point control at the points of interconnection within the range of 0.90 leading to 0.90 lagging, as available. If Buyer requests reactive power or a voltage set-point outside the Generating Facility's capacity at its currently dispatched real power set-point, Buyer will dispatch the Generating Facility downward to a set-point that permits the desired reactive power within the capabilities of the Facility. The amount of Energy that could have been but was not produced due to such dispatch down shall be an Un-Dispatched Amount if occurring during the Dispatchable Period or FRP Deemed Delivered Energy if occurring during the Full

Requirements Period. In furtherance of the requirements of the IA, the Facility will provide voltage set point control at the point of interconnection for the scheduled real-power output, as available, within the capabilities of the Facility shown in Exhibit 22. The Facility shall provide dynamic reactive power as required for voltage regulation twenty-four (24) hours per day, if the Facility is capable of providing reactive power, regardless of real power output. The performance of reactive power output to provide voltage support shall be according to unit real/reactive capability curves provided in Exhibit 22.

3.4.6 Dispatchable Accuracy Rate. During the Dispatchable Period, Supplier shall meet the Dispatchable Accuracy Rate subject to Section 3.6.2.

3.4.7 Automated Generation Control. Subject to Section 3.6.2, during the Dispatchable Period, Supplier shall ensure that the Generating Facility is able to be dispatched by Buyer's Energy Management System sending signals to Supplier's AGC so that the Generating Facility can be dispatched dynamically. The energy dispatched in this manner is the "Dispatched Amount."

3.4.8 Charging Energy Management.

3.4.8.1 During the Dispatchable Period (excluding the months of June, July and August), Supplier shall take any and all action necessary to deliver Buyer's Charging Energy to the Storage Facility in order to deliver the Storage Product in accordance with the terms of this Agreement, including maintenance, repair or replacement of equipment in Supplier's possession or control used to deliver Buyer's Charging Energy from the Generating Facility to the Storage Facility.

3.4.8.2 Subject to the requirements and limitations set forth in this Agreement, including the Storage Operating Procedures and Supplier's right to charge the Storage Facility using Supplier's Charging Energy and to charge the Storage Facility in order to meet Supplier's obligations during the Full Requirements Period, during the Dispatchable Period (excluding the months of June, July and August), Buyer will have the right to charge the Storage Facility seven (7) days per week and twenty-four (24) hours per day (including holidays), by providing Charging Notices to Supplier electronically; provided that the Generating Facility is producing Energy, the Charging Notice does not request a Stored Energy Level that exceeds the Energy available, and the Charging Notice is otherwise compliant with the Storage Operating Procedures. Each Charging Notice will be effective unless and until Buyer modifies such Charging Notice by providing Supplier with an updated Charging

Notice. If an electronic submittal is not possible for reasons beyond Buyer's control, Buyer may provide Charging Notices by (in order or preference, unless the Parties agree to a different order) electronic mail, facsimile transmission or telephonically to Supplier's personnel designated in Exhibit 4 to receive such communications. Notwithstanding the above, Buyer shall not have the right to send a Charging Notice during the months of June, July or August or to charge the Storage Facility with energy that is not generated by the Generating Facility.

3.4.8.3 Supplier shall not charge the Storage Facility during the Dispatchable Period (excluding the months of June, July and August) other than pursuant to a Charging Notice, in connection with a Storage Capacity Test, using Supplier's Charging Energy, or as required by Supplier to meet Supplier's obligations during the Full Requirements Period in accordance with Section 14.2.4. If during the Dispatchable Period (excluding the months of June, July and August), Supplier charges the Storage Facility except as provided in the preceding sentence, then (x) Supplier shall be responsible for all costs associated with the additional energy in the Storage Facility due to such unauthorized charging ("Excess Charging Energy"), (y) Buyer shall not be required to pay for such Excess Charging Energy, and (z) Buyer shall be entitled to use such Excess Charging Energy and to all of the benefits (including Storage Product) associated with discharging such Excess Charging Energy. During the months of June, July and August, Supplier may charge the Storage Facility as it determines in its sole discretion.

3.4.9 Storage Capacity Tests.

3.4.9.1 Prior to the Commercial Operation Date, Supplier shall schedule and complete one or more Storage Capacity Tests in accordance with Exhibit 25. Thereafter, at least once per Contract Year, Supplier shall schedule and complete a Storage Capacity Test in accordance with Exhibit 25. Buyer shall have the right to run a retest of the Storage Capacity Test in accordance with Exhibit 25. Supplier shall have the right to run one or more retests of the Storage Capacity Test in accordance with Exhibit 25.

3.4.9.2 Buyer shall have the right to send one or more representative(s) to witness all Storage Capacity Tests. Buyer shall be responsible for all costs, expenses and fees payable or reimbursable to its representative(s) witnessing any Storage Capacity Test. All other costs of any Storage Capacity Test shall be borne by Supplier (other than any third party costs incurred by Supplier for any retest required by Buyer pursuant to Section 3.4.7, unless such retest shall result in the Storage Contract Capacity being reduced from the Storage Contract Capacity established by the immediately preceding Storage Capacity Test, in which case Supplier shall be responsible for such costs).

3.4.9.3 Following each Storage Capacity Test, Supplier shall submit a testing report to Buyer in accordance with Exhibit 25 and reasonable support data requested by Buyer. If the actual capacity determined pursuant to a Storage Capacity Test is less than the then current Storage Contract Capacity, then the actual capacity determined pursuant to such Storage Capacity Test shall become the new Storage Contract Capacity at the beginning of the day following the completion of the test for all purposes under this Agreement until a new Storage Contract Capacity is determined pursuant to a subsequent Storage Capacity Test, provided, that (a) in no event shall the Storage Contract Capacity be revised more frequently than monthly, and (b) the Storage Contract Capacity cannot exceed three hundred eighty (380) MW.

3.4.10 <u>Storage Availability</u>.

3.4.10.1 During the months of January through May and September through December (the "<u>Dispatch Availability Months</u>") of the Term, the Storage Facility shall maintain a Monthly Storage Availability of no less than ninety-eight percent (98%) (the "<u>Guaranteed Storage Availability</u>"), which Monthly Storage Availability shall be calculated in accordance with Exhibit 26.

If the Monthly Storage Availability during the Dispatch Availability Months is less than the Guaranteed Storage Availability, then Supplier shall cure such failure by paying to Buyer Availability Liquidated Damages calculated in accordance with Exhibit 26. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such Availability Liquidated Damages in accordance with Exhibit 26.

3.4.10.2 The Parties recognize and agree that the payment of amounts by Supplier pursuant to this Section 3.4.10 is an appropriate remedy and that any such payment does not constitute a forfeiture or penalty of any kind, but rather constitutes anticipated costs to Buyer under the terms of this Agreement. The Parties further acknowledge and agree that the amount payable by Supplier pursuant to this Section 3.4.10 is difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient and the damages calculated hereunder constitute a reasonable approximation of the harm or loss.

3.5 Renewable Energy System. Notwithstanding anything in this Agreement to the contrary, Buyer shall not be obligated to purchase or accept delivery of Product if the Generating Facility: (a) is not at the time of delivery qualified as a Renewable Energy System; or (b) is not delivering to Buyer all of the Renewable Energy Benefits generated with the Net Energy and Discharging Energy being delivered; provided that if there is a change in the Renewable Energy Law after the execution of this Agreement that causes the Net Energy and Discharging Energy from the Generating Facility to be ineligible or non-qualifying as a Renewable Energy System under such Renewable Energy Law, Supplier shall use commercially reasonable efforts to comply with such Renewable Energy Law. For purposes hereof, commercially reasonable efforts shall include the expenditure of amounts up to six hundred ninety thousand dollars ($690,000) (the "Compliance Cost Cap") in any Contract Year. If Supplier reasonably concludes that it may incur costs in excess of the Compliance Cost Cap in any Contract Year in order to comply with the Renewable Energy Law, it shall provide Buyer with a notice itemizing such excess costs. Buyer shall evaluate such notice and either: (i) agree to reimburse Supplier for such excess costs (the "Accepted Compliance Costs"); or (ii) waive Supplier's obligation to comply with the Renewable Energy Law to the extent such inability results from failing to expend amounts in excess of the Compliance Cost Cap. If Buyer agrees to reimburse Supplier for the Accepted Compliance Costs, then Supplier shall be required to comply in full with the Renewable Energy Law, and Buyer shall reimburse Supplier for Supplier's actual and reasonable out-of-pocket compliance costs in excess of the Compliance Cost Cap, not to exceed the Accepted Compliance Costs. If Supplier's inability to comply with the Renewable Energy Law cannot be cured by the expenditure of money, such noncompliance shall be excused and shall not constitute an Event of Default, and Buyer's payment obligations to Supplier hereunder shall not be excused or reduced in any manner.

3.6 Shortfall; Replacement Costs; DAR. Supplier shall pay Buyer Replacement Costs, DAR Threshold remedies and any Regulatory Penalties, if any, incurred as a result of any Shortfall in any Measurement Period in accordance with the following provisions:

3.6.1 Dispatchable Period Shortfall.

3.6.1.1 If (a) the sum of all Delivered Amounts, and all Excused Product for the Dispatchable Period during a Measurement Period is less than (b) (i) ninety-five hundredths (0.95), multiplied by (ii) the Resource-Adjusted Backcast Amount minus the Full Requirements Period Charging Energy for the Dispatchable Period during such

Measurement Period, then an availability shortfall (a "Dispatch Availability Shortfall") will be deemed to exist for such Dispatchable Period equal to (b) minus (a) (the "Dispatch Availability Shortfall Amount").

3.6.1.2 Buyer's "Dispatchable Period Replacement Costs" with respect to any Dispatchable Period in any Measurement Period for which there is a Dispatch Availability Shortfall shall equal the product of (a) the Dispatch Availability Shortfall Amount for such Dispatchable Period, multiplied by (b) an amount equal to the positive difference, if any, between the Market Price for such Dispatchable Period minus the Dispatchable Period Product Rate.

3.6.1.3 Within five (5) Business Days after the end of any Measurement Period in which a Dispatch Availability Shortfall has occurred, Supplier shall calculate the Dispatchable Period Replacement Costs with respect to such Dispatch Availability Shortfall Amount and provide Buyer with written notice of such calculation. Such Dispatchable Period Replacement Costs shall be reflected on the Invoice for the same Billing Period in which such Dispatchable Period Replacement Costs are calculated.

3.6.2 Dispatchable Accuracy Rate.

3.6.2.1 In the event the Generating Facility's DAR is less than ninety-seven percent (97%) ("DAR Threshold") for any calendar month during the Dispatchable Period, and not to exceed any three (3) consecutive calendar months, Buyer will not pay Supplier for an amount of megawatt hours equal to the product of (a) 0.97, less the Generating Facility's DAR for such month, expressed as a decimal, and (b) the Dispatched Amount for such month (the "Deviation Amount"). For the Invoice immediately following any such calendar month that includes a Deviation Amount, the invoiced amount shall be reduced by an amount equal to the Deviation Amount multiplied by the applicable Dispatchable Period Product Rate.

3.6.2.2 If after three (3) consecutive months the Generating Facility does not meet the DAR Threshold for the fourth (4th) consecutive month or for any consecutive month thereafter through the sixth (6th) consecutive month, Buyer shall only pay Supplier for the Dispatched Amount during such months (and shall not be obligated to compensate Supplier for any Un-Dispatched Amount in such months).

3.6.2.3 If after six (6) consecutive months but not to exceed twelve (12) consecutive months the Generating Facility does not meet the DAR Threshold for each such consecutive month after the sixth (6th) consecutive month, Supplier shall only be entitled to receive 75% of the Dispatchable Period Product Rate for the Dispatched Amount during such months and Buyer shall only pay Supplier for the Dispatched Amount during such months (and shall not be obligated to compensate Supplier for any Un-Dispatched Amount in such months).

3.6.2.4 If after twelve (12) consecutive months the Generating Facility's DAR is less than the DAR Threshold for each such month then Buyer shall have the right to terminate this Agreement pursuant to Section 24.1.7.

3.6.2.5 If Supplier fails to meet the DAR Threshold for any thirty-six (36) non-consecutive months during the Dispatchable Periods of the Term, Buyer will have the right to terminate this Agreement pursuant to Section 24.1.8.

3.6.3 Full Requirements Period Over Delivery.

3.6.3.1 If for any Full Requirements Period, the Delivered Amount is greater than the Full Requirements Period Product by more than five (5%) percent, then the Delivered Amount in excess of such five (5%) percent threshold is the "Over Delivery Amount."

3.6.4 Full Requirements Capacity Shortfall.

3.6.4.1 If for any Full Requirements Period of a Contract Year, (a) the Delivered Amount plus Excused Product during the Full Requirements Period is less than (b) ninety-five hundredths (0.95) multiplied by the Full Requirements Period Product, then a shortfall (a "Full Requirements Capacity Shortfall") will be deemed to exist for such Full Requirements Period equal to (b) minus (a) (the "Full Requirements Capacity Shortfall Amount"). Supplier shall pay Replacement Costs for such Full Requirements Capacity Shortfall Amount equal to the product of (x) Full Requirements Capacity Shortfall Amount, times (y) an amount equal to the positive difference (if any) between the Market Price for the Full Requirements Period minus the Full Requirements Period Product Rate (the result of such calculation, the "Full Requirements Period Replacement Costs", which shall not be less than zero).

3.6.4.2 If in a second (2nd) consecutive Full Requirements Period, Supplier incurs another Full Requirements Capacity Shortfall, then for the purpose of calculating payment to Supplier in the immediately successive Invoice, such invoiced amount shall be reduced by an amount equal to: (i) the Full Requirements Capacity Shortfall for such second (2nd) consecutive Full Requirements Period multiplied by (ii) the applicable Full Requirements Period Product Rate. If this reduction results in a negative Invoice amount, subsequent Invoices will be reduced until the entire reduction amount calculated pursuant to this Section 3.6.4.2 has been recovered by Buyer.

3.6.4.3 If after the second (2nd) consecutive Full Requirements Period described in Section 3.6.4.2, Supplier incurs a third (3rd) Full Requirements Capacity Shortfall, Supplier shall pay the amount calculated using the methodology in Section 3.6.4.2 for such third (3rd) consecutive Full Requirements Period, and Buyer shall have the right to terminate this Agreement pursuant to Section 24.1.9. Buyer's termination right must be exercised, if at all, within one hundred eighty (180) days after the end of such third (3rd) consecutive Full Requirements Period. If Buyer does not terminate and for consecutive subsequent Full Requirements Periods thereafter a Full Requirements Capacity Shortfall occurs, Buyer shall have the right to terminate this Agreement pursuant to Section 24.1.9 after each such consecutive subsequent Full Requirements Period until the occurrence of a Full Requirements Period in which Supplier does not have a Full Requirements Capacity Shortfall, after which time the termination right will reset and Supplier will have to have three (3) consecutive Full Requirements Periods with Full Requirements Capacity Shortfalls for Buyer again to have the termination right defined in this Section 3.6.4.3 and Section 24.1.9.

3.6.4.4 Within five (5) Business Days after the end of any Full Requirements Period in which a Full Requirements Capacity Shortfall has occurred, Supplier will calculate the Full Requirements Period Replacement Costs with respect to such Full Requirements Capacity Shortfall and provide Buyer with written notice of such calculation. Such Replacement Costs shall be reflected on the Invoice immediately subsequent to the Full Requirements Period and will reflect any set-off or true-ups in accordance with this Agreement.

3.6.5 Not a Penalty. The Parties recognize and agree that the remedies that Buyer has against Supplier pursuant to this Section 3.6 are appropriate remedies and that any such remedy (including liquidated damages) does not constitute a forfeiture or penalty of any kind, but rather constitutes anticipated costs to Buyer under the terms of this Agreement. The Parties further acknowledge and agree that Buyer's damages for the failure of Supplier to perform any of its obligations under sections 3.6.1, 3.6.2 and 3.6.3 are difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient, and the remedies and any amounts applying to any of them as calculated thereunder constitute a reasonable approximation of the harm or loss to Buyer.

3.6.6 Calculations. As soon as practicable following any period of: (a) Force Majeure; (b) Buyer's failure to accept Net Energy or PCs in breach of this Agreement; (c) Emergency (except as provided in Section 9.4); (d) Planned

Outage; (e) Curtailed Product; (f) Transmission Provider Instructions; (g) an Un-Dispatched Amount, or (h) FRP Deemed Delivered Energy, in each case, as a result of which Supplier has failed to deliver any portion of the Product to Buyer during such period and, subject to the terms of this Agreement, such failure and Supplier's liability for damages therefor are excused, Supplier shall calculate the amount of Net Energy that Supplier was unable to generate, or discharge if any portion of such period occurs during the Full Requirements Period, solely as a result of such event, by summing for each hour of the period the difference between (i) the Availability Backcast Amount, plus any Discharging Energy that could have been delivered for each hour during the Full Requirements Period but was not delivered due to one or more events described in this Section 3.6.6, and (ii) the Delivered Amount during each hour (the "Excused Product").

3.7 PC Shortfall; PC Replacement Costs.

3.7.1 If after the PC Administrator issues all the PC statements or certificates for any Contract Year there is a PC Shortfall, then Supplier shall pay Buyer for the replacement costs and any Regulatory Penalties associated with such PC Shortfall (collectively, the "PC Replacement Costs"). Subject to the last sentence of this Section 3.7.1, for purposes of this Agreement a "PC Shortfall" shall occur in any Contract Year if the sum of all Delivered PCs is less than the "PC Shortfall Threshold" defined as the product of (a) 0.90 multiplied by (b) an amount equal to (i) the Yearly PC Amount for the Contract Year, minus (ii) the total amount of PCs associated with Excused Product during such Contract Year. For purposes of this Agreement, a "PC Shortfall Amount" with respect to any Contract Year means: (A) the PC Shortfall Threshold for such Contract Year; minus (B) the Delivered PCs during such Contract Year. If the calculation of the PC Shortfall Amount set forth in this Section 3.7.1 yields an amount of zero or less for any Contract Year, then no PC Shortfall will be deemed to exist with respect to such Contract Year.

3.7.2 The PC Replacement Costs shall be determined by Buyer exercising its reasonable discretion based on the estimated cost of purchasing PCs to replace the PC Shortfall Amount from the same resource type with a comparable expiration date or the cost of replacing the PC Shortfall Amount with PCs of Buyer's choice already in Buyer's PC Account; provided, however, that Buyer shall not be required to actually purchase replacement PCs in order to receive payment from Supplier for PC Replacement Costs. Buyer shall include in the PC Replacement Costs any Regulatory Penalties allocable to Supplier's proportionate amount of Buyer's aggregate shortfall under the applicable Portfolio Standard (factoring in Supplier's PC Shortfall Amount in prior years carried forward as a deficit or reducing the surplus in such prior years).

3.7.3 The Parties recognize and agree that the payment of amounts by Supplier pursuant to this Section 3.7 is an appropriate remedy and that any such payment does not constitute a forfeiture or penalty of any kind, but rather constitutes anticipated costs to Buyer under the terms of this Agreement. The Parties further acknowledge and agree that the amount payable by Supplier pursuant to this Section 3.7 is difficult or impossible to determine, or otherwise obtaining an adequate remedy is inconvenient and the damages calculated hereunder constitute a reasonable approximation of the harm or loss.

3.7.4 All information used by Buyer to establish PC Replacement Costs shall be verifiable by Supplier; and Buyer shall provide reasonable access to all such information supporting calculations within five (5) Business Days of Supplier's request for such information. Supplier agrees to execute a confidentiality agreement regarding the review of this information upon request by Buyer.

3.7.5 For any Contract Year, Buyer, at its sole option, may allow Supplier to meet its PC Replacement Cost obligation by transferring a quantity of PCs to Buyer in the amount of no less than the PC Shortfall Amount. Such PCs shall be from the same resource type with a comparable expiration date as the PCs that should have been delivered to Buyer under this Agreement.

3.8 Supply Degradation. Beginning with the second Contract Year, and each Contract Year thereafter, (a) the Dispatch Availability Amount and the Maximum Amount shall be reduced by five-tenths of a percent (0.5%), and (b) the Yearly PC Amount shall be reduced by seven-tenths of a percent (0.7%), in each case, such that the applicable amount is reduced by such percentage using the prior year adjusted amount (i.e. after the reduction for the prior year has been applied) as the base amount to which the percentage is applied. No later than January 1 of each Contract Year Buyer shall deliver to Supplier revised Exhibits 13 and 18 which shall reflect such reductions, and effective as of January 1 of each Contract Year this Agreement shall automatically be amended to substitute such revised Exhibits 13 and 18 for the then existing Exhibits 13 and 18.

4. PRICE OF PRODUCT

4.1 Product Payments. Supplier shall be paid for the Product as follows:

4.1.1 Prior to the Commercial Operation Date.

4.1.1.1 On and after the Operation Date and prior to the Commercial Operation Date, all Product associated with Delivered Amounts of Net Energy from the Generating Facility, other than (a) Excess Energy (which shall not be compensable) and (b) Provisional Energy, shall be considered "Test Energy" and shall be paid for by Buyer at the lesser of: (i) fifty percent (50%) of the applicable Product Rate; or (ii) the Market Price for each Delivery Hour of Test Energy ("Test Product Rate").

4.1.1.2 Notwithstanding the above, if Buyer requests Supplier to deliver Provisional Energy and Supplier elects to deliver Provisional Energy and delivers written notice to Buyer that it is delivering Provisional Energy in accordance with Section 3.4.4, Buyer shall pay Supplier seventy-five percent (75%) of the applicable Product Rate ("Provisional Product Rate") for such Provisional Energy.

4.1.1.3 Provisional Energy shall be distinguished from Test Energy in so far as Provisional Energy is for a determined amount of energy provided as the Generating Facility is capable of consistently generating such amounts of energy, whereas Test Energy is energy generated after the Operation Date and prior to Commercial Operation that is needed to commission the Generating Facility. Supplier shall provide notice when Provisional Energy is available and Buyer and Supplier shall mutually agree to the date and time when Provisional Energy requested by Buyer and agreed to by Supplier shall be supplied in accordance with Section 3.4.4. Five (5) Business Days prior to the start of each month, beginning with the month in which the Operation Date is expected to occur, Supplier shall provide notice to Buyer with an estimate of the forecasted amounts of Test Energy and Provisional Energy for that month with correlated meter data for actual amounts of Test Energy and Provisional Energy amounts to be provided with invoicing. Such determination shall be subject to verification by Buyer in the exercise of its reasonable discretion.

4.1.2 Subsequent to the Commercial Operation Date. On and after the Commercial Operation Date:

4.1.2.1 All Product associated with Delivered Amounts of Net Energy from the Generating Facility, other than Excess Energy, shall be paid for by Buyer at the applicable Product Rate set forth in Exhibit 2A and based on the quantity of Net Energy; provided that such payment constitutes the entirety of the amount due to Supplier from Buyer for the Product associated with Delivered Amounts of Net Energy other than Excess Energy; provided further that Supplier shall be paid at the Test Product Rate for the month in which the Commercial Operation Date occurs if the Commercial Operation Date occurs on or after the sixteenth (16^{th}) day of such month.

4.1.2.2 All Un-Dispatched Amount of Product shall be paid for at the Dispatchable Period Product Rate in consideration for Ancillary Services and Capacity.

4.1.2.3 All Product associated with Excess Energy shall be paid for at the Test Product Rate.

4.1.2.4 All FRP Deemed Delivered Energy shall be paid for at the Full Requirements Period Product Rate.

4.1.2.5 The payment for all Storage Product is included in payments for the applicable Product Rates.

4.1.2.6 All Over Delivery Amounts shall be paid for at three (3) times the Dispatchable Period Product Rate for the Over Delivery Amount.

4.1.3 No payment shall be owing to Supplier for any Product associated with Energy that is for any reason not Net Energy except as otherwise provided in Section 4.1.2.2 and Section 4.1.2.4.

4.1.4 Buyer shall not be required to accept from Supplier any Product associated with Delivered Amounts (excluding Buyer's Charging Energy) of Net Energy from the Generating Facility delivered during any Delivery Hour in excess of the Delivery Points Maximum Amount and no payment shall be owing to Supplier for any Product associated with Delivered Amounts (excluding Buyer's Charging Energy) of Net Energy from the Generating Facility accepted by Buyer during any Delivery Hour in excess of the Delivery Points Maximum Amount.

4.2 Excused Product. Buyer shall not pay for Product comprising Excused Product except for Excused Product described in Sections 3.6.6(b), (g) and (h).

4.3 Tax Credits. The Parties agree that neither any Product Rate nor the Test Product Rate are subject to adjustment or amendment if Supplier fails to receive any Tax Credits, or if any Tax Credits expire, are repealed or otherwise cease to apply to Supplier or the Facility in whole or in part, or Supplier or its investors are unable to benefit from any Tax Credits. Supplier shall bear all risks, financial and otherwise, throughout the Term, associated with Supplier's or the Facility's eligibility to receive Tax Credits or to qualify for accelerated depreciation for Supplier's accounting, reporting or Tax purposes. The obligations of the Parties hereunder, including those obligations set forth herein regarding the purchase and price for and Supplier's obligation to deliver Net Energy and Discharging Energy and Product, shall be effective regardless of whether the sale of Energy or Net Energy from the Facility is eligible for, or receives Tax Credits during the Term.

5. PORTFOLIO ENERGY CREDITS/RENEWABLE ENERGY BENEFITS

5.1 Delivery of Renewable Energy Benefits and Portfolio Energy Credits.

5.1.1 All Renewable Energy Benefits are exclusively dedicated to and vested in Buyer. Supplier shall deliver to Buyer all Renewable Energy Benefits derived from the Facility, including Renewable Energy Benefits associated with Energy for Station Usage, if any. Supplier shall timely prepare and execute all documents and take all actions necessary under Law or the requirements of any Governmental Authority or Person and otherwise to cause the Renewable Energy Benefits to vest in Buyer, without further compensation, including: (a) taking all actions necessary to register or certify any Renewable Energy Benefits or the Facility with the PUCN or any other Person (pursuant to NAC 704.8921 or otherwise) and WREGIS; (b) causing the automatic transfer of the Renewable Energy Benefits derived from the Facility to Buyer (pursuant to NAC 704.8927 or otherwise); (c) providing all production data and satisfying the reporting requirements of the PUCN or PC Administrator, as applicable; and (d) cooperating in any registration by Buyer of the Facility in any other renewable portfolio standard or equivalent program in any states in which Buyer may wish to register or maintain registration of the Facility, including providing copies of all such information as Buyer reasonably requires for such registration. Without limitation of the foregoing, Supplier acknowledges that the Renewable Energy Benefits, may be used by Buyer in meeting its present and future obligations pursuant to applicable Law, including the Portfolio Standard, and agrees to cooperate with Buyer to assist in Buyer's compliance with all applicable requirements set forth in the Portfolio Standard and provide all information reasonably requested by Buyer or otherwise necessary to allow the PUCN to determine compliance with the Portfolio Standard. No Person other than Buyer (or its designee) will be entitled to claim Renewable Energy Benefits in any jurisdiction in connection with the Facility. All representations and warranties made by Supplier with respect to Renewable Energy Benefits are freely transferrable by Buyer to any purchaser or transferee of such Renewable Energy Benefits or part thereof.

5.1.2 On or before January 31 of each year following the Operation Date, Supplier, as owner or operator of the Renewable Energy System, shall deliver to Buyer a written attestation for the prior year that no part of the Renewable Energy Benefits: have been or will be (a) used for or by any Person to obtain renewable energy credit in any state or jurisdiction, except for Buyer pursuant to this Agreement; (b) sold or otherwise exchanged for compensation or used for credit in any other state or jurisdiction; and (c) included within a blended energy product certified to include a fixed percentage of renewable energy in any other state or jurisdiction, pursuant to Chapter 704 of the NAC. No Person other than Buyer (or its designee) will be entitled to claim Portfolio Energy Credits, Renewable Energy Benefits (or equivalents in any jurisdiction) in connection with the Facility.

5.2 Injunction. If any Person other than Buyer (or its designee) attempts to claim such Renewable Energy Benefits or part thereof, the Parties agree that remedies at Law may be inadequate to protect Buyer in the event of a breach of this Section 5.2, and Supplier hereby in advance agrees: (a) that Buyer shall be entitled to seek without proof of actual damages or the necessity of posting any bond or other security, temporary, preliminary and permanent injunctive relief from any Governmental

Authority of competent jurisdiction restraining Supplier from committing or continuing any breach of this Section 5.2; and (b) that Supplier will promptly undertake all necessary actions to prevent such other Person from claiming such Renewable Energy Benefits (including joining with or otherwise assisting Buyer in seeking the relief described in clause (a)).

5.3 Transfers. Buyer shall be entitled to PC Replacement Costs for Renewable Energy Benefits associated with any Energy for which WREGIS Certificates, PCs or any part of the Renewable Energy Benefits that are not delivered to Buyer. Supplier shall promptly give Buyer copies of all documentation it submits to WREGIS or PUCN or otherwise with respect to Renewable Energy Benefits. Further, in the event of the promulgation of a scheme involving any part of the Renewable Energy Benefits administered by CAMD, upon notification by CAMD that any transfers contemplated by this Agreement will not be recorded, the Parties shall promptly cooperate in taking all reasonable actions necessary so that such transfers can be recorded. Supplier shall not report under Section 1605(b) of the Energy Policy Act of 1992 or under any applicable program that any of the Renewable Energy Benefits belong to any person other than Buyer. Without limiting the generality of Buyer's ownership of the Renewable Energy Benefit Reporting Rights, Buyer may report under such program that all Renewable Energy Benefits purchased hereunder belong to it. Each Party shall promptly give the other Party copies of all documents it submits to the CAMD to effectuate any transfers.

6. RIGHT OF FIRST OFFER; RIGHT OF FIRST REFUSAL; EARLY PURCHASE OPTION; END OF TERM PURCHASE OPTION

6.1 Right of First Offer ("ROFO").

6.1.1 Except in accordance with this Article 6, Supplier: (a) shall not sell, transfer or offer or negotiate to sell or transfer, the Facility; and (b) shall cause its immediately upstream owner(s) (together with Supplier, each a "ROFO Seller") not to sell, transfer or offer or negotiate to sell or transfer, any ownership interest in Supplier (the Facility and ownership interests in Supplier, each the "Offered Interests") other than to an Affiliate in accordance with the provisions of Section 23.2 and other than a Supplier's Lenders Transaction (each a "Restricted Transaction"). For purposes hereof, a "Supplier's Lenders Transaction" means any transaction between Supplier or its Affiliates, on the one hand, and Supplier's Lenders, on the other hand. If a ROFO Seller intends to enter into a Restricted Transaction, Supplier shall provide Buyer with written notice of same (a "Seller ROFO Notice"), and Buyer shall have a right of first offer with respect to the purchase of such Offered Interests. Within fifteen (15) days, if prior to Commercial Operation Date, or thirty (30) days if on or after the Commercial Operation Date, after receipt of the Seller ROFO Notice, Buyer shall notify Supplier in writing of its decision whether or not to negotiate with ROFO Seller for the purchase of the Offered Interests (the "Buyer ROFO Notice"). If Buyer elects to negotiate with ROFO Seller for the purchase of the Offered Interests, Supplier shall cause ROFO Seller to negotiate in good faith and exclusively with Buyer, for a period of not less than sixty (60) days, if prior to Commercial Operation Date, or ninety (90) days if on or after the Commercial Operation Date, following ROFO Seller's receipt of the Buyer ROFO Notice, the terms of a purchase by Buyer or its designee of the Offered Interests (such fifteen (15) day or thirty (30) day period as extended, if applicable, by such sixty (60) day period, or ninety (90) day period as applicable the "ROFO Period"). NV Energy may seek PUCN approval of the final agreement for the acquisition of the Offered Interests. If Buyer elects not to negotiate with ROFO Seller, or, after commencing negotiations, if Buyer determines that it will not purchase the Offered Interests, then, in either case, Buyer shall promptly notify Supplier thereof, and the ROFO Period shall terminate as of the date that any such notice is provided by Buyer.

6.1.2 In the event that: (a) Buyer does not elect to negotiate with ROFO Seller for the purchase of the Offered Interests pursuant to Section 6.1.1, or (b) negotiations commence pursuant to Section 6.1.1 but Buyer thereafter notifies Supplier that it has determined it will not purchase the Offered Interests, ROFO Seller may negotiate a Restricted Transaction with any other Person within one hundred eighty (180) days following ROFO Seller's receipt of the Buyer ROFO Notice, subject, in all cases, to the terms and conditions of this Agreement, including Section 6.1.3 and the provisions of Article 23. Except as set forth in Section 6.6, in no event may ROFO Seller enter into a Restricted Transaction with any other Person on terms less favorable to ROFO Seller than such terms, if any, as were offered by Buyer during the ROFO Period. If definitive transaction documents between ROFO Seller and Buyer or its designee are not executed with respect to the Offered Interests within the ROFO Period, then the Parties will pursue the auction process set forth in Section 6.6.

6.1.3 Except as set forth in Section 6.6, if ROFO Seller and such other Person do not agree upon the terms, conditions and pricing for the Offered Interests by entering into definitive transaction documents within one hundred eighty (180) days following the expiration of the ROFO Period, ROFO Seller and any Offered Interests shall again be subject to this Section 6.1 with respect to any Restricted Transaction.

6.2 Early Purchase Option.

6.2.1 Supplier hereby grants to Buyer options to purchase the Facility ("Early Purchase Option") on a date chosen by Buyer during the six (6) months after the Facility's 10^{th}, 15^{th} and 20^{th} anniversaries of the Commercial Operation Date at the Fair Market Value, which option may be exercised by Buyer providing written notice to Supplier no less than one hundred and eighty (180) days before the applicable anniversary ("Preliminary Interest Notice").

6.2.2 Determination of Fair Market Value of the Facility. Promptly following delivery of a Preliminary Interest Notice, Buyer and Supplier shall mutually agree to the Fair Market Value of the Facility. If Buyer and Supplier cannot mutually agree to a Fair Market Value of the Facility within one (1) month of delivery of the Preliminary Interest Notice, then the Parties will pursue the auction process set forth in Section 6.6.

6.3 Purchase Option at the End of Term. Supplier hereby grants to Buyer the option to purchase the Facility at the end of the Term at the Fair Market Value (the "Final Purchase Option"), which option may be exercised by Buyer providing a notice to Supplier no less than one hundred and eighty (180) days prior to the end of the Term of Buyer's election to exercise such option.

6.4 Efforts Required to Transfer Facility and Offered Interests. If Buyer exercises the Early Purchase Option, the Final Purchase Option or otherwise agrees to purchase the Facility pursuant to Section 6.1, then such purchase shall occur pursuant to a form of purchase and sale agreement which shall contain customary representations, warranties and covenants and otherwise be in form reasonably acceptable to the Parties. If the Parties are unable to reach agreement on the terms and conditions of the purchase and sale agreement within ninety (90) days after reaching mutual agreement on the Fair Market Value of the Facility, then the Parties will pursue the auction process set forth in Section 6.6. It shall be a condition of any such purchase that Buyer obtains all necessary Governmental Approvals and notwithstanding any language to the contrary in this Agreement Buyer shall be given sufficient time to obtain such approvals in accordance with applicable statutes and regulations. Pursuant to the purchase and sale agreement, Supplier will take all actions necessary to transfer by deed, bill of sale, or both, the Facility to Buyer, as well as all other improvements placed on the Project Site by Supplier that are required for the continued and uninterrupted use, maintenance and operation of the Facility, free and clear from any lien or monetary encumbrance created by or on behalf of Supplier or its Affiliates. In addition, Supplier will assign to Buyer all transferrable Governmental Approvals applicable to the Facility and Required Facility Documents, and all transferrable warranties for the Facility. Supplier shall cooperate with Buyer to assign and enforce any and all warranties that apply to the Facility or any of its component parts, which obligation shall survive the termination of this Agreement.

6.5 Due Diligence; Cooperation; Governmental Approvals; Notice of Rights. Supplier will provide in a timely manner, information regarding the Offered Interests which is reasonably requested by Buyer to allow Buyer to perform due diligence for the purchase of the Offered Interests pursuant to this Article 6. Supplier shall further provide commercially reasonable cooperation and assistance to Buyer, without further compensation, throughout Buyer's efforts to properly account for and obtain any necessary Governmental Approvals with respect to the purchase of the Offered Interests pursuant to this Article 6. Notwithstanding anything in this Agreement or any definitive transaction documentation, Buyer shall not be obligated to proceed with the purchase of any Offered Interests pursuant to this Article 6 if Buyer does not receive all necessary Governmental Approvals in connection with such transaction. Supplier shall put any Person with which it enters into discussions or negotiations regarding a Restricted Transaction on notice of the rights of Buyer set forth in this Article 6. Buyer shall be permitted to file a notice of the rights contained in this Article 6 with respect to the Project Site.

6.6 Auction Process. If Buyer and Supplier are unable to agree on both price and non-pricing terms and conditions of any proposed acquisition of the Facility or the equity interests in Supplier by Buyer pursuant to Sections 6.1-6.5, then within thirty (30) days after the failure to agree upon price and the terms of the definitive transaction documents pursuant to Section 6.1.2, the Fair Market Value pursuant to Sections 6.2.2 and 6.3, or the terms and conditions of the purchase and sale agreement pursuant to Section 6.4, as applicable, Supplier shall engage a nationally recognized investment advisor experienced in advising on the sale of assets similar to the Facility who shall commence a formal process for the sale of either the Facility or the equity interests in Supplier, at Supplier's election. Buyer shall be permitted to participate in any such process on the same terms as all other bidders and as outlined in the process guidelines issued by Supplier. Supplier may select any party participating in such a process that is a Qualified Transferee as the purchaser of the Facility or the equity interests in Supplier and, notwithstanding anything to the contrary herein, Buyer shall have no further right of consent with regard thereto and shall cooperate with Supplier in consummation of the transactions with such Qualified Transferee. Notwithstanding any time limitations relating to any ROFO or any Purchase Option, Supplier shall have a period of nine (9) months from date of selection of the investment advisor in accordance with this Section 6.6 to sign a binding agreement with a Qualified Transferee for the sale of the Facility or the equity interests in Supplier, during which period Buyer shall have no other rights relating to the acquisition of the Facility or the equity interests in Supplier other than the right to participate in such process.

6.7 Termination of Agreement. Upon the acquisition of the Facility by Buyer pursuant to Section 6.4 or Section 6.6, this Agreement shall terminate and neither Party shall have any obligation to the other under this Agreement, except with respect to the terms and provisions hereof that expressly survive the termination of this Agreement.

7. METERING, INVOICING AND PAYMENTS

7.1 Metering.

7.1.1 Meters. Buyer shall, at Supplier's cost, provide, install, own, operate and maintain all Meter(s) in good operating condition. The metering system design shall be subject to Buyer's approval, which shall be consistent with Good Utility Practice, and shall be submitted to Buyer not later than Supplier's completion of the Project Milestone in Section 2(B) of Exhibit 6. The meter system shall have Buyer specified equipment to connect with Buyer's automated meter database, allowing for the DC-coupled nature of the Storage Facility. The Meters shall be used for quantity measurements under this Agreement. Such equipment shall be bi-directional, shall be capable of measuring and reading instantaneous and hourly real and reactive energy and capacity and account for losses from the meter location to the Delivery Points or to the Storage Facility Metering Points. Supplier, at its expense, may install additional check meters. Supplier shall not install any check-metering equipment on or connected to Buyer-owned facilities including instrument transformers or metering circuitry wiring. Supplier shall, at its sole expense, install any additional or different Meters or related equipment necessary to comply with the requirements of Transmission Provider, any Electric System Authority or any Governmental Authority.

7.1.2 WREGIS Metering. Supplier shall cause, at its sole cost and expense, the Facility to implement all necessary generation information communications in WREGIS, and report generation information to WREGIS pursuant to one or more WREGIS-approved meters that are dedicated to the Facility and only the Facility. Supplier shall be responsible to obtain all qualified reporting entity services required by WREGIS at Supplier's expense should Buyer not in its sole and absolute discretion provide them.

7.1.3 Location. Meters shall be installed at the location(s) specified in Exhibit 5, or as otherwise may be reasonably determined by Buyer and Supplier to effectuate this Agreement.

7.1.4 Non-Interference. Supplier shall not undertake any action that may interfere with the operation of the Meters. Supplier shall be liable for all costs, expense, and liability associated with any such interference with the Meters. Metering requirements shall apply such that there is no impact on the infrastructure and output associated with the Facility due to the presence of any other contiguous project.

7.1.5 Meter Testing. Meters shall be tested at least once every two (2) years by Buyer. Either Party may request a special test of Meters or check meters, but the requesting Party shall bear the cost of such testing unless there is an inaccuracy outside the limits established in American National Standard Institute Code for Electricity Metering (ANSI C12.1), latest version, or nationally approved equivalent (as available for DC meters), in which case the Party whose meters were found to be inaccurate (i.e. Buyer with respect to the Meters and Supplier with respect to check meters) shall be responsible for the costs of the special testing. Meters installed pursuant to this Agreement shall be sealed and the seal broken only when the meters are to be adjusted, inspected or tested. Authorized representatives of both Parties shall have the right to be present at all routine or special tests and to inspect any readings, testing, adjustment or calibration of the Meters or check meters. Buyer's Operating Representative shall provide fifteen (15) Business Days prior notice of routine Meter testing to Supplier's Operating Representative. If Supplier has installed check meters in accordance with Section 7.1.1, Supplier shall test and calibrate each such meter at least once every two (2) years. Supplier's Operating Representative shall provide fifteen (15) Business Days prior notice of routine check meter testing to

Buyer's Operating Representative. In the event of special Meter testing, the Parties' Operating Representatives shall notify each other with as much advance notice as practicable.

7.1.6 Metering Accuracy. If the Meters are registering but their accuracy is outside the limits established in ANSI C12.1 or nationally approved equivalent (as available for DC meters), Buyer shall repair and recalibrate or replace the Meters, and Buyer shall adjust payments to Supplier for the Delivered Amount for the lesser of the period in which the inaccuracy existed and ninety (90) days. If the period in which the inaccuracy existed cannot be determined, adjusted payments shall be made for a period equal to one-half of the elapsed time since the latest prior test and calibration of the Meters; provided, however, that the adjustment period shall not exceed ninety (90) days. If adjusted payments are required, Buyer shall render a statement describing the adjustments to Supplier within thirty (30) days of the date on which the inaccuracy was rectified. Additional payments to Supplier by Buyer shall be made within thirty (30) days of receipt of Buyer's statement. Any payments due Buyer pursuant to this Section 7.1.6 shall accompany Supplier's next Billing Period statement.

7.1.7 Failed Meters. If the Meters fail to register, Buyer shall make payments to Supplier based upon Supplier's check metering; provided, however, that if the accuracy of the check meters is subsequently determined to be outside the limits established in ANSI C12.1, Buyer shall adjust the payments to Supplier for the Delivered Amount calculated using the check meters for the lesser of the period in which the inaccuracy existed and ninety (90) days. If the period in which the inaccuracy existed cannot be determined, adjusted payments shall be made for a period equal to one-half of the elapsed time since the latest prior test and calibration of the check meters; provided, however, that the adjustment period shall not exceed ninety (90) days. If no such metering is available, payments shall be based upon the Parties' best estimate of the Delivered Amount. In such event, such payments made based upon the Parties' estimate of the Delivered Amount shall be in full satisfaction of payments due hereunder. If the Parties cannot agree on a best estimate of the Delivered Amount the Dispute shall be resolved in accordance with Article 21.

7.1.8 Weather Meter. Supplier shall, at Supplier's cost and no later than six (6) months prior to the Commercial Operation Date, provide, install, own, operate and maintain a device for the measurement of weather conditions relevant to the generation of Energy at the Project Site (the "Weather Meter"), provided that Supplier shall not select the type of Weather Meter without the prior written consent of Buyer, which shall not be unreasonably withheld. No later than twelve (12) months prior to the Commercial Operation Date, the Parties shall agree on the location of the Weather Meter and any applicable protocols for testing, accuracy, failure or other relevant characteristics of the Weather Meter.

7.2 Invoices.

7.2.1 Monthly Invoicing and Payment. On or before the 10th day of each month, Supplier shall send to Buyer an Invoice for the prior month (a "Billing Period"). Supplier shall calculate the Invoice based upon Meter data available to Supplier and as set forth in Exhibit 2B. Any correction or Dispute with respect to an Invoice is waived unless Buyer is notified within twelve (12) months, or Supplier is notified within thirty-six (36) months, after the Invoice is rendered or any specific adjustment to the Invoice is made. If an Invoice is not delivered to Buyer within twelve (12) months after the close of the Billing Period, the right to payment for such Billing Period is waived.

7.2.2 Replacement PC Invoice Calculation. In addition to the requirements for monthly Invoices set forth in this Section 7.2, if after the PC Administrator issues its final PC statement covering any Measurement Period and a PC Shortfall (as determined in accordance with Section 3.7.1) exists, Buyer shall send to Supplier an Invoice for such Measurement Period, which shall include the calculations set forth in Exhibit 2C.

7.2.3 Amounts Owing to Buyer. The Invoice referred to in Section 7.2.1 shall offset any amounts owing to Buyer with amounts owing to Supplier, and shall indicate the net payment due Supplier or Buyer, as applicable. Supplier shall provide supporting data in reasonable detail to support its calculations of any amounts owing to Buyer. Buyer may prepare and send to Supplier an Invoice for amounts owing to Buyer under this Agreement, and any such amounts will be payable to Buyer within ten (10) Business Days from Supplier's receipt of such Invoice, subject to the terms and provisions of Section 7.2.5.

7.2.4 Method of Payment. Buyer or Supplier, as applicable, shall remit the payment of any undisputed amounts by wire or electronic fund transfer or otherwise pursuant to the instructions stated in Exhibit 4. Payment will be made on or before the later of the twentieth (20th) day following the end of each Billing Period (or the next following Business Day, if such twentieth (20th) day does not fall on a Business Day) or ten (10) Business Days from receipt of Invoice.

7.2.5 Examination and Correction of Invoices. As soon as practicable either Party shall notify the other Party in writing of any alleged error in an Invoice.

7.2.5.1 If a Party notifies the other Party of an alleged error in an Invoice, the Parties agree to use good faith efforts to reconcile the billing and mutually agree on the appropriate correction, if any.

7.2.5.2 If a correction is determined to be required, the invoicing Party shall provide an adjusted Invoice to the invoiced Party. If such error results in an additional payment to the invoicing Party, the invoiced Party shall pay such invoicing Party the amount of the adjusted Invoice within thirty (30) days of the date of receipt of the adjusted Invoice. If such error resulted in a refund owed to the invoiced Party, the invoicing Party shall pay the invoiced Party the amount of the adjusted Invoice within thirty (30) days of the date of receipt of the statement or at the invoiced Party's option, the invoiced Party may net such amount against the subsequent monthly payment to the invoicing Party.

7.3 Overdue Amounts and Refunds. Overdue amounts and refunds of overpayments shall bear interest from and including, the due date or the date of overpayment, as the case may be, to the date of payment of such overdue amounts or refund at a rate calculated pursuant to 18 C.F.R. § 35.19a.

7.4 Access to Books and Records. Supplier agrees to make available for inspection upon five (5) Business Days written notice from Buyer its books and records as necessary for the purpose of allowing Buyer to verify the information contained within the invoices presented pursuant to Section 7.2.

7.5 Parties' Right to Offset. Either Party shall have the right to offset any amounts owed to the other Party under this Agreement including amounts owed by Supplier to Buyer for Standby Service.

7.6 Taxes. Buyer is responsible for any Taxes imposed on or associated with the Energy or Discharging Energy or its delivery from and after the Delivery Points. Supplier is responsible for any Taxes imposed on or associated with the Energy or Discharging Energy or its delivery up to or at the Delivery Points. Either Party, upon written request of the other Party, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if such Party is exempt from Taxes, and shall use reasonable efforts to obtain and cooperate with the other Party in obtaining any exemption from or reduction of any Tax. Each Party shall hold harmless the other Party in accordance with Article 18 from and against Taxes imposed on the other Party as a result of such Party's actions or inactions in contravention of this Section 7.6.

8. FACILITY CONSTRUCTION; OPERATIONS AND MODIFICATIONS

8.1 Construction of Facility. Supplier shall construct or cause the Facility to be constructed in accordance with Good Utility Practices and the Project Milestones and to ensure that: (a) Supplier is capable of meeting its supply and delivery obligations with respect to Product over the Term; (b) the Facility is consistent with the technical specifications set forth in Exhibit 11; (c) subject to Section 3.5, the Generating Facility is at all times considered a Renewable Energy System; and (d) subject to Section 3.5, the Generating Facility is at all times in compliance with all requirements imposed on Renewable Energy Systems as set forth in the applicable Renewable Energy Law. Supplier shall deliver to Buyer an ALTA Survey of the Project Site within ten (10) days of such survey becoming available to Supplier, but in no event later than the issuance of the Notice to Proceed in accordance with Exhibit 6. Supplier shall provide to Buyer in a form satisfactory to Buyer: (y) not later than the Project Milestone described in Section 2(B) of Exhibit 6, a completed version of Exhibit 14; and (z) within thirty (30) days after the Commercial Operation Date, a revised version of Exhibit 14 reflecting the Facility as built. Supplier shall provide Buyer with copies of the Construction Contract promptly after its execution and any documentation and drawings reasonably requested by Buyer, redacted of any pricing or other proprietary information and any other information Supplier is not permitted to disclose pursuant to a confidentiality agreement, provided that Supplier shall use commercially reasonable efforts to secure in the Construction Contract the ability to disclose the terms of the Construction Contract other than pricing information. The Parties acknowledge and agree that the Shared Facilities may be subject to certain shared facilities or co-tenancy agreements to be entered into among Supplier, Supplier's Affiliates, or third parties pursuant to which certain Shared Facilities may be subject to joint ownership and shared maintenance and operation arrangements; *provided* that such agreements (i) shall permit Supplier to perform or satisfy, and shall not purport to limit, its obligations hereunder and (ii) provide for separate metering of the Facility.

8.2 Performance of Project Milestones. Supplier shall complete each Project Milestone specified in Exhibit 6 on or before 16:00 hours PPT on the date specified for each Project Milestone listed in Exhibit 6.

8.2.1 Completion of Project Milestones. Upon Supplier's completion of each Project Milestone, Supplier shall provide to Buyer in writing, pursuant to Section 29.1, documentation as specified in Exhibit 6 and reasonably satisfactory to Buyer demonstrating such Project Milestone completion. Such documentation shall be provided within thirty (30) days of such completion but, if it is provided later than the date specified for such Project Milestone listed in Exhibit 6, Seller shall also provide the information described below and, if the Project Milestone is a Critical Project Milestone, pay liquidated damages as provided below. Buyer shall acknowledge receipt of the documentation provided under this Section 8.2.1 and shall provide Supplier with written acceptance or denial of each Project Milestone within fifteen (15) Business Days of receipt of the documentation. If Buyer does not acknowledge receipt or provide written acceptance or denial of any Project Milestone within fifteen (15) Business Days, then such Project Milestone will be deemed to occur on the date that such documentation was provided to Buyer. Failure of Supplier to achieve a Critical Project Milestone on or before the scheduled date (or, in the case of the Commercial Operation Deadline, after expiration of the applicable period for which Daily Delay Damages are owed by Supplier pursuant to Section 8.5.1), will constitute an Event of Default as provided in Article 24. If any Project Milestone (other than a Critical Project Milestone) is not completed on or before the date specified in Exhibit 6, Supplier will (i) inform Buyer of a revised projected date for the occurrence or completion of such Project Milestone (which will be deemed the new deadline for such Project Milestone), and any impact on the timing of the Commercial Operation Date (and on any other Project Milestone) and (ii) provide Buyer with a written report containing Supplier's analysis of the reasons behind the failure to meet the original Project Milestone deadline and whether remedial actions are necessary or appropriate, and describing any remedial actions that Supplier intends to undertake to ensure the timely achievement of the Commercial Operation Date. Provided that Supplier complies with the preceding sentence, no failure of Supplier to achieve a Project Milestone (other than a Critical Project Milestone) on or before the scheduled date will constitute an Event of Default.

8.2.2 Progress Towards Completion. Supplier shall notify Buyer's Contract Representatives promptly (and in any event within ten (10) Business Days) following its becoming aware of information that leads to a reasonable conclusion that a Project Milestone will not be met, and shall convene a meeting with Buyer to discuss the situation not later than fifteen (15) Business Days after becoming aware of this information.

8.2.3 Interconnection Study. Supplier has submitted an interconnection request to the Transmission Provider requesting to increase the interconnection capacity available under the 230 kV IA, to allow the entire Facility to be interconnected at 230 kV through a single point of interconnection pursuant to the 230 kV IA. Promptly after receiving a system impact study report from the Transmission Provider for this interconnection request, Supplier shall provide a copy of the report to Buyer. If the estimated cost of network upgrades assigned to Supplier in the system impact study report for this interconnection request are less than five million seven hundred thousand dollars ($5,700,000), then (a) the definition of "IA" will be revised to refer only to the 230 kV IA, (b) the references to "Delivery Points" throughout this Agreement will be revised to refer to a single 230 kV Delivery Point, and (c) Supplier will provide revised versions of Exhibits 1, 3A, 3B, and 5, which will supersede the then existing Exhibits 1, 3A, 3B, and 5.

8.3 Commercial Operation Date.

8.3.1 Notice of Testing. Supplier shall notify Buyer's Contract Representatives at least ten (10) Business Days prior to the commencement of any performance tests required by the Construction Contract, including any performance tests required by Exhibit 7. Buyer shall have the right to witness all tests or have Buyer's representatives witness all tests. The presence of Buyer or a Buyer representative shall not be construed as an obligation on Buyer's part to design, conduct, monitor or endorse any test results or as a ratification or acceptance thereof. Buyer shall be deemed to waive its right to be present at the performance tests if Buyer fails to appear at the scheduled time for the performance tests.

8.3.2 Certifications. Within five (5) Business Days of the successful completion of the performance tests pursuant to Exhibit 7, Supplier shall provide Buyer with written notice stating when Supplier believes that the Facility has achieved Commercial Operation, including the following written certifications.

8.3.2.1 A certification by a duly authorized officer of Supplier stating the following:

"I, [Name], in my capacity as the duly appointed [Title] of [Supplier] ("Supplier") hereby certify, on behalf of Supplier that: (a) the Facility has been constructed in accordance with Good Utility Practice and the Generating Facility has delivered Energy to and at the Delivery Points and Charging Energy to the Storage Facility Metering Points; (b) all of the requirements set forth in Sections 8.1, 8.3 and 17.2, and Exhibits 6 and 7 of the Long-Term Renewable Power Purchase Agreement between Supplier and Buyer dated [________], ("Agreement") have been satisfied; (c) I am authorized to act on behalf of and bind Supplier with respect to this certificate; (d) Supplier has received the Supplier Required Regulatory Approvals listed in Exhibit 10 and has entered into or obtained all Required Facility Documents as listed in Exhibit 12, true, correct and complete copies of which are attached (other than confidential or commercial terms which have been redacted); and (e) Supplier acknowledges that Buyer is relying on this certification in connection with carrying out its obligations under the Agreement and Supplier will indemnify Buyer for any inaccuracy related to this certification; and (f) the Storage Facility is fully capable of charging, storing and discharging energy up to the Storage Contract Capacity."

8.3.2.2 A certificate addressed to Buyer from a Licensed Professional Engineer confirming: (1) the nameplate capacity rating of the Generating Facility at the anticipated time of Commercial Operation in MW AC ("<u>Certified Nameplate Capacity Rating</u>") and (2) that the Facility is able to generate and deliver electric power reliably in amounts expected by this Agreement and in accordance with all other terms and conditions hereof, including the Storage Operating Procedures; and, (3) performance tests required by Exhibit 7 have been successfully completed; and (4) that the Storage Facility is able to charge, store and discharge energy reliably in amounts expected by this Agreement and in accordance with all other terms and conditions hereof, including the Storage Operating Procedures. The Certified Nameplate Capacity Rating must not be less than six hundred twenty-one (621) MW.

8.3.2.3 A certificate addressed to Buyer from a Licensed Professional Engineer stating that, all required interconnection tests have been completed and the Facility is physically interconnected with the Transmission System and able to deliver Net Energy consistent with the terms of this Agreement.

8.3.2.4 An opinion from an attorney licensed in the state of Nevada that is not an employee of Supplier (or any Affiliate) and has no financial interest in the Facility addressed to Buyer stating that Supplier has received the Supplier Required Regulatory Approvals listed in Exhibit 10 and has entered into or obtained all Required Facility Documents as listed in Exhibit 12, and attaching copies of the Supplier Required Regulatory Approvals listed in Exhibit 10 and all Required Facility Documents listed in Exhibit 12, provided, however, that Supplier may redact or omit confidential or commercial terms from such documents. The opinion shall further state that the real estate rights obtained by Supplier with respect to the Project Site are adequate in all respects for the ownership, operation, access to and maintenance of the Facility as of the date of the opinion.

8.3.3 Dispute of Commercial Operation. Buyer will have fifteen (15) Business Days after receipt of the certifications required by this Section 8.3 in which to Dispute the Commercial Operation Date by written notice to Supplier. In the event of such a Dispute, Buyer and Supplier will attempt in good faith to resolve the Dispute. If the Parties are unable to resolve the Dispute within fifteen (15) Business Days' after Buyer's notice of Dispute, then either Party may seek resolution of the Dispute in accordance with Article 21. Notwithstanding the foregoing, Buyer's failure to Dispute the certification will in no way affect its rights to indemnification for any inaccuracy related to the certification, including overpayments that may be paid by Buyer due to such inaccurate certification.

8.4 Failure to Achieve Commercial Operation.

8.4.1 In the event Supplier fails to achieve Commercial Operation by the Commercial Operation Deadline and Supplier fails to promptly pay Daily Delay Damages as provided in Section 8.5.1, Buyer may elect to terminate this Agreement and, Supplier shall pay to Buyer, and Buyer shall be entitled to collect or retain, as applicable, the full Development Security amount as liquidated damages for Supplier's failure to meet its obligations prior to the Commercial Operation Deadline. Upon Buyer's collection of the full Development Security amount from Supplier (or from security provided on Supplier's behalf), this Agreement will be terminated, and neither Party will have any further obligations under this Agreement, including under Section 8.5, except those obligations expressly provided to survive termination pursuant to Section 2.4. The Parties agree that it would be extremely difficult and impracticable under presently known and anticipated facts and circumstances to ascertain and fix the actual damages Buyer would incur if the Supplier does not meet its obligations hereunder prior to the Commercial Operation Deadline, and, accordingly, the Parties agree that retention by Buyer of the full Development Security is reasonable as liquidated damages, and is not a penalty, and except as provided otherwise in this Agreement, shall constitute Buyer's sole and exclusive remedy in the event that the Agreement is terminated pursuant to this Section 8.4.1.

8.4.2 The provisions of this Section 8.4 are in addition to, and not in lieu of, any of Buyer's rights or remedies under this Agreement, including Article 24, for Events of Default other than the failure to achieve Commercial Operation by the Commercial Operation Deadline.

8.5 Delay Damages.

8.5.1 In the event Supplier fails to achieve Commercial Operation by the Commercial Operation Deadline, then for each day up to, but not exceeding, one hundred and eighty (180) days, that Supplier fails to achieve Commercial Operation, Supplier shall be obligated to pay to Buyer liquidated damages equal to Daily Delay Damages. If Daily Delay Damages have been accumulated for one hundred and eighty (180) days and Commercial Operation has not been achieved, Buyer may terminate this Agreement. Supplier shall pay any amounts owed to Buyer under this Section 8.5 in the Billing Periods immediately succeeding the Billing Period during which Supplier's obligation to pay such amounts arose.

8.5.2 In addition to amounts payable pursuant to Section 8.5.1, Supplier shall be liable, in accordance with Section 18.1, for any Regulatory Penalties incurred or suffered by Buyer as a result of Supplier's failure to achieve Commercial Operation by the Commercial Operation Deadline.

8.5.3 The provisions of this Section 8.5 are in addition to, and not in lieu of, any of Buyer's rights or remedies under Article 24 for Events of Default other than the failure to achieve Commercial Operation by the Commercial Operation Deadline.

8.5.4 The Parties agree that it would be extremely difficult and impracticable under presently known and anticipated facts and circumstances to ascertain and fix the actual damages Buyer would incur if the Supplier does not meet its obligations hereunder prior to the Commercial Operation Deadline, and, accordingly, the Parties agree that payment by Supplier of Daily Delay Damages is reasonable as liquidated damages, and is not a penalty.

8.6 Nameplate Damages.

8.6.1 If the Certified Nameplate Capacity Rating is less than the Expected Nameplate Capacity Rating, Supplier shall provide Buyer a onetime payment in an amount equal to (a) subtracting (i) Certified Nameplate Capacity Rating from (ii) the Expected Nameplate Capacity Rating in MW, multiplied by (b) Deficit Damages Rate per MW of difference ("Deficit Damages"), provided that in no event shall the Certified Nameplate

Capacity Rating be less than six hundred twenty-one (621) MW. Supplier's total liability for Deficit Damages shall not exceed thirteen million eight hundred thousand dollars ($13,800,000). Deficit Damages, if any, shall be paid to Buyer within five (5) Business Days of Buyer's receipt of the certification required in Section 8.3.2.2. Upon payment of Deficit Damages: (i) Exhibit 1 shall be revised to reflect the Certified Nameplate Capacity Rating; and (ii) the Dispatch Availability Amount, the Maximum Amount and the Yearly PC Amount shall each be adjusted by the ratio of the Certified Nameplate Capacity Rating to the Expected Nameplate Capacity Rating, and Exhibits 13 and 18 shall be revised accordingly.

8.6.2 If the Certified Nameplate Capacity Rating is greater than the Expected Nameplate Capacity Rating by greater than two percent (2%), Supplier shall pay Buyer a onetime payment in an amount equal to one half of the Development Security, paid to Buyer within five (5) Business Days of Buyer's receipt of the certification required in Section 8.3.2.2. If Supplier fails to make such payment in a timely manner, Buyer may retain such amount from the Development Security or Operating Security. Supplier shall take all necessary actions, including but not limited to software or hardware solutions, to limit the Certified Nameplate Capacity Rating to the Expected Nameplate Capacity Rating.

8.6.3 If the tested Storage Contract Capacity as of the Commercial Operation Date is more than three percent (3%) below three hundred eighty (380) MW, Supplier shall provide Buyer, as Buyer's sole remedy for such shortfall, a onetime payment in an amount equal to (a) subtracting (i) the tested Storage Contract Capacity from (ii) three hundred sixty-eight and six-tenths (368.6) MW, multiplied by (b) Storage Deficit Damages Rate per MW of difference ("Storage Deficit Damages"), provided that in no event shall the Storage Contract Capacity be less than three hundred sixty (360) MW. Supplier's total liability for Storage Deficit Damages shall not exceed five million, one hundred sixty thousand dollars ($5,160,000). Storage Deficit Damages, if any, shall be paid to Buyer within five (5) Business Days after the Commercial Operation Date. Upon payment of Deficit Damages, Exhibit 1 shall be revised to reflect the tested Storage Contract Capacity as deemed appropriate by an independent, licensed engineer for the purpose of all relevant calculations hereunder.

8.7 Modification. Except as otherwise permitted in this Agreement, Supplier shall not be permitted to make any modification to the Generating Facility without the prior written consent of the Buyer which may be withheld in Buyer's sole discretion. The above shall not prevent Supplier from performing maintenance and repairs to the Generating Facility so long as such maintenance and repairs do not alter the Generating Facility as defined. In addition, Supplier shall be permitted, without Buyer's prior consent, to make any change (a) in electrical inverters, subject to approval in the Interconnection Process, as set forth in Section 25.6; (b) any change to the number, sizing, type, chemical composition, or efficiency of the photovoltaic modules; (c) any change with respect to Storage Facility battery chemistry so long as the battery chemistry remains within the lithium-ion category; and (d) subject to Supplier's compliance with Section 25.14, if applicable, any change with respect to equipment suppliers for the Facility; provided, however, that such changes may not increase any of the parameters set forth in Exhibit 1 by more than one percent (1%) without Buyer's prior written consent except for Section 9(e) of Exhibit 1. Any modifications requiring Buyer's consent and for which Buyer has provided written consent shall be conducted in accordance with Good Utility Practice and all applicable Laws and reliability criteria, as such may be amended from time to time, and the requirements of Article 11. If Supplier makes a modification to the Facility that requires Buyer's consent under this Section 8.7 and is not approved by Buyer, Buyer shall be entitled to receive in addition to any other remedy available to Buyer as liquidated damages the full amount of the Development Security or Operating Security, as applicable. The Parties agree that it would be extremely difficult and impracticable under presently known and anticipated facts and circumstances to ascertain and fix the actual damages Buyer would incur if the Supplier does not meet its obligations hereunder, and, accordingly, the Parties agree that payment by Supplier of Development Security or Operating Security, as applicable, is reasonable as liquidated damages, and is not a penalty.

8.8 Operation and Maintenance. Subject to Section 3.5, Supplier, at all times shall install, operate, maintain and repair the Facility in accordance with Good Utility Practice and applicable Laws and to ensure: (a) Supplier is capable of meeting its supply obligations over the Term; (b) the Generating Facility is at all times a Renewable Energy System; and (c) Supplier is at all times in compliance with all requirements of a renewable energy generator set forth in the Renewable Energy Law. Supplier shall (x) maintain records of all operations of the Facility in accordance with Good Utility Practice, and (y) follow all regulations, directions and procedures of Buyer, Transmission Provider, any Electric System Authority and any other Governmental Authority to protect and prevent the Transmission System from experiencing any negative impacts resulting from the operation of the Facility. In the event of an inconsistency between any applicable procedures, Buyer may direct which procedures shall govern (or barring direction from Buyer, the more stringent procedure shall govern). Supplier shall use all reasonable efforts to avoid any interference with Buyer's operations. Supplier shall cause the Energy to meet the Power Quality Standards at all times, and shall operate the Facility consistent with WECC, NERC, Buyer, Electric System Authority, Governmental Authority and Transmission Provider requirements. Prior to the beginning of the Term, the Parties shall mutually develop written procedures governing operations of the Storage Facility, not in contravention or amendment of any right or obligation set forth herein, including (a) minimum and maximum operating parameters; (b) procedures for scheduling and dispatch, (c) methods of day-to-day communications, (d) key personnel lists, (e) recordkeeping and (f) such other procedures and protocols as the Parties deem appropriate for implementation of this Agreement (the "Storage Operating Procedures"); provided that failure to agree on such procedures shall not relieve either of the Parties of its obligations under this Agreement. The Storage Operating Procedures are provided in Exhibit 24.

8.9 Operation and Maintenance Agreement. No later than one hundred eighty (180) days prior to the Commercial Operation Date, if Supplier intends to subcontract any aspect of the operation of the Facility, Supplier shall provide a copy of any proposed agreement between Supplier and such sub-operator which requires the sub-operator to operate the Facility in accordance with the terms hereof which shall be attached to this Agreement as Exhibit 15. Supplier shall also provide a certified copy of a certificate warranting that the sub-operator is a corporation, limited liability company or partnership in good standing with the State in which the Facility is located, which shall be attached to this Agreement as part of Exhibit 15. Buyer shall have fifteen (15) days in which to notify Supplier of its objection to any proposed sub-operator that is not a Qualified Operator, in which case Supplier shall not subcontract with such proposed sub-operator.

8.10 Right to Review. Buyer shall have the right to review during normal business hours the relevant books and records of Supplier to confirm the accuracy of anything relating to this Agreement. Buyer is under no obligation to exercise any of these review rights. Buyer shall have no liability to Supplier for failing to advise it of any condition, damages, circumstances, infraction, fact, act, omission or disclosure discovered or not discovered by Buyer with respect to the Facility or this Agreement.

8.11 Undertaking of Agreement; Professionals and Experts. Supplier has engaged those professionals or other experts it believes necessary to understand its rights and obligations pursuant to this Agreement. All professionals or experts, including engineers, attorneys or accountants, that Supplier may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Supplier. In entering into this Agreement and the undertaking by Supplier of the obligations set forth herein, Supplier has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of Buyer in connection with the transactions contemplated by this Agreement.

9. EMERGENCY

9.1 Compliance. Supplier shall promptly comply with any applicable requirements of any Electric System Authority, Governmental Authority, Transmission Provider, transmission operator or their successors, regarding the reduced or increased production of the Facility or otherwise in the event of any Emergency.

9.2 Notification. Supplier shall provide prompt oral and written notification to Buyer of any Emergency, including a description in reasonable detail of the Emergency and any actions undertaken to prevent, avoid or mitigate Loss therefrom or to expedite the restoration of service.

9.3 Due Care. In the event of an Emergency, Supplier shall take all reasonable actions to prevent, avoid or mitigate Loss therefrom or to expedite the restoration of service; provided, however, that Supplier shall give Buyer prior notice, if practicable, before taking any action. This Section 9.3 shall not be construed to supersede Sections 9.1 and 9.2.

9.4 Not Excused Product. An Emergency declared by Supplier with respect to the Facility will not result in any Excused Product except to the extent the Emergency qualifies as an event of Force Majeure.

9.5 No Buyer Liability. Notwithstanding any provision to the contrary contained in this Agreement, Buyer shall have no obligation to pay Supplier in respect of any Product Supplier is unable to deliver or Buyer is unable to receive in accordance with the requirements of this Agreement due to an Emergency or Force Majeure.

10. CURTAILMENT & DISPATCHABILITY

10.1 Transmission Provider Instructions. Supplier shall obey all Transmission Provider Instructions for curtailment of Energy by the Transmission Provider or orders for curtailment of Energy by any Electric System Authority. For any period of curtailment described in this Section 10.1 that occurs during the Dispatch Availability Months, if the Storage Facility is capable of accepting Charging Energy during such period, then Buyer's Charging Notice will be automatically deemed revised to allow Net Energy that would have been delivered to the Delivery Points absent such curtailment to be delivered, to the maximum extent feasible in accordance with the Storage Operating Procedures, to the Storage Facility Metering Points as Buyer's Charging Energy instead.

10.1.1 Curtailments. Without limiting Section 10.1, Buyer shall not be obligated to purchase, receive, pay for, or pay any damages associated with, or incur any liability with respect to, compliance or curtailment of Energy by Supplier made in response to any orders for curtailment provided for in Section 10.1, including in respect of Net Energy (or associated Renewable Energy Benefits) not delivered to the Delivery Points due to any of the following: (a) the interconnection between the Facility and the Transmission System is disconnected, suspended or interrupted, in whole or in part; (b) the Transmission Provider, Electric System Authority or Market Operator (other than for economic reasons due to scheduling, such economically curtailed amounts being Un-Dispatched Amounts if occurring during the Dispatchable Period or FRP Deemed Delivered Energy if occurring during the Full Requirements Period) directs a general curtailment, reduction or re-dispatch of generation in the area (which would include the Net Energy), for any reason, even if such curtailment, reduction or re-dispatch directive is carried out by Buyer; (c) if Buyer curtails or otherwise reduces the Net Energy in order to meet its obligations to the Transmission Provider, Electric System Authority or Market Operator (other than for economic reasons due to scheduling, such economically curtailed amounts being Un-Dispatched Amounts if occurring during the Dispatchable Period or FRP Deemed Delivered Energy if occurring during the Full Requirements Period) to operate within system limitations; (d) the Facility's Energy is not received because the Facility is not fully integrated or synchronized with the Transmission System; or (e) an event of Force Majeure prevents either Party from delivering or receiving Net Energy ("Curtailed Product").

10.1.2 Curtailed Product Verification. Supplier shall promptly calculate, based on the Availability Backcast Amount plus any curtailed Discharging Energy during the Full Requirements Period, and provide Buyer with such information and data as Buyer may request to confirm, the amount of the Curtailed Product that was not generated as a result of the curtailment. During any such period of curtailment, Supplier shall not deliver Net Energy to the Delivery Points (to the extent curtailed by Transmission Provider) or sell Product to any third party. Curtailed Product shall constitute Excused Product for purposes of calculating a Shortfall or PC Shortfall. Under no circumstance shall the provisions of this Section 10.1.2 apply to a curtailment of the Facility based upon an Emergency with respect to the Facility.

10.2 Dispatchability.

10.2.1 Buyer is permitted to schedule Energy deliveries in accordance with Article 14 during any Dispatchable Period.

10.2.2 Except as expressly provided in this Agreement, Supplier shall comply with the schedules provided by Buyer during the Dispatchable Period. For any period during the Dispatchable Period, the "Un-Dispatched Amount" is the Availability Backcast Amount minus the Delivered Amount minus an amount equal to the Excused Product described in Sections 3.6.6(a) through (f) and (h). During the Dispatchable Period, Supplier shall produce Energy solely in accordance with Buyer's schedule (except as otherwise expressly provided herein) and Supplier shall not sell Product to any third party that was not scheduled by Buyer.

10.3 Network Resource Designation. Within sixty (60) days after the Effective Date, Buyer will submit an application to Transmission Provider to designate the Facility as a Network Resource. Supplier will provide all information related to the Facility required for such application within thirty (30) days after the Effective Date. Buyer will provide a copy of such application to Supplier.

11. PLANNED OUTAGES

11.1 Approvals. Supplier shall request and obtain Buyer's prior written approval, which approval shall not be unreasonably withheld, before conducting any non-forced outage of the Facility or reducing the capability of the Generating Facility to deliver Energy or the Storage Facility to receive Buyer's Charging Energy or deliver Discharging Energy (each such reduction or outage, a "Planned Outage") so as to minimize the impact on the availability of the Facility. Supplier shall only schedule Planned Outages during the months of January, February, March, April, October, November and December, unless otherwise approved by Buyer, and as may be otherwise restricted by Law.

11.2 Schedules. Planned Outages will be scheduled and conducted in accordance with the following:

11.2.1 Within ninety (90) days prior to the Commercial Operation Date and on or before October 1 of each Contract Year, Supplier shall provide Buyer with a schedule of proposed Planned Outages for the remainder of the year or upcoming Contract Year, as applicable. The proposed schedule will designate the Delivery Hours and amount (in MWh) in which the Energy will be reduced in whole or in part by the proposed Planned Outages. Each proposed schedule shall include all applicable information, including the following: the month, day and Delivery Hour each requested outage will begin and conclude, the facilities impacted, the purpose of the requested outage, and any other relevant information. The total combined Delivery Hours of: (i) Planned Outages and (ii) unplanned outages of the Storage Facility for the months of January through April and October through December, in any Contract Year (based on the Dispatch Availability Amounts for such Delivery Hours) shall not exceed four percent (4%) of the total annual Dispatch Availability Amounts for all hours in the applicable Contract Year (prorated for the Stub Period, if any) unless otherwise approved by Buyer.

11.2.2 Buyer shall promptly review Supplier's proposed schedule of Planned Outages and either require modifications or approve the proposed schedule within thirty (30) days of Buyer's receipt of such schedule. If Buyer requires modifications to the proposed schedule, then Supplier shall promptly circulate a revised schedule of Planned Outages to Buyer consistent with Buyer's requested modifications. Under no circumstances will Supplier schedule Planned Outages to occur during May, June, July, August or September. Product not delivered to Buyer during periods of Planned Outages, up to the MWh specified, (a) will comprise Excused Product to the extent such Planned Outages are conducted in accordance with the Planned Outage schedule approved by Buyer in accordance with this Article 11, and (b) will not comprise Excused Product to the extent any outage period or MWh exceed that set forth in the Planned Outage schedule approved by Buyer in accordance with this Article 11, or the Planned Outage is not approved by Buyer. Supplier shall make reasonable efforts to accommodate any proposed revisions by Buyer to the approved Planned Outage schedule.

11.2.3 Regardless of approval of a Planned Outage, Supplier shall not start a Planned Outage on the Facility without confirming the approved Planned Outage with Buyer's Operating Representative five (5) Business Days prior to the start of such Planned Outage.

11.2.4 If following a notice pursuant to Section 11.2.3, Buyer requests that Supplier not undertake an approved Planned Outage as scheduled, for reasons other than Force Majeure, Transmission Provider Instructions or Emergency, then Supplier may promptly deliver to Buyer a written reasonable estimate of the costs expected to be incurred as a result of Supplier not undertaking the Planned Outage as scheduled. If Buyer agrees to the estimated costs, then Supplier shall not undertake the Planned Outage, and Buyer shall reimburse Supplier for its documented out-of-pocket costs actually incurred by Supplier in connection with not undertaking such Planned Outage (not to exceed the written estimated costs prepared by Supplier and delivered to Buyer). Any Planned Outage that is not instituted pursuant to this Section 11.2.4 will be rescheduled to occur in the same Contract Year in which it was originally scheduled, in accordance with Section 11.2.2.

12. REPORTS; OPERATIONAL LOG

12.1 Copies of Communications. Supplier shall promptly provide Buyer with copies of any orders, decrees, letters or other written communications to or from any Governmental Authority asserting or indicating any violation of Laws which relate to Supplier or construction, operation or maintenance of the Facility. Supplier shall keep Buyer apprised of the status of any such matters.

12.2 Notification of Facility Regulatory Status. Supplier shall notify Buyer of the regulatory status of the Facility as an EWG or QF no later than ninety (90) days prior to the Operation Date, and will provide Buyer with evidence documenting receipt of the required Governmental Approvals related to such designation (as such approvals are set forth in Exhibit 10). Following the Operation Date, Supplier shall notify Buyer, as soon as practicable, of any changes in regulatory status of the Facility, and will provide Buyer with evidence documenting receipt of the required Governmental Approvals related to such changed regulatory status (as such approvals are set forth in Exhibit 10) and reasonable support data requested by Buyer.

12.3 Notices of Change in Facility. In addition to any consent required pursuant to Section 8.7, Supplier shall provide notice to Buyer as soon as practicable prior to any temporary or permanent change to the performance, operating characteristics, or major generation components (such as generators, inverters, solar panels or similar equipment, as applicable) of the Facility. Such notice shall describe any changes, expected or otherwise, to the Expected Nameplate Capacity Rating, generating capability, the rate of production and delivery of Net Energy, Discharging Energy and other Product, interconnection and transmission issues, and any additional information requested by Buyer.

12.4 Project Reports and Project Review Meetings.

12.4.1 Prior to the Commercial Operation Date. Prior to the Commercial Operation Date, Supplier shall provide to Buyer a monthly project report, which shall include the following: status in obtaining Project Milestones, including level one schedule; progress in obtaining any Governmental Approvals in connection with achieving the Commercial Operation Date; and a discussion of any foreseeable disruptions or delays. The monthly project reports will be provided to Buyer no later than ten (10) Business Days after expiration of the previous month. The Parties shall conduct meetings every six (6) months (or more frequently if requested by Buyer) to review this data and any information related to Supplier's completion of or progress toward the Project Milestone activities listed in Exhibit 6. In addition to any other requirements for Commercial Operation under this Agreement, Supplier shall: (a) provide notice to Buyer of its best estimate of the projected Operation Date and Commercial Operation Date; (b) notify Buyer as soon as Supplier becomes aware of any changes in such projected dates: and (c) coordinate with Buyer regarding the commencement of operation of the Facility. In addition to the foregoing, Supplier will provide Buyer with such other operational or technical data as Buyer may reasonably request and as may be reasonably necessary to determine Supplier's compliance with its obligations hereunder and its progress toward Commercial Operation.

12.4.2 After Commercial Operation Date. After the Commercial Operation Date, Supplier shall provide to Buyer within thirty (30) days of the end of each quarter throughout the Term, in electronic format, a report which shall include all pertinent information in connection with the Facility, including: (a) all weather data from any collection device measuring data with respect to the Facility (such as a met tower or similar measurement device); (b) any available site condition reports; (c) all reporting information maintained in the operational log and any other SCADA data from the Facility; and (d) any reports pertaining to the Facility resource and such other data and reports as may be reasonably requested by Buyer and which should be maintained by Supplier in accordance with Good Utility Practice for the relevant technology. In addition, Supplier shall provide remote access to Buyer for the Facility's operations and maintenance data for purposes of Buyer integrating such data into Buyer's Monitoring & Diagnostics center.

12.4.3 Operations Log. Supplier shall maintain in accordance with Good Utility Practice an operations log, which shall include: (a) all Planned Outages and unplanned outages, alarms, circuit breaker trip operations, partial deratings of equipment, mechanical impairments defects or unavailability with respect to generating equipment; (b) the cause (including any root cause analysis undertaken) and remediation undertaken by Supplier with respect to the events listed in (a); (c) the Delivered Amounts for the Stub Period and each Contract Year; and (d) any other significant event or information related to the operation of the Facility or the delivery of Net Energy or other Product. The operations logs shall be available for inspection by Buyer upon two (2) Business Days' notice together with all data maintained by Supplier as support for such logs. Supplier shall be responsible for maintaining sufficient evidentiary support in order to document the information contained in such operation logs.

12.5 Financial Information. Within thirty (30) days of Buyer's written request, Supplier shall provide Buyer with copies of Supplier's most recent quarterly and annual unaudited financial statements, which financial statements shall be prepared in accordance with generally accepted accounting principles.

12.6 Information to Governmental Authorities. Supplier shall, promptly upon written request from Buyer, provide Buyer with data collected by Supplier related to the construction, operation and maintenance of the Facility reasonably required by Buyer or an Affiliate thereof for reports to, and information requests from, any Governmental Authority, or any intervenor or party in any rate case or regulatory proceeding of Buyer or an Affiliate thereof. In addition, Supplier shall provide to Buyer copies of all submittals to a Governmental Authority directed by Buyer and related to the operation of the Facility with a certificate that the contents of the submittals are true and accurate to the best of Supplier's knowledge after due inquiry. Supplier shall use commercially reasonable efforts to provide this information to Buyer with sufficient advance notice to enable Buyer to review such information and meet any submission deadlines imposed by the requesting Governmental Authority.

12.7 Accounting Standards. If Buyer or one of its Affiliates determines that it may hold a variable interest in Supplier under the Accounting Standards Codification ("ASC") 810, Consolidation of Variable Interest Entities, or requirements of Law, but it lacks the information necessary to make a definitive conclusion, Supplier hereby agrees to provide, upon Buyer's written request, sufficient financial and ownership information so that Buyer or its Affiliate may confirm whether a variable interest does exist under ASC 810 or requirements of Law. If Buyer or its Affiliate determines that, it holds such a variable interest in Supplier, Supplier hereby agrees to provide, upon Buyer's written request, sufficient financial and other information to Buyer or its Affiliate so that Buyer may properly consolidate the entity in which it holds the variable interest or present the disclosures required by ASC 810 or applicable Law. Supplier shall have the right to seek confidential treatment of any such information from any Governmental Authority entitled to receive such information. Information provided pursuant to this Section 12.7 is subject to Buyer's rights to disclose such information pursuant to this Agreement and pursuant to any applicable requirements of Law.

12.8 Documents to Governmental Authorities. Supplier shall promptly provide to Buyer a copy of any statement, application, and report or any document with any Governmental Authority relating to operation and maintenance of the Facility.

12.9 Environmental Information. Supplier shall, promptly upon written request from Buyer, provide Buyer with all data reasonably requested by Buyer relating to environmental information under any Required Facility Document listed in Exhibit 12 or otherwise in effect with respect to the Facility. Supplier shall further provide Buyer with information relating to environmental impact mitigation measures it is taking in connection with the Facility's construction or operation that are required by any Governmental Authority. As soon as it is known to Supplier, Supplier shall disclose to Buyer, the extent of any actual or alleged violation of any Environmental Laws arising out of the construction or operation of the Facility, or the actual or alleged presence of Environmental Contamination at the Facility or on the Project Site, or occurrence of any enforcement, legal or regulatory action or proceeding relating to the foregoing.

13. COMMUNICATIONS

13.1 Supplier's Operating Representative. Supplier's Operating Representative shall be available to address and make decisions on all operational matters under this Agreement on a twenty-four (24) hour per day, seven (7) day per week basis. Supplier shall, at its expense, provide a protocol with Buyer's Operating Representative at Buyer's operations center and with Buyer's scheduling personnel, as listed on Exhibit 4, to maintain communications between personnel at the Facility and Buyer's Operating Representative, Buyer's schedulers and Electric System Authorities at all times.

13.2 Communications. In connection with meeting its obligations pursuant to this Article 13, Supplier shall provide at its expense:

13.2.1 For the purposes of telemetering, a telecommunications circuit from the Facility to Buyer's operations center, or other readily accessible real-time performance monitoring (e.g., a web-based performance monitoring system);

13.2.2 Two (2) dedicated T1 lines for purposes of accessing Buyer's metering equipment and for communications with Buyer's operations center; and

13.2.3 Equipment to transmit to and receive facsimiles and email from Buyer and the Balancing Authority Area Operator, including cellular telephones.

14. SCHEDULING NOTIFICATION

14.1 Availability Notice.

14.1.1 No later than 0500 PPT each day or as otherwise specified (or agreed to) by Buyer consistent with Good Utility Practice, Supplier shall deliver to Buyer's Operating Representative an Availability Notice, in accordance with WECC scheduling protocols and deadlines, containing information including Supplier's good faith daily and hourly forecast of the Delivered Amount, Full Requirements Period Charging Energy, Planned Outages, Derating, other outages and similar changes that may affect the Delivered Amount and the availability of Product in the form set forth in Exhibit 8. The Availability Notice will cover WECC scheduling practices for day-ahead energy or such other period specified by Buyer consistent with Good Utility Practice. The Parties agree to modify the Availability Notice as may be required consistent with other scheduling practices which may be applicable to the Facility from time to time.

14.1.2 Supplier shall update the Availability Notice and notify Buyer's Operating Representative as soon as practical after becoming aware of: (a) an expected Derating; (b) an expected change in Full Requirements Period Charging Energy, (c) an expected increase of Delivered Amount; or (d) reductions to estimated hourly Delivered Amount. The updated Availability Notice shall include Supplier's best estimate of the time required to resolve the condition(s) that caused the reductions to the estimated hourly Delivered Amount.

14.1.3 The information in any Availability Notice, including the forecasted Delivered Amount, will be Supplier's good faith forecast and will indicate any Delivery Hour for which the Delivered Amount is expected to be less than or greater than the Scheduled Amount.

14.1.4 In the event of a Derating of the Facility, Supplier shall provide: (a) the extent, if any, to which the Derating is attributable to a Planned Outage; (b) the magnitude of the Derating; (c) the Delivery Hours during which the Derating is expected to apply; and (d) the cause of the Derating.

14.2 Scheduling. Buyer's right to schedule the Generating Facility during June, July and August is limited by Supplier's schedule of Energy, Full Requirements Period Charging Energy, Supplier's Charging Energy and Discharging Energy as utilized to meet its obligations during the Full Requirements Period. Supplier shall deliver Energy and operate the Generating Facility in order to comply with this Section 14.2, provided that, subject to Sections 3.6.1 and 3.6.2, the actual amount of Energy delivered by Supplier for any hour may be more than or less than the Scheduled Amount.

14.2.1 For the Dispatchable Period, except as provided above with respect to June, July and August, the Parties shall schedule energy to be delivered pursuant to this Agreement. All scheduling communications shall be by email or by telephone with an email confirmation. Buyer shall submit to Supplier each day's hourly energy preschedule by the earlier of 0700 PPT or 30 minutes prior to the prescheduling deadline on each WECC prescheduling day, which shall provide notice of Buyer's intent to schedule energy for the following day or days consistent with the then-current WECC prescheduling calendar ("Scheduled Amount"). Supplier shall electronically confirm the preschedule with Buyer by 0730 PPT on each WECC prescheduling day.

14.2.2 For changes in the Scheduled Amount that are not delivered by Buyer's Energy Management System sending signals to Supplier's AGC, Buyer shall have the right to change the Scheduled Amount on an intraday basis ("Intraday Schedule Change") only if Buyer has provided at least one (1) hour's notice prior to the delivery hour; provided, however, that Supplier shall make commercially reasonable efforts to accommodate Intraday Schedule Changes upon less notice.

14.2.3 During the Full Requirements Period Buyer shall not, and shall not be obligated to, submit a schedule, and Supplier shall deliver Full Requirements Period Product in accordance with Exhibit 13A and B, provided that, subject to Section 3.6.4, the actual amount of Product delivered for any hour during the Full Requirements Period may be less than or more than the amounts set forth in Exhibit 13A and 13B.

14.2.4 Except as set forth in Section 14.3.2., during the months of June, July and August, Buyer's schedule may be limited by the amount of Energy required by Supplier in its sole discretion for Full Requirements Period Charging Energy to charge the Storage Facility to meet Supplier's obligations during the Full Requirements Period. In such event, Buyer's schedules during any Dispatchable Period may be limited as set forth in any applicable Availability Notice.

14.3 Storage Facility Scheduling.

14.3.1 Subject to Section 14.3.2, during the Dispatchable Period (except the months of June, July and August), Buyer has the exclusive right to schedule or designate the Storage Facility to deliver the Storage Product to Buyer and/or accept Buyer Charging Energy, in accordance with the Storage Operating Procedures and the operational requirements specified in Exhibit 1. Except as set forth in Section 14.3.2, during the Full Requirements Period, Supplier may discharge the Storage Facility as it determines in its sole discretion.

14.3.2 Notwithstanding anything in this Agreement to the contrary, during the months of June, July and August, Buyer has the right to schedule, notwithstanding Supplier's Availability Notice in Section 14.2, Energy and Discharging Energy from the Storage Facility, in which case (a) the Discharging Energy delivered from the Storage Facility during the Dispatchable Period, (b) any Energy that could have been used as Full Requirements Period Charging Energy, but was not able to be used by Supplier due to Buyer's use of the Storage Facility or Generating Facility, and (c) Energy and Discharging Energy that could have been delivered to Buyer as Net Energy, but was not able to be delivered by Supplier due to Buyer's use of the Storage Facility or Generating Facility, shall collectively be considered "FRP Deemed Delivered Energy". The amount of FRP Deemed Delivered Energy will not be considered a shortfall for the Full Requirements Period and Buyer shall pay Supplier the Full Requirements Period Product Rate for the FRP Deemed Delivered Energy. Supplier has no obligation to charge the Storage Facility to satisfy Buyer's Discharging Notice. The Storage Facility will only be discharged in accordance with Section 14.3.4 to ensure that Supplier can continue to use energy from the

Storage Facility to serve Station Usage notwithstanding Buyer's scheduling of the Storage Facility under this Section 14.3.2.

14.3.3 The operational requirements specified in Exhibit 1 will allow Buyer to schedule the Storage Facility for seven (7) days per week and twenty-four (24) hours per day (including holidays) for all available components of the Storage Product, unless the Storage Facility is, in whole or in part, incapable of operations due to Force Majeure, Transmission Provider Instructions, an Emergency, a Planned Outage or a forced outage (but without relieving Supplier of any liability it may have for damages hereunder due to such forced outage). Subject to Sections 14.2 and 14.3.2, during the Term Supplier shall operate the Storage Facility to charge or discharge the Storage Facility in accordance with Buyer's instruction pursuant to Section 3.4.8. The Storage Facility may only be charged with Charging Energy from the Generating Facility. Subject to Sections 14.2 and 14.3.2, during the Dispatchable Period Supplier shall not dispatch and operate the Storage Facility other than pursuant to an instruction by Buyer pursuant to Section 3.4.8.

14.3.4 Supplier shall be entitled to use Energy from the Generating Facility, when available, to serve Station Usage or to charge the Storage Facility so that it can be used to serve Station Usage, but Supplier's use of Energy as described in this sentence will not excuse any failure by Supplier to meet its performance obligations hereunder. When the Generating Facility is not generating Energy, Supplier may use energy from the Storage Facility to serve Station Usage, but Supplier's use of energy from the Storage Facility as described in this sentence will not excuse any failure by Supplier to meet its performance obligations hereunder.

15. COMPLIANCE

15.1 Laws. Each Party shall comply with all relevant Laws in connection with the performance of its obligations under this Agreement. Subject to Section 3.5, Supplier shall comply with all Laws to ensure that, the Generating Facility is at all times a Renewable Energy System and Supplier is at all times in compliance with all requirements of a renewable energy generator as set forth in the Renewable Energy Law, and shall, at its sole expense, maintain in full force and effect all relevant material Governmental Approvals required for the maintenance of the Facility and the performance of its obligations under this Agreement. Supplier shall be responsible for any costs associated with any obligations imposed on Supplier under the Clean Power Plan, including for obtaining, at its sole cost, any allowances that may be required for Supplier under applicable Law pertaining to the Clean Power Plan, in a quantity or amount sufficient to support Supplier's obligations set forth in this Agreement. Each Party and its representatives shall comply with all relevant requirements of each Electric System Authority, Transmission Provider and each Governmental Authority to ensure the safety of its employees and the public.

15.2 Good Utility Practice. Each of Buyer and Supplier shall perform, or cause to be performed, its obligations under this Agreement in all material respects in accordance with Good Utility Practice.

15.3 Interconnection Agreement. Supplier shall operate the Facility in accordance with the IA and to the extent there is a conflict between this Agreement and the IA, the IA shall prevail.

16. APPROVALS

16.1 Condition Precedent. Unless Buyer waives its right to terminate or otherwise fails to exercise its right to terminate this Agreement pursuant to Section 16.3, then notwithstanding any provision to the contrary contained in this Agreement, each Party's performance of its respective obligations under Articles 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 and 15 of this Agreement is subject to: Buyer obtaining the PUCN Approval described in Section 16.2 before the PUCN Approval Deadline and in form and substance satisfactory to Buyer in its sole discretion.

16.2 PUCN Approval. Within one hundred twenty (120) days after the Effective Date and in accordance with the requirements of Law, Buyer shall submit this Agreement to the PUCN for approval ("PUCN Approval") consisting of:

16.2.1 A determination that the terms and conditions of this Agreement are just and reasonable; and

16.2.2 A determination that the costs of purchasing Product under this Agreement are prudently incurred and that the Buyer may recover all just and reasonable costs of Product purchased under this Agreement.

16.3 Failure to Obtain PUCN Approval; Conditions of PUCN Approval. If the PUCN fails to grant the PUCN Approval on or before the PUCN Approval Deadline or grants the PUCN Approval on or before the PUCN Approval Deadline, but in form and substance not acceptable to Buyer in its sole discretion, then within thirty (30) days after the PUCN Approval Deadline or the date PUCN grants the PUCN Approval, as the case may be, Buyer shall have the right to terminate this Agreement upon ten (10) Business Days prior written notice to Supplier. Under no circumstances shall either Party have any liability to the other Party due to the failure of the PUCN to grant PUCN Approval by the PUCN Approval Deadline or the inclusion of conditions to the PUCN Approval which are unacceptable to Buyer.

16.4 Cooperation. If requested by Buyer, Supplier shall cooperate with Buyer as Buyer may deem necessary in order to obtain any Governmental Approval (including the PUCN Approval and any FERC approval) in connection with this Agreement, including providing affidavits, providing timely responses to data requests of the relevant Governmental Authority, intervening in any relevant dockets, and requesting "commenter" or "intervener" status in any relevant docket. Each Party agrees to notify the other Party of any significant developments in obtaining any

Governmental Approval in connection with achieving Commercial Operation of the Facility, including the PUCN Approval. Each Party shall use reasonable efforts to obtain such required Governmental Approvals and shall exercise due diligence and shall act in good faith to cooperate with and assist each other in acquiring each Governmental Approval necessary to effectuate this Agreement.

17. SECURITY

17.1 Development Security. As a condition of Buyer's execution of and continuing obligations under this Agreement, Supplier shall provide to Buyer, as security for the performance of Supplier's obligations hereunder, either: (a) a letter of credit from a Qualified Financial Institution substantially in the form attached hereto as Exhibit 17; (b) a cash deposit; (c) Guarantee from a Qualified Guarantor; or (d) a surety bond that is issued by a surety or insurance company that has an A.M. Best Financial Strength Rating (FSR) equal to or better than B+ or an equivalent Standard & Poor's Ratings Services or Moody's Investors Service rating (A- or A3) or that is otherwise acceptable to Buyer and in a form that is reasonably acceptable to Buyer, in any case, in an amount equal to twenty six million seven hundred fifty thousand dollars ($26,750,000) (the "Development Security"). The Development Security shall be posted within five (5) Business Days after the Effective Date. Upon the PUCN Approval Date, the Development Security shall increase to an amount equal to seventy four million, nine hundred thousand dollars ($74,900,000). The revised Development Security shall be posted within ten (10) days after the PUCN Approval Date and be maintained until fifteen (15) Business Days after the Commercial Operation Date. Buyer shall have the right to draw upon the Development Security, at Buyer's sole discretion: (i) as a non-exclusive remedy available to Buyer under Article 24; (ii) in the event Supplier fails to achieve Commercial Operation by the Commercial Operation Deadline and fails to pay Daily Delay Damages as provided in Section 8.5.1; (iii) if Supplier fails to make any payments owing under this Agreement; or (iv) if Supplier fails to reimburse Buyer for costs, including Replacement Costs, PC Replacement Costs and Regulatory Penalties, that Buyer has incurred or may incur as a result of Supplier's failure to perform its obligations under this Agreement. Unless this Agreement is terminated, any such drawing on the Development Security by Buyer shall give rise to an obligation of Supplier to replenish the Development Security to its required amount within three (3) Business Days of the drawing. In the event that no amounts are due and owing by Supplier to Buyer under this Agreement and Supplier has provided the Operating Security to Buyer, the Development Security shall be released to Supplier upon the earlier of (x) termination of this Agreement in accordance with its terms or (y) on the fifteenth (15^{th}) Business Day after the Facility achieves Commercial Operation. With the consent of Buyer, Supplier may apply and maintain the Development Security as a portion of Operating Security required to be provided by Supplier pursuant to Section 17.2. Notwithstanding the foregoing, in the event of a termination of this Agreement pursuant to Section 2.3.2 or Article 16, the Development Security shall be released to Supplier within five (5) Business Days after such termination.

17.2 Operating Security. As a condition to achieving Commercial Operation, Supplier shall provide to Buyer, as security for the performance of Supplier's obligations hereunder, either: (a) a letter of credit from a Qualified Financial Institution substantially in the form attached hereto as Exhibit 17; (b) a cash deposit; (c) Guarantee from a Qualified Guarantor; or (d) a surety bond that is issued by a surety or insurance company that has an A.M. Best Financial Strength Rating (FSR) equal to or better than B+ or an equivalent Standard & Poor's Ratings Services or Moody's Investors Service rating (A- or A3) or that is otherwise acceptable to Buyer and in a form that is reasonably acceptable to Buyer, in an amount equal to sixty eight million nine thousand five hundred dollars ($68,009,500) (the "Operating Security"). The Operating Security shall be posted no later than five (5) Business Days prior to the Commercial Operation Date. Buyer shall have the right to draw upon the Operating Security, at Buyer's sole discretion: (1) as a non-exclusive remedy available to Buyer in the event this Agreement is terminated under Article 24; (2) in the event Supplier fails to make any payments owing under this Agreement; or (3) if Supplier fails to reimburse Buyer for costs, including Replacement Costs, PC Replacement Costs and Regulatory Penalties that Buyer has incurred or may incur as a result of Supplier's failure to perform its obligations under this Agreement. Unless this Agreement is terminated, any such drawing on the Operating Security by Buyer shall give rise to an obligation of Supplier to replenish the Operating Security to its original amount within three (3) Business Days. In the event that no amounts are due and owing by Supplier to Buyer under this Agreement, the Operating Security shall be released to Supplier upon the fifteenth (15^{th}) Business Day after the earlier of (x) termination of this Agreement in accordance with its terms or (y) the expiration of the Term.

17.3 Letters of Credit. With respect to any letter of credit posted by Supplier as Development Security or Operating Security: (a) no later than thirty (30) days prior to the expiration date of any such letter of credit, Supplier shall cause the letter of credit to be renewed or replaced with another letter of credit in an equal amount; (b) in addition to the conditions specified in Sections 17.1 and 17.2, Buyer shall have the right to draw on such letter of credit, at Buyer's sole discretion (i) if such letter of credit has not been renewed or replaced at least thirty (30) days prior to the date of its expiration or (ii) if the Credit Rating of the financial institution that issued such letter of credit has been downgraded to below that required of a Qualified Financial Institution and Supplier has not caused a replacement letter of credit to be issued for the benefit of Buyer within five (5) Business Days of such downgrade pursuant to Section 17.4.

17.4 Maintaining Letter of Credit. If at any time after the Effective Date of this Agreement, Standard & Poor's, Moody's or another nationally recognized firm downgrades the Credit Rating of the financial institution issuing a letter of credit pursuant to this Agreement to below that required of a Qualified Financial Institution, then Supplier shall: (a) provide Buyer with written notice of such downgrade within two (2) Business Days of Supplier being notified of any such downgrade; and (b) cause a replacement letter of credit satisfying the conditions of Section 17.3 or other acceptable Development Security or Operating Security, as applicable, to be issued in favor of Buyer within five (5) Business Days of such downgrade. In the event such a downgrade also constitutes an Event of Default pursuant to Article 24, then the requirements of this Section 17.4 are in addition to, and not in lieu of, the provisions of Article 24. Supplier shall take all necessary action and shall be in compliance with Section 17.1 and/or Section 17.2, as the case may be, within five (5) Business Days of the downgrade.

17.5 Guarantors. Supplier shall provide Buyer, or shall cause any guarantor to provide Buyer, audited financials of guarantor within ten (10) days of them becoming available. Further, Supplier shall promptly notify Buyer regarding downgrade or other material change regarding the creditworthiness or financial condition of any guarantor providing a Guarantee pursuant to Sections 17.1 or 17.2. If at any time after the Effective Date, any guarantor providing a Guarantee pursuant to Sections 17.1 or 17.2 experiences a downgrade or other material change described in the prior sentence and, as a result, such guarantor fails to meet the Minimum Credit Rating, if such guarantor has a Credit Rating, or fails to meet Buyer's minimum credit requirements as determined by Buyer in its sole and absolute discretion, if such guarantor does not have a Credit Rating, then Buyer shall notify Supplier in writing and Supplier shall cause a replacement Guarantee, surety bond, letter of credit or cash meeting the requirements of Section 17.1 or 17.2, as applicable, and in the amount of the Development Security or Operating Security, as the case may be, to be delivered to Buyer within five (5) Business Days of such notice. Failure to provide the Development Security or Operating Security pursuant hereto in a timely manner shall constitute an Event of Default pursuant to Article 24.

17.6 No Interest on Supplier Security. Supplier shall not earn or be entitled to any interest on any security provided pursuant to this Article 17, including any cash amounts deposited.

17.7 Grant of Security Interest. To secure its obligations under this Agreement, Supplier hereby grants to Buyer, as the secured party, a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all Development Security or Operating Security, as the case may be, posted with Buyer in the form of cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, Buyer. Supplier agrees to take such action as Buyer reasonably requires in order to perfect a first-priority security interest in, and lien on (and right of setoff against), such performance assurance and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default, Buyer, as the Non-Defaulting Party, may do any one or more of the following: (a) exercise any of the rights and remedies of a secured party with respect to all Development Security or Operating Security, as applicable, including any such rights and remedies under Law then in effect; (b) exercise its right of setoff against any and all property of Supplier, as the Defaulting Party, in the possession of the Buyer or Buyer's agent; (c) draw on any outstanding letter of credit issued for its benefit; and (d) liquidate all Development Security or Operating Security, as applicable, then held by or for the benefit of Buyer free from any claim or right of any nature whatsoever by Supplier, including any equity or right of purchase or redemption by Supplier. Buyer shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce Supplier's obligations under the Agreement (Supplier remaining liable for any amounts owing to Buyer after such application), subject to the Buyer's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

17.8 Waiver of Buyer Security. Supplier hereby waives any and all rights it may have, including rights at Law or otherwise, to require Buyer to provide financial assurances or security (including cash, letters of credit, bonds or other collateral) in respect of its obligations under this Agreement.

17.9 Security is Not a Limit on Supplier's Liability. Subject to Section 8.4.1, the security contemplated by this Agreement: (a) constitutes security for, but is not a limitation of, Supplier's obligations hereunder; and (b) shall not be Buyer's exclusive remedy for Supplier's failure to perform in accordance with this Agreement.

18. INDEMNIFICATION

18.1 Indemnification for Losses. Each Party to this Agreement (the "Indemnifying Party") shall indemnify, defend and hold harmless, on and after state and federal Tax basis, the other Party, its Affiliates, and each of their officers, directors, employees, attorneys, agents and successors and assigns (each an "Indemnified Party") from, for and against any and all Losses arising out of, relating to, or resulting from the Indemnifying Party's breach, or performance or non-performance of its obligations under this Agreement, including the Indemnifying Party's negligence and willful misconduct (including reasonable attorneys' fees and costs); provided, however, that no Indemnified Party shall be indemnified hereunder for any Loss to the extent resulting from its own gross negligence, fraud or willful misconduct. Supplier shall be solely responsible for (and shall defend and hold Buyer harmless against) any damage that may occur as a direct result of Supplier's acts that affect the Transmission System.

18.1.1 In furtherance of the foregoing indemnification and not by way of limitation thereof, the Indemnifying Party hereby waives any defense it otherwise might have against the Indemnified Party under applicable workers' compensation Laws.

18.1.2 In claims against any Indemnified Party by an agent of the Indemnifying Party, or anyone directly or indirectly employed by them or anyone for whose acts the Indemnifying Party may be liable, the indemnification obligation under this Article 18 shall not be limited by a limitation on amount or type of damages, compensation or benefits payable by or for the Indemnifying Party or a subcontractor under workers' or workmen's compensation acts, disability benefit acts or other employee benefit acts.

18.2 No Negation of Existing Indemnities; Survival. Each Party's indemnity obligations under this Agreement shall not be construed to negate, abridge or reduce other rights or obligations, which would otherwise exist at Law or in equity. The obligations contained herein shall survive the termination or expiration of this Agreement to the extent that any third-party claim is commenced during the applicable statute of limitations period.

18.3 Indemnification Procedures.

18.3.1 Any Indemnified Party seeking indemnification under this Agreement for any Loss shall give the Indemnifying Party notice of such Loss promptly but in any event on or before thirty (30) days after the Indemnified Party's actual knowledge of such claim or action. Such notice shall describe the Loss in reasonable detail, and shall indicate the amount (estimated if necessary) of the Loss that has been, or may be sustained by, the Indemnified Party. To the extent that the Indemnifying Party will have been actually and materially prejudiced as a result of the failure to provide such notice, the Indemnified Party shall bear all responsibility for any additional costs or expenses incurred by the Indemnifying Party as a result of such failure to provide notice.

18.3.2 In any action or proceeding brought against an Indemnified Party by reason of any claim indemnifiable hereunder, the Indemnifying Party may, at its sole option, elect to assume the defense at the Indemnifying Party's expense, and shall have the right to control the defense thereof and to determine the settlement or compromise of any such action or proceeding. Notwithstanding the foregoing, an Indemnified Party shall in all cases be entitled to control its own defense in any action if it:

18.3.2.1 May result in injunctions or other equitable remedies with respect to the Indemnified Party;

18.3.2.2 May result in material liabilities which may not be fully indemnified hereunder; or

18.3.2.3 May have a Material Adverse Effect on the Indemnified Party (including a Material Adverse Effect on the Tax liabilities, earnings, ongoing business relationships or regulation of the Indemnified Party) even if the Indemnifying Party pays all indemnification amounts in full.

18.3.3 Subject to Section 18.3.2, neither Party may settle or compromise any claim for which indemnification is sought under this Agreement without the prior written consent of the other Party; provided, however, that said consent shall not be unreasonably withheld, conditioned or delayed.

19. LIMITATION OF LIABILITY

19.1 Responsibility for Damages. Except where caused by the other Party's breach, negligence or non-performance of its obligations under this Agreement, each Party shall be responsible for all physical damage to or destruction of the property, equipment and/or facilities owned by it, and each Party hereby releases the other Party from any reimbursement for such damage or destruction.

19.2 Limitation on Damages. To the fullest extent permitted by Law and notwithstanding any other provisions of this Agreement to the contrary, except for Replacement Costs, PC Replacement Costs or payment made by either Party to satisfy Regulatory Penalties or payments owing under Sections 3.4, 3.5, 3.6, 3.7, 7.5, 8.4, 8.5, 15.1, 17.1, 17.2, 18.1, 19.1, 27.1, in no event shall a Party be liable to the other Party, whether in contract, warranty, tort, negligence, strict liability, or otherwise, for special, indirect, incidental, multiple, consequential (including lost profits or revenues, business interruption damages and lost business opportunities), exemplary or punitive damages related to, arising out of, or resulting from performance or nonperformance of this Agreement (unless due to the willful or intentional breach of this Agreement by such Party, in which case the limitation shall not apply). In addition, this limitation on damages shall not apply with respect to claims brought by third parties for which a Party is entitled to indemnification under this Agreement.

19.3 Survival. The provisions of this Article 19 shall survive the termination or expiration of this Agreement.

20. FORCE MAJEURE

20.1 Excuse. Subject to Section 20.4, neither Party shall be considered in default under this Agreement for any delay or failure in the performance of its obligations under this Agreement (including any obligation to deliver or accept Product) if such delay or failure is due to an event of Force Majeure.

20.2 Definition. "Force Majeure" or "an event of Force Majeure" means an event that: (a) is not reasonably anticipated as of the Effective Date; (b) is not within the reasonable control of the Party affected by the event; (c) is not the result of the affected Party's negligence or failure to act; and (d) could not be overcome by the affected Party's use of due diligence in the circumstances. Force Majeure includes, but is not restricted to, events of the following types (but only to the extent that such an event, in consideration of the circumstances, satisfies the requirements set forth in the preceding sentence): acts of God; civil disturbance; sabotage; strikes not attributable to Supplier's actions; lock-outs not attributable to Supplier's actions; work stoppages not attributable to Supplier's actions; action or restraint by court order or Governmental Authority (as long as the affected Party has not applied for or assisted in the application for, and has opposed to the extent reasonable, such action or restraint).

20.3 Exclusions. Notwithstanding the foregoing, none of the following shall constitute Force Majeure:

20.3.1 Economic hardship of either Party, including lack of money;

20.3.2 The non-availability or reduced availability of the resource supply to generate electricity from the Generating Facility, including due to weather, high or low temperatures or climate conditions, except to the extent caused by acts of God;

20.3.3 A Party's failure to obtain any Governmental Approval from a Governmental Authority;

20.3.4 A Party's failure to meet a Project Milestone, except to the extent it is caused by an event of Force Majeure;

20.3.5 The imposition of costs or Taxes on a Party;

20.3.6 Supplier's failure to obtain, or perform under, the IA, or its other contracts and obligations to Transmission Provider unless due to a Force Majeure event;

20.3.7 Supplier's ability to sell, or Buyer's ability to purchase energy, PCs (and equivalent rights in any other jurisdiction), Renewable Energy Benefits, or Capacity Rights at a more advantageous price than is provided hereunder;

20.3.8 Any breakdown or malfunction of the Facility's equipment (including any serial equipment defect) that is not caused by an independent event of Force Majeure;

20.3.9 Delay or failure of Supplier to obtain or perform any Required Facility Document unless due to a Force Majeure event;

20.3.10 Any delay, alleged breach of contract, or failure by the Transmission Provider unless due to a Force Majeure event;

20.3.11 Maintenance upgrade or repair of any facilities or right of way corridors whether performed by or for Supplier, or other third parties (except for repairs made necessary as a result of an event of Force Majeure); or

20.3.12 The increased cost of electricity, equipment, steel, labor, or transportation.

20.4 Conditions. In addition to the conditions set forth in Section 20.2, a Party may rely on a claim of Force Majeure to excuse its performance only to the extent that such Party:

20.4.1 Provides prompt notice of such Force Majeure event to the other Party, giving an estimate of its expected duration and the probable impact on the performance of its obligations under this Agreement (which notice, in the case of Supplier, shall be provided within forty-eight (48) hours following such Force Majeure event);

20.4.2 Exercises all reasonable efforts to continue to perform its obligations under this Agreement;

20.4.3 Expeditiously takes action to correct or cure the Force Majeure event excusing performance so that the suspension of performance is no greater in scope and no longer in duration than is dictated by the event; provided, however, that nothing herein requires a Party to settle a strike or other labor dispute;

20.4.4 Exercises all reasonable efforts to mitigate or limit damages to the other Party resulting from the Force Majeure event; and

20.4.5 Provides prompt notice to the other Party of the cessation of the Force Majeure event giving rise to its excuse from performance.

21. DISPUTES

21.1 Dispute or Claim. Any cause of action, claim or dispute which either Party may have against the other Party arising out of or relating to this Agreement, including the interpretation of the terms hereof or any Laws that affect this Agreement, or the transactions contemplated hereunder, or the breach, termination or validity hereof ("Dispute") shall be submitted in writing to the other Party. The written submission of any Dispute shall include a concise statement of the question or issue in dispute together with a statement listing the relevant facts and appropriate supporting documentation.

21.2 Good Faith Resolution. The Parties agree to cooperate in good faith to expedite the resolution of any Dispute. Pending resolution of a Dispute, the Parties shall proceed diligently with the performance of their obligations under this Agreement.

21.3 Informal Negotiation. The Parties shall first attempt in good faith to resolve any Dispute through informal negotiations by the Operating Representatives or Contract Representatives and senior management of each Party. If the Parties fail to resolve any Dispute through informal negotiations within thirty (30) days after the Dispute is submitted in writing to the other Party in accordance with Section 21.1, then either Party may (a) send a Technical Dispute Notice for a Dispute regarding the calculation of Availability Backcast Amounts or the Resource-Adjusted Backcast Amount, or (b) for any other Dispute, exercise their rights at equity or law to resolve such Dispute.

21.4 Technical Expert. If the Dispute regards the calculation of Availability Backcast Amounts or the Resource-Adjusted Backcast Amount, then the Parties will have such Dispute resolved pursuant to this Section 21.4. Any such Dispute will be determined by an independent technical expert, who shall be a mutually acceptable third party with training and experience in the disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation or opinion (the "Technical Expert"), which determination shall be (x) except as otherwise provided in this Section 21.4, made in accordance with the Construction Industry Arbitration Rules and Mediation Procedures (Including Procedures for Large, Complex Construction Disputes) of the American Arbitration Association ("AAA"), as amended and effective on the date a Party provides notice of its intent to submit the Dispute to a technical expert, and (y) binding upon the Parties.

21.4.1 Either Party may commence the technical dispute process with AAA by notifying AAA and the other Party in writing ("Technical Dispute Notice") of such Party's desire that the Dispute be resolved through a determination by a technical expert.

21.4.2 The determination shall be conducted by a sole Technical Expert. The Parties may select any mutually acceptable Technical Expert. If the Parties cannot agree on a Technical Expert within five (5) days after the date of the Technical Dispute Notice, then the AAA's arbitration administrator shall send a list and resumes of three (3) available technical experts meeting the qualifications set forth in Section 21.4 to the Parties, each of whom shall strike one name, and the remaining person shall be appointed as the Technical Expert. If more than one name remains, either because one or both Parties have failed to respond to the AAA's arbitration administrator within five (5) days after receiving the list or because one or both Parties have failed to strike a name from the list or because both Parties strike the same name, the AAA's arbitration administrator will choose the Technical Expert from the remaining names. If the designated Technical Expert shall die, become incapable or, unwilling to, or unable to serve or proceed with the determination, a substitute technical expert shall be appointed in accordance with the selection procedure described above, and such substitute Technical Expert shall have all such powers as if he or she has been originally appointed herein.

21.4.3 Within thirty (30) days of the appointment of the Technical Expert pursuant to Section 21.4.2, each Party shall submit to the Technical Expert a written report containing its position with respect to the Dispute, and arguments therefor together with supporting documentation and calculations. Discovery shall be limited to Facility documentation relating to the Dispute. Within sixty (60) days from receipt of such submissions, the Technical Expert shall select one or the other Party's position with respect to the Dispute, whereupon such selection shall be a binding determination upon the Parties for all purposes hereof. The costs of the determination by the Technical Expert of any Dispute, including fees and expenses, shall be borne by the Party whose position was not selected by the Technical Expert. If the Technical Expert fails to render a decision within ninety (90) days from receipt of each Party's submissions, either Party may initiate litigation in accordance with the provisions herein.

21.4.4 All verbal and written communications between the Parties and issued or prepared in connection with this Section 21.4 shall be deemed prepared and communicated in furtherance, and in the context, of dispute settlement, and shall be exempt from discovery and production, and shall not be admissible in evidence (whether as admission or otherwise) in any litigation or other proceedings for the resolution of the Dispute.

21.4.5 All deadlines specified in this Section 21.4 may be extended by mutual agreement of the Parties.

21.5 Jurisdiction, Venue. Each Party irrevocably: (a) submits to the exclusive jurisdiction of the federal and state courts located in the County of Washoe, State of Nevada; (b) waives any objection which it may have to the laying of jurisdiction or venue of any proceedings brought in any such court; and (c) waives any claim that such proceedings have been brought in an inconvenient forum.

21.6 Recovery of Costs and Attorneys' Fees. In the event of a Dispute arising from or relating to this Agreement, whether or not an action is commenced in any court to enforce any provision or for damages by reason of any alleged breach of this Agreement, the prevailing Party will be entitled to recover from the other Party all costs and attorneys' fees reasonably incurred in resolving the Dispute. For purposes hereof, the "prevailing" Party need not prevail on every issue involved in the Dispute, but only on the main issue giving rise to the Dispute.

21.7 Waiver of Jury Trial. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

22. NATURE OF OBLIGATIONS

22.1 Relationship of the Parties. The provisions of this Agreement shall not be construed to create an association, trust, partnership, or joint venture; or impose a trust or partnership duty, obligation, or liability or agency relationship between the Parties.

22.2 No Public Dedication. By this Agreement, neither Party dedicates any part of its facilities nor the services provided under this Agreement to the public.

23. ASSIGNMENT

Except as stated below, neither this Agreement nor any of the rights or obligations hereunder shall be assigned by either Party, including by operation of Law, without the prior written consent of the other Party, which consent shall not be unreasonably withheld. Any assignment of this Agreement in violation of the foregoing shall be, at the option of the non-assigning Party, void.

23.1 Buyer Assignment. Buyer may, without the consent of Supplier, assign this Agreement or assign or delegate its rights and obligations under this Agreement, in whole or in part, if such assignment or delegation is made to: (a) Sierra Pacific Power Company; (b) any successor to Buyer, provided that such successor is a public utility holding a certificate of public convenience and necessity granted by the PUCN pursuant to NRS Chapter 704, where such assignment does not occur by operation of Law; (c) a Person (other than a natural person) providing retail electric service in Nevada and which meets the Minimum Credit Rating; (d) a wholesale electric provider which meets the Minimum Credit Rating or provides adequate credit assurance or a guarantee from a party that meets the Minimum Credit Rating; (e) a Person (other than a natural person) whose Credit Rating, as published by either Relevant Rating Agency, is equal or superior to the Minimum Credit Rating as of the time of assignment and provided such assignment would not have a material adverse regulatory consequence on Supplier; or (f) a Person (other than a natural person) as otherwise required by Law which meets the Minimum Credit Rating and provided such assignment would not have a material adverse regulatory consequence on Supplier. Buyer shall provide Supplier with written notice of any assignment pursuant to this Section 23.1.

23.2 Supplier Assignment. Supplier may, without the consent of Buyer (and without relieving itself from liability hereunder), transfer or assign a Controlling Interest in Supplier to any of Supplier's Affiliates or this Agreement to any of Supplier's Affiliates in connection with a transfer of the Facility to such Affiliate or a corporate reorganization between Supplier and its Affiliates so long as the purposes of the ROFO in Article 6 are not frustrated by such a transfer or assignment; provided that Supplier provides Buyer prior notice of any such transfer or assignment and (a) either (i) the Credit Rating of such Affiliate is equal to or superior to the Credit Rating of Supplier as of the Effective Date, as determined by Buyer in its reasonable discretion, or (ii) the Development Security or Operational Security, as applicable, is maintained without change due to such transfer or assignment or is replaced with Development Security or Operational Security, as applicable, in accordance with the requirements of Article 17, and (b) such Affiliate enters into an assignment and assumption agreement, in form and substance satisfactory to Buyer, pursuant to which such Affiliate assumes all of Supplier's obligations hereunder and otherwise agrees to be bound by the terms of this Agreement. Supplier agrees that it will provide written notice to Buyer (and, if required, the PUCN Regulatory Operations Staff, and the State of Nevada Attorney General's Bureau of Consumer Protection) of any transfer or assignment of this Agreement by Supplier to an Affiliate pursuant to this Section 23.2, together with information supporting the permissible nature of the transfer or assignment in accordance with the requirements of this Section 23.2, no less than five (5) Business Days prior to the effective date of any such transfer or assignment.

23.3 Liability After Assignment. A Party's assignment or transfer of rights or obligations pursuant to this Article 23 (other than Section 23.2) of this Agreement shall relieve such Party from any liability and financial responsibility for the performance thereof arising after any such transfer or assignment, provided that such transferee enters into an assignment and assumption agreement, in form and substance satisfactory to the other Party, pursuant to which such transferee assumes all of the assigning or transferring Party's obligations hereunder and otherwise agrees to be bound by the terms of this Agreement.

23.4 Transfers of Ownership. Subject to the provisions of Article 6, Supplier shall not directly or indirectly sell, transfer, assign or otherwise dispose of its ownership interest in the Facility to any third party absent: (a) a transfer of this Agreement to such third party; (b) Supplier entering into an assignment and assumption agreement, in form and substance satisfactory to Buyer, with such third party pursuant to which such third party assumes all of Supplier's obligations hereunder and otherwise agrees to be bound by the terms of this Agreement; (c) Buyer's prior written approval, not to be unreasonably withheld, of such third party; and (d) such third party being a Qualified Transferee. This Section 23.4 shall not apply or restrict any sale, transfer, assignment or disposal of the Facility in accordance with the provisions of Section 6.6, Section 23.2, or Section 23.8. This Section 23.4 shall also not apply to any sale, transfer, assignment or disposal of the Facility to a third party pursuant to any Restricted Transaction(s) permitted in accordance with the ROFO provisions of Section 6.1, provided that such transfer is to a Qualified Transferee.

23.5 Controlling Interest. Subject to the provisions of Article 6, no Controlling Interest in Supplier may be directly or indirectly sold, transferred or assigned (whether through a single transaction or a series of transactions over time) without Buyer's prior written approval, not to be unreasonably withheld, and then only to a Qualified Transferee. This Section 23.5 shall not apply or restrict any sale, transfer or assignment of a Controlling Interest in Supplier (a) in accordance with the provisions of Section 6.6 or Section 23.2, (b) that is a Permitted Transfer, or (c) pursuant to any Restricted Transaction(s) permitted in accordance with the ROFO provisions of Section 6.1, provided that such transfer is to a Qualified Transferee.

23.6 Assignee Obligations with Respect to Granting a Security Interest. As a condition precedent to granting any Person a security interest in the Facility, Supplier shall (a) satisfy the requirements of Section 23.8 or (b) procure and deliver to Buyer an agreement, enforceable by Buyer and in form and substance satisfactory to Buyer, from each such Person to the effect that, if such Person forecloses on its security interest, (i) it will assume Supplier's obligations under and otherwise be bound by the terms of this Agreement, and (ii) it will not sell, transfer or otherwise dispose of its interest in the Facility to any Person other than in accordance with the provisions of this Article 23.

23.7 Successors and Assigns. This Agreement and all of the provisions hereof are binding upon, and inure to the benefit of, the Parties and their respective permitted successors and permitted assigns.

23.8 Collateral Assignment by Supplier. Supplier may, without the consent of Buyer (and without relieving itself from liability hereunder), transfer, pledge, encumber or collaterally assign this Agreement or the account, revenues or proceeds hereof to Supplier's Lender in connection with any financing, including tax equity financing, or other financial arrangements for the Facility. In the event that Supplier intends to transfer, pledge, encumber or collaterally assign this Agreement to Supplier's Lenders, Supplier shall provide at least thirty (30) days' prior written notice thereof to Buyer, including the address of Supplier's Lenders. Any negotiation of documentation required in connection with a collateral assignment or other financing activity of Supplier shall be at the sole cost and expense of Supplier, and Supplier shall reimburse Buyer for all documented third-party and internal costs in connection with such activities. As a condition precedent to the effectiveness of any such transfer, pledge, encumbrance or collateral assignment to Supplier's Lenders, Buyer and Supplier and Supplier's Lenders shall have entered into a consent to collateral assignment agreement, which agreement shall be substantially in the form and substance of the Lender's Consent in Exhibit 19, including such revisions as may be reasonably requested by Supplier's Lenders.

24. DEFAULT AND REMEDIES

24.1 Events of Default. An event of default ("Event of Default") shall be deemed to have occurred with respect to a Party (the "Defaulting Party") upon the occurrence of one or more of the following events and expiration of any applicable Cure Period:

24.1.1 failure to comply with any of its material obligations under this Agreement (not otherwise specifically addressed below) or failure of any its representations or warranties in this Agreement to be true and correct in all material respect when made or deemed made;

24.1.2 failure to make timely payments due under this Agreement;

24.1.3 failure to comply with the material requirements of any Electric System Authority, Transmission Provider or any Governmental Authority;

24.1.4 in the case of Supplier, its failure at any time to qualify and maintain, subject to Section 3.5, the Generating Facility as a Renewable Energy System;

24.1.5 in the case of Supplier, its failure to install, operate, maintain or repair the Facility in accordance in all material respects with Good Utility Practice;

24.1.6 in the case of Supplier, unless excused by an event of Force Majeure, its failure to timely achieve: (a) any of the Critical Project Milestones (excluding Commercial Operation) before the scheduled date set forth in Exhibit 6; and (b) Commercial Operation by the Commercial Operation Deadline as set forth in Exhibit 6, after expiration of the applicable period for which Daily Delay Damages are owed by Supplier pursuant to Section 8.5.1;

24.1.7 In the case of Supplier, a termination event has occurred pursuant to Section 3.6.2.4.

24.1.8 In the case of Supplier, a termination event has occurred pursuant to Section 3.6.2.5.

24.1.9 In the case of Supplier, a termination event has occurred pursuant to Section 3.6.4.3.

24.1.10 in the case of Supplier, its failure to comply with the provisions of Section 17 (including any replenishment requirement);

24.1.11 its failure to comply with the provisions of Section 23;

24.1.12 in the case of Supplier, its failure to comply with the provisions of Section 27;

24.1.13 in the case of Supplier, if Supplier: (a) becomes insolvent, files for or is forced into bankruptcy (and in the case of an involuntary bankruptcy, such proceeding is not dismissed within sixty (60) days); (b) makes an assignment for the benefit of creditors; (c) is unable to pay its debts as they become due; or (d) is subject to a similar action or proceeding (and in the case of an involuntary bankruptcy, such proceeding is not dismissed within sixty (60) days); and

24.1.14 in the case of Supplier, if Supplier: (a) relinquished possession and control of all or substantially all of the Facility, other than pursuant to a transfer permitted under this Agreement; or (b) after commencement of the construction of the Facility, and prior to the Commercial Operation Date, completely ceases construction, testing, and inspection of the Facility for ninety (90) consecutive days, if not attributable to an Event of Default of, or request by Buyer, or an event of Force Majeure; and

24.1.15 in the case of Supplier, if: (a) the Storage Contract Capacity of the Storage Facility determined pursuant to a Storage Capacity Test is less than or equal to ninety percent (90%) of the Storage Contract Capacity that was in effect as of the Commercial Operation Date for at least two (2) consecutive Contract Years; or (b) the Monthly Storage Availability is less than or equal to seventy-five percent (75%) for at least three (3) consecutive Dispatch Availability Months during any Contract Year or any five (5) non-consecutive Dispatch Availability Months during a period of two (2) consecutive Contract Years.

24.2 Duty/Right to Mitigate. Each Party has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of its obligations under this Agreement. For the purpose of this Section 24.2, commercially reasonable efforts by Supplier shall include seeking to maximize the price for Product received by Supplier from third parties, including entering into an enabling agreement with, or being affiliated with, one or more power marketers of nationally recognized standing to market such Product not purchased or accepted by Buyer during a period Buyer is a Defaulting Party and Supplier is entitled to sell such Product to third parties in accordance with the terms of this Agreement.

24.3 Cure Period. Other than for an Event of Default under Sections 24.1.6 or 24.1.13 or 24.1.15 for which there is no cure period, an Event of Default shall not be deemed to have occurred under Section 24.1, unless and until the Defaulting Party shall: (a) for purposes of Section 24.1.2, 24.1.7, 24.1.8, 24.1.9, and 24.1.11, had a period of ten (10) Business Days from the date the applicable payment or performance was due; and (b) for purposes of all other Events of Default described in Section 24.1 (other than Sections 24.1.2, 24.1.6, 24.1.7, 24.1.8, 24.1.9, 24.1.11, 24.1.13 or 24.1.15 which are addressed above), had a period of thirty (30) days from the date of receipt of written notice of the occurrence of any of the Events of Default described in Section 24.1 (each of the cure periods in Section 24.3(a) and (b), a "Cure Period") to cure such potential Event of Default; provided that such thirty (30)-day period may be extended for an additional reasonable period of time (not to exceed ninety (90) days) if: (i) the potential Event of Default is not reasonably capable of being cured within such thirty (30)-day period; (ii) such potential Event of Default is capable of being cured within an additional reasonable period of time (not to exceed ninety (90) days); and (iii) Supplier is diligently and continuously proceeding to cure such potential Event of Default.

24.4 Remedies. If an Event of Default is not cured by the Defaulting Party during the applicable Cure Period, if any, then, subject to Section 8.4.1, the Non-Defaulting Party shall be entitled to all legal and equitable remedies that are not expressly prohibited by the terms of this Agreement, including termination of this Agreement as provided in Section 2.3, payment of damages, and in the case of Buyer, drawing upon the Development Security and the Operating Security.

24.5 Termination of Duty to Buy. If this Agreement is terminated because of an Event of Default by Supplier, neither Supplier nor any Affiliate of Supplier, nor any successor to Supplier with respect to the ownership of the Facility or the Project Site, may thereafter require or seek to require Buyer to make any purchases from the Facility or any electric generation facility constructed on the Project Site, under the Public Utility Regulatory Policies Act of 1978 or any other Law, for any periods that would have been within the Term had this Agreement remained in effect. Supplier, on behalf of itself and any other entity on whose behalf it may act, hereby waives its rights to require Buyer so to do.

24.5.1 Right of First Offer for Product. If Buyer terminates this Agreement in accordance with Section 2.3.1 due to a Supplier Event of Default, then neither Supplier nor Supplier's Affiliates may sell, or enter into a contract to sell, Net Energy or any Product generated by, associated with or attributable to a generating facility that from time to time may be constructed by Supplier or any Affiliate of Supplier on the Project Site installed at the Project Site to a party other than Buyer for a period of three (3) years following the effective date of such termination ("Restricted Period"). The foregoing prohibition on contracting and sale will not apply if, before entering into such contract or making a sale to a party other than

Buyer, Supplier or Supplier's Affiliate provides Buyer with a written offer to sell the Net Energy or any Product to Buyer at the rate set forth in this Agreement and otherwise on terms and conditions materially similar to the terms and conditions set forth in this Agreement and Buyer fails to accept such offer within (A) forty-five (45) days after Buyer's receipt of such offer if this Agreement had originally been terminated by Buyer after the commencement of construction of the Facility, and (B) one hundred twenty (120) days after Buyer's receipt of such offer if this Agreement had originally been terminated by Buyer prior to the commencement of construction of the Facility. If Buyer elects to purchase such Product, then the Parties shall enter into a binding agreement consistent with the foregoing and otherwise on terms and conditions substantially similar with this Agreement, the same being modified only as necessary to address changes which arise due to the passage of time. Neither Supplier nor Supplier's Affiliates may sell or transfer the Facility, or any part thereof, or their land rights or interests in the Project Site (including the interconnection queue position) during the Restricted Period so long as the limitations contained in this Section 24.5.1 apply, unless the transferee agrees to be bound by the terms set forth in this Section 24.5.1 pursuant to a written agreement approved by Buyer. Notwithstanding the above prohibition on a sale of transfer, this prohibition will not prevent the sale by Supplier or Supplier's Affiliates of their interests in the Project Site to a third party if an independent engineer provides a notarized certification to the fact that a solar facility cannot be developed on the Project Site. Buyer shall be permitted to file a notice of the rights contained in this Section 24.5.1 with respect to the Supplier's and Supplier's Affiliates' interests in the Project Site. Supplier shall indemnify and hold Buyer harmless from all Losses sustained by Buyer as a result of any breach of the covenants contained in this Section 24.5.1.

24.6 Step-In Rights.

24.6.1 Step-In Rights following an Event of Default. The Buyer step-in rights described in this Section 24.6 are subject to and subordinate to the rights of Supplier's Lenders set forth in this Agreement and any consent to collateral assignment agreement entered into by Buyer and Supplier's Lenders. If Supplier commits an Event of Default, including pursuant to Section 24.1.6(b), and this Agreement has not been terminated by Buyer, then without limiting its other rights and remedies hereunder, Buyer shall have the right to enter the Project Site and take possession of the Facility and to take or cause to be taken all such actions and do or cause to be done all such things as Buyer may consider necessary or desirable to cure the Event of Default, including to complete the Facility and cause Commercial Operation to occur. Following the cure of the Event of Default, Buyer shall: (a) return possession of the Facility to Supplier upon execution by Supplier of an indemnity and release agreement, in form and substance reasonably acceptable to Buyer, pursuant to which Supplier shall indemnify and release Buyer from all claims arising out of Buyer's exercise of its rights pursuant to this Section 24.6; or (b) failing the execution of such indemnity and release agreement: (i) operate the Facility for all or such portion of the remaining Term as Buyer may elect, in its sole discretion, pursuant to the license granted in Section 24.6.2; and/or (ii) exercise its other rights and remedies under this Agreement, including the right to terminate this Agreement without the payment of any damages by Buyer.

24.6.2 License to Operate Facility. Supplier hereby irrevocably grants to Buyer the right, license and authority to enter the Project Site, to construct, operate and maintain the Facility for the Term during the continuance of and following any Event of Default by Supplier. During any period in which Buyer constructs, operates or maintains the Facility pursuant to the license granted in this Section 24.6.2, Supplier shall, upon request from Buyer, reimburse Buyer for all reasonable costs and expenses incurred by Buyer to construct, operate and maintain the Facility.

24.6.3 Records and Access. Supplier shall collect and have available at a convenient, central location at the Project Site all documents, contracts, books, manuals, reports, and records required to construct, operate and maintain the Facility in accordance with Good Utility Practice. Upon Buyer's notice of intent to exercise its rights under this Section 24.6, Buyer, its employees, contractors, or designated third parties shall have the right to enter the Project Site and the Facility for the purpose of constructing, operating or maintaining the Facility. Upon the exercise by Buyer of the its rights under this Section 24.6, Supplier shall cause the Facility contractor or operator (and any Person within the control of Supplier) to give Buyer access to and control of the construction, operation and maintenance of the Facility, as applicable, to the extent reasonably necessary to enable Buyer to exercise its rights under this Section 24.6, and shall provide reasonable assistance and cooperation to Buyer to effect safely the transfer of responsibility for construction, operation and maintenance as may be requested by Buyer. Supplier shall execute such documents and take such other action as may be necessary for Buyer to effectuate its rights under this Section 24.6.

24.6.4 Return. Buyer may, at any time and in its sole discretion, terminate its exercise of its rights under this Section 24.6 whether or not the applicable Event of Default has been cured. If at any time after exercising its rights under this Agreement, Buyer elects to return possession of the Facility to Supplier, Buyer shall provide Supplier with at least ten (10) days advance notice of the date Buyer intends to return such possession, and upon receipt of such notice Supplier shall take all actions necessary to resume possession of the Facility on such date.

24.6.5 No Assumption. Buyer's exercise of its rights under this Section 24.6 shall not be deemed an assumption by Buyer of any liability of Supplier due and owing prior to the exercise of such rights. Buyer shall not assume any liability of Supplier for the period during which Buyer exercises its rights under this Section 24.6. During any period that Buyer is exercising its rights, Supplier shall retain legal title to and ownership of the Facility and all of its other property and its revenues. When exercising its rights under this Section 24.6, Buyer shall assume possession, operation, and control of the Facility solely as agent for Supplier. In no event shall Buyer's election to exercise its rights under this Section 24.6 be deemed to constitute a transfer of ownership of or title to the Facility, the Project Site or any assets of Supplier.

24.6.6 Costs and Expenses. Supplier shall indemnify and hold harmless Buyer from and against all Losses incurred by Buyer in connection with exercise of its rights under this Section 24.6 other than due to the negligence or willful misconduct of Buyer. In connection with its exercise of its rights under this Section 24.6, Buyer shall have the right to recoup and set off all such Losses against amounts otherwise owed by Buyer hereunder. Buyer's exercise of such recoupment and set off rights shall not limit the other rights and remedies available to Buyer hereunder or otherwise.

25. REPRESENTATIONS AND WARRANTIES OF SUPPLIER

Supplier represents and warrants to Buyer as of the Effective Date and for the term of this Agreement and at the Commercial Operation Date as set forth in Sections 25.1 through 25.12, and covenants to Buyer as set forth in Sections 25.13 through 25.15:

25.1 Organization. Supplier is a limited liability company duly organized, validly existing and in good standing under the Laws of the State of Delaware and has all requisite entity power and authority to own or lease and operate its properties and to carry on its business as is now being conducted. Supplier is duly qualified or licensed to do business and is in good standing in the State of Nevada and in each other jurisdiction in which the property owned, leased or operated by it or the nature of the business conducted by it makes such qualification necessary, except where the failure to be so duly qualified or licensed and in good standing would not reasonably be expected to have a Material Adverse Effect on Supplier.

25.2 Authority. Supplier has full authority to execute, deliver and perform its obligations under this Agreement and to consummate the transactions contemplated herein and has taken all corporate actions necessary to authorize the execution, delivery and performance of its obligations under this Agreement. No other proceedings or approvals on the part of Supplier are necessary to authorize this Agreement. This Agreement constitutes a legal, valid and binding obligation of Supplier enforceable in accordance with its terms except as the enforcement thereof may be limited by (a) applicable bankruptcy, insolvency or similar Laws affecting the enforcement of creditors' rights generally and (b) general principles of equity, whether considered in a proceeding in equity or at law.

25.3 Governmental Approvals; No Violation. Other than obtaining the Supplier's Required Regulatory Approvals as set out in Exhibit 10, the execution, delivery and performance of this Agreement by Supplier shall not: (a) conflict with or result in any breach of any provision of the articles of organization (and/or other governing documents) of Supplier; (b) require any Governmental Approval, except where the failure to obtain such Governmental Approval would not reasonably be expected to have a Material Adverse Effect on Supplier; or (c) result in a default (or give rise to any right of termination, cancellation or acceleration) under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, agreement, lease or other instrument or obligation to which Supplier or any of its subsidiaries is a party or by which any of their respective assets may be bound, except for such defaults (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained.

25.4 Regulation as a Utility. Except for its anticipated future status as a "public utility" as defined in the Federal Power Act, and as set forth in Exhibit 10, Supplier is not subject to regulation as a public utility or public service company (or similar designation) by any Governmental Authority.

25.5 Availability of Funds. Supplier has, or will have, and shall maintain sufficient funds available to it to perform all of its obligations under this Agreement and to consummate the transactions contemplated pursuant hereto.

25.6 Interconnection Process; Transmission. Supplier has initiated with the Transmission Provider the process of obtaining the rights to interconnect the Facility to the Transmission System in order to provide for the delivery of Net Energy and Discharging Energy to and at the Delivery Points.

25.7 Interconnection Cost Due Diligence. Supplier has conducted due diligence regarding the costs of all facilities and equipment necessary to interconnect the Facility to and at the Delivery Points and all such costs are covered by payments for Product provided for in this Agreement.

25.8 Required Facility Documents. All Required Facility Documents are listed on Exhibit 12. Pursuant to the Required Facility Documents, Supplier holds as of the Effective Date, or will hold by the Commercial Operation Date (or such other later date as may be specified under requirements of Law), and will maintain for the Term all Required Facility Documents (including all material authorizations, rights and entitlements) necessary to construct, own, operate and maintain the Facility and to perform its obligations under this Agreement, including the sale and delivery of Product to Buyer in accordance with this Agreement. The anticipated use of the Facility complies with all applicable restrictive covenants affecting the Facility or the Project Site.

25.9 Governmental Approvals. Supplier has applied or will apply for or has received the Governmental Approvals listed in Exhibits 10 and 12, and no other Governmental Approvals are required by Supplier to construct, own, operate and maintain the Facility or perform its obligations under this Agreement. Following the Commercial Operation Date, Supplier shall notify Buyer of any additional material Governmental Approvals that are required for the ownership, operation and maintenance of the Facility or the performance by Supplier of its obligations under this Agreement, in each case, promptly after Supplier makes any such determination.

25.10 Related Agreements. Supplier has entered into or will enter into all material agreements as listed in Exhibit 12 necessary for the construction, ownership, operation and maintenance of the Facility and the performance of its obligations under this Agreement.

25.11 Certification. Subject to Section 3.5, the Generating Facility qualifies as a Renewable Energy System and Supplier has been and is in compliance with all requirements set forth in the Renewable Energy Law.

25.12 Title. Supplier will own all Product attributable to the Facility and has the right to sell such Product to Buyer. Supplier will convey good title to the Product to Buyer free and clear of any liens or other encumbrances or title defects, including any which would affect Buyer's ownership of any portion of such Product or prevent the subsequent transfer of any portion of such Product by Buyer to a third party.

25.13 Project Execution Plan. Supplier will execute the development and construction of the Facility in accordance with the project execution plan submitted by Supplier to Buyer pursuant to the October 16, 2018 request for proposals, but subject to modifications as may be required to reflect changes in contractors and suppliers, subject to Section 25.14, and modifications as may be required to reflect the final design of the Facility, subject to Section 8.7. Supplier shall not make any material modifications to the project execution plan without the consent of Buyer, such consent not to be unreasonably withheld, conditioned or delayed.

25.14 Approved Vendors. To the extent the Facility uses equipment types listed on Exhibit 23, Supplier shall construct the Facility using only such equipment manufactured by the vendors, subcontractors and equipment suppliers listed on Exhibit 23, which shall be provided by Buyer.

25.15 Work Site Agreement. Supplier shall enter into a work site agreement, memorandum of understanding, or similar document in the form attached hereto as Exhibit 21.

25.16 Continuing Nature of Representations and Warranties; Notice. The representations and warranties set forth in this Article 25 are made as of the Effective Date and shall be deemed repeated as of the Commercial Operation Date. If at any time during the Term, Supplier obtains actual knowledge of any fact, circumstance, event or information that would have caused or cause any of the representations and warranties in this Article 25 to be materially untrue or misleading at the time given or deemed given or at any time thereafter for so long as this Agreement is in force and effect, then Supplier shall provide Buyer with written notice of the fact, circumstance, event or information, the representations and warranties affected, and the action, if any, which Supplier intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section 25.16 shall be given as soon as practicable after Supplier obtains actual knowledge of any such fact, circumstance, event or information.

26. REPRESENTATIONS AND WARRANTIES OF BUYER

Buyer represents and warrants to Supplier as of the Effective Date as follows and covenants to Supplier that such representations and warranties will be true and correct for so long as this Agreement is in force and effect:

26.1 Organization; Qualification. Buyer is a corporation duly organized, validly existing and in good standing under the Laws of the State of Nevada and has all requisite corporate power and authority to own, lease, and operate its properties and to carry on its business as is now being conducted. Buyer is duly qualified or licensed to do business and is in good standing in each jurisdiction in which the property owned, leased or operated by it or the nature of the business conducted by it makes such qualification necessary, except where the failure to be so duly qualified or licensed and in good standing would not reasonably be expected to have a Material Adverse Effect on Buyer.

26.2 Authority. Buyer has full authority to execute, deliver and perform its obligations under this Agreement and to consummate the transactions contemplated herein and has taken all corporate actions necessary to authorize the execution, delivery and performance of its obligations under this Agreement. No other proceedings or approvals on the part of Buyer are necessary to authorize this Agreement. This Agreement constitutes a legal, valid and binding obligation of Buyer enforceable in accordance with its terms except as the enforcement thereof may be limited by (a) applicable bankruptcy, insolvency or similar Laws affecting the enforcement of creditors' rights generally and (b) general principles of equity, whether considered in a proceeding in equity or at law.

26.3 Governmental Approvals; No Violation. Other than obtaining Buyer's Required Regulatory Approvals as set out in Exhibit 9, the execution, delivery and performance of its obligations under this Agreement by Buyer shall not: (a) conflict with or result in any breach of any provision of the articles of organization (or other similar governing documents) of Buyer; (b) require any Governmental Approval, except: (i) where the failure to obtain such Governmental Approval would not reasonably be expected to have a Material Adverse Effect on Buyer; or (ii) for Governmental Approvals which become applicable to Buyer as a result of specific regulatory status of Buyer or as a result of any other facts that specifically relate to the business or activities in which Buyer is or proposes to be engaged, which Governmental Approvals have been obtained or made by Buyer; or (c) result in a default (or give rise to any right of termination, cancellation or acceleration) under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, agreement, lease or other instrument or obligation to which Buyer or any of its subsidiaries is a party or by which any of their respective assets may be bound, except for such defaults (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained.

26.4 Continuing Nature of Representations and Warranties; Notice. The representations and warranties set forth in this Article 26 are made as of the Effective Date. If at any time during the Term, Buyer obtains actual knowledge of any fact, circumstance, event or information that would have caused or cause any of the representations and warranties in this Article 26 to be materially untrue or misleading at the time given or at any time thereafter for so long as this Agreement is in force and effect, Buyer shall provide Supplier with prompt written notice of the fact, circumstance, event or information, the representations and warranties affected, and the action, if any, which Buyer intends to take to make the representations and warranties true and correct.

27. INSURANCE

27.1 General Requirements. From and after the Effective Date, Supplier shall maintain at all times, at its own expense, general-commercial liability, worker's compensation, and other forms of insurance relating to its property, operations and facilities in the manner and amounts set forth in this Article 27. Supplier shall maintain coverage on all policies written on a "claims made" or "occurrence" basis. If any policy is maintained on a "claims made" form and is converted to an "occurrence form," the new policy shall be endorsed to provide coverage back to a retroactive date acceptable to Buyer.

27.2 Qualified Insurers. Every contract of insurance providing the coverage required herein shall be with an insurer or eligible surplus lines insurer qualified to do business in the State of Nevada and with the equivalent, on a continuous basis, of an "A.M. Best Company Rating" of "A" or better and shall include provisions or endorsements:

27.2.1 Stating that such insurance is primary insurance with respect to the interest of Buyer and that any insurance maintained by Buyer is excess and not contributory insurance required hereunder;

27.2.2 Stating that no reduction, cancellation or non-renewal of the policy shall be effective until thirty (30) days from the date notice thereof is actually received by Buyer; provided that upon Supplier's receipt of any notice of reduction, cancellation or non-renewal, Supplier shall immediately provide notice thereof to Buyer;

27.2.3 Providing Buyer with subrogation waivers on all coverage;

27.2.4 Providing for Separation of Insured coverage in the general liability and auto liability insurance policies; and

27.2.5 Naming Buyer as an additional insured on the general liability and auto liability insurance policies of Supplier as its interests may appear with respect to this Agreement.

27.3 Certificates of Insurance. Within thirty (30) days of the Effective Date and each anniversary thereafter during the Term, and upon any change in coverage or at the request of Buyer (not to exceed once each year), Supplier shall provide to Buyer properly executed and current certificates of insurance with respect to all insurance policies required to be maintained by Supplier under this Agreement. Certificates of insurance shall provide the following information:

27.3.1 The name of insurance company, policy number and expiration date;

27.3.2 The coverage required and the limits on each, including the amount of deductibles or self-insured retentions, which shall be for the account of Supplier; and

27.3.3 A statement indicating that Buyer shall receive at least thirty (30) days prior notice of cancellation or non-renewal of a policy or of a reduction of liability limits with respect to a policy.

27.4 Certified Copies of Insurance Policies. At Buyer's request, in addition to the foregoing certificates of insurance, Supplier shall deliver to Buyer a copy of each insurance policy, certified as a true and complete copy by an authorized representative of the issuing insurance company.

27.5 Inspection of Insurance Policies. Buyer shall have the right to inspect the original policies of insurance applicable to this Agreement at Supplier's place of business during regular business hours.

27.6 Supplier's Minimum Insurance Requirements.

27.6.1 Worker's Compensation. Workers' compensation insurance in the form and manner required by statutory requirements and endorsement providing insurance for obligations under the U.S. Longshoremen's and Harbor Worker's Compensation Act and the Jones Act where applicable. Employer's liability insurance with the following limits: (a) one million dollars ($1,000,000.00) per each bodily injury by accident; (b) one million dollars ($1,000,000.00) per each employee bodily injury by occupational disease; and (c) one million dollars ($1,000,000.00) in the annual aggregate per each bodily injury by occupational disease.

27.6.2 General Liability. General liability insurance including bodily injury, property damage, products/completed operations, contractual and personal injury liability with a combined single limit of at least five million dollars ($5,000,000) per occurrence and at least five million dollars ($5,000,000) annual aggregate.

27.6.3 Automobile Liability. Automobile liability insurance including owned, non-owned and hired automobiles with combined bodily injury and property damage with a combined single limit of at least two million dollars ($2,000,000). The minimum insurance limits set forth in Sections 27.6.1, 27.6.2, and 27.6.3 can be met by Supplier's underlying workers' compensation/employer's liability, general liability, and automobile liability policies in combination with an excess insurance policy.

27.6.4 Excess Liability. Excess liability insurance with a minimum limit of five million dollars ($5,000,000) ("Excess Minimum") for each occurrence and an aggregate where applicable on a following form basis to be excess of the insurance coverage and limits required in Supplier's general liability insurance and automobile liability insurance. Supplier shall promptly notify Buyer if the Excess Minimum is not available and Supplier shall purchase additional insurance coverage up to the Excess Minimum if required by Buyer.

27.6.5 Failure to Comply. If Supplier fails to comply with the provisions of this Article 27, Supplier shall save harmless and indemnify Buyer from any direct or indirect Loss, including attorneys' fees and other costs of litigation, resulting from the injury or death of any person or damage to any property if Buyer would have been protected had Supplier complied with the requirements of this Article 27, in accordance with the indemnification provisions of Article 18.

28. NO EXPECTATION OF CONFIDENTIALITY; PUBLIC STATEMENTS

28.1 No Expectation of Confidentiality. Supplier has no expectation that any of the terms of this Agreement will be treated as confidential by Buyer, and Buyer has no obligation to seek confidential treatment of this Agreement in connection with Buyer's Required Regulatory Approvals or otherwise.

28.2 Public Statements. The Parties shall consult with each other prior to issuing any public announcement, public statement or other public disclosure with respect to this Agreement and Supplier shall not issue any such public announcement, public statement or other public disclosure without having first received the written consent of Buyer, except as may be required by Law. Notwithstanding the foregoing, Supplier acknowledges and agrees that Buyer may advertise, issue brochures or make other announcements, publications or releases regarding this Agreement and the Facility for educational, promotional or informational purposes and Supplier may disclose this Agreement and information regarding the Facility to its members, officers, directors, employees, suppliers, contractors, attorneys, agents and representatives in connection with the execution, delivery and performance of its obligations under this Agreement. Supplier shall reasonably cooperate with Buyer regarding such activities, including providing Buyer with reasonable access to the Facility and authorizing the use of pictures of the Facility for such activities. It shall not be deemed a violation of this Section 28.2 to file this Agreement with the PUCN or FERC or any other Governmental Authority in connection with Buyer's Required Regulatory Approvals, Supplier's Required Regulatory Approvals or otherwise.

29. MISCELLANEOUS

29.1 Notices.

29.1.1 All notices, requests, demands, submittals, waivers and other communications required or permitted to be given under this Agreement (each, a "Notice") shall, unless expressly specified otherwise, be in writing and shall be addressed, except as otherwise stated herein, to the Parties' Contract Representatives as set forth in Exhibit 4, as the same may be modified from time to time by Notice from the respective Party to the other Party.

29.1.2 All Notices required by this Agreement shall be sent by regular first class U.S. mail, registered or certified U.S. mail (postage paid return receipt requested), overnight courier delivery, or electronic mail. Such Notices will be effective upon receipt by the addressee, except that Notices transmitted by electronic mail shall be deemed to have been validly and effectively given on the day (if a Business Day and, if not, on the next following Business Day) on which it is transmitted if transmitted before 16:00 PPT, and if transmitted after that time, on the following Business Day. If any Notice sent by regular first class U.S. mail, registered or certified U.S. mail postage paid return receipt requested, or overnight courier delivery is tendered to an addressee and the delivery thereof is refused by such addressee, then such Notice shall be deemed validly and effectively given upon such tender. All oral notifications required under this Agreement shall be made to the receiving Party's Contract Representative or Operating Representative (as applicable) and shall promptly be followed by Notice as provided in this Section 29.1.

29.1.3 Notices of Force Majeure or an Event of Default pursuant to Article 20 or Article 24, respectively, and Notices of a change to Exhibit 4 shall be sent either by registered or certified U.S. mail (postage paid return receipt requested), overnight courier delivery or electronic mail. If any such Notice is sent via electronic mail, then a copy of such Notice shall also be sent either by registered or certified U.S. mail (postage paid return receipt requested), or overnight courier delivery. Such Notices will be effective as provided in Section 29.1.2.

29.1.4 Any payments required to be made to a Party under this Agreement shall be made pursuant to the payment instructions in Exhibit 4, as such payment instructions may be amended by such Party from time to time by Notice to the other Party.

29.2 Merger. This Agreement contains the entire agreement and understanding between the Parties with respect to all of the subject matter contained herein, thereby merging and superseding all prior agreements and representations by the Parties with respect to such subject matter contained herein whether written or oral.

29.3 Counterparts. This Agreement may be executed in multiple counterparts, each of which shall be deemed an original.

29.4 Rules of Construction; Interpretation. Unless otherwise required by the context in which any term appears: (a) the singular includes the plural and vice versa; (b) references to "Articles," "Sections," "Schedules," or "Exhibits" are to articles, sections, schedules, or exhibits hereof; (c) all references to a particular Person include a reference to such Person's permitted successors and assigns; (d) "herein," "hereof" and "hereunder" refer to this Agreement as a whole; (e) all accounting terms not specifically defined herein shall be construed in accordance with generally accepted accounting principles, consistently applied; (f) the masculine includes the feminine and neuter and vice versa; (g) "including" (and the correlative terms "include", "includes" and "included") means "including, without limitation" or "including, but not limited to"; (h) all references to a particular Law means that Law as amended, supplemented or otherwise modified from time to time; (i) all references to energy or capacity are to be interpreted as utilizing alternating current, unless expressly stated otherwise; and (j) the word "or" is not necessarily exclusive. Reference to "days", "months", "quarters" and "years" shall be to calendar days, months, quarters and years, unless expressly stated otherwise herein. In the event an ambiguity or question of intent or interpretation arises with respect to this Agreement, this Agreement shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of authorship of any of the provisions of this Agreement. Any reference to any Law shall be deemed also to refer to all rules and regulations promulgated thereunder, unless the context requires otherwise.

29.5 Headings and Titles. The headings and section titles in this Agreement are for convenience of the Parties only and shall not be used to construe this Agreement.

29.6 Discontinued or Modified Index. If any index publisher discontinues publishing or substantially modifies any index utilized herein, then the index used herein will be modified to the most appropriate available index, with appropriate adjustments to take into account any changes in the location of measurement.

29.7 Severability. If any term, provision or condition of this Agreement is held to be invalid, void or unenforceable by a Governmental Authority and such holding is subject to no further appeal or judicial review, then such invalid, void, or unenforceable term, provision or condition shall be deemed severed from this Agreement and all remaining terms, provisions and conditions of this Agreement shall continue in full force and effect. The Parties shall endeavor in good faith to replace such invalid, void or unenforceable terms, provisions or conditions with valid and enforceable provisions which achieve the purpose intended by the Parties to the greatest extent permitted by Law.

29.8 Waivers; Remedies Cumulative. No failure or delay on the part of a Party in exercising any of its rights under this Agreement or in insisting upon strict performance of provisions of this Agreement, no partial exercise by either Party of any of its rights under this Agreement, and no course of dealing, usage of trade or course of performance between the Parties shall constitute a waiver of the rights of either Party under this Agreement. Any waiver shall be effective only by a written instrument signed by the Party granting such waiver, and such shall not operate as a waiver of, or estoppel with respect to, any subsequent failure to comply therewith. The remedies provided in this Agreement are cumulative and not exclusive of any remedies provided by Law or in equity. Notwithstanding the foregoing or any other provision hereof, for breach of any provision hereof for which an express remedy or measure of damages is provided (including Sections 3.4 (Delivery Responsibilities), 3.5 (Renewable Energy System), 3.6 (Shortfall; Replacement Costs), 3.7 (PC Shortfall; PC Replacement Costs), 8.4 (Failure to Achieve Commercial Operation), 8.5 (Delay Damages), 8.6 (Nameplate Damages) and 8.7 (Modification)), such express remedy or measure of damages will be the sole and exclusive remedy, the obligor's liability will be limited as set forth in such provision and all other remedies or damages at law or in equity are waived, unless the provision in question provides that the express remedies are in addition to other remedies that may be available.

29.9 Amendments. Amendments or modifications to this Agreement must be in writing and executed by an authorized representative of each Party. Buyer may determine that submitting an amendment or modification to this Agreement to the PUCN and FERC, as applicable, for filing, acceptance or approval shall be a condition precedent to the effectiveness of any such amendment.

29.10 Time is of the Essence. Time is of the essence to this Agreement and in the performance of all of the covenants, agreements, obligations and conditions hereof.

29.11 Choice of Law. This Agreement and the rights and obligations of the Parties hereunder shall be construed and governed by the Laws of the State of Nevada, except for such Laws that would require the application of the Laws of another jurisdiction.

29.12 Further Assurances. The Parties agree to execute and deliver promptly, at the expense of the Party requesting such action, any and all other and further instruments, documents and information which a Party may request and which are reasonably necessary or appropriate to give full force and effect to the terms and intent of this Agreement. Without limiting the foregoing, whenever revised or updated exhibits are delivered or generated hereunder for attachment to this Agreement, the Parties will memorialize the same in a reasonable written instrument, to be executed and delivered by both Parties.

29.13 Forward Contract. The Parties acknowledge and agree that this Agreement and the transactions contemplated hereunder constitute a "forward contract" within the meaning of the United States Bankruptcy Code.

29.14 No Third-Party Beneficiaries. Nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any third party, no third party shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder, and this Agreement is intended solely for the benefit of the Parties, and the Parties expressly disclaim any intent to create any rights in any third party as a third-party beneficiary to this Agreement or the services to be provided hereunder.

29.15 Specific Performance.

29.15.1 Subject always to Section 29.15.2 (a) Buyer shall be entitled to seek and obtain a decree compelling specific performance or granting injunctive relief with respect to, and shall be entitled, to enjoin any actual or threatened breach of any material obligation of Supplier hereunder, (b) the Parties agree that specific performance (including temporary and preliminary relief) and injunctive relief are proper in the event of any actual or threatened breach of any material obligation of Supplier hereunder, and that any liability limits contained herein shall not operate to limit the exercise of Buyer's remedies in equity to cause Supplier to perform its obligations hereunder, and (c) Supplier agrees that it will not assert as a defense to Buyer's action for specific performance of, or injunctive relief relating to, Buyer's obligations hereunder that the amounts payable or paid by Supplier in respect of liquidated damages constitute an adequate remedy for the breach of such obligation, and Supplier hereby conclusively waives such defense. Supplier shall at all times during the Term, own, lease, control, hold in its own name or be signatory to (as the case may be) all assets relating to the Facility to the extent necessary to prevent a material adverse effect on Buyer's right to specific performance or injunctive relief.

29.15.2 Buyer shall not be entitled to seek and obtain a decree compelling specific performance or granting injunctive relief for Supplier's breach of any provision hereof for which an express remedy or measure of damages is provided (including Sections 3.4 (Delivery Responsibilities), 3.5 (Renewable Energy System), 3.6 (Shortfall; Replacement Costs), 3.7 (PC Shortfall; PC Replacement Costs), 8.4 (Failure to Achieve Commercial Operation), 8.5 (Delay Damages), and 8.6 (Nameplate Damages)).

29.16 Mobile-Sierra. Absent agreement of all Parties to a proposed modification of this Agreement, the standard of review the FERC shall apply when acting on proposed modifications to this Agreement, either on FERC's own motion or on behalf of a signatory or a non-signatory, shall be the "public interest" application of the "just and reasonable" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and clarified by Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. I of Snohomish, 554 U.S. 527, 128 S.Ct. 2733, 171 L.Ed.2d. 607 (2008) and NRG Power Marketing, LLC v. Maine Pub. Util. Comm'n, 558 U.S. 165 (2010).

[SIGNATURES APPEAR ON THE FOLLOWING PAGE]

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representative as of the Effective Date.

BUYER:	**SUPPLIER:**
NEVADA POWER COMPANY d/b/a NV ENERGY	**SOLAR PARTNERS XI, LLC**
By:	By:
Name: Douglas A. Cannon	Name: David Scaysbrook
Title: President	Title: Managing Partner

EXHIBIT 1

DESCRIPTION OF FACILITY

1. Name of Generating Facility: Gemini Solar
   - (a) Location: Clark County, Nevada
   - (b) Delivery Points: 230kv Crystal Substation, and 525kv South Crystal (Navajo) Substation

2. Supplier: Solar Partners XI, LLC

3. Parent: Valley of Fire Solar, LLC

4. Operator: Supplier

5. Equipment:
   - (a) Type of Generating Facility: Photovoltaic solar
   - (b) Installed Nameplate Capacity:
     - (i) Total capacity: 745.6 MVA (sum of inverter rating)
     - (ii) Expected Nameplate Capacity Rating at Delivery Points: 690 MW AC @ +/- 0.95, subject to the provisions of Section 3.4.5 (gross nameplate of 707 MW with software-controlled limit to achieve 690 MW at Delivery Points)
     - (iii) Total gross output capacity: 745.6 MW
     - (iv) Total capacity net of Station Usage and other losses: 690 MW (at Delivery Points)
     - (v) Full Requirements Period Capacity Factor: 65%
     - (vi) Full Requirements Period Product: 206,310 MWh over each Full Requirements Period
   - (c) Additional Technology Specific Information, if any:

6. Operating Characteristics of Generating Facility during Generating Facility-Only Generation:
   - (a) Max VAR, leading: 226.8 MVAR (@delivery of 690 MW at Delivery Points)
   - (b) Max VAR, lagging: 226.8 MVAR (@delivery of 690 MW at Delivery Points)
   - (c) Power Factor: +/- 0.95, subject to the provisions of Section 3.4.5
   - (d) Controlled Ramp Rate: <10 second to rated capacity or as specified by inverter manufacturer
   - (e) Minimum Operating Capacity (MW): 10 MW, provided, however that any interval in which the dispatch is less than 34.5 MW will be excluded from the calculation of the Dispatchable Accuracy Rate pursuant to Exhibit 16

7. Operating Characteristics of Generating Facility during Storage Facility Discharge:
   - (a) Max VAR, leading: 124.9 MVAR (@delivery of 380 MW at the Delivery Points from Storage Facility)
   - (b) Max VAR, lagging: 124.9 MVAR (@delivery of 380 MW at the Delivery Points from Storage Facility)

EXHIBIT 1

DESCRIPTION OF FACILITY

(c) Power Factor: +/- 0.95, subject to the provisions of Section 3.4.5
(d) Controlled Ramp Rate: <10 second to 380 MVA (real/reactive power to be limited to Storage capacity at Delivery Points/4)
(e) Minimum Operating Capacity (MW): 10 MW, provided, however that any interval in which the dispatch is less than 34.5 MW will be excluded from the calculation of the Dispatchable Accuracy Rate pursuant to Exhibit 16

8. Type of Storage Facility: (e.g. AC or DC coupled, technology, chemistry, etc.)
    (a) DC-coupled Battery System

9. Operating Characteristics of Storage Facility available to Buyer:
    (a) Charge capacity at the Storage Facility Metering Points on DC side: 400 MW
    (b) Discharge capacity at Delivery Points: 380 MW
    (c) Discharge capacity at the Delivery Points for a 3.7-hour duration: 380 MW as of COD
    (d) Storage capacity at Delivery Points: 1,416 MWh as of COD
    (e) Projected Storage capacity at Delivery Point by contract year [%]

Year 1	**100%**
Year 2	**94.2%**
Year 3	**91.8%**
Year 4	**90.5%**
Year 5	**103.9%**
Year 6	**102.0%**
Year 7	**100.6%**
Year 8	**99.5%**
Year 9	**98.4%**
Year 10	**97.5%**
Year 11	**96.6%**
Year 12	**95.7%**
Year 13	**109.4%**
Year 14	**107.6%**
Year 15	**106.4%**
Year 16	**105.3%**
Year 17	**104.2%**
Year 18	**103.2%**
Year 19	**102.1%**
Year 20	**107.9%**
Year 21	**106.9%**
Year 22	**105.8%**
Year 23	**104.7%**
Year 24	**103.6%**
Year 25	**102.5%**

EXHIBIT 2A

PRODUCT RATES

DISPATCHABLE PERIOD PRODUCT RATE

The Dispatchable Period Product Rate shall be $24.79 per MWh.

FULL REQUIREMENTS PERIOD PRODUCT RATE

The Full Requirements Period Product Rate during the Full Requirements Period shall be 6.5 times the Dispatchable Product Rate for the applicable period (the "Full Requirements Period Product Rate") as represented below.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Feb	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Mar	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Apr	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
May	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Jun	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	6.5x	6.5x	6.5x	6.5x	6.5x	x	x	x
Jul	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	6.5x	6.5x	6.5x	6.5x	6.5x	x	x	x
Aug	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	6.5x	6.5x	6.5x	6.5x	6.5x	x	x	x
Sep	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Oct	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Nov	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Dec	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x

EXHIBIT 2B

FORM OF MONTHLY ENERGY INVOICE

Supplier Letterhead

Facility: ____________________________ **Date:** ________________

Facility ID: ____________________________ **Billing Period:** ________________

Invoice Number: ________________

CURRENT MONTHLY BILLING DATA INPUT

Pricing	**$/MWh**
Dispatchable Period Product Rate	__________
Full Requirements Period Product Rate	__________
Provisional Product Rate	__________
Test Product Rate	__________
Over Delivery Amount Rate	__________

Excused Product	
Planned Outages	______________
Force Majeure	______________
Emergencies (as applicable)	______________
Curtailed Product	______________
Un-Dispatched Amount	______________
Transmission Provider Instructions	______________
Buyer's Failure to Accept Net Energy	______________
FRP Deemed Delivered Energy	______________
Total Excused Product	______________

Delivered Amount (kWh)	**On-Peak**	**Off-Peak**
Dispatchable Period – Net Energy	______________	______________
Full Requirements Period – Net Energy	______________	______________
Total Delivered Amount	______________	______________

CURRENT MONTHLY INVOICE CALCULATION

	Net Energy		**Rate/kWh**		**Amount**
a. Dispatchable Period Product[1]	______________	x	______________	=	$ ______________
b. Full Requirements Period Product	______________	x	______________	=	$ ______________
c. FRP Deemed Delivered Energy	______________	x	______________	=	$ ______________
d. Un-Dispatched Amount	______________	x	______________	=	$ ______________
e. Provisional Energy	______________	x	______________	=	$ ______________
f. Test Energy	______________	x	______________	=	$ ______________
g. Shortfall/Replacement Cost (from page 2B-2)					$ ______________
h Over Delivery Amount	______________	x	______________	=	$ ______________
i. Total Product Payment (a+b+c+d+e+f-g+h)					$ ______________
j. Adjustments (+/-)					$ ______________
TOTAL AMOUNT DUE (i + j)					$ ______________

PAYMENT DUE DATE NO LATER THAN: _________________

[1] Excluding Provisional Energy and Test Energy

EXHIBIT 2B

FORM OF MONTHLY ENERGY INVOICE

REPLACEMENT COST CALCULATION – For Billing Period: ______________________

Full Requirements Period

a. Full Requirements Period Product ________________ kWh
b. 95% of FRP Product (0.95 * a) ________________ kWh
c. Excused Product ________________ kWh
d. Delivered Amount ________________ kWh
e. Reserved

Shortfall (Y/N)? ________

f. Shortfall Amount (max b – c – d or zero) ________________ kWh

Replacement Cost Calculation
g. Average Market Price ________________ $/MWh
h. Full Requirements Period Product Rate ________________ $/MWh
i. Difference (max g – h or zero) ________________ $/MWh

j. Replacement Cost (f * i) $ ________________

REPLACEMENT COST CALCULATION – For Billing Period: ______________________

Dispatchable Period

k. Resource-Adjusted Backcast Amount ________________ kWh
l. FRP Charging Energy ________________ kWh
m. Difference (k – l) ________________ kWh
n. 95% of Difference (0.95 * m) ________________ kWh

o. Delivered Amount ________________ kWh
p. Excused Product ________________ kWh

q. Shortfall (Y/N)? ________

r. Shortfall Amount (max n – o – p or zero) ________________ kWh

Replacement Cost Calculation
s. Average Market Price ________________ $/MWh
t. Dispatchable Period Product Rate ________________ $/MWh
u. Difference (max s – t or zero) ________________ $/MWh

v. Replacement Cost (r * u) $ ________________

EXHIBIT 2B

FORM OF MONTHLY ENERGY INVOICE DETAIL

Date	Hour Ending	On-Peak/ Off-Peak	Dispatch Availability Amount	Total Delivered Amount	Base Product Amount	Product Rate	Full Requirements Period Delivered Amount	Un-Dispatched Amount	Base Product Cost	Excess Energy	Maximum Amount Energy	Excused Product	Reason for Excused Product
	0100												
	0200												
	0300												
	0400												
	0500												
	0600												
	0700												
	0800												
	0900												
	1000												
	1100												
	1200												
	1300												
	1400												
	1500												
	1600												
	1700												
	1800												
	1900												
	2000												
	2100												
	2200												
	2300												
	2400												
Total On-Peak:													
Total Off-Peak:													
TOTAL:													

EXHIBIT 2C

FORM OF PC REPLACEMENT INVOICE

Buyer Letterhead

Facility: ____________________		Date:	______
Facility ID: ____________________		Contract Year:	______
		Invoice Number:	______
		Payment Due Date:	______

PC REPLACEMENT COSTS CALCULATION

Contract Year Data	**PCs**
a. Yearly PC Amount	______
b. Delivered PCs	______
PCs Associated with Excused Product:	
c. Planned Outages	______
d. Force Majeure	______
e. Emergencies	______
f. Curtailed Product	______
g. Un-Dispatched Amount	______
h. Transmission Provider Instructions	______
i. Buyer's Failure to Accept Net Energy	______
j. FRP Deemed Delivered Energy	______
k. Excused Product (c + d + e + f + g + h + i + j)	______
l. Difference (a - k)	______
m. 90% of Difference (0.9 * l)	______
n. PC Shortfall Amount (max m – b or zero)	______
o. PC Replacement Rate	**$** ______
p. PC REPLACEMENT COSTS (n * o)	**$** ______

EXHIBIT 3A

DESCRIPTION OF PROJECT SITE

All Project Site is located on BLM Lands. The following property intersect the Project Site, in Clark County, Nevada:

Block A

- Section 13, Township 17 South, Range 64 East
- Northeast 1/6, Section 14, Township 17 South, Range 64 East
- Southeast 3/4, Section 12, Township 17 South, Range 64 East
- Southwest 1/2, Section 7, Township 17 South, Range 65 East
- Northwest 1/2, Section 18, Township 17 South, Range 65 East
- Southwest 1/3, Section 18, Township 17 South, Range 65 East

Consisting of approximately 862 acres.

Block B

- Southeast ½, Northeast 1/3, Section 7, Township 17 South, Range 65 East
- Northwest, Southwest, Southeast 1/3, Section 8, Township 17 South, Range 65 East
- Northeast ½, Southeast ½, Section 18, Township 17 South, Range 65 East
- Northwest, Southwest, Southeast, Northeast 2/3, Section 17, Township 17 South, Range 65 East
- Northwest 1/5, Southwest 1/2, Southeast, Northeast, Section 19, Township 17 South, Range 65 East
- Northwest, Southwest 1/2, Northeast 1/2, Section 20, Township 17 South, Range 65 East
- Northeast 1/6, Southeast 1/3, Section 25, Township 17 South, Range 64 East
- Northwest, Southwest, Northeast 1/2, Southeast 2/3, Section 30, Township 17 South, Range 65 East
- Northeast 2/3, Southeast, Section 36, Township 17 South, Range 64 East
- Northwest, Southwest 1/2, Northeast 1/3, Section 31, Township 17 South, Range 65 East
- Northwest 1/2, Northeast 2/3, Section 01, Township 18 South, Range 64 East

Consisting of approximately 3340 acres.

Block C

- Northeast, Southeast 2/3, Section 8, Township 17 South, Range 65 East
- Northwest, Southwest 2/3, Section 9, Township 17 South, Range 65 East
- Northeast 1/4, Section 17, Township 17 South, Range 65 East
- Northwest 1/3, Section 16, Township 17 South, Range 65 East

Consisting of approximately 472 acres.

Block D

- Southwest 1/4, Southeast 1/4, Section 20, Township 17 South, Range 65 East
- Northwest 1/2, Northeast 1/2, Southwest 3/4, Southeast 3/4, Section 29, Township 17 South, Range 65 East
- Northwest, Northeast 3/4, Southwest, Southeast, Section 32, Township 17 South, Range 65 East
- Northeast 1/3, Southeast 3/4, Section 31, Township 17 South, Range 65 East
- Section 05 3/4, Section 06 1/8, Section 04 1/8 Township 18 South, Range 65 East

Consisting of approximately 1913 acres.

Block E

- Southeast 1/5, Section 20, Township 17 South, Range 65 East
- Southwest 1/5, Section 21, Township 17 South, Range 65 East
- Northeast 1/4, Southeast 1/8, Section 29, Township 17 South, Range 65 East
- Northwest 2/3, Southwest 3/4, Section 28, Township 17 South, Range 65 East
- Northwest 1/2, Section 33, Township 17 South, Range 65 East

Consisting of approximately 402 acres.

EXHIBIT 3A

DESCRIPTION OF PROJECT SITE

Gen-tie parcels (3 options):

- Southwest, Southeast, Section 10, Township 17 South, Range 64 East
- Southwest, Southeast, Section 11, Township 17 South, Range 64 East
- Southwest, Northwest, Northeast Section 12, Township 17 South, Range 64 East
- Northwest, Northeast, Section 07, Township 17 South, Range 64 East
- Northwest, Northeast, Section 15, Township 17 South, Range 64 East
- Northwest, Northeast, Southeast, Section 14, Township 17 South, Range 64 East
- Southeast, Southwest, Section 13, Township 17 South, Range 64 East
- Southwest, Section 18, Township 17 South, Range 65 East
- Northwest, Section 19, Township 17 South, Range 65 East

EXHIBIT 3B

MAP DEPICTING PROJECT SITE

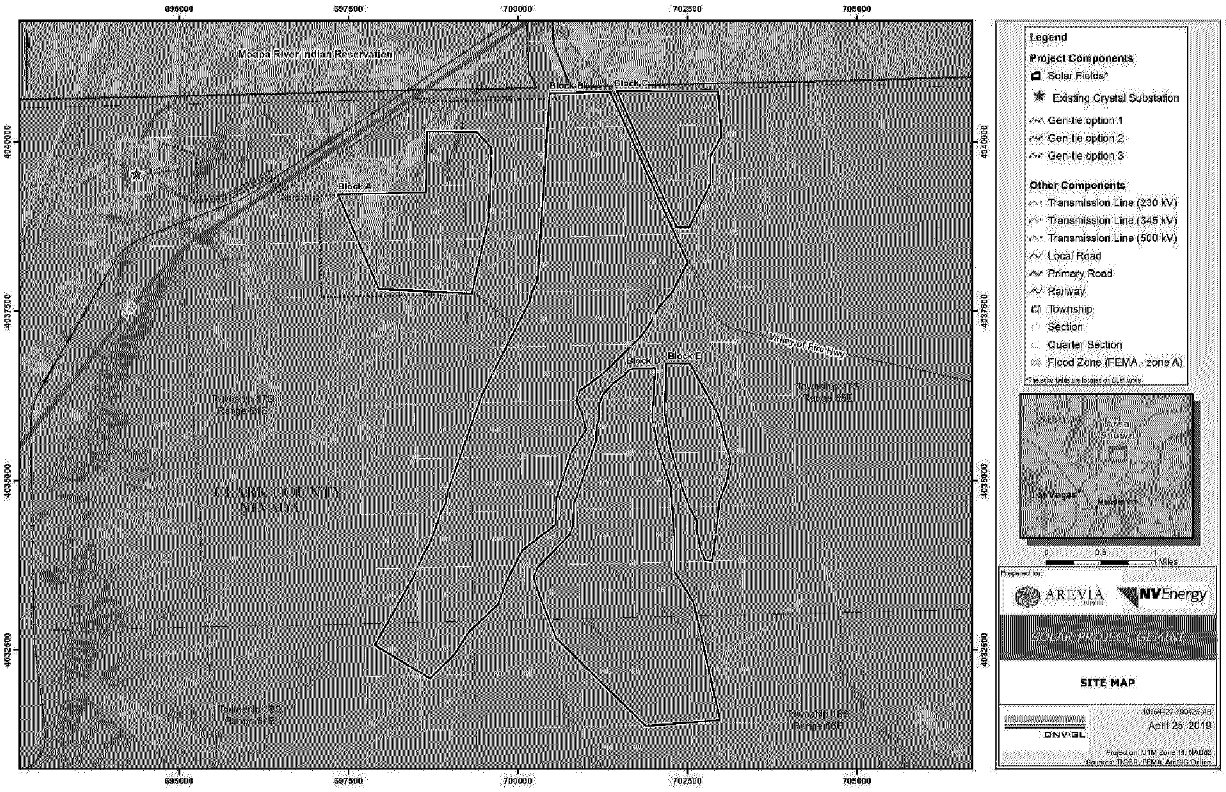


EXHIBIT 4

NOTICES, BILLING AND PAYMENT INSTRUCTIONS

SUPPLIER:

Solar Partners XI, LLC

Contact	Mailing Address	Phone	E-mail
CONTRACT REPRESENTATIVE:			
Prior to Commercial Operation Date:			
Mark Boyadjian	c/o Valley of Fire LLC	917-653-8116	Mark@areviapower.com
	500 N. Central Ave Suite 600 Glendale, CA, 91203		
From and after Commercial Operation Date:			
David Scaysbrook	c/o Valley of Fire LLC		
	15 Via Roma Suite 1.303, Isle of Capri, QLD 4217 Australia	61 400 439 590	ds@quinbrook.com
OPERATING REPRESENTATIVE:			
Prior to Commercial Operation Date:			
Mark Boyadjian	c/o Valley of Fire LLC	917-653-8116	Mark@areviapower.com
	500 N. Central Ave Suite 600 Glendale, CA, 91203		
From and after Commercial Operation Date:			
David Scaysbrook	c/o Valley of Fire LLC		
	15 Via Roma Suite 1.303, Isle of Capri, QLD 4217 Australia	61 400 439 590	ds@quinbrook.com
CHARGING AND DISCHARGING NOTICE COMMUNICATIONS:	[To be provided prior to start of construction]		
OPERATING NOTIFICATIONS:	[To be provided prior to start of construction]		
Prescheduling			
Real-Time			
Monthly Checkout			

EXHIBIT 4

NOTICES, BILLING AND PAYMENT INSTRUCTIONS

INVOICES:

Mark Boyadjian	c/o Valley of Fire LLC 500 N. Central Ave Suite 600 Glendale, CA, 91203	917-653-8116	Mark@areviapower.com

PAYMENT INSTRUCTIONS [To be provided by Supplier]

BUYER: NV ENERGY

Nevada Power Company d/b/a NV Energy

Contact	Phone	E-mail
CONTRACT REPRESENTATIVE:		
Manager, Energy Supply Contract Management 6226 W Sahara Ave, M/S 26A Las Vegas, NV 89146	702/402-5667	ContractManagement@nvenergy.com
OPERATING REPRESENTATIVES		
Scheduling		
- Portfolio Analytics-NPC (Normal Business Hours)	702/402-2882	PortfolioAnalytics@nvenergy.com
- Portfolio Analytics-SPPC (Normal Business Hours)	702/402-2884	PortfolioAnalytics@nvenergy.com
- Generation Dispatch (Control Area Operations)	702/402-7111	Sysopr@nvenergy.com
- Daily Availability Notice-NPC (Spreadsheet)	702/402-2882	PortfolioAnalytics@nvenergy.com
- Daily Availability Notice-SPPC (Spreadsheet)	702/402-2884	PortfolioAnalytics@nvenergy.com
Emergencies (including Force Majeure)		
- Grid Reliability	775/834-4216	Grid_Reliability@nvenergy.com
- Portfolio Analytics	702/402-1954	PortfolioAnalytics@nvenergy.com
Planned Outages-NPC	702/402-6602	esccoc@nvenergy.com
Planned Outages-SPPC	775/834-4716	esccoc@nvenergy.com
Metering-NPC	702/402-6110	NPCMeterOps@nvenergy.com
Metering-SPPC	775/834-7156	Electric_Meter_Ops_North@nvenergy.com
INVOICES		
Energy Supply Contract Management 6226 W Sahara Ave, M/S 26A Las Vegas, NV 89146	702/402-5667	ContractManagement@nvenergy.com
CC all invoices to: Fuel & Purchased Power Accounting 6100 Neil Road, M/S S2A20 Reno, NV 89511	775/834-6281	cmcelwee@nvenergy.com

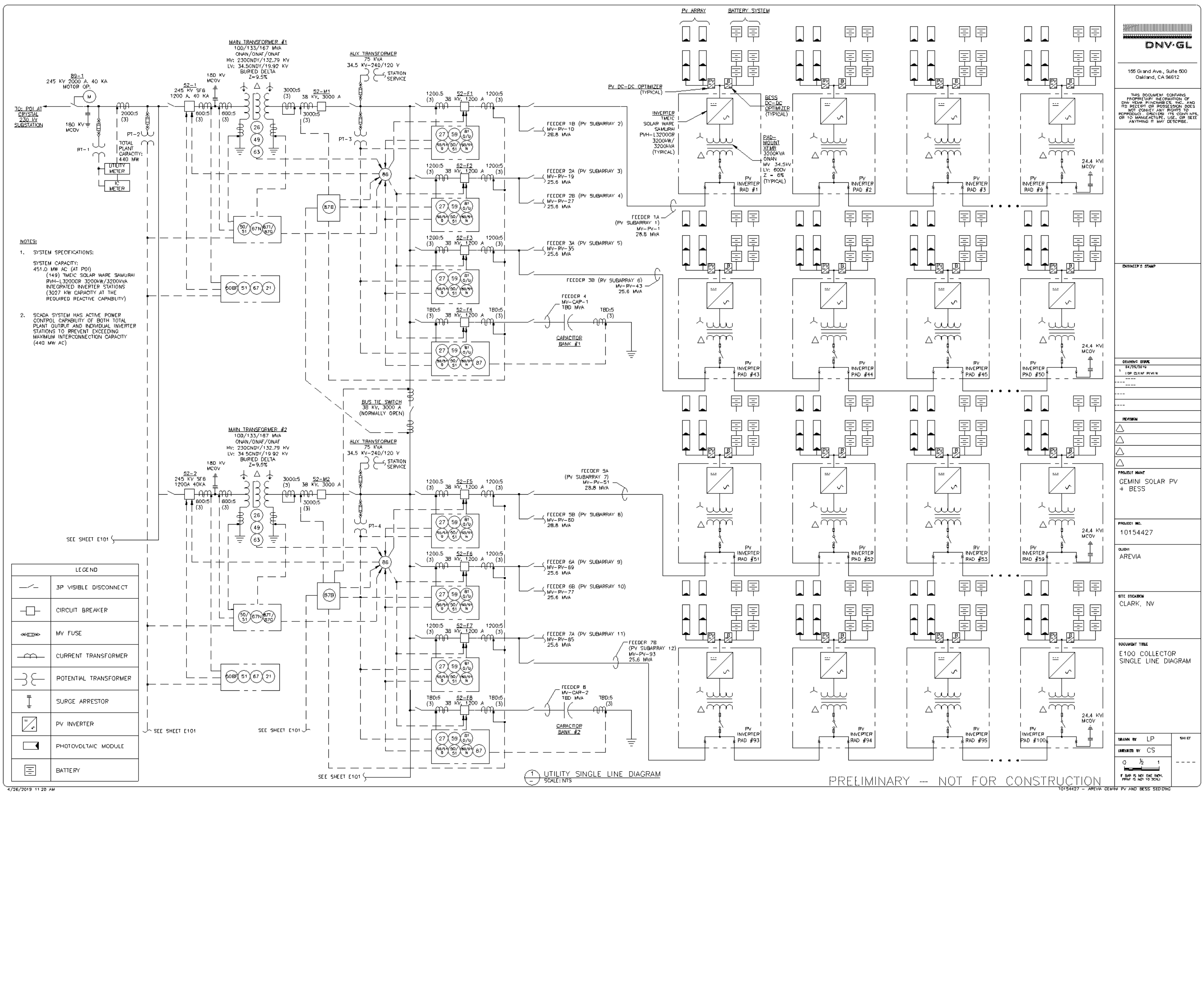
“EVENT OF DEFAULT”, “COMMERCIAL OPERATION DATE” AND “FORCE MAJEURE”

CC all notices to:
Office of General Counsel
6226 W. Sahara Ave, M/S 3A
Las Vegas, NV 89146

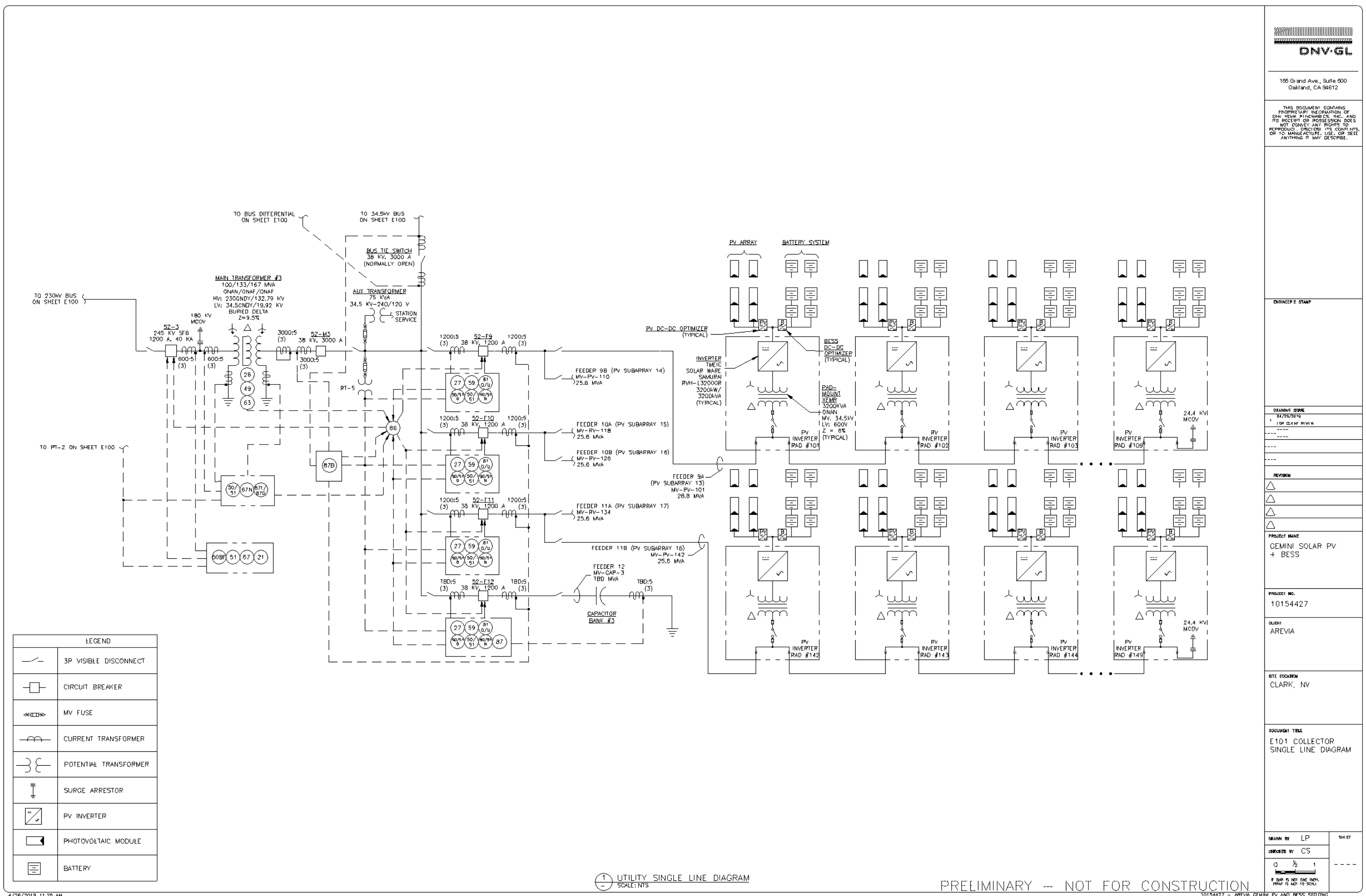
EXHIBIT 5

ONE-LINE DIAGRAM OF FACILITY AND DELIVERY POINT

Attached is a one-line diagram of the Facility, which indicates the Delivery Points and the ownership and the location of Meters, including the Storage Facility Metering Points.



NOTES:
1. SYSTEM SPECIFICATIONS:
SYSTEM CAPACITY:
451.0 MW AC (AT POI)
(149) TMEIC SOLAR WARE SAMURAI PVH-L3200GR 3200kW/3200kVA INTEGRATED INVERTER STATIONS (3027 KW CAPACITY AT THE REQUIRED REACTIVE CAPABILITY)
2. SCADA SYSTEM HAS ACTIVE POWER CONTROL CAPABILITY OF BOTH TOTAL PLANT OUTPUT AND INDIVIDUAL INVERTER STATIONS TO PREVENT EXCEEDING MAXIMUM INTERCONNECTION CAPACITY (440 MW AC)
MAIN TRANSFORMER #1
MAIN TRANSFORMER #2
AUX TRANSFORMER
BUS TIE SWITCH
38 KV, 3000 A
(NORMALLY OPEN)
TO: POI AT CRYSTAL 230 KV SUBSTATION
UTILITY METER
IC METER
CAPACITOR BANK #1
CAPACITOR BANK #2
PV ARRAY
BATTERY SYSTEM
LEGEND
3P VISIBLE DISCONNECT
CIRCUIT BREAKER
MV FUSE
CURRENT TRANSFORMER
POTENTIAL TRANSFORMER
SURGE ARRESTOR
PV INVERTER
PHOTOVOLTAIC MODULE
BATTERY
1 UTILITY SINGLE LINE DIAGRAM
SCALE: NTS
PRELIMINARY -- NOT FOR CONSTRUCTION
DNV·GL
155 Grand Ave., Suite 500
Oakland, CA 94612
ENGINEER'S STAMP
DRAWING ISSUE
REVISION
PROJECT NAME
GEMINI SOLAR PV + BESS
PROJECT NO.
10154427
CLIENT
AREVIA
SITE LOCATION
CLARK, NV
DOCUMENT TITLE
E100 COLLECTOR SINGLE LINE DIAGRAM
DRAWN BY LP
CHECKED BY CS


DNV·GL
155 Grand Ave., Suite 600
Oakland, CA 94612
THIS DOCUMENT CONTAINS PROPRIETARY INFORMATION OF DNV KEMA RENEWABLES, INC. AND ITS RECEIPT OR POSSESSION DOES NOT CONVEY ANY RIGHTS TO REPRODUCE, DISCLOSE ITS CONTENTS, OR TO MANUFACTURE, USE, OR SELL ANYTHING IT MAY DESCRIBE.
ENGINEER'S STAMP
REVISION
PROJECT NAME
GEMINI SOLAR PV + BESS
PROJECT NO.
10154427
CLIENT
AREVIA
SITE LOCATION
CLARK, NV
DOCUMENT TITLE
E101 COLLECTOR SINGLE LINE DIAGRAM
DRAWN BY LP
CHECKED BY CS
TO 230kV BUS ON SHEET E100
TO BUS DIFFERENTIAL ON SHEET E100
TO 34.5kV BUS ON SHEET E100
BUS TIE SWITCH
38 KV, 3000 A
(NORMALLY OPEN)
MAIN TRANSFORMER #3
100/133/167 MVA
ONAN/ONAF/ONAF
HV: 230GNDY/132.79 KV
LV: 34.5GNDY/19.92 KV
BURIED DELTA
Z=9.5%
AUX TRANSFORMER
75 KVA
34.5 KV-240/120 V
STATION SERVICE
52-3
245 KV SF6
1200 A, 40 KA
180 KV MCOV
52-M3
38 KV, 3000 A
TO PT-2 ON SHEET E100
PT-5
FEEDER 9B (PV SUBARRAY 14)
MV-PV-110
25.8 MVA
FEEDER 10A (PV SUBARRAY 15)
MV-PV-118
25.8 MVA
FEEDER 10B (PV SUBARRAY 16)
MV-PV-126
25.8 MVA
FEEDER 9A
(PV SUBARRAY 13)
MV-PV-101
28.8 MVA
FEEDER 11A (PV SUBARRAY 17)
MV-PV-134
25.8 MVA
FEEDER 11B (PV SUBARRAY 18)
MV-PV-142
25.8 MVA
FEEDER 12
MV-CAP-3
TBD MVA
CAPACITOR BANK #3
52-F9
52-F10
52-F11
52-F12
38 KV, 1200 A
PV ARRAY
BATTERY SYSTEM
PV DC-DC OPTIMIZER (TYPICAL)
BESS DC-DC OPTIMIZER (TYPICAL)
INVERTER
TMEIC
SOLAR WARE
SAMURAI
PVH-L3200GR
3200kW/
3200kVA
(TYPICAL)
PAD-MOUNT XFMR
3200KVA
ONAN
MV: 34.5kV
LV: 600V
Z = 6%
(TYPICAL)
24.4 KV MCOV
PV INVERTER PAD #101
PV INVERTER PAD #102
PV INVERTER PAD #103
PV INVERTER PAD #109
PV INVERTER PAD #142
PV INVERTER PAD #143
PV INVERTER PAD #144
PV INVERTER PAD #149
LEGEND
3P VISIBLE DISCONNECT
CIRCUIT BREAKER
MV FUSE
CURRENT TRANSFORMER
POTENTIAL TRANSFORMER
SURGE ARRESTOR
PV INVERTER
PHOTOVOLTAIC MODULE
BATTERY
1 UTILITY SINGLE LINE DIAGRAM
SCALE: NTS
PRELIMINARY — NOT FOR CONSTRUCTION
4/26/2019 11:20 AM

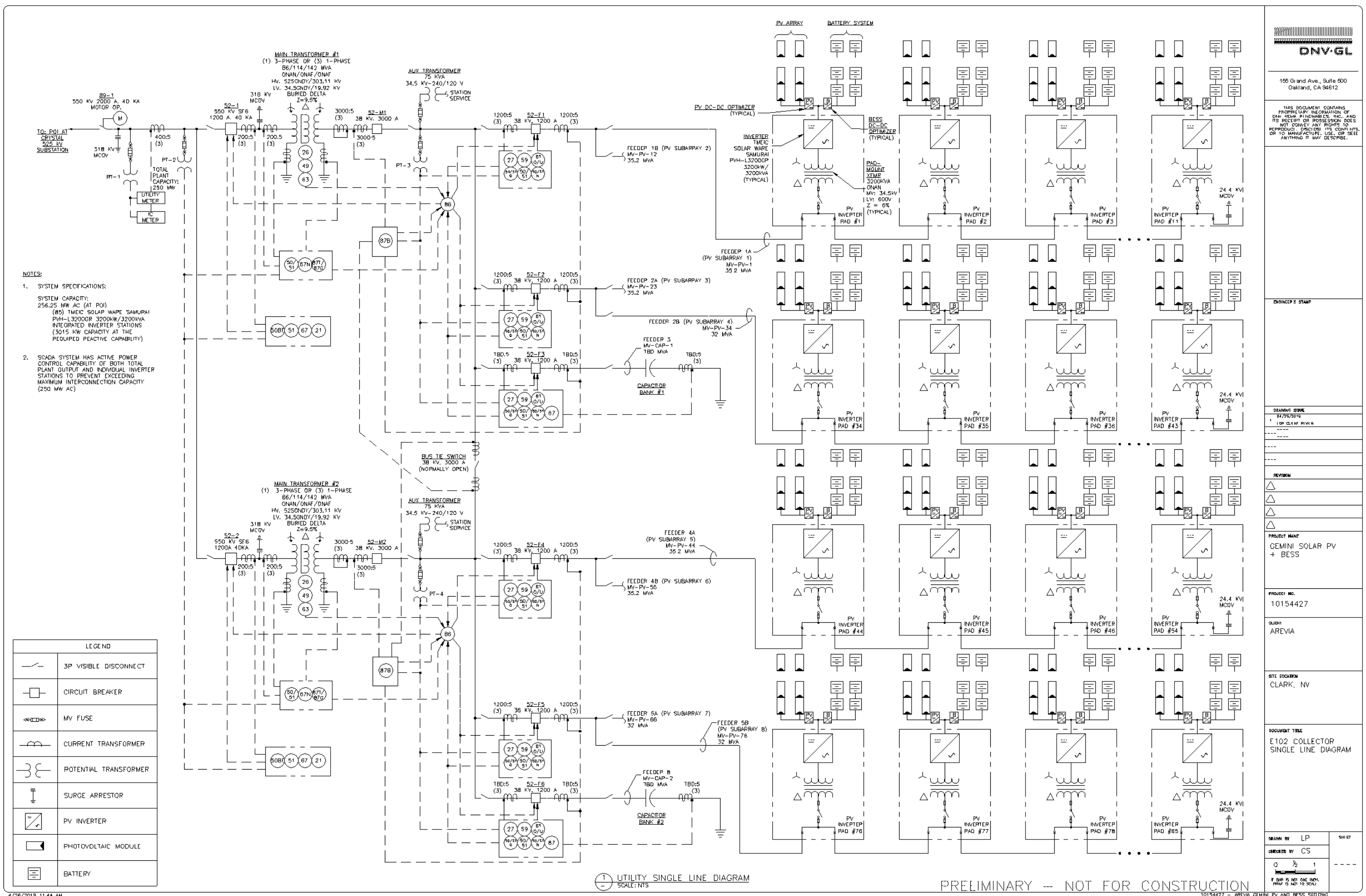

NOTES:
1. SYSTEM SPECIFICATIONS:
SYSTEM CAPACITY:
256.25 MW AC (AT POI)
(85) TMEIC SOLAR WARE SAMURAI PVH-L3200GR 3200kW/3200kVA INTEGRATED INVERTER STATIONS (3015 KW CAPACITY AT THE REQUIRED REACTIVE CAPABILITY)
2. SCADA SYSTEM HAS ACTIVE POWER CONTROL CAPABILITY OF BOTH TOTAL PLANT OUTPUT AND INDIVIDUAL INVERTER STATIONS TO PREVENT EXCEEDING MAXIMUM INTERCONNECTION CAPACITY (250 MW AC)
TO: POI AT CRYSTAL 500 KV SUBSTATION
89-1
550 KV 2000 A, 40 KA MOTOR OP.
318 KV MCOV
TOTAL PLANT CAPACITY: 250 MW
UTILITY METER
AC METER
MAIN TRANSFORMER #1
(1) 3-PHASE OR (3) 1-PHASE
86/114/142 MVA
ONAN/ONAF/ONAF
HV: 525GNDY/303.11 KV
LV: 34.5GNDY/19.92 KV
BURIED DELTA
Z=9.5%
MAIN TRANSFORMER #2
AUX TRANSFORMER
75 KVA
34.5 KV-240/120 V
STATION SERVICE
BUS TIE SWITCH
38 KV, 3000 A
(NORMALLY OPEN)
FEEDER 1A (PV SUBARRAY 1) MV-PV-1 35.2 MVA
FEEDER 1B (PV SUBARRAY 2) MV-PV-12 35.2 MVA
FEEDER 2A (PV SUBARRAY 3) MV-PV-23 35.2 MVA
FEEDER 2B (PV SUBARRAY 4) MV-PV-34 32 MVA
FEEDER 3 MV-CAP-1 TBD MVA
CAPACITOR BANK #1
FEEDER 4A (PV SUBARRAY 5) MV-PV-44 35.2 MVA
FEEDER 4B (PV SUBARRAY 6) MV-PV-56 35.2 MVA
FEEDER 5A (PV SUBARRAY 7) MV-PV-66 32 MVA
FEEDER 5B (PV SUBARRAY 8) MV-PV-76 32 MVA
FEEDER 6 MV-CAP-2 TBD MVA
CAPACITOR BANK #2
PV ARRAY
BATTERY SYSTEM
PV DC-DC OPTIMIZER (TYPICAL)
BESS DC-DC OPTIMIZER (TYPICAL)
INVERTER TMEIC SOLAR WARE SAMURAI PVH-L3200GR 3200kW/3200kVA (TYPICAL)
PAD-MOUNT XFMR 3200KVA ONAN MV: 34.5V LV: 600V Z = 6% (TYPICAL)
24.4 KV MCOV
PV INVERTER PAD #1
PV INVERTER PAD #2
PV INVERTER PAD #3
PV INVERTER PAD #11
PV INVERTER PAD #34
PV INVERTER PAD #35
PV INVERTER PAD #36
PV INVERTER PAD #43
PV INVERTER PAD #44
PV INVERTER PAD #45
PV INVERTER PAD #46
PV INVERTER PAD #54
PV INVERTER PAD #76
PV INVERTER PAD #77
PV INVERTER PAD #78
PV INVERTER PAD #85
LEGEND
3P VISIBLE DISCONNECT
CIRCUIT BREAKER
MV FUSE
CURRENT TRANSFORMER
POTENTIAL TRANSFORMER
SURGE ARRESTOR
PV INVERTER
PHOTOVOLTAIC MODULE
BATTERY
UTILITY SINGLE LINE DIAGRAM
SCALE: NTS
PRELIMINARY -- NOT FOR CONSTRUCTION
DNV·GL
155 Grand Ave., Suite 500
Oakland, CA 94612
PROJECT NAME
GEMINI SOLAR PV + BESS
PROJECT NO.
10154427
CLIENT
AREVIA
SITE LOCATION
CLARK, NV
DOCUMENT TITLE
E102 COLLECTOR SINGLE LINE DIAGRAM
DRAWN BY LP
CHECKED BY CS
4/26/2019 11:44 AM

EXHIBIT 6

PROJECT MILESTONE SCHEDULE

1. All time periods are in months after the last day of the month in which the PUCN Approval Date (designated as "AA" below). Any other timing is as otherwise described in specific items below. Buyer will update this Exhibit 6 with actual dates after the PUCN Approval is received.

2. All milestones may be completed earlier than stated times, at the sole option of Supplier.

A) Project Milestone: Supplier shall issue Limited Notices to Proceed (LNTPs) for equipment and initial construction-related activities.

Completion Date: later of thirty-five (37) months AA or September 30, 2022

Documentation: Supplier shall provide Buyer a copy of the executed LNTP acknowledged by the Construction Contractor and documentation from qualified professionals which indicates that equipment is planned to be procured. Such documentation will also indicate the type of initial construction-related activities and physical work that has begun at the Project Site.

B) Project Milestone: Supplier shall obtain all Required Facility Documents to construct the Facility.

Completion Date: later of forty-one (41) months AA or January 31, 2023.

Documentation: Supplier shall provide Buyer with an officer's certificate from an authorized representative of Supplier certifying that the Required Facility Documents to construct the Facility as listed in Exhibit 12 (Construction Documents) have been obtained, together with the metering system design for the Facility (submitted for Buyer's approval in accordance with Section 7.1) and a completed version of Exhibit 14.

C) Project Milestone: Supplier's major equipment shall be delivered to the Project Site

Completion Date: later of forty-three (43) months AA or March 31, 2023.

Documentation: Supplier shall provide Buyer with documentation that the major equipment (including step-up and medium voltage transformers [and inverters]) has been delivered to the Project Site.

D) Project Milestone: Supplier shall obtain the Required Facility Documents to operate (but not achieve Commercial Operation) the Facility, including registration with PC Administrator.

Completion Date: later of fifty-one (51) months AA or November 30, 2023.

Documentation: Supplier shall provide Buyer with an officer's certificate from an authorized representative of Supplier certifying that Required Facility Documents to operate (but not achieve Commercial Operation) the Facility as listed in Exhibit

12 have been obtained, together with reasonable documentation evidencing registration with PC Administrator.

E) Project Milestone: The Facility achieves the Operation Date.

Completion Date: later of (51) months AA or November 30, 2023.

Documentation: Buyer's Meters shall record Energy being delivered from the Generating Facility to Buyer and the Storage Facility and Discharging Energy being delivered from the Storage Facility to Buyer, and Supplier provides written notice to Buyer that the Facility satisfies the definition of Operation Date.

CRITICAL PROJECT MILESTONES

F) Project Milestone: Supplier shall demonstrate to Buyer that it has complete financing for construction of the Facility.

Completion Date: later of forty-two (42) months AA or February 28, 2023.

Documentation: Supplier shall provide Buyer with an officer's certificate from an authorized Representative of Supplier certifying that debt and equity financing arrangements have been executed for funding of 100% of the construction financing of the Facility.

G) Project Milestone: Notice to Proceed has been issued to the Construction Contractor under the Construction Contract and construction of the Facility has commenced.

Completion Date: later of forty-two (42) months AA or February 28, 2023.

Documentation: Supplier shall provide Buyer a copy of the executed Notice to Proceed acknowledged by the Construction Contractor and documentation from qualified professionals which indicates that physical work has begun at the Project Site regarding the construction of the Facility, as well as an ALTA Survey for the Project Site. Supplier shall provide Buyer with a copy of the Construction Contract.

H) Project Milestone: The Facility achieves the Commercial Operation Date.

Completion Date: the 1st day of the month following the later of fifty-two (52) months AA or December 1, 2023 ("Commercial Operation Deadline").

Documentation: Supplier provides certifications required by Section 8.3.2 to Buyer.

EXHIBIT 7

PERFORMANCE TESTS

1. Performance tests required by the Construction Contract.
2. Such other tests as may be required by Law or by Buyer to document resource supply.

EXHIBIT 8

FORM OF AVAILABILITY NOTICE

Unit Name	Date	Measure	HE 01	HE 02	HE 03	HE 04	HE 05	HE 06	HE 07	HE 08	HE 09	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
	Day 1	BaseMW																								
	Day 2	BaseMW																								
	Day 3	BaseMW																								
	Day 1	Max Capability																								
	Day 2	Max Capability																								
	Day 3	Max Capability																								
	Day 1	Min Capability																								
	Day 2	Min Capability																								
	Day 3	Min Capability																								
	Day 1	Min Capability																								
	Day 2	Min Capability																								
	Day 3	Min Capability																								

Describe any Generating Facility impairments including cause and expected return to full availability (“NA” if none):

Describe any Storage Facility charging impairments including cause and expected return to full availability (“NA” if none):

Describe any Storage Facility discharging impairments including cause and expected return to full availability (“NA” if none):

Storage Facility state of charge:____________

Note: Form of Availability Notice to be provided by Buyer to Supplier in Excel format. The format of the form may not be changed, except by Buyer.[2]

[2] NTD: Exhibit 8 to accommodate relevant information with respect to the Storage Facility.

EXHIBIT 8

FORM OF AVAILABILITY NOTICE

Date For Notice:	
Supplier:	
Name of Suppliers Representative:	
Buyer:	Nevada Power Company
Contact Info:	Supplier Address here
	City, State, Zip here
	123-456-7890

Hour	Net Availability From Plant MWh	Total Derating MWh	Plant Total MWh	Cause and Time of Derating (include whether any derating impacts ability to charge or discharge the Storage Facility)
1:00	0	0	0	
2:00	0	0	0	
3:00	0	0	0	
4:00	0	0	0	
5:00	0	0	0	
6:00	0	0	0	
7:00	0	0	0	
8:00	0	0	0	
9:00	0	0	0	
10:00	0	0	0	
11:00	0	0	0	
12:00	0	0	0	
13:00	0	0	0	
14:00	0	0	0	
15:00	0	0	0	
16:00	0	0	0	
17:00	0	0	0	
18:00	0	0	0	
19:00	0	0	0	
20:00	0	0	0	
21:00	0	0	0	
22:00	0	0	0	
23:00	0	0	0	
0:00	0	0	0	
Total	0	0	0	

Include other considerations current or anticipated events potentially impacting the Generating Facility's ability to produce the Delivered Amount or Ancillary Services including any Supplier plans to charge the battery.

Note: Supplier to submit Form of Availability Notice in Excel format to Balancing Authority Area Operator as identified in Exhibit 4 Notices. Form requires 7 days of availability.

EXHIBIT 9

BUYER'S REQUIRED REGULATORY APPROVALS

1. PUCN Approval of this Agreement.

EXHIBIT 10

SUPPLIER'S REQUIRED REGULATORY APPROVALS

1. Renewable Energy System certification as specified in WREGIS.

2. PUCN Approval of this Agreement.

3. Although obtaining EWG status is not a Supplier Required Regulatory Approval, if Supplier elects to obtain EWG status for the Facility, Supplier shall obtain: (a) a Notice of Self Certification as an EWG, or (b) an order from FERC granting the Facility EWG status.

4. Market-Based-Rate Authority based on Supplier's status as a "public utility" under the Federal Power Act, FERC authorization under section 205 of the Federal Power Act to make sales of electric energy, capacity, and ancillary services from the Facility.

5. U.S. Energy Information Administration, filing of Forms 860 and 923

6. Environmental Impact Statement (EIS) and associated Record of Decision (ROD) issued by Bureau of Land Management (BLM) under the National Environmental Protection Act (NEPA)

7. Bureau of Land Management, right of way grant(s) issued pursuant to the Federal Land Policy Management Act

8. U.S. Fish and Wildlife Service, Endangered Species Act, Section 7 Consultation and Biological Opinion

9. State Historical Preservation Office, National Historical Preservation Act, Section 106 Consultation

10. Clean Water Act Section 404, Jurisdictional Determination, Nation Wide Permit or Individual Permit if applicable

11. Clean Water Act, Section 401, state way quality certification, if required in connection with other permits

12. Public Utilities Commission Nevada, Utility Environmental Protection Act, order and permit to construct

13. Nevada Division of Environmental Protection, Construction Water General Permit

14. Clark County Department of Planning, Special Use Permit (SUP)

15. Clark County Department of Air Quality, Dust Control Permit

16. Clark County Building Department, Construction Permits

EXHIBIT 11

TECHNICAL SPECIFICATIONS

In accordance with Section 8.1, Supplier shall provide, not later than Supplier's completion of the Project Milestone relating to obtaining Required Facility Documentation (Section (B) of Exhibit 6), a completed version of Exhibit 11.

EXHIBIT 12

REQUIRED FACILITY DOCUMENTS

Construction Documents

1. Construction Contract
2. Construction Permits
3. This Agreement
4. Permits and approvals listed as items 6 through 16 on Exhibit 10

Operating Documents

1. Permits and approvals listed as items 1 through 5 on Exhibit 10
2. PUCN Approval of this Agreement.
3. Operating and Maintenance Agreement.
4. Interconnection Agreement
5. California Energy Commission, Renewable Portfolio Standard Pre-Certification and Certification, if applicable.
6. Western Renewable Energy Generation Information System (WREGIS), registrations, including as a Nevada Renewable Energy System, as applicable.
7. Transmission Provider's permission to operate.
8. Crossing consents or easements, Nevada Department of Transportation (NDOT), Union Pacific Rail Road (UPRR) and other utility crossings, as applicable

EXHIBIT 13A

DISPATCH AVAILABILITY AMOUNT

The Dispatch Availability Amount shall be the Energy amounts for each Delivery Hour that shall be made available by Supplier to Buyer, pursuant to this Agreement, as specified by each value in the table below.

Hour Ending		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
0100	Off-Peak	-	-	-	-	-	-	-	-	-	-	-	-
0200		-	-	-	-	-	-	-	-	-	-	-	-
0300		-	-	-	-	-	-	-	-	-	-	-	-
0400		-	-	-	-	-	-	-	-	-	-	-	-
0500		-	-	-	-	1.9	10.8	1.7	-	-	-	-	-
0600		-	-	0.7	53.9	192.6	288.3	157.5	75.1	19.5	0.3	-	-
0700	On Peak	-	16.5	170.8	420.4	608.5	656.5	537.0	491.2	365.7	174.5	27.5	0.5
0800		129.9	312.5	555.4	627.3	668.7	683.0	624.9	643.5	636.7	557.1	358.7	151.3
0900		474.9	560.6	623.8	645.5	670.3	687.3	667.3	665.4	663.9	619.4	541.2	447.3
1000		506.9	568.9	651.0	665.3	666.5	678.0	683.2	654.4	666.7	627.4	538.8	498.3
1100		483.6	579.9	652.3	661.8	663.8	684.1	690.0	663.3	666.4	618.6	538.3	460.3
1200		477.4	561.1	649.9	663.3	672.4	690.0	679.7	658.0	672.0	606.0	510.5	444.0
1300		485.0	549.7	642.9	673.9	673.6	685.2	653.7	661.3	668.3	614.5	535.6	462.9
1400		491.8	588.6	639.9	661.9	654.9	674.6	647.0	657.7	658.1	619.5	567.8	467.6
1500		518.2	579.2	609.6	597.8	662.4	677.6	627.0	585.2	638.9	617.0	543.7	420.6
1600		379.4	501.7	575.4	606.7	657.7	635.2	582.3	591.1	634.6	521.3	292.5	224.6
1700		47.0	191.9	396.0	518.8	594.3	633.7	543.0	586.5	422.2	114.7	10.8	5.0
1800		-	3.2	46.0	128.0	296.1	414.8	345.8	231.7	47.5	-	-	-
1900		-	-	-	0.2	17.1	55.0	47.0	7.1	-	-	-	-
2000		-	-	-	-	-	-	-	-	-	-	-	-
2100		-	-	-	-	-	-	-	-	-	-	-	-
2200		-	-	-	-	-	-	-	-	-	-	-	-
2300	Off-Peak	-	-	-	-	-	-	-	-	-	-	-	-
2400		-	-	-	-	-	-	-	-	-	-	-	-
Daily Dispatch Availability Amount (MWh)		3,994	5,014	6,214	6,925	7,701	8,154	7,487	7,172	6,760	5,690	4,465	3,583
Daily On-Peak Dispatch Availability Amount (MWh)		3,994	5,014	6,213	6,871	7,506	7,855	7,328	7,096	6,741	5,690	4,465	3,583
Monthly Dispatch Availability Amount (MWh)		123,815	140,385	192,624	207,750	238,728	244,624	232,104	222,318	202,813	176,400	133,963	111,058
Annual Dispatch Availability Amount (MWh)		2,226,581											
Delivery Points Maximum Amount (MW)		690.0											

EXHIBIT 13B

PERFORMANCE PERIODS
(Dispatchable Period, Full Requirements Period and Full Requirements Period Product)

The Dispatchable Period, the Full Requirements Period and the Full Requirements Period Product[3] are identified in the table below.[4]

Hour Ending	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
0100												
0200												
0300												
0400												
0500												
0600												
0700												
0800						Dispatchable Period						
0900												
1000												
1100												
1200												
1300												
1400												
1500												
1600												
1700						448.5	448.5	448.5				
1800						448.5	448.5	448.5				
1900						448.5	448.5	448.5				
2000						448.5	448.5	448.5				
2100						448.5	448.5	448.5				
2200												
2300												
2400												

Full Requirements Period Product (annual total)[5]: 206,310 MWh

[3] The hourly megawatt values stated in this table are for illustrative purposes only, which represents the estimated average hourly Net Energy deliveries during the hours of the Full Requirements Period. Supplier shall be required to deliver a total quantity of megawatt-hours during the Full Requirements Period, which is the sum of the megawatts delivered during all hours of the Full Requirements Period, the Full Requirements Period Product.

[4] The hourly values in the table are an average of the complete Full Requirement Period and have been rounded to a single decimal point for each Delivery Hour in the Full Requirements Period.

[5] Full Requirements Period Product equals (the sum of June output hours ending 1700-2100 multiplied by 30) + (the sum of July output hours ending 1700-2100 multiplied by 31) + (the sum of August output hours ending 1700-2100 multiplied by 31)

EXHIBIT 14

DIAGRAM OF FACILITY

In accordance with Section 8.1, Supplier shall provide: (a) not later than Supplier's completion of the Project Milestone relating to obtaining Required Facility Documentation (Section 2(B) of Exhibit 6), a completed version of Exhibit 14; and (b) within thirty (30) Business Days after the Commercial Operation Date, a revised version of Exhibit 14 reflecting the Facility as built.

The diagram of the Facility to be attached as Exhibit 14 will include a detailed layout of the Facility, including size, type, location and electrical infrastructure.

<u>EXHIBIT 15</u>

**OPERATIONS AND MAINTENANCE AGREEMENT;
OPERATOR GOOD STANDING CERTIFICATE**

In accordance with Section 8.9, Supplier shall provide Exhibit 15 no later than ninety (90) days prior to the Commercial Operation Date.

EXHIBIT 16

DISPATCHABLE ACCURACY RATE

For purposes of determining whether the Generating Facility remains capable of being dispatched by the Buyer, the ability of the Generating Facility to timely reach output levels sent by the Energy Management System to the Facility's Automatic Generation Control system will be tracked at five minute intervals during the Dispatchable Period.

1. The Generating Facility's Dispatchable Accuracy Rate during the Dispatchable Period will be calculated as follows:
   a. Determine the absolute value of the difference between the output level sent by Buyer's Energy Management System (which shall not exceed the instantaneous maximum capability of the Generating Facility as communicated electronically from Supplier to Buyer) to the Facility's Automatic Generation Control and the Delivered Amount (excluding any Buyer Charging Energy delivered to the Storage Facility Metering Points) of the Facility, as recorded and tracked at five minute intervals by Buyer;
   b. During an interval that includes a ramp from one set point to another, the comparison described in Section 1a of this Exhibit 16 will be made between the average of the start and finish output levels sent by Buyer's Energy Management System (which shall not exceed the instantaneous maximum capability of the Generating Facility) to the Facility's Automatic Generation Control and the Delivered Amount (excluding any Buyer Charging Energy delivered to the Storage Facility Metering Points)
   c. Divide this difference by the output level sent by the Buyer's Energy Management System;
   d. Subtract this quotient from 1.00.

For example: If Automatic Generation Control signal was 50MW and Facility Delivered Amount was 48MW. Therefore[6]: a. = 2, c. = 2/50= 0.04, d. = 1.0 - 0.04 = 0.96, which expressed as a percentage is 96%

2. Each calendar month, the Facility's average Dispatchable Accuracy Rate during the Dispatchable Period will be calculated as follows:
   a. Sum each recorded five minute interval difference between the output level sent by the EMS to the Facility's AGC and the actual output of the Facility as described above (for purposes of summation, treat all differences, whether positive or negative, as positive values);
   b. Sum each five minute recorded output level sent by the EMS to the Facility's AGC;
   c. Divide the summed difference by the summed output level sent by the Facility's EMS to the Facility's AGC;
   d. Subtract this quotient from 1.00;
   e. This difference represents the Facility's average Dispatchable Accuracy Rate for the calendar month.

3. Those periods in which the Facility is in a planned outage or wholly or partially unavailable due to Force Majeure, Emergencies, Transmission Provider Instructions or curtailment and therefore unable to follow dispatch orders shall be excluded for calculation of Dispatchable Accuracy Rate.

4. Real-Time and/or Instantaneous Availability of Supplier's Generating Facility

[6] Where a, b and c represent the above concepts.

EXHIBIT 16

DISPATCHABLE ACCURACY RATE

a. On an ongoing basis, the Generating Facility will provide real-time, instantaneous availability levels of minimum real power that could be generated at the referenced meter (pMinimum) and maximum real power that could be generated at the referenced meter (pMaximum). The pMinimum and pMaximum shall be reported at least once per six seconds as an estimated forecast.
b. Power set-point instructions from Buyer's EMS to the Generating Facility's AGC will recognize and obey real-time, instantaneous pMinimum and pMaximum availability levels, and any other constraints which are caused due to real-time weather conditions. In the event the Power set-point instructions from Buyer's EMS to the Generating Facility's AGC are lower than the instantaneous PMaximum, then Section 10.2.2 shall apply.
c. The Dispatchable Accuracy Rate will therefore be an indication of how the Generating Facility performed relative to its real-time or instantaneous capabilities as a result of existing weather and site conditions.

5. The difference between the set-point sent by the Buyer's Energy Management System and the Delivered Amount from the Facility shall be considered zero for purposes of calculating the Dispatchable Accuracy Rate under the following conditions:
   a. Those periods in which the Generating Facility is in a planned outage or affected by a force outage or Force Majeure or Emergency and therefore unable to follow dispatch orders shall be excluded for calculation of Dispatchable Accuracy Rate.
   b. Those periods when the Buyer's Energy Management System is not sending the Generating Facility a dispatch command
   c. The actual available solar generation is less than the estimated pMaximum forecast during the five minute set-point.
   d. The 12 seconds following the receipt of an AGC signal for required response time of the Facility.
   e. Those periods when the ramp rate of the Buyer's AGC exceeds 10% per minute of the Expected Nameplate Capacity Rating as reported in Exhibit 1, Section 5(b)(ii) during the 5 minute dispatch period.
   f. The referenced meter is the Delivery Point for the Generating Facility's AGC set-point but the Storage Facility is given a charge/discharge notice.
   g. Frequency response, Volt-Watt or other operating set-points are triggered that require the Storage Facility to charge or discharge something other than the AGC set-point.
   h. Those periods when the Power set-point instructions from Buyer's EMS to the Generating Facility's AGC are higher than the instantaneous PMaximum.

EXHIBIT 17

FORM OF LETTER OF CREDIT

IRREVOCABLE STANDBY LETTER OF CREDIT

[Name of Issuing Bank]
[Address of Issuing Bank]
[City, State of Issuing Bank]

Letter Of Credit No. [_______]
Irrevocable Standby Letter Of Credit

Date of Issue: [________], 20__

Stated Expiration Date: [___________]

Applicant:
[Name and address]
[_____________]
[_____________]

Stated Amount: USD $[____________]

Beneficiary:
Nevada Power Company d/b/a NV Energy
6226 W. Sahara Avenue
Las Vegas, NV 89146
Attn: Jenny Venter – Risk Control
Mailstop 9A

Credit Available With: [__________]

EXHIBIT 17

FORM OF LETTER OF CREDIT

Ladies and Gentlemen:

At the request and for the account of [____________] (the "Applicant"), we hereby establish in favor of Nevada Power Company ("Beneficiary") for the aggregate amount not to exceed [_________] million United States Dollars ($[_________]), in connection with the Long Term Renewable Power Purchase Agreement dated as of [_____] (as amended, restated, amended and restated or otherwise modified, the "Agreement"), by and between the Applicant and Beneficiary this Irrevocable Standby Letter of Credit no. [_____] (this "Letter of Credit") expiring on [date not earlier than 364 days from issuance] (the "Stated Expiration Date").

We irrevocably authorize you to draw on this Letter of Credit, in accordance with the terms and conditions hereinafter set forth, in any amount up to the full Available Amount (as defined below) available against presentation of a dated drawing request drawn on [***Name of Issuing Bank***] manually signed by a purported authorized representative of a Beneficiary completed in the form of Annex 1 hereto (a "Drawing Request"). Partial drawings and multiple drawings are allowed under this Letter of Credit. Each Drawing Request honored by us shall immediately reduce the amount available to be drawn hereunder by the amount of the payment made in satisfaction of such Drawing Request (each, an "Automatic Reduction").

On any given date, the Stated Amount (as set forth on the first page of this Letter of Credit) minus any Automatic Reductions plus any amounts increased pursuant to the terms and conditions hereto shall be the aggregate amount available hereunder (the "Available Amount").

Drawing Requests and all communications with respect to this Letter of Credit shall be in writing, addressed or presented in person to us at: [***Address of Issuing Bank***], Attn: [__________], referencing this Letter of Credit No. [_____]. In addition, presentation of a Drawing Request may also be made by facsimile transmission to [***Fax number of Issuing Bank***], or such other facsimile number identified by us in a written notice to you. To the extent a Drawing Request is made by facsimile transmission, you must (i) provide telephone notification to us at [***Telephone number of Issuing Bank***] prior to or simultaneously with the sending of such facsimile transmission and (ii) send the original of such Drawing Request to us by overnight courier, at the same address provided above; provided, however, that our receipt of such telephone notice or original documents shall not be a condition to payment hereunder. Presentation of the original of this Letter of Credit shall only be required for any drawing of the entire Available Amount.

If a Drawing Request is presented in compliance with the terms of this Letter of Credit to us at such address or facsimile number by 11:00 a.m., New York City time, on any Business Day (as defined below), payment will be made not later than the close of business, New York City time, on the following Business Day, and if such Drawing Request is so presented to us after 11:00 a.m., New York City time, on any Business Day, payment will be made on the second following Business Day not later than the close of business, New York City time on such following Business Day. Payment under this Letter of Credit shall be made in immediately available funds by wire transfer to such account as specified in the Drawing Request.

EXHIBIT 17

FORM OF LETTER OF CREDIT

As used in this Letter of Credit, "Business Day" means any day other than a Saturday, Sunday or other day on which commercial banks are authorized or required by Law to remain closed in the State of New York.

This Letter of Credit shall expire on the earliest to occur of (1) our receipt of written confirmation from a Beneficiary authorizing us to cancel this Letter of Credit accompanied by the original of this Letter of Credit; (2) the close of business, New York time, on the date (the "Early Expiration Date") specified in a notice of early expiration in the form of Annex 2 hereto sent by us to the Beneficiary and the Applicant by courier, mail delivery or delivery in person or facsimile transmission and stating that this Letter of Credit shall terminate on such date, which date shall be no less than thirty (30) days after the date of such notice, with the Beneficiary remaining authorized to draw on us prior to such Early Expiration Date in accordance with the terms hereof; or (3) the Stated Expiration Date. It is a condition of this letter of credit that it shall be deemed automatically extended without an amendment for periods of one (1) year each beginning on the present expiry date hereof and upon each anniversary of such date, unless at least thirty (30) days prior to any such expiry date we have sent you written notice (the "Notice of Non-Renewal") by certified mail or overnight courier service that we elect not to permit this Letter of Credit to be so extended beyond, and will expire on its then current expiry date. No presentation made under this Letter of Credit after such expiry date will be honored. To the extent a Notice of Non-Renewal has been provided to the Beneficiary and Applicant in accordance herewith, the Beneficiary are authorized to draw on us up to, in the aggregate, the full Available Amount of this Letter of Credit, by presentation to us, in the manner and at the address specified in the third preceding paragraph, of a Drawing Request completed in the form of Annex 1 hereto and sent and purportedly signed by a Beneficiary's authorized representative.

This Letter of Credit is effective immediately.

In the event that a Drawing Request fails to comply with the terms of this Letter of Credit, we shall provide the Beneficiary prompt notice of same stating the reasons therefore and shall upon receipt of a Beneficiary's instructions, hold any nonconforming Drawing Request and other documents at your disposal or return any non-conforming Drawing Request and other documents to the Beneficiary at the addresses set forth above by delivery in person or facsimile transmission. Upon being notified that the drawing was not effected in compliance with this Letter of Credit, a Beneficiary may attempt to correct such non-complying Drawing Request in accordance with the terms of this Letter of Credit.

This Letter of Credit sets forth in full the terms of our undertaking and this undertaking shall not in any way be modified, amended, limited or amplified by reference to any document, instrument or agreement referred to herein, and any such reference shall not be deemed to incorporate herein by reference any document, instrument, or agreement except for Drawing Requests and certificates. The foregoing notwithstanding, this Letter of Credit is subject to the rules of the "International Standby Practices 1998, International Chamber of Commerce, Publication No. 590" published by the Institute of International Banking Law and Practice ("ISP 98") and, as to matters not governed by ISP 98, shall be governed by and construed in accordance with the Laws of the State of New York.

FORM OF LETTER OF CREDIT

This Letter of Credit is transferable, only in its entirety and not in part, upon presentation to us, at our presentation office specified herein, of a signed transfer certificate in the form of Annex 3 accompanied by this original Letter of Credit and all amendments, if any, in which a Beneficiary irrevocably transfers to its successor or assign all of its rights hereunder, whereupon we will either issue a substitute letter of credit to such successor or assign or endorse such transfer on the reverse of this Letter of Credit. Transfers to designated foreign nationals are not permitted as being contrary to the U.S. Treasury Department or Foreign Assets Controls Regulations.

Any voluntary reduction hereunder shall be in the form of Annex 4 hereto.

All banking charges are for the account of the Applicant. All transfer fees are for the account of the Beneficiary.

All Drawing Requests under this Letter of Credit must bear the clause: "Drawn under [***Name of Issuing Bank***], Letter of Credit Number [______] dated [____________]."

This Letter of Credit shall not be amended except with the written concurrence of [***Name of Issuing Bank***], the Applicant and the Beneficiary.

We hereby engage with you that a Drawing Request drawn strictly in compliance with the terms of this Letter of Credit and any amendments thereto shall be honored.

We irrevocably agree with you that any legal action or proceeding with respect to this Letter of Credit shall be brought in the courts of the State of New York in the County of New York or of the United States of America in the Southern District of New York. You and we irrevocably submit to the nonexclusive jurisdiction of such courts solely for the purposes of this Letter of Credit. You and we hereby waive to the fullest extent permitted by Law any objection either of us may now or hereafter have to the laying of venue in any such action or proceeding in any such court.

[***Name of Issuing Bank***]

Authorized signature

EXHIBIT 17

FORM OF LETTER OF CREDIT

ANNEX 1
[Letterhead of a Beneficiary]

Drawn under [insert name of Issuing Bank],
Letter of Credit Number [______] dated [________]

DRAWING REQUEST
[Date]

[name and address of Issuing Bank]

Ladies and Gentlemen:

The undersigned, a duly authorized representative of a Beneficiary hereby draws on [insert name of Issuing Bank], Irrevocable Standby Letter of Credit No. [______] (the "Letter of Credit") dated [___________] issued by you in favor of us. Any capitalized term used herein and not defined herein shall have its respective meaning as set forth in the Letter of Credit.

In connection with this drawing, we hereby certify that:

A) This drawing in the amount of US$__________ is being made pursuant to the Letter of Credit;

[Use one or more of the following forms of paragraph B, as applicable, and include in this Drawing Request]

B-1) Beneficiary is authorized to make a drawing under this Letter of Credit in accordance with the terms of the Agreement applicable to Beneficiary.

or

B-2) The Letter of Credit will expire within thirty (30) days of the date of this Drawing Request pursuant to a Notice of Non-Renewal and the Applicant has failed to provide a replacement letter of credit from an acceptable credit provider and satisfying the requirements of the Agreement applicable to Beneficiary;

or

B-3) [insert name of Issuing Bank] has delivered an Early Expiration Notice and such Early Expiration Notice has not been rescinded and the Applicant has not replaced the Letter of Credit;

; and

C) You are directed to make payment of the requested drawing to:

FORM OF LETTER OF CREDIT

IN WITNESS WHEREOF, the undersigned has executed and delivered this request on this ____ day of _________________.

[Beneficiary]

By: __________________________
Name:
Title:

EXHIBIT 17

FORM OF LETTER OF CREDIT

ANNEX 2
NOTICE OF EARLY EXPIRATION
[Date]

[Beneficiary name and address]

Ladies and Gentlemen:

Reference is made to that Irrevocable Standby Letter of Credit No. [______] (the "Letter of Credit") dated [___________] issued by [Issuing Bank] in favor of [_________] (the "Beneficiary"). Any capitalized term used herein and not defined herein shall have its respective meaning as set forth in the Letter of Credit.

This constitutes our notice to you pursuant to the Letter of Credit that the Letter of Credit shall terminate on__________, ____ [*insert a date which is thirty (30) or more days after the date of this notice of early expiration*] (the "Early Expiration Date").

Pursuant to the terms of the Letter of Credit, the Beneficiary is authorized to draw (pursuant to one or more drawings), prior to the Early Expiration Date, on the Letter of Credit in an aggregate amount that does not exceed the then Available Amount (as defined in the Letter of Credit).

IN WITNESS WHEREOF, the undersigned has executed and delivered this request on this ____ day of _________________.

[ISSUING BANK]

By: __________________________
Name:
Title:

cc:

[Applicant name and address]

EXHIBIT 17

FORM OF LETTER OF CREDIT

ANNEX 3

REQUEST FOR TRANSFER OF LETTER OF CREDIT IN ITS ENTIRETY

[*Name of Issuing Bank*], Date: _________________

[*Address*]
[*City, State*]

Attn: Trade Services Department

Re: [*Name of Issuing Bank*], Irrevocable Standby Letter of Credit No. [_______________]

For value received, the undersigned beneficiary hereby irrevocably transfers to:

NAME OF TRANSFEREE

____

ADDRESS OF TRANSFEREE

____

____

CITY, STATE/COUNTRY ZIP

____

(hereinafter, the "transferee") all rights of the undersigned beneficiary to draw under above letter of credit, in its entirety.

By this transfer, all rights of the undersigned beneficiary in such Letter of Credit are transferred to the transferee and the transferee shall have the sole rights as beneficiary hereof, including sole rights relating to any amendments, whether increases or extensions or other amendments and whether now existing or hereafter made. All amendments are to be advised directly to the transferee without necessity of any consent of or notice to the undersigned beneficiary.

The original of such Letter of Credit and all amendments, if any, is returned herewith, and we ask you to endorse the transfer on the reverse thereof, and forward it directly to the transferee with your customary notice of transfer.

In payment of your transfer commission in amount equal to a minimum of $[____] and maximum of $[_______].

Select one of the following:
____ we enclose a cashier's/certified check
____ we have wired funds to you through ______________________________________ bank
____ we authorize you to debit our account # ______________________ with you, and in addition thereto, we agree to pay you on demand any expenses which may be incurred by you in connection with this transfer

We certify that this transfer request is not in violation of any federal or state laws and further confirm our understanding that the execution of this transfer request by you is subject to compliance with all legal requirements and related procedures implemented by your bank under applicable laws of the United States of America [and the jurisdiction of Issuing Bank].

Very truly yours,

[BENEFICIARY NAME]

____

Authorized Signature

The signature(s) of ______________________________with title(s) as stated conforms to those on file with us; are authorized for the execution of such instrument; and the beneficiary has been approved under our bank's Customer Identification Program. Further, pursuant to Section 326 of the USA Patriot Act and the applicable regulations promulgated thereunder, we represent and warrant that the undersigned bank: (i) is subject to a rule implementing the anti-money laundering compliance program requirements of 31 U.S.C. section 5318(h); (ii) is regulated by a Federal functional regulator [as such term is defined in 31 C.F.R. section 103.120(a)(2)]; and (iii) has a Customer Identification Program that fully complies with the requirements of the regulations.

____

____

(Signature of Authenticating Bank) (Name of Bank)

____

____

(Printed Name/Title) (Date)

IN WITNESS WHEREOF, the undersigned has executed and delivered this request on this ____ day of _________________.

[Beneficiary name]

By: __________________________
Name:
Title:

cc:
[insert name and address of Transferee]
[insert name and address of Applicant]

EXHIBIT 17

FORM OF LETTER OF CREDIT

ANNEX 4
VOLUNTARY REDUCTION REQUEST CERTIFICATE
[Date]

[insert name of Issuing Bank]
[insert address of Issuing Bank]

Ladies and Gentlemen:

Reference is made to that Irrevocable Standby Letter of Credit No. [______] (the "Letter of Credit") dated [___________] issued by you in favor of [______] (the "Beneficiary"). Any capitalized term used herein and not defined herein shall have its respective meaning as set forth in the Letter of Credit.

The undersigned, a duly authorized representative of the Beneficiary, having been so directed by [_______] (the "Applicant"), hereby requests that the Stated Amount (as such term is defined in the Letter of Credit) of the Letter of Credit be reduced by U.S.$[___________] to U.S.$[___________].

We hereby certify that the undersigned is a duly authorized representative of the Beneficiary.

IN WITNESS WHEREOF, the undersigned has executed and delivered this request on this ____ day of _________________.

[Beneficiary name]

By: _________________________
Name:
Title:

cc:

[Applicant name and address]

EXHIBIT 18

YEARLY PC AMOUNT

Yearly PC Amount	2,226,581 MWh

EXHIBIT 19

FORM OF LENDERS CONSENT

This CONSENT AND AGREEMENT (this "Consent"), dated as of __________, 20__, is entered into by and among Nevada Power Company, a Nevada corporation, d/b/a NV Energy, acting in its merchant function capacity (together with its permitted successors and assigns, "NVE"), _________________, in its capacity as **[Administrative Agent]** for the Lenders referred to below (together with its successors, designees and assigns in such capacity, "Administrative Agent"), and ________________, a ___________ formed and existing under the Laws of the State of ___________ (together with its permitted successors and assigns, "Borrower"). Unless otherwise defined, all capitalized terms have the meaning given in the PPA (as hereinafter defined).

WHEREAS, Borrower intends to develop, construct, install, test, own, operate and use an approximately ___ MW solar-powered electric generating facility and integrated storage facility located _____________, known as the __________ (the "Project").

WHEREAS, in order to partially finance the development, construction, installation, testing, operation and use of the Project, Borrower has entered into that certain **[Financing Agreement,]** dated as of ________ (as amended, amended and restated, supplemented or otherwise modified from time to time, the "Financing Agreement"), among Borrower, the financial institutions from time to time parties thereto (collectively, the "Lenders"), and Administrative Agent for the Lenders, pursuant to which, among other things, Lenders have extended commitments to make loans and other financial accommodations to, and for the benefit of, Borrower.

[WHEREAS, Borrower anticipates that, prior to the completion of construction of the Project, it will seek an additional investor (the "Tax Investor") to make an investment in Borrower to provide additional funds to finance the operation and use of the Project.]

WHEREAS, Buyer and Borrower have entered into that certain Power Purchase Agreement, dated as of _____________ (collectively with all documents entered into in connection therewith that are listed on [Schedule A] attached hereto and incorporated herein by reference, as all are amended, amended and restated, supplemented or otherwise modified from time to time in accordance with the terms thereof and hereof, the "PPA").

WHEREAS, pursuant to a security agreement executed by Borrower and Administrative Agent for the Lenders (as amended, amended and restated, supplemented or otherwise modified from time to time, the "Security Agreement"), Borrower has agreed, among other things, to assign, as collateral security for its obligations under the Financing Agreement and related documents (collectively, the "Financing Documents"), all of its right, title and interest in, to and under the PPA to Administrative Agent for the benefit of itself, the Lenders and each other entity or person providing collateral security under the Financing Documents.

NOW THEREFORE, for good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, and intending to be legally bound, the parties hereto hereby agree as follows:

EXHIBIT 19

FORM OF LENDERS CONSENT

SECTION 1. CONSENT TO ASSIGNMENT

NVE acknowledges the collateral assignment by Borrower of, among other things all of its right, title and interest in, to and under the PPA to Administrative Agent for the benefit of itself, the Lenders and each other entity or person providing collateral security under the Financing Documents, consents to an assignment of the PPA pursuant thereto, and agrees with Administrative Agent as follows:

(A) Administrative Agent shall be entitled (but not obligated) to exercise all rights and to cure any defaults of Borrower under the PPA, subject to applicable notice and cure periods provided in the PPA and Section 1(C) below. Upon receipt of notice from Administrative Agent, NVE agrees to accept such exercise and cure by Administrative Agent if timely made by Administrative Agent under the PPA and this Consent. Upon receipt of Administrative Agent's written instructions, NVE agrees to make directly to Administrative Agent all payments to be made by NVE to Borrower under the PPA from and after NVE's receipt of such instructions, and Borrower consents to any such action.

(B) NVE will not, without the prior written consent of Administrative Agent (such consent not to be unreasonably withheld), (i) cancel, terminate or suspend its performance under the PPA, (ii) consent to or accept any cancellation, termination or suspension thereof by Borrower, except as provided in the PPA and in accordance with subparagraph 1(C) hereof

(C) NVE agrees to deliver duplicates or copies of all notices of default delivered by NVE under or pursuant to the PPA to Administrative Agent in accordance with the notice provisions of this Consent. NVE may deliver any such notices concurrently with delivery of the notice to Borrower under the PPA. Administrative Agent shall have: (a) the same period of time to cure the breach or default that Borrower is entitled to under the PPA plus an additional fifteen (15) days if such default is the failure to pay amounts to NVE which are due and payable by Borrower under the PPA, except that if NVE does not deliver the default notice to Administrative Agent concurrently with delivery of the notice to Borrower under the PPA, then as to Administrative Agent, the applicable cure period under the PPA shall begin on the date on which the notice is given to Administrative Agent, or (b) the later of the applicable cure period under the PPA or thirty (30) days from the date notice of default or breach is delivered to Administrative Agent to cure such default if such breach or default cannot be cured by the payment of money to NVE, so long as Administrative Agent continues to perform any monetary obligations under the PPA and all other obligations under the PPA are performed by Borrower or Administrative Agent or its designees or assignees. If possession of the Project is necessary to cure such breach or default, and Administrative Agent or its designees or assignees declare Borrower in default and commence foreclosure proceedings, Administrative Agent or its designees or assignees will be allowed a reasonable period to complete such proceedings but not to exceed ninety (90) days. NVE consents to the transfer of Borrower's interest under the PPA to a Qualified Transferee upon enforcement of such security at a foreclosure sale by judicial or non-judicial foreclosure and sale or by a conveyance by Borrower in lieu of foreclosure and agrees that upon such foreclosure, sale or conveyance, NVE shall recognize such Qualified Transferee as the applicable party under the PPA (provided that such Qualified Transferee assumes the obligations of Borrower under the PPA). "Qualified Transferee" means a Person that is at least as financially and operationally qualified as Borrower and, at a minimum, (i) has a tangible net worth of at least seven million five hundred thousand dollars ($7,500,000) or provides adequate assurance in an amount and form reasonably acceptable to Buyer and (ii) has (or agrees to contract with an operator who has) (x) at least three (3) years of experience operating a generating plant of at least 100 MW and of similar technology to the generating facility component of the Project and (y) at least two (2) years of experience operating a storage facility of at least 10 MW and of similar technology to the storage facility component of the Project. Subject to the terms herein, NVE shall execute and deliver, at the reasonable request of the Administrative Agent, all documents reasonably necessary or appropriate to implement this Consent, including to effect a foreclosure and transfer.

(D) Notwithstanding subparagraph 1(C) above, in the event that the PPA is rejected by a trustee or debtor-in-possession in any bankruptcy or insolvency proceeding, or if the PPA is terminated for any reason other than a default which could have been but was not cured by Administrative Agent or its designees or assignees as provided in subparagraph 1(C) above, and if, within forty-five (45) days after such rejection or termination, the Lenders or their successors or assigns shall so request, to the extent permitted by applicable law, NVE will enter into a new contract with a Qualified Transferee. Such new contract shall be on the same terms and conditions as the original PPA for the remaining term of the original PPA before giving effect to such termination, provided, however that such terms shall be modified to the extent NVE reasonably determines such modifications are necessary to comply with any laws, rules or regulations applicable to Borrower, NVE or Lender, including any state, and federal constitutions, statutes, rules, regulations, published rates, and orders of governmental bodies and all judicial orders, judgments and decrees (hereinafter "Applicable Law") in effect at such time. Lenders or Administrative Agent shall cure or cause the cure of any payment defaults then existing under the original PPA prior to NVE entering into a new contract.

(E) In the event Administrative Agent, the Lenders or their designees or assignees elect to perform Borrower's obligations under the PPA as provided in subparagraph 1(C) above or enter into a new contract as provided in subparagraph 1(D) above, the recourse of NVE against Administrative Agent, Lenders or their designees and assignees shall be limited to such parties' interests in the Project, the Development Security and Operating Security required under the PPA, and recourse against the assets of any party or entity that assumes the PPA or that enters into such new contract. Nothing herein abrogates, and any Qualifying Assignee shall be subject to, NVE's rights under Article 6 of the PPA.

(F) In the event a Qualified Transferee succeeds to Borrower's interest under the PPA, Administrative Agent, the Lenders or their designees or assignees shall cure any then-existing payment and performance defaults under the PPA, except any performance defaults of Borrower itself which by their nature are not capable of being cured and do not impair NVE's rights under the PPA. Administrative Agent, the Lenders and their designees or assignees shall have the right to assign the PPA or the new contract entered into pursuant to subparagraph 1(d) above to any Qualified Transferee to whom Borrower's interest in the Project is transferred, provided that such transferee assumes the obligations of Borrower under the PPA. Upon such assignment, Administrative Agent and the Lenders and their designees or assignees (including their agents and employees, but excluding Borrower) shall be released from any further liability thereunder accruing from and after the date of such assignment.

SECTION 2. REPRESENTATIONS AND WARRANTIES

NVE, acting in its merchant function capacity (and therefore specifically excluding the knowledge of NVE, acting in its transmission function capacity ("NVE Transmission"), as to any of the matters stated below, and without imputation to NVE of any knowledge whatsoever relating to the NVE Transmission, whether as a result of information publicly posted to the open access same-time information system or otherwise), hereby represents and warrants that as of the date of this Consent:

(A) It (i) is a corporation duly formed and validly existing under the laws of the state of its organization, (ii) is duly qualified, authorized to do business and in good standing in every jurisdiction necessary to perform its obligations under this Consent, and (iii) has all requisite corporate power and authority to enter into and to perform its obligations hereunder and under the PPA, and to carry out the terms hereof and thereof and the transactions contemplated hereby and thereby;

(B) the execution, delivery and performance of this Consent and the PPA have been duly authorized by all necessary corporate action on its part and do not require any approvals, material filings with, or consents of any entity or person which have not previously been obtained or made;

(C) each of this Consent and the PPA is in full force and effect;

(D) each of this Consent and the PPA has been duly executed and delivered on its behalf and constitutes its legal, valid and binding obligation, enforceable against it in accordance with its terms;

(E) the execution, delivery and performance by it of this Consent and the PPA, and the consummation of the transactions contemplated hereby, will not result in any violation of, breach of or default under any term of (i) its formation or governance documents, or (ii) any material contract or material agreement to which it is a party or by which it or its property is bound, or of any material Applicable Law presently in effect having applicability to it, the violation, breach or default of which could materially and adversely affect its ability to perform its obligations under this Consent;

(F) neither NVE nor, to NVE's actual knowledge, any other party to the PPA, is in default of any of its obligations thereunder.

SECTION 3. NOTICES

All notices required or permitted hereunder shall be in writing and shall be effective (a) upon receipt if hand delivered, (b) upon telephonic verification of receipt if sent by facsimile and (c) if otherwise delivered, upon the earlier of receipt or three (3) Business Days after being sent registered or certified mail, return receipt requested, with proper postage affixed thereto, or by private courier or delivery service with charges prepaid, and addressed as specified below:

If to NVE:

[________________________________]

[________________________________]
[________________________________]
Telephone No.: [____________________]
Telecopy No.: [_____________________]
Attn: [___________________________]

If to Administrative Agent:
[________________________________]
[________________________________]
[________________________________]
Telephone No.: [____________________]
Telecopy No.: [_____________________]
Attn: [___________________________]

If to Borrower:
[________________________________]
[________________________________]
[________________________________]
Telephone No.: [____________________]
Telecopy No.: [_____________________]
Attn: [___________________________]

Any party shall have the right to change its address for notice hereunder to any other location within the United States by giving thirty (30) days written notice to the other parties in the manner set forth above. Further, the Tax Investor shall be entitled to receive notices from NVE by providing written notice to NVE of Tax Investor's address for notices. NVE's failure to provide any notice to the Tax Investor shall not be a breach of this Consent.

SECTION 4. CONFIRMATION, TERMINATION, AMENDMENT AND GOVERNING LAW

NVE agrees to (a) confirm its continuing obligation hereunder in writing upon the reasonable request of (and at the expense of) Borrower, Administrative Agent, the Lenders or any of their respective successors, transferees or assigns. No termination, amendment, variation or waiver of any provisions of this Consent shall be effective unless in writing and executed by the parties hereto. This Consent shall be governed by the laws of the State of New York (without giving effect to the principles thereof relating to conflicts of law except Section 5-1401 and 5-1402 of the New York General Obligations Law).

SECTION 5. COUNTERPARTS

This Consent may be executed in one or more duplicate counterparts, and when executed and delivered by all the parties listed below, shall constitute a single binding agreement.

SECTION 6. SEVERABILITY

In case any provision of this Consent, or the obligations of any of the parties hereto, shall be invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions, or the obligations of the other parties hereto, shall not in any way be affected or impaired thereby.

SECTION 7. ACKNOWLEDGMENTS BY BORROWER.

Borrower, by its execution hereof, acknowledges and agrees that notwithstanding any term to the contrary in the PPA, NVE may perform as set forth herein and that neither the execution of this Consent, the performance by NVE of any of the obligations of NVE hereunder, the exercise of any of the rights of NVE hereunder, or the acceptance by NVE of performance of the PPA by any party other than Borrower shall (1) release Borrower from any obligation of Borrower under the PPA, (2) constitute a consent by NVE to, or impute knowledge to NVE of, any specific terms or conditions of the Financing Agreement, the Security Agreement or any of the other Financing Documents, or (3) constitute a waiver by NVE of any of its rights under the PPA. Borrower and Administrative Agent acknowledge hereby for the benefit of NVE that none of the Financing Agreement, the Security Agreement, the Financing Documents or any other documents executed in connection therewith alter, amend, modify or impair (or purport to alter, amend, modify or impair) any provisions of the PPA. Borrower shall have no rights against NVE on account of this Consent.

SECTION 8. JURY TRIAL WAIVER

THE PARTIES EACH HEREBY IRREVOCABLY WAIVE ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR RELATING THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

IN WITNESS WHEREOF, the parties by their officers duly authorized, have duly executed this Consent as of the date first set forth above.

Nevada Power Company

By: ______________________________
Name: ____________________________
Title: _____________________________

______________________,
a ___________________

By: ______________________________
Name: ____________________________
Title: _____________________________

_________________________,
as Administrative Agent for the Lenders

[Borrower]

By: ______________________________________
Name: ____________________________________
Title: _____________________________________

EXHIBIT 20

FORM OF GUARANTEE

This GUARANTEE (this "Guarantee"), dated as of ____________, 20__, is issued by Quinbrook Low Carbon Power Parallel Fund (US) LP, a limited partnership organized and existing under the laws of Delaware and Quinbrook Low Carbon Power LP, a limited partnership organized and existing under the laws of Jersey ("Guarantors") in favor of Nevada Power Company, a Nevada corporation doing business as NV Energy ("Company").

Pursuant to that certain Long-Term Renewable Power Purchase Agreement, dated as of ___________, 20__ (as the same may be amended, modified or supplemented from time to time, the "Agreement"), by and between Company and [_______________], a [__________] [__________], of which Guarantors are the indirect parent entities ("Subsidiary"), and pursuant to which Guarantors will indirectly benefit from the terms and conditions thereof, and the performance by Subsidiary of its obligations thereunder, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Guarantors, jointly and severally, hereby covenant, undertake and agree with Company as follows:

Section 1. **Definitions**. Capitalized terms used herein and not otherwise defined shall have their respective meanings as set forth in the Agreement.

Section 2. **Guarantee.**

(a) **Guarantee.** Guarantors hereby, jointly and severally, irrevocably and unconditionally guarantee to and for the benefit of Company, the full and prompt payment by Subsidiary of each and every obligation of Subsidiary arising under the Agreement up to (i) twenty six million seven hundred fifty thousand ($26,750,000) prior to the PUCN Approval Date, (ii) seventy four million nine hundred thousand ($74,900,000) from and after the PUCN Approval Date until the Commercial Operation Date, and (iii) sixty eight million nine thousand five hundred dollars ($68,009,500) from and after the Commercial Operation Date (collectively, the "Cap"), including, without limitation, the payment of all indemnities, refunds and liquidated damages payable at any time under the Agreement (the "Guaranteed Obligations"). The Guaranteed Obligations shall further include, without limitation, interest accruing as part of the Guaranteed Obligations according to the terms thereof following the commencement by or against the Subsidiary of any case or proceeding under any Applicable Law relating to bankruptcy, insolvency, reorganization, winding-up, liquidation, dissolution or composition or adjustment of debt and (ii) all reasonable costs and expenses (including reasonable attorneys' fees), if any, incurred by Company in enforcing Company's rights under this Guarantee up to a one million dollar ($1,000,000) limit which is in addition to the Cap in each instance. Guarantors further agree that if Subsidiary shall fail to pay in full all or any part of the Guaranteed Obligations, Guarantors will pay (or procure the payment of) the same in accordance with Section 4 herein. Notwithstanding anything in this Guarantee or in the Agreement to the contrary, the maximum aggregate obligation and liability of Guarantors under this Guarantee, and the maximum recovery from Guarantors under this Guarantee, shall in no event exceed the Cap plus all reasonable costs and expenses (including reasonable attorneys' fees), if any, incurred by Company in enforcing Company's rights under this Guarantee up to a one million dollar ($1,000,000) limit; *provided that* Guarantors shall not be liable for such fees and expenses of Company under this Section 2(a) if it is finally determined by a court of competent jurisdiction that no payment under this Guarantee is due.

(b) **Nature of Guarantee.** The Guarantee and the obligations of Guarantors hereunder shall continue to be effective or be automatically reinstated, as the case may be, if at any time payment of any of the Guaranteed Obligations is rendered unenforceable or is rescinded or must otherwise be returned by Company upon the occurrence of any action or event including, without limitation, the bankruptcy, reorganization, winding-up, liquidation, dissolution or insolvency of the Subsidiary, Guarantors, any other Person or otherwise, all as though the payment had not been made.

(c) **Absolute Guarantee.** Guarantors agree that their obligations under this Guarantee are irrevocable, absolute, independent, unconditional and continuing and shall not be affected by any circumstance that constitutes a legal or equitable discharge of a guarantor or surety other than payment in full of the Guaranteed Obligations. In furtherance of the foregoing and without limiting the generality thereof, Guarantors agree, subject to the other terms and conditions hereof, as follows:

(i) this Guarantee is a guarantee of payment and not of collectability or performance;

(ii) Company may from time to time in accordance with the terms of the Agreement, without notice or demand and without affecting the validity or enforceability of this Guarantee or giving rise to any limitation, impairment or discharge of Guarantors' liability hereunder, (A) renew, extend, accelerate or otherwise change the time, place, manner or terms of payment of the Guaranteed Obligations, (B) settle, compromise, release or discharge, or accept or refuse any offer of payment with respect to, or substitutions for, the Guaranteed Obligations or any agreement relating thereto and/or subordinate the payment of the same to the payment of any other obligations, (C) request and accept other guaranties of or security for the Guaranteed Obligations and take and hold security for the payment of this Guarantee or payment of the Guaranteed Obligations, (D) release, exchange, compromise, subordinate or modify, with or without consideration, any security for payment of the Guaranteed Obligations, any other guarantees of the Guaranteed Obligations, or any other obligation of any person with respect to the Guaranteed Obligations, (E) enforce and apply any security now or hereafter held by or for the benefit of Company in respect of this Guarantee or the Guaranteed Obligations and direct the order or manner of sale thereof, or exercise any other right or remedy that Company may have against any such security, as Company in its discretion may determine consistent with the Agreement and any applicable security agreement, and even though such action operates to impair or extinguish any right of reimbursement or subrogation or any other right or remedy of Guarantors against Subsidiary or any other guarantor of the Guaranteed Obligations or any other guarantee of or security for the Guaranteed Obligations, and (F) exercise any other rights available to Company under the Agreement, at law or in equity; and

(iii) this Guarantee and the obligations of Guarantors hereunder shall be valid and enforceable and shall not be subject to any limitation, impairment or discharge for any reason (other than payment in full of the Guaranteed Obligations and otherwise as set forth in this Guarantee), including, without limitation, the occurrence of any of the following, whether or not Guarantors shall have had notice or knowledge of any of them: (A) any failure to assert or enforce, or agreement not to assert or enforce, or the stay or enjoining, by order of court, by operation of law or otherwise, or the exercise or enforcement of, any claim or demand or any right, power or remedy with respect to the Guaranteed Obligations or any agreement relating thereto, or with respect to any other guarantee of or security for the payment of the Guaranteed Obligations; (B) any waiver, amendment or modification of, or any consent to departure from, any of the terms or provisions of the Agreement or any agreement or instrument executed pursuant thereto or of any other guarantee or security for the Guaranteed Obligations; (C) the Guaranteed Obligations, or any agreement relating thereto, at any time being found to be illegal, invalid or unenforceable in any respect; (D) the personal or corporate incapacity of any person; (E) any change in the financial condition, or the bankruptcy, administration, receivership or insolvency of Subsidiary or any other person, or any rejection, release, stay or discharge of Subsidiary's or any other person's obligations in connection with any bankruptcy, administration, receivership or similar proceeding or otherwise or any disallowance of all or any portion of any claim by Company, its successors or permitted assigns in connection with any such proceeding; (F) any change in the corporate existence of, or cessation of existence of, Guarantors or the Subsidiary (whether by way of merger, amalgamation, transfer, sale, lease or otherwise); (G) the failure to create, preserve, validate, perfect or protect any security interest granted to, or in favor of, any person; (H) any substitution, modification, exchange, release, settlement or compromise of any security or collateral for or guarantee of any of the Guaranteed Obligations or failure to apply such security or collateral or failure to enforce such guarantee; (I) the existence of any claim, set-off, or other rights which Guarantors or any affiliates thereof may have at any time against Company or any affiliate thereof in connection with any matter unrelated to the Agreement; and (J) any other act or thing or omission, or delay to do any other act or thing, which may or might in any manner or to any extent vary the risk of Guarantors as obligors in respect of the Guaranteed Obligations.

(d) **Currency.** All payments made by Guarantors hereunder shall be made in U.S. dollars in immediately available funds.

(e) **Defenses.** Notwithstanding anything herein to the contrary, each Guarantor specifically reserves to itself all rights, counterclaims and other defenses that the Subsidiary is or may be entitled to arising from or out of the Agreement, except for any defenses arising out of the bankruptcy, insolvency, dissolution or liquidation of the Subsidiary, the lack of power or authority of the Subsidiary to enter into the Agreement and to perform its obligations thereunder, or the lack of validity or enforceability of the Subsidiary's obligations under the Agreement or any transaction thereunder.

Section 3. **Other Provisions of the Guarantee.**

(a) **Waivers by Guarantor.** Each Guarantor hereby waives for the benefit of Company, to the maximum extent permitted by Applicable Law:

(i) notice of acceptance hereof;

(ii) notice of any action taken or omitted to be taken by Company in reliance hereon;

(iii) any right to require Company, as a condition of payment by Guarantor, to (A) proceed against or exhaust its remedies against Subsidiary or any person, including any other guarantor of the Guaranteed Obligations, or (B) proceed against or exhaust any security held from Subsidiary or any person, including any other guarantor of the Guaranteed Obligations;

(iv) subject to Clause 2(e), any defense arising by reason of the incapacity, lack of authority or any disability of Subsidiary including, without limitation, any defense based on or arising out of the lack of validity or the unenforceability of the Guaranteed Obligations or any agreement or instrument relating thereto or by reason of the cessation of the liability of Subsidiary from any cause other than payment in full of the Guaranteed Obligations or termination of this Guarantee in accordance with its terms;

(v) any requirement that Company protect, secure, perfect or insure any security interest or lien or any property subject thereto;

(vi) other than as provided in Section 4, any requirement that Company be diligent or prompt in making demands hereunder or give notices of default under the Agreement, notices of any renewal, extension or modification of the Guaranteed Obligations or any agreement related thereto, and any right to consent to any thereof; and

(vii) any event, occurrence or other circumstance which might otherwise constitute a legal or equitable discharge of a surety, including promptness, diligence, notice of acceptance and notice of any default under the Agreement, notice of presentment, demand, protest, and notice of dishonor or nonpayment, notice of acceleration or other demand and any other notice with respect to this Guarantee.

(b) Deferral of Subrogation. Until such time as the Guaranteed Obligations have been paid or performed in full, notwithstanding any payment made by a Guarantor hereunder or the receipt of any amounts by Company with respect to the Guaranteed Obligations, (i) each Guarantor (on behalf of itself, its successors and assigns, including any surety) hereby expressly agrees not to exercise any right, nor assert the impairment of such rights, it may have to be subrogated to any of the rights of Company against Subsidiary or against any other collateral security held by Company for the payment of the Guaranteed Obligations, (ii) each Guarantor agrees that it will not seek any reimbursement from Company in respect of payments made by such Guarantor in connection with the Guaranteed Obligations, or amounts realized by Company in connection with the Guaranteed Obligations and (iii) such Guarantor shall not claim or prove in a liquidation or other insolvency proceeding of the Subsidiary in competition with the Company. If any amount shall be paid to a Guarantor on account of such subrogation rights at any time when all of the Guaranteed Obligations shall not have been paid in full or otherwise fully satisfied, such amount shall be held in trust by such Guarantor for the benefit of Company and shall forthwith be paid to Company, to be credited and applied to the Guaranteed Obligations.

Section 4. Payment. If Subsidiary fails or refuses to pay any Guaranteed Obligation, Company shall notify Subsidiary and Guarantors in writing of such failure to pay and demand that payment be made by Guarantors (a "Demand Notice"). Guarantors shall make the requested payment within five (5) Business Days of receipt of a Demand Notice.

Section 5. Representations and Covenants of Guarantors.

(a) Each Guarantor hereby represents as of the date hereof as follows:

(i) Guarantor is duly organized, validly existing and in good standing under the laws of its jurisdiction of organization, and has the corporate power, authority and legal right to own its property and assets and to transact the business in which it is engaged.

(ii) Guarantor has full power, authority and legal right to execute and deliver this Guarantee and all other instruments, documents and agreements required by the provisions of this Guarantee to be executed, delivered and performed by Guarantor, and to perform its obligations hereunder and thereunder.

(iii) The execution, delivery and performance of this Guarantee and all other instruments, documents and agreements required by the provisions of this Guarantee to be executed, delivered and performed by Guarantor have been duly authorized by all necessary action on the part of Guarantor and do not contravene or conflict with Guarantor's governance documents.

(iv) This Guarantee and all other instruments, documents and agreements required by the provisions of this Guarantee to be executed, delivered and performed by Guarantor have been duly executed and delivered by Guarantor and constitute the legal, valid and binding obligations of Guarantor, enforceable against it in accordance with their respective terms.

(v) Neither the execution and delivery of this Guarantee nor the performance of the terms and conditions hereof by Guarantor shall result in (i) a violation or breach of, or a default under, or a right to accelerate, terminate or amend, any contract, commitment or other obligation to which Guarantor is a party or is subject or by which any of its assets are bound, or (ii) a violation by Guarantor of any Applicable Law.

(vi) To the actual knowledge of Guarantor, there are no actions, suits, investigations, proceedings, condemnations, or audits by or before any court or other governmental or regulatory authority or any arbitration proceeding pending or threatened against or affecting Guarantor, its properties, or its assets that would adversely affect its ability to perform under this Guarantee.

(vii) All necessary action has been taken under Applicable Laws to authorize the execution, delivery and performance of this Guarantee. No governmental approvals or other consents, approvals, or notices of or to any person are required in connection with the execution, delivery, performance by Guarantor, or the validity or enforceability, of this Guarantee.

(viii) That the obligations under this Guarantee do not exceed Undrawn Commitments (as such term is defined in the Limited Partnership Agreement of Quinbrook Low Carbon Power Parallel Fund (US) LP (the "LP")) of the Guarantor.

(b) Each Guarantor hereby covenants:

(i) That so long as there are Undrawn Commitments (as such term is defined in the Limited Partnership Agreement of Quinbrook Low Carbon Power Parallel Fund (US) LP (the "LP")) and this Guarantee is in effect, the Manager will not consent to a transfer of LP interests unless the transferee has the legal, financial and operating power, authority, capacity and assets to satisfy the obligations of the transferring LP in respect of the transferred interest. That the General Partner will not consent to any amendment to the LP that would adversely affect or otherwise impair the LP's ability to satisfy its obligations under this Guarantee.

Section 6. **<u>Notices</u>.** All notices, demands, instructions, waivers, consents, or other communications required or permitted hereunder shall be in writing in the English language and shall be sent by personal delivery, courier, certified mail or facsimile, to the following addresses:

(a) If to Guarantors:

Quinbrook Infrastructure Partners
1330 Post Oak Boulevard
Suite 1350
Houston, TX 77056
Attention: David Scaysbrook
Facsimile:

With a copy to (which shall not constitute notice):

Winston & Strawn LLP
1700 K Street, NW
Washington, DC 20006-3817
Attention: Patrick E. Groomes
Facsimile: [__________________]

(b) If to Company:

Nevada Power Company
6226 W. Sahara Avenue
Las Vegas, Nevada 89146
Facsimile No.: 702-402-2455
Email: ContractManagement@nvenergy.com
Attn: [___________________]

With a copy to (which shall not constitute notice):

Nevada Power Company
6226 W. Sahara Avenue
Las Vegas, Nevada 89146
Facsimile: (702) 402-2069
Attn: [________________]

The addresses and facsimile numbers of either party for notices given pursuant to this Guarantee may be changed by means of a written notice given to the other party at least three (3) Business Days (being a day on which clearing banks are generally open for business in the jurisdiction of the party to whom a notice is sent) prior to the effective date of such change. Any notice required or authorized to be given hereunder shall be in writing (unless otherwise provided) and shall be served (i) personally, (ii) by courier service or (iii) by facsimile transmission addressed to the relevant Person at the address stated below or at any other address notified by that Person as its address for service. Any notice so given personally shall be deemed to have been served on delivery, any notice so given by express courier service shall be deemed to have been served the next Business Day after the same shall have been delivered to the intended Person, and any notice so given by facsimile transmission shall be deemed to have been served on dispatch unless dispatched after the recipient's normal business hours on a Business Day or dispatched on any day other than a Business Day, in which case such notice shall be deemed to have been delivered on the next Business Day. As proof of such service it shall be sufficient to produce a receipt showing personal service, the receipt of a courier company showing the correct address of the addressee or an activity report of the sender's facsimile machine showing the correct facsimile number of the Person on whom notice is served and the correct number of pages transmitted.

Section 7. Miscellaneous Provisions.

(a) Waiver; Remedies Cumulative. No failure on the part of Company to exercise, and no delay on the part of Company in exercising, any right or remedy, in whole or in part hereunder shall operate as a waiver thereof. No single or partial exercise of any right or remedy shall preclude any other or further exercise thereof or the exercise of any other right or remedy. No waiver by Company shall be effective unless it is in writing and such writing expressly states that it is intended to constitute such waiver. Any waiver given by Company of any right, power or remedy in any one instance shall be effective only in that specific instance and only for the purpose for which given, and will not be construed as a waiver of any right, power or remedy on any future occasion. The rights and remedies of Company herein provided are cumulative and not exclusive of any rights or remedies provided by Applicable Law.

(b) Successors and Assigns. This Guarantee shall be binding upon the successors of Guarantors and shall inure to the benefit of Company and its successors and permitted assigns. Guarantors shall not assign or transfer all or any part of its rights or obligations hereunder without the prior written consent of Company. Any purported assignment or delegation without such written consent shall be null and void. Company may assign its rights and obligations hereunder to any assignee of its rights under the Agreement permitted in accordance with the Agreement.

(c) Amendment. This Guarantee may not be modified, amended, terminated or revoked, in whole or in part, except by an agreement in writing signed by Company and Guarantors.

(d) Termination, Limits and Release. This Guarantee is irrevocable, unconditional and continuing in nature and is made with respect to all Guaranteed Obligations now existing or hereafter arising and shall remain in full force and effect until the time when in accordance with the terms of the Agreement all of the Guaranteed Obligations are fully satisfied and discharged, and then, and only then, this Guarantee shall automatically be released and shall be of no further force and effect; otherwise, it shall remain in full force and effect. Other than as set forth in the previous sentence, no release of this Guarantee shall be valid unless executed by Company and delivered to Guarantors. Under no circumstances will Guarantors' aggregate liability hereunder exceed the Cap.

(e) Law and Jurisdiction.

(i) THIS GUARANTEE IS GOVERNED BY AND SHALL BE CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEVADA, WITHOUT REGARD FOR ANY PRINCIPLES OF CONFLICTS OF LAW THAT WOULD DIRECT OR PERMIT THE APPLICATION OF THE LAW OF ANY OTHER JURISDICTION.

(ii) GUARANTORS AND COMPANY IRREVOCABLY AGREE THAT THE STATE AND FEDERAL COURTS LOCATED IN CLARK COUNTY, NEVADA, SHALL HAVE EXCLUSIVE JURISDICTION TO HEAR AND DETERMINE ANY SUIT, ACTION OR

PROCEEDING, AND TO SETTLE ANY DISPUTE, WHICH MAY ARISE OUT OF OR IN CONNECTION WITH THIS GUARANTEE, AND FOR SUCH PURPOSES HEREBY IRREVOCABLY SUBMIT TO THE JURISDICTION OF SUCH COURTS, AND GUARANTORS CONSENT TO THE JURISDICTION OF, AND TO THE LAYING OF VENUE IN, SUCH COURTS FOR SUCH PURPOSES AND HEREBY WAIVES ANY DEFENSE BASED ON LACK OF VENUE OR PERSONAL JURISDICTION OR OF INCONVENIENT FORUM.

(f) Severability. Any provision of this Guarantee that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. Where provisions of law or regulation resulting in such prohibition or unenforceability may be waived they are hereby waived by Guarantors and Company to the full extent permitted by law so that this Guarantee shall be deemed a valid binding agreement in each case enforceable in accordance with its terms.

(g) Third Party Rights. The terms and provisions of this Guarantee are intended solely for the benefit of Company and Guarantors and their respective successors and permitted assigns, and it is not the intention of Company or Guarantors to confer upon any other persons any rights by reason of this Guarantee.

(h) No Set-off, Deduction or Withholding. Guarantors hereby guarantee that payments hereunder shall be made without set-off or counterclaim and free and clear of and without deduction or withholding for any taxes; provided, that if the Guarantor shall be required under Applicable Law to deduct or withhold any taxes from such payments, then (i) the sum payable by Guarantor shall be increased as necessary so that after making all required deductions and withholdings (including deductions and withholdings applicable to additional sums payable pursuant to this sentence) the Company receives an amount equal to the sum it would have received had no such deduction or withholding been required, (ii) Guarantor shall make such deduction or withholding, and (iii) Guarantor shall timely pay the full amount deducted or withheld to the relevant governmental authority in accordance with Applicable Law.

(i) Waiver of Right to Trial by Jury. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF GUARANTORS AND COMPANY WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS GUARANTEE. EACH OF GUARANTORS AND COMPANY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

(j) Counterparts; Facsimile Signatures. This Guarantee may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Signatures delivered by facsimile shall be deemed to be original signatures.

[Signature page follows.]

FORM OF GUARANTEE

IN WITNESS WHEREOF, each Guarantor has duly executed this Guarantee on the day and year first before written.

Quinbrook Low Carbon Power LP

____
By: Quinbrook Infrastructure Partners (Jersey) Limited
As Manager of Quinbrook Low Carbon Power LP
Name:
Title:

Quinbrook Low Carbon Parallel Fund (US) LP

____
By: Quinbrook Infrastructure Partners (Jersey) Limited
As Manager of Quinbrook Low Carbon Parallel Fund (US) LP
Name:
Title:

Acknowledged and Accepted:

NEVADA POWER COMPANY D/B/A NV ENERGY, A NEVADA CORPORATION

____
Name:
Title:

EXHIBIT 21

WORK SITE AGREEMENT

[See Attached.]

GEMINI SOLAR PROJECT
SOLAR POWER XL
WORK SITE AGREEMENT

1. INITIAL PROVISIONS

1.1. This Work Site Agreement ("Agreement") is entered into by [General Contractor's Name] ("Primary Employer"), and IBEW Local Unions 357 & 396 ("the Unions").

1.2. The Gemini Solar Project, Solar Power XI, (the "Project") has a potential to provide approximately 690 MW as a solar photovoltaic power plant located in Southern Nevada. This location is known as the "Project Site". The Project is owned and operated by Arevia Power Company on behalf of Valley of Fire Solar, LLC ("Owner"). It is understood and agreed by and between the Parties to this Agreement that the final plans for the Project may be subject to modifications and approval by those public agencies possessing lawful approval authority over the Project and that this Agreement applies to the Project as it is finally approved by such entities and agencies. Once a final physical address is secured for this Project Site, they will be incorporated into this Agreement.

1.3. Owner is responsible for the construction of the Project and has engaged the Primary Employer to handle such construction.

1.4. As provided below, all persons or entities assigning, awarding or subcontracting Covered Work (as defined in Article 2) on the Project, or authorizing another party to assign, award or subcontract Covered Work on the Project, or performing Covered Work on the Project (all of whom are individually and collectively referred to as "Employer" or "Employers") will (except for the Owner and Primary Employer) become subject to this Agreement by executing Attachment A (the "Agreement To Be Bound").

1.5. The Unions are labor organizations whose members are construction industry employees who generally work in close proximity to one another at construction job sites and whose jobs are closely related and coordinated. The Unions are party to a multi-employer collective bargaining agreement ("Master Agreement") that covers the geographic area of the Project. Where the term Master Agreement is used, it means the existing Master Agreement in effect on the date hereof for the labor unions noted herein.

1.6. A large labor pool represented by the Unions will be required to execute the work involved in the Project. AREVIA and Employers wish, and it is the purpose of this Agreement to ensure, that a sufficient supply of skilled craft workers are available at the Project, that all construction work and related work performed by the members of the Unions on this Project proceed continuously and economically, without interruption, in a safe and efficient manner. The parties also expressly recognize that the Project is located in a desert region that is subject to high temperatures. Employers will provide a safe work site and comply with all state and federal requirements related to protection from heat. The Unions will not seek to restrict productivity based on the desert location. In furtherance of these purposes and to secure optimum productivity, harmonious relations between the parties and the orderly performance of the work, the parties to this Agreement agree to establish adequate and fair wage levels and working conditions.

1.7. A central purpose of the parties in executing this Agreement is to guarantee labor peace on the Project by minimizing the jobsite friction that could arise at a common-situs jobsite when union employees are required to work alongside non-union employees in those other crafts with which they generally work in close proximity performing work that is closely related and coordinated, and by ensuring there will be no disruption of the work should any non-union workers be present to perform work outside the scope of the Agreement. This Agreement accomplishes these objectives by requiring that all Covered Work on the Project be performed by workers who are members of the Unions.

1.8. In the interest of the future of the construction industry in the local area, of which the Unions are a vital part, and to maintain the most efficient and competitive posture possible, the Unions pledge to work and cooperate with the Owner, Primary Employer and all other Employers to produce the most efficient utilization of labor and equipment in accordance with this Agreement. In particular, the Unions shall make all efforts to first source labor local to the Project Site. In addition, the Union shall not afford preferential status to other jobs in the jurisdiction; to the extent such preference will inhibit the availability of qualified workers for the Project.

2. <u>SCOPE OF AGREEMENT</u>

2.0. All work to construct Project covered by this Agreement as defined below is referred to as "Covered Work." This Agreement also covers work done in temporary yards or facilities adjacent to or near the Project that is otherwise Covered Work described below. The scope of Covered Work set forth in this Agreement for this Project shall not be considered precedential.

2.1. IBEW Inside Covered Work Includes:

2.1.1. This Agreement covers the following on-site electrical construction work within the scope of the Union's Master Agreement: handling and installation of photovoltaic panels, installation and connection of any electrical wires and cables, connections to power conversion stations, electrical fixtures, electrical appliances, electrical apparatus, electrical raceways or trays, electrical conduits, electrical instrumentation and controls. All of the foregoing work with the exception of any excluded work in Section 2.3 is referred to as "Covered Work."

2.1.2. IBEW Inside Covered Work also includes all work performed by electrical craft labor that is part of startup and commissioning, including, but not limited to, loop checks and rework and modifications during start-up and commissioning. The Primary Employer, manufacturer's representatives, vendor's representatives, and plant operating personnel may supervise and direct employees performing startup and commissioning, including loop checks and rework and modifications during start-up and commissioning. This related craft work is typically performed as part of a joint effort with these representatives and personnel. After a system or subsystem becomes operational and upon acceptance by the Primary Employer, Covered Work on that system or subsystem is completed. However, rework and modifications normally provided as a function of the initial construction effort, and other related initial construction work normally performed by members of the Unions, will be performed by members of the Unions. Nothing set forth in this Section 2.1.2 or the rest of this Agreement shall be construed as prohibiting or limiting the following: (1) permanent operating personnel, who are not members of the Unions, from operating systems prior to Covered Work being completed; or (2) the performance of industry standard work performed by a manufacturer or vendor or its representatives to satisfy its guarantee or warranty prior to startup of a piece of equipment.

2.2. IBEW Outside Line Covered Work includes all construction of transmission and distribution lines, outside substations, switchyards, and sub-station or switchyard related ground grids. To the extent there is additional work needed by Employer on the Project that is outside of the above language, but covered within the scope of work for the IBEW Outside Line Construction Agreement, IBEW Local 396 and the Employer agree to meet and confer to determine if that work can be covered by IBEW Local 396.

2.3. Excluded Employees from Covered Work: The following individuals/employees are specifically excluded from this Agreement and not subject to the provisions of this Agreement:

a) Supervisors or managers, assistant supervisors, superintendents technical or non-manual employees including, but not limited to executives, office and clerical personnel, clerks, project managers, drafters, engineers, surveyors, schedulers, planners, timekeepers, messengers/mail carriers, procurement and/or material receipt personnel, inspectors and testers (including necessary resources required for commissioning and testing scope of work), quality control/assurance personnel, janitors, guards, technicians, professionals, or any other employees above the classification of general foreman who perform administrative/clerical functions.

b) Employees and entities not engaged in the work listed in Section 2.1, 2.1.2 and 2.2, above;

c) Employees of any Employer or construction manager, except those performing Covered Work;

d) Vendors and employees of vendors engaged expressly for repair, testing, inspection, delivery, training, warranty work, or engaged in corrections of defective equipment or material;

e) Employees engaged in geophysical and/or environmental testing or other site-specific investigatory work (whether land, water or air);

f) Employees performing preconstruction site preparation work including fence installation, cleaning, grubbing, grading and compaction and dust control/watering;

g) Employees engaged in ancillary work on the Project which is performed by third parties, such as electric utilities (i.e. NV Energy), gas utilities, telephone companies and railroads, or any other similar work;

h) Employees engaged in the delivery and unloading of material, supplies and equipment to the Project Site or to locations designated throughout the Project Site for equipment and material staging, as determined by the Owner or Employer;

i) Employees of any federal, state, county, city or other governmental bodies and/or agencies or their contractors; and

j) Employees and contractors of lenders engaged in work on the Project Site as part of the lenders' due diligence or monitoring, which work is ancillary to Project work.

2.4. Purchase of any manufactured item produced in a genuine manufacturing facility for the supply of products is not Covered Work and shall not be considered subcontracting under Article 3 below. Any offsite fabrication, kitting, preparation or other assembly of components for the Project is Covered Work and shall be performed on site. For the convenience of the Employer, such work may be performed offsite if performed in accordance with the union standards for the applicable Union established by this Agreement. Covered Work does not include creating inverter skids, if they are created, built, or assembled in a genuine manufacturing facility.

2.5. The initial delivery of materials to the Project site, to a drop off location within the site, or to a temporary yard at/or area near the Project is not Covered Work. The loading, unloading and distributing of electrical materials within the site after the initial delivery are Covered Work.

2.6. The manual and physical work typically performed by the Unions as part of startup and commissioning prior to turnover acceptance pursuant to Section 2.7 is Covered Work. It is understood that the Owner, Primary Employer, or any other Employers (including temporary employees under their direction performing non-manual functions), manufacturer's representatives, vendor's representatives, and plant operating personnel may supervise and direct start-up and commissioning activities. If craft labor is required to perform commissioning and testing related work, it will be performed as part of a joint effort with the commissioning and testing representative directing the work and represented personnel.

2.7. Upon turnover and acceptance of a portion of the Project by the Owner or Primary Employer, such portion of the Project shall no longer be subject to the terms of this Agreement and any work done on such portion shall not be Covered Work. In the event that the Owner or Primary Employer is not willing to accept the Project until substantial completion of the entire Project is reached, after approval by the Owner, the Primary Employer will issue to the Unions notice in writing of the completion of the section of the Project and the issuance of this letter to the Union will constitute the end of the terms and conditions of this Agreement and any work done on such portion after the issuance of this letter shall not be Covered Work. A copy of this letter will be provided to Owner by the Primary Employer at the time of issuance to the Unions. The turnover process provided in this Section shall not diminish the scope of Covered Work that has customarily been included as part of Covered Work in similar projects.

2.8. Covered Work does not include operations or maintenance work.

3. SUBCONTRACTING

3.1. Primary Employer and each other Employer agree that they will contract for the assignment, awarding or subcontracting of Covered Work, or authorize another party to assign, award or subcontract Covered Work, only to a person, firm, corporation or other entity that, at the time the contract is executed, has become a party to this Agreement by executing the Agreement to Be Bound.

3.2. Primary Employer and each other Employer agree that they will subcontract Covered Work only to a person, firm, or corporation who is or becomes signatory to this Work Site Agreement and who is or becomes signatory to the Union's Master Agreement for any non-residential solar work. The subcontractor agrees to become a signatory of the Master Agreement under this provision only for the life of the current Master Agreement. Any Employer performing Covered Work on the Project shall, as a condition to working on the Project, become signatory to and perform all work under the terms of this Agreement and the Master Agreement. Before being authorized to perform any Covered Work, Employers (other than Primary Employer) shall become a party to this Agreement by signing an Agreement To Be Bound, which is provided as Attachment A to this Agreement. Every Employer shall notify the Unions in writing within five business days after it has subcontracted work, and shall at the same time provide to the Unions a copy of an Agreement To Be Bound executed by the Employer.

3.3. Nothing in this Agreement shall in any manner whatsoever limit the rights of Primary Employer or any other Employer, to subcontract work or to select its contractors or subcontractors, provided, however, that all Employers, at all tiers, performing Covered Work shall be required to comply with the provisions of this Agreement. Primary Employer and every other Employer shall notify each of its contractors and subcontractors of the provisions of this Agreement and require as a condition precedent to the award of any construction contract or subcontract for Covered Work or allowing any subcontracted Covered Work to be performed, that all such contractors and subcontractors at all tiers become signatory to this Agreement and the Master Agreement for non-residential solar work. If any Employer fails to provide the Union with the Agreement To Be Bound executed by its subcontractor, that Employer shall be liable for any contributions to any trust funds that the subcontractor, or any subcontractor to that subcontractor, fails to make

4. WAGES, BENEFITS, HOURS OF WORK, SHIFT WORK, HOLIDAYS

4.1. All employees covered by this Agreement (including foremen and general foremen if they are covered by a Master Agreement) shall be classified and paid wages, and contributions made on their behalf to multi-employer trust funds, all in accordance with the appropriate Master Agreement.

4.2. The standard work day shall consist of eight (8) hours of work between 6:00 a.m. and 5:30 p.m. with one-half hour designated as an unpaid period for lunch. Breaks will be allowed in accordance with Federal/State Law. The standard work week shall be five (5) consecutive days starting on Monday. Nothing herein shall be construed as guaranteeing any employee eight (8) hours of work per day or forty (40) hours of work per week.

4.3. It is recognized by the parties to this Agreement that the standard work week may not be desirable or cost effective for the Project, and other arrangements for hours of work may be considered. Such proposed modifications to the standard work week will be established with the consent of the Employer and the Union.

4.4. Shifts may be established when considered necessary by the Employer. Shift hours will be as follows: First shift will be eight (8) hours pay for eight (8) hours worked, plus one-half hour unpaid lunch period. Second shift will be eight (8) hours pay for eight (8) hours worked, plus the shift differential set forth in the Master Agreement.

4.5. A four (4) day, ten (10) hour per day work week may be established. Forty (40) hours per week constitutes the work week Monday through Thursday. Hours beyond ten (10) will be paid at the double time rate. Overtime on Friday will be paid at time and one-half for the first eight (8) hours; hours beyond eight (8) will be paid at the rate established in the Master Agreement, not to exceed double time. There shall be no make-up days.

4.6. The Employer may establish two four (4) day ten (10) hour per day shifts at the straight time rate of pay Monday through Thursday. The first shift shall be ten (10) hours pay for ten (10) hours worked at the regular straight time hourly rate, exclusive of thirty (30) minute unpaid meal period. The second shift shall be ten (10) hours pay for ten (10) hours worked plus the shift differential set forth in the Master Agreement.

4.7. There will be no pyramiding of overtime rates.

4.8. Recognized holidays shall be as follows: New Year's Day, Martin Luther King, Jr. Day, Presidents' Day, Memorial Day, Fourth of July, Labor Day, Veterans Day, Thanksgiving Day, Day after Thanksgiving, and Christmas Day. Under no circumstances shall any work be performed on Labor Day except in cases of emergency involving life or property. In the event a holiday falls on Saturday, the previous day, Friday, shall be observed as such holiday. In the event a holiday falls on Sunday, the following day, Monday, shall be observed as such holiday. There shall be no paid holidays. If employees are required to work on a holiday, they shall receive the appropriate rate as provided in the Master Agreement not to exceed double the straight time rate of pay. Work on Labor Day requires the prior approval of the Business Manager of the applicable Union. The listed holidays may be modified by mutual agreement of the Primary Employer and the Unions.

4.9. Employees performing Covered Work dispatched off the Helper Book shall, at a minimum, receive wages and benefits as specified in Attachment C.

5. UNION RECOGNITION AND REFERRAL

5.1. The Employers recognize the Unions signatory to this Agreement as the sole and exclusive collective bargaining agents for its construction craft employees performing Covered Work for the Project, and further recognize the traditional and customary craft jurisdiction of the Unions.

5.2. All employees performing Covered Work shall be or shall become and then remain members in good standing of the Union as a condition of employment on or before the eighth (8th) day of employment, or the eighth (8th) day following the execution of this Agreement, whichever is later.

5.3. The Unions shall be the source of all craft employees for Covered Work for the Project. Employers agree to be bound by the hiring and layoff practices of the Unions, including hiring of apprentices, and to utilize its registration facilities and referral systems. Notwithstanding this provision, Primary Employer and all other Employers shall have the right to determine the competency of all referrals; determine the number of employees required; determine the selection of employees to be laid-off and reject any applicant referred by the Unions.

5.4. The Unions will exert their utmost efforts to recruit sufficient numbers of skilled and qualified craft employees to fulfill the requirements of each Employer. The Unions and the Employers agree that they will not discriminate against any employee or applicant for employment because of race, color, religion, sex, sexual orientation, national origin, disability, age, pregnancy, any genetic information or any other protected classification protected by law or regulation. Primary Employer each other Employer, and the Unions agree that they will not require any employee or applicant to submit to genetic testing or non-job related medical inquiries.

5.5. Primary Employer is aware of the importance of local hiring on any construction project. Local hiring brings a sense of community to the initiative and supports the local economy in which it is doing business. In continuance of that initiative, the parties agree that hiring will be from the Union's book for the geographic area.

5.6. In the event the referral facilities maintained by the Unions do not refer the employees as requested by the Employer within a forty eight (48) hour period after such requisition is made by the Employer (Saturdays, Sundays and Holidays excepted), the Employer may employ applicants from any source.

5.7. Employers may utilize the workmen dispatched from the Helper Books described in Attachment C. These workmen may be used for all work involving PV module installation and material/trash distribution/removal. Module Installation Crews shall be setup in teams of 1 Foreman, 3 Apprentices, and 3 Helpers. Module

Material Distribution Crews and Trash Crews shall have at least 1 (JW) foreman and any combination of Apprentices, Helpers, and Material Expediters not exceeding a crew size of 15 workmen. Once the modules are installed, any further work downstream of this identified work will be performed by either Apprentices or Journeymen as per the Master Agreement. In accordance with Section 4.28 of the Master Agreement, a foreman is required on any job with (3) or more workmen and may supervise up to (15) workmen including himself/herself.

5.8. If there are insufficient apprentices available, Primary Employer may utilize the workmen dispatched from the Helper Books with the consent of the Union.

6. <u>STRIKES AND LOCKOUTS</u>

6.1. During the term of this Agreement, the Unions agrees that they shall not (and that they shall not cause their agents, representatives and employees) to incite, encourage, condone or participate in any strike, walkout, slowdown, sit-down, stay-in, boycott, sympathy strike, picketing or other work stoppage for any cause whatsoever with respect to this Project; and it is expressly agreed that any such action is in violation of this Agreement. In the event of a violation of this provision, any Employer shall be entitled to seek relief in court, specifically including injunctive relief, to restrain any such action on the part of the Unions, and/or any of their agents, representatives or employees, in addition to the Liquidated Damages for violation of this Section 6.1 of this Agreement.

6.2. Upon written notice of a violation to the Union and its' officers, and their agents, representatives, employees and persons acting in concert with it, the Union shall take immediate action and will use its best efforts to prevent, end or avert any such activity or the threat thereof by any of its officers, members, representatives or employees, either individually or collectively, including but not limited to, publicly disavowing any such action and ordering all such officers, representatives, employees or members who participate in such unauthorized activity to cease and desist from same immediately and to return to work and comply with its orders. Nothing in this Agreement shall be construed to limit or restrict the right of any of the parties to this Agreement to pursue fully any and all remedies available under law in the event of a violation of this Article 6.

6.3. The parties agree that to the extent the Master Agreement provisions of the Union's current labor agreement apply to this Project, they shall continue to apply throughout the duration of this Project notwithstanding the expiration of that agreement for all affected Employers on this Project.

6.4. Neither Owner, Primary Employer, nor any other Employer shall incite, encourage or participate in any lockout or cause to be locked out any employee covered under the provisions of this Agreement. The term "lockout" does not refer to the discharge, termination or layoff of employees by any Employer for any reasons in the exercise of its rights as set forth in any provision of this Agreement, nor does "lockout" include a decision by Owner, Primary Employer, or any Employer to terminate or suspend work on the Project Site or any portion thereof for any reason other than a labor dispute.

6.5. Notwithstanding the provisions of Section 6.1, it is agreed that the Union retains the right to withhold the services of its members from a particular Employer who fails to make timely payments to the Union's benefit plans, or fails to timely pay its weekly payroll, in accordance with the Master Agreement; provided, in the event the Union or any of its members withholds their services from such Employer, Owner, Primary Employer, or the applicable Employer shall have the right to replace such Employer with any other Employer who executes the Agreement To Be Bound. The Union shall not withhold the services of its members under this provision without first giving Owner, Primary Employer, and the individual Employer alleged to be delinquent in its payments at least five (5) business days' notice, in the case of payroll delinquencies, and ten (10) business days' notice, in the case of benefit fund delinquencies, and an opportunity to cure the delinquency by tendering payment to the relevant employees or trust funds.

7. <u>GRIEVANCE PROCEDURE</u>

7.1. It is mutually agreed that any question arising out of and during the term of this Agreement involving interpretation and application of this Agreement shall be considered a grievance. Any grievances involving interpretation and application of this Agreement will be governed by this Agreement's grievance procedure as set forth below. Any grievances involving interpretation and application of the Master Agreement will be governed by the Master Agreement's grievance procedure.

7.2. Owner, Primary Employer, and any other Employer, as well as the Union, may bring forth grievances under this Article.

7.3. A grievance shall be considered null and void if not brought to the attention of the Employer(s) within five (5) working days after the incident that initiated the alleged grievance occurred or was discovered, whichever is later. The term "working days" as used in this Article shall exclude Saturdays, Sundays or holidays regardless of whether any work is actually performed on such days.

7.4. Grievances shall be settled according to the following procedure, except that grievances that do not involve an individual grievant shall be discussed by Primary Employer and the Union, and then, if not resolved within five (5) working days of written notice unless extended by mutual consent, commence at Step 4:

7.5. <u>Step 1</u>. The steward and the grievant shall attempt to resolve the grievance with the Employer's supervisor within five (5) working days after the grievance has been brought to the attention of the Employer.

7.6. <u>Step 2</u>. In the event the matter remains unresolved in Step 1 above after five (5) working days, within five (5) working days after notice to the Union, the alleged grievance, in writing, may then be referred to the Business Manager of the Union and the Labor Relations representative of the Employer for discussion and resolution. A copy of the written grievance shall also be mailed/e-mailed to Primary Employer.

7.7. <u>Step 3</u>. In the event the matter remains unresolved in Step 2 above after five (5) working days, within five (5) working days, the alleged grievance, in writing, may then be referred to the Business Manager of the Union and the Manager of Labor Relations of the Primary Employer or the Manager's designated representative and the Owner for discussion and resolution.

7.8. <u>Step 4</u>. If the grievance is not settled in Step 3 within five (5) working days, within five (5) days thereafter, either party may request the dispute be submitted to arbitration or the time may be extended by mutual consent of both parties. The request for arbitration and/or the request for an extension of time must be in writing with a copy to Primary Employer and the Owner. Should the parties be unable to mutually agree on the selection of an arbitrator, selection for that given arbitration shall be made by seeking a list of seven (7) labor arbitrators with construction experience from the Federal Mediation and Conciliation Service and alternately striking names from the list of names on the list until the parties agree on an Arbitrator or until one name remains. The first party to strike a name from the list shall alternate between the party bringing forth the grievance and the party defending the grievance. Primary Employer shall keep a record of the sequence and shall notify the parties to the grievance as to which party has the right to strike a name first.

7.9. The selected arbitrator ("Arbitrator") shall conduct a hearing at which the parties to the grievance shall be entitled to present testimonial and documentary evidence. Hearings will be transcribed by a certified court reporter. The parties shall be entitled to file written briefs after the close of the hearing and receipt of the transcript.

7.10. Upon expiration of the time for the parties to file briefs, the Arbitrator shall issue a written decision that will be served on all parties and on Primary Employer. The Arbitrator shall have the authority to utilize any equitable or legal remedy to prevent and/or cure any breach or threatened breach of this Agreement. The Arbitrator's decision shall be final and binding as to all parties signatory to this Agreement. No arbitration decision or award under this Article may provide retroactive relief of any kind exceeding fifteen (15) calendar days prior to the date the grievance was first initiated at Step 1.

7.11. The cost of the Arbitrator and the court reporter, and any cost to pay for facilities for the hearing, shall be borne equally by the parties to the grievance. All other costs and expenses in connection with the grievance hearing shall be borne by the party who incurs them.

7.12. The Arbitrator's decision shall be confined to the issue(s) posed by the grievance and the Arbitrator shall not have the authority to modify, amend, alter, add to or subtract from any provision of this Agreement.

7.13. Any party to a grievance may invite Owner or Primary Employer to participate in resolution of a grievance. Owner or Primary Employer may, at its own initiative, participate in Steps 1 through 3 of the grievance procedure.

7.14. In determining whether the time limits of Steps 2 through 4 of the grievance procedure have been met, a written referral or request shall be considered timely if it is personally delivered, sent by overnight mail or e-mailed within the five (5) working day period. Any of the time periods set forth in this Article may be extended in writing by mutual consent of the parties to the grievance, and any written referral or request shall be considered timely if it is personally delivered, sent by overnight mail or e-mailed during the extended time period.

7.15. For purposes of e-mailed copies of grievances to Owner or Primary Employer, they can be sent to the following e-mail address: --------------------------------------@-----------------

8. <u>MANAGEMENT RIGHTS</u>

8.1. Except as expressly limited by the specific provisions of this Agreement, the Owner, Primary Employer, and all other Employers retain full and exclusive authority for the management of their respective Project operations and work forces, except as expressly limited by the terms of this Agreement. This authority includes, but is not limited to, the right to plan, direct and control the operations of all the work and the work force; decide the number to be hired and the qualifications therefore; decide the number and type of employees assigned to any specific work; hire, promote, transfer, and layoff employees; select and hire directly all supervisory personnel above the classification of general foreman it considers necessary and desirable, without such persons being referred by the Union; discipline or discharge of employees; decide the type of equipment to be used; decide the assignment and schedule of work; the promulgation of reasonable Project work rules, safety rules, and drug and alcohol policies pursuant to Section 10.8; determine the work methods and procedures; determine the competency of all employees; assign and schedule work and determine when overtime will be worked; determine the selection and use any type or kind of materials, apparatus or equipment regardless of source, manufacturer or designer; and determine the requirement, timing and number of employees to be utilized for Covered Work. Except as provided in the Master Agreement, no rules, customs, or practices of the Unions which limit or restrict productivity or efficiency of the individual, and/or joint working efforts with other employees shall be permitted or observed. The foregoing enumeration of management rights shall not be deemed to exclude other functions not specifically covered by this Agreement. The Owner, Primary Employer, and all other Employers, therefore, retain all legal rights not specifically given up in this Agreement.

8.2. There shall be no limitations or restriction upon the Owner, Primary Employer, or any other Employer's choice of materials, techniques, methods, technology or design, or, regardless of source (including but not limited to country source of origin) or location, upon the use and installation of equipment, machinery, package units, pre-cast, pre-fabricated, pre-finished, or pre-assembled materials of any kind, tools, or other labor-saving devices. The Union agrees that such material and equipment is to be installed without incident.

8.3. In recognition of the dynamic nature of the PV solar industry, the parties agree that Owner, Primary Employer or any other Employer may apply new technologies to the Project as they are developed, (including technological advances in the construction of PV solar plants) even if such application results in a reduction of the amount of labor on the Project.

8.4. All construction equipment assigned by an Employer to the Project shall be under the control of Owner, Primary Employer or any other Employer and they shall have the right to determine how many pieces of construction equipment an individual shall operate.

8.5 Owner, Primary Employer or any other Employer retains the right to deny access to the Project to any employee on the basis of violating any safety processes and procedures.

9. SUCCESSORSHIP AND SURVIVABILITY

9.1. The subcontracting obligations described in Article 3 are independent obligations of Primary Employer which shall survive any full or partial termination of Primary Employer's involvement in the Project for any reason, including, without limitation: (i) any full or partial termination or transfer of Primary Employer's right to control and coordinate construction of Covered Work on the Project; (ii) any full or partial termination or transfer of a contract, if any, between Primary Employer and the Owner for any Covered Work; (iii) the transfer of all or any portion of the Project or any interest in the Project by the Owner; or (iv) any other event that results in the replacement of Primary Employer with another contractor.

9.2. The parties agree that: (i) if Primary Employer's involvement in the Project is terminated and (ii) Covered Work is performed by a contractor or subcontractor that is not in compliance with the provisions of Article 3, then Primary Employer shall pay liquidated damages for each hour of Covered Work performed, as set forth on Attachment B.

9.3. Upon execution and delivery of an agreement assuming all the obligations of this Agreement and determination by the Unions that the successor is financially responsible, Primary Employer shall be released from any liability under this Agreement for the payment of liquidated damages under this Article 9 and shall have no liability for any breach of this Agreement by a successor employer or contractor. A successor shall be considered financially responsible if the Unions, in the exercise of their reasonable judgment, determine that the successor is financially capable of completing the Project and complying with the obligations and undertakings of Primary Employer under this Agreement, including any obligation to pay liquidated damages under this Article 9.

9.4. This Article shall be enforceable in any court of competent jurisdiction, and shall not be subject to the grievance procedure.

10. GENERAL PROVISIONS

10.1. If any article or provision of this Agreement shall be declared invalid, inoperative, or unenforceable by any competent authority of the executive legislative, judicial or administrative branch of the federal or state government, the Employers and the Union shall suspend the operation of such article or provisions during the period of its invalidity and shall substitute by mutual consent, in its place and stead, an article or provision which will satisfy the objections to its validity and which, to the greatest extent possible, will be in accord with the intent and purpose of the article or provision in question. At all relevant times, the provisions of Article 6 will apply.

10.2. If any article or provision of this Agreement shall be held invalid, inoperative or unenforceable by operation of law, or by any of the above mentioned tribunals of competent jurisdiction, the remainder of the Agreement or application of such article or provision to persons or circumstances other than to which it has been held invalid, inoperative or unenforceable shall not be affected thereby.

10.3. Except as enumerated in this Agreement, all other terms and conditions of employment described in the Master Agreements that are in effect shall apply.

10.4. The provisions of this Agreement shall take precedence over conflicting provisions of the Master Agreement of the Union.

10.5. The parties agree that all covered employees will be required to be at his or her work station and ready to begin work at the designated starting times. The parties support a pay arrangement that provides for the covered employee to be at his or her work station and ready to work at the start of this shift without compensation for the time traveled to his or her workstation however the parties further agree that employees will be compensated at the appropriate hourly rate of pay for travel time back to their vehicles from the workstation.

10.6. Each person executing this Agreement represents and warrants that he or she is authorized to execute this Agreement on behalf of the party or parties indicated.

10.7. Rights of Owner. Nothing in this Agreement shall be construed as limiting the Owner, in its sole discretion at any time to terminate, delay, cease, or suspend construction activities, in whole or part, on this Project and/or shut down the Project Site or any part thereof for reason other than a labor dispute without any liability whatsoever, except for liability incurred prior to such action.

10.8. This Agreement may be executed in counterparts.

10.9. The parties recognize that Primary Employer strongly supports a drug free work environment on each of its projects. To that end, the parties agree that Primary Employer's drug testing policies shall be applied to the Project by each Employer on the site. Specifically, that policy includes pre-employment drug testing prior to starting work on the site, random drug testing on the worksite once employed and drug testing following any industrial accident resulting in an injury or any damage to Owner, Primary Employer, or any other Employer's property. Should Primary Employer require a pre-employment drug test of the employee(s) of the signatory Employer as noted above, and the employee(s) (through the signatory Employer) will be paid (1) hour show up pay if he successfully passes the pre-employment drug test. Should an employee(s) initial test be deemed inconclusive and require further testing that employee(s) shall be paid (2) hour waiting time per day upon successfully passing the pre-employment drug testing. This pay provision shall only apply to pre-employment drug tests.

10.10. Any notices required under this Agreement shall be given as follows. Either party may notify the other in writing if its person designated to receive notice is changed.

To Primary Employer:

With a copy to:

Mark Boyadjian
Arevia Power Company
1044 10th Avenue
Redwood City, CA 94063

To the Unions:

Al D. Davis, Business Manager – Financial Secretary
IBEW Local 357
808 N. Lamb Blvd.
Las Vegas, NV 89110
Telephone: (702) 452-9357

Jesse Newman, Business Manager-Financial Secretary
IBEW Local 396
3520 Boulder HWY
Las Vegas, NV 89121
Telephone: (702) 457-3011

11. TERM OF AGREEMENT

11.1. The term of this Agreement shall commence on the date an agreement is executed between Primary Employer and Owner for the Project regarding this Project as identified in Section 1.2, and shall continue in effect until completion of all Covered Work pursuant to Article 2.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed and effective as of 12/27, 2017.

[GENERAL CONTRACTOR]

By:
Its:

AREVIA POWER COMPANY

By: Mark Boyadjian
Its: Managing Partner, Arevia Power

IBEW LOCAL 396

By: Jesse Newman
IBEW 396 Business Manager - Financial Secretary

IBEW LOCAL 357

By: Al D. Davis
IBEW 357 Business Manager – Financial Secretary

ATTACHMENT A
AGREEMENT TO BE BOUND

WORK SITE AGREEMENT
GEMINI SOLAR PROJECT

The undersigned hereby certifies and agrees that:

1.) It is an Employer as that term is defined in Section 1.4 of the Gemini Solar Project Work Site Agreement ("Agreement") because it has been, or will be, awarded a contract or subcontract to assign, award or subcontract Covered Work on the Project (as defined in Article 2 of the Agreement), or to authorize another party to assign, award or subcontract Covered Work, or to perform Covered Work.

2.) In consideration of the award of such contract or subcontract, and in further consideration of the promises made in the Agreement and all attachments thereto (a copy of which was received and is hereby acknowledged), it accepts and agrees to be bound by the terms and conditions of the Agreement, together with any and all amendments and supplements now existing or which are later made thereto.

3.) If it performs Covered Work, it will be bound by the legally established trust agreements designated in local master collective bargaining agreements, and hereby authorize the parties to such local trust agreements to appoint trustees and successor trustee to administer the trust funds, and hereby ratifies and accepts the trustees so appointed as if made by the undersigned.

4.) It has no commitments or agreements that would preclude its full and complete compliance with the terms and conditions of the Agreement.

5.) It will secure a duly executed Agreement To Be Bound, in form identical to this document, from any Employer(s) at any tier or tiers with which it contracts to assign, award, or subcontract Covered Work, or to authorize another party to assign, award or subcontract Covered Work, or to perform Covered Work.

DATED: ___________ Name of Employer ______________________________

____
(Authorized Officer& Title)

____

____
(Address)

ATTACHMENT B
SCHEDULE OF LIQUIDATED DAMAGES FOR BOTH PARTIES

WORK SITE AGREEMENT
GEMINI SOLAR PROJECTI

1. Strikes: In the event the Union violates the terms of Section 6.1 of the Work Site Agreement, including without limitation, by interfering with the Project or by supporting a strike at the work site, then the Union shall be jointly and severally liable for an amount equal to twenty thousand dollars ($20,000) for each day in which the Union is in violation of the terms of Sections 6.1.

2. Failure of Successor to Assume. In the event Primary Employer fails to cause its successor to assume the Work Site Agreement, Primary Employer shall pay an amount equal to the journeyman electrician's or journeyman lineman's total compensation, as applicable, for each hour that Covered Work was performed on the Project within the scope of this Agreement by employees of contractors or subcontractors who are not signatory to this Agreement as follows:

Fifty Percent (50%) per hour to the qualified pension plan and
Fifty Percent (50%) per hour to the qualified health and welfare plan

of the Unions performed by the contractor(s) or subcontractor(s) not signatory to this Agreement. The parties agree that the Unions shall enforce, collect and receive the liquidated damages described herein on behalf of its qualified pension plan and its qualified health and welfare plan. The qualified pension plans and the qualified health and welfare plans shall have no right to independently enforce the provisions of this Agreement.

3. The liability of the Owner, Primary Employer, any other Employer and/or the Union under this Agreement shall be several and not joint. Neither the Owner, nor any Primary Employer or any other Employer shall be liable for any violations of this Agreement by any other contractor or party; and the Unions shall not be liable for any violations of this Agreement by any other union or party.

4. In no event shall Owner, Primary Employer's or Unions' liability for violation of this Agreement exceed $1,000,000 (One Million Dollars).

Appendix C

IBEW 357 Gemini Solar Project Helper Rates

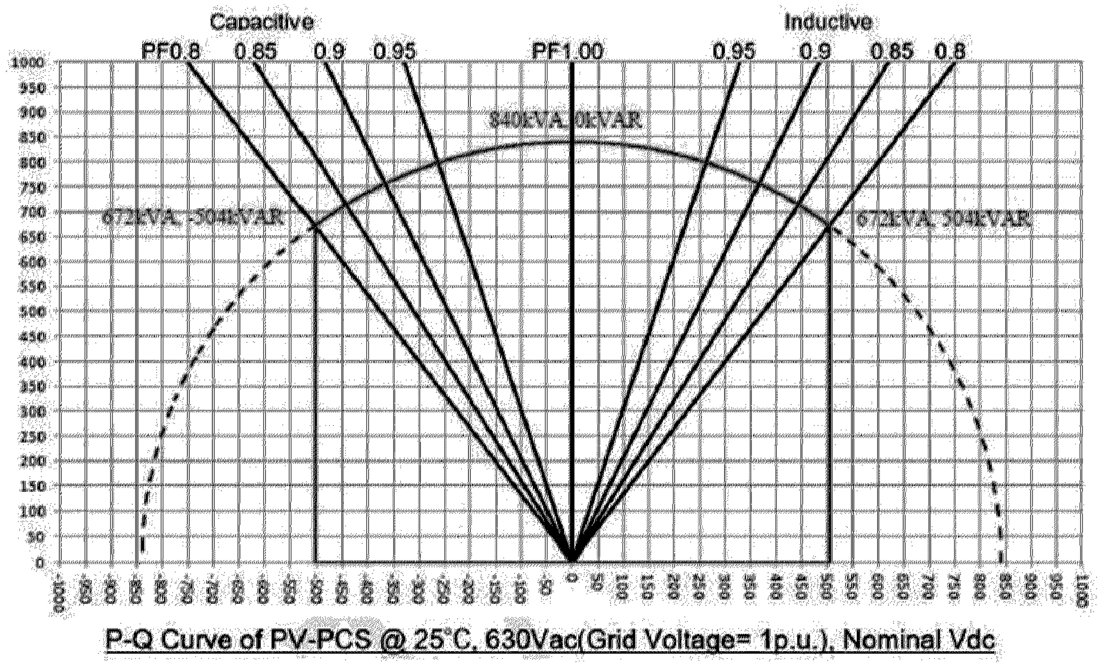
	Check	H&W	DFW	B-Plan	JATC	LMCC	NLMCC	NEBF 3%	CAF 0.2%	Total
9/1/17	$21.00	$5.45	$.06	$1.00	$0.66	$0.15*	$0.01	$0.63	$0.04	$29.00
1/1/19	$21.75	$5.45	$.06	$1.00	$0.66	$0.15*	$0.01	$0.65	$0.04	$29.77
1/1/20						TBD				

* LMCC is a total of $0.30 $0.15 contribution from the contractor and $0.15 deduction from the employees' wages.

Wages and Benefits are for workers dispatched from the Helper Books for the Gemini Solar Project.

EXHIBIT 22

REACTIVE CAPABILITY CURVES



Subject to limitations described in Exhibit 1, Sections 6 and 7.

EXHIBIT 23

APPROVED VENDORS LIST

[To be provided by Buyer]

EXHIBIT 24

STORAGE OPERATING PROCEDURES

The operating guidelines of the Generation Facility and Energy Storage Facility will be defined herein. The main operations are broken into two parts: Charging Notice and Discharging Notice. Final Operating Procedures for the Facilities will be mutually developed and agreed upon within 90 days of the Operation Date. The procedures will be periodically reviewed to optimize operations for both parties. Parties shall cooperate to integrate the systems and controls necessary to implement the Operating Procedures.

I. Forecasting

A. Supplier will provide to Buyer a 7-day hourly rolling availability forecast, the Availability Notice, of the solar resource, which incorporates the following information:
   1) Supplier's optimal charging schedule, including charging window and hourly charging rate;
   2) hourly maximum charging rate availability of the Storage Facility;
   3) hourly minimum charging rate availability of the Storage Facility; and
   4) current status of the Storage Facility, expressed in a percentage of total battery available for discharge or state of charge;

B. Planned and forced outage notification and scheduling shall be via the Availability Notice. Additionally, in the event of a forced outage, Supplier shall notify the appropriate NV Energy personnel of forced outage and expected return to service.

II. Charging Notices and Discharging Notices

A. A Discharging Notice will be delivered to the Supplier in conjunction with each Charging Notice
B. Buyer will provide to Supplier, per the Western Electricity Coordinating Council ("WECC") pre-scheduling calendar, a forecasted Charging Notice and Discharging Notice. The Charging and Discharging Notice will incorporate Supplier's solar resource availability per Supplier's 7-day hourly rolling forecast.
C. For the Charging component of the Charging and Discharging Notice, Buyer shall provide Supplier with the following information:
   1) the hours in which Supplier shall charge the Storage Facility;
   2) the Stored Energy Level the Supplier shall charge the Storage Facility to, by the end of the last hour in which Supplier shall charge the Storage Facility.
   3) Buyer, whenever feasible, will utilize Supplier's provided optimal charging window identified in section I.A.1.

D. For the Discharging Notice, Buyer shall provide Supplier with the following information:
   1) the hours in which the Supplier shall discharge the Storage Facility;
   2) the energy discharged in each hour the Supplier shall discharge the Storage Facility.

STORAGE OPERATING PROCEDURES

III. Modifications to the Charging and Discharging Notices

A. On the day of operation, to the degree that it is technically feasible, Buyer reserves the right to make adjustments to its Charging Notices and Discharging Notices. To this end, Supplier will provide to Buyer real-time software application(s) which allow(s) Buyer to access the Stored Energy Level status of the Storage Facility, as well the current forecasts of PV generation.

B. To make intraday adjustments on the day of operation, Buyer will communicate with Supplier in a manner that is mutually agreeable to both Buyer and Supplier:
   1) either through a software application which allows Buyer to directly adjust the charge or discharge status of the Storage Facility, including the rate of charge or discharge of the Storage Facility; or
   2) telephonically with Supplier to verbally request adjustments to the charge or discharge status of the Storage Facility, including the rate of charge or discharge of the Storage Facility; or
   3) through a software application which allows for real-time communication, such as Microsoft Lync, Skype for Business, etc. to request adjustments to the charge or discharge status of the Storage Facility, including the rate of charge or discharge of the Storage Facility.
   4) A real-time dispatch signal will be the primary control of the Facility

C. Supplier will communicate with Buyer, utilizing the manner of communication mutually agreed upon above, whether Buyer's requested adjustment to the charge or discharge schedule contained in Buyer's Charging Notice and Discharging Notice is feasible, both in terms of the hour(s) requested, as well as the rate of charge or discharge requested. Should Buyer's requested adjustment to the charge or discharge schedule be infeasible, due to the current charged or discharged status of the Storage Facility, Buyer and Supplier shall mutually agree to:
   1) an alternate adjustment to the charge or discharge schedule, which is technically feasible given the Stored Energy Level or discharge of the Storage Facility; or
   2) reject Buyer's adjustment to the charge or discharge schedule, and resume Buyer's original charge or discharge schedule as specified in Buyer's Charging and Discharging notice.
   3) any adjustments necessary to future charge or discharge schedules contained in Buyer's Charging and Discharging Notices which will be rendered infeasible due to Buyer's requested adjustment to the charge or discharge schedules on the day of operation.

IV. Delivery

A. The Supplier will deliver the Discharging Energy to the Delivery Points. To this end, Supplier will provide to Buyer a real-time software application which allows Buyer to access the status of the Storage Facility, as well the current forecasts of PV generation.
A real-time point of delivery in response to:

EXHIBIT 24

STORAGE OPERATING PROCEDURES

1. Primarily with a real-time dispatch command Per section III above
2. Or an automated, scheduled Discharge Notice per section II.D above as a backup.

The total discharged energy in real-time will be limited to the Stored Energy Level (less any losses to deliver such stored Energy to the Delivery Points) and to the available power rating of the Generating Facility.

V. Measurement and Verification

Buyer will also have real-time access to view the Supplier's Energy Management system and data historian that will monitor the Storage Facility's state of health metrics as well usage metrics such as Equivalent Cycles to date. In accordance to Exhibit 1 Buyer will be allowed to use 273 Equivalent Cycles per year. Buyer will be able to monitor the amount of cycles that have occurred over the life of the project on a real-time basis. As soon as the Storage Facility meets the cycle limit, the supplier will no longer be able to execute Charge and Discharges for that year.

VI. Scheduling Reports

Supplier will send out a daily report to the Buyer so they may transmit to other parties. The report will include at a minimum the following day's Charging Notice and Discharging Notice as well as forecasted Energy Generation, including the forecasted output of the solar facility in so much as it is reduced by charging the Storage Facility.

VII. Operating Parameters

#	OPERATING PARAMETER	VALUES	NOTES
1	Charging Method	Constant Power (CP)-Constant Voltage (CV)	
2	Discharging Method	Constant Power (CP)	
3	Maximum CP-rate for Charging and Discharging the Storage Facility	400 MW_{DC}, which can be adjusted accordingly, as reasonably agreed upon by the Parties, based upon the final design of the Facility	Measured at the Storage Facility Metering Point
4	Charging Source	Generating Facility only	This is for main power, but station power to feed auxiliary loads may come from grid charging.
5	Maximum Annual Average State of Charge (SOC)	35.0%	
6	Resting State of Charge (SOC) of the Storage Facility	20%-30% or as per manufacturer recommendation	When not actively charging or discharging for more than a period of 24 hours, the SOC of the

EXHIBIT 24

STORAGE OPERATING PROCEDURES

			Storage Facility shall be maintained in this range
7	Operational State of Charge (SOC) Limits	0%-100% or as per manufacturer recommendation	As defined in the EMS
8	Maximum Number of Equivalent Full Cycles per Calendar Year	365	Buyer allowed to use a total of 273 cycles in all months other than June, July and August
9	Maximum Cumulative Energy Discharge per Calendar Year	516,840 MWh	which is 380MW (the Storage Contract Capacity (MW) of the Storage Facility for the given Contract Year) * 3.726h * 365 = 516,840 MWh
10	Maximum Cumulative Energy Discharge per Calendar Day	1,416 MWh	which is 380MW(the Storage Contract Capacity (MW) of the Storage Facility for the given Contract Year) * 3.726h = 1,416 MWh

EXHIBIT 25

STORAGE CAPACITY TESTS

Upon no less than ten (10) Business Days prior notice to Buyer, and at any time and from time to time up until the Commercial Operation Date, Supplier shall schedule and complete a Storage Capacity Test to determine the Storage Contract Capacity of the Storage Facility for the first Contract Year. The Storage Capacity Test shall require the Supplier to maintain Discharging Energy from the Storage Facility for three and seven-tenths (3.7) consecutive hours and the Storage Contract Capacity in megawatts (MW) shall be determined as the quotient of the aggregate quantity of Discharging Energy (MWh) at the end of the three and seven-tenths (3.7) hour test period, as measured at the Delivery Points, divided by three and seven-tenths (3.7); provided, however, that the Storage Contract Capacity cannot exceed three hundred eighty (380) MW.

Thereafter, at least once per Contract Year within the first quarter of each Contract Year, upon no less than five (5) Business Days prior notice to Buyer, Supplier shall schedule and complete a Storage Capacity Test. In addition, Buyer shall have the right to require a retest of the Storage Capacity Test at any time upon five (5) days prior written notice to Supplier if Buyer reasonably believes that the Storage Capacity has varied materially from the results of the most recent tests. Supplier shall have the right to run up to four (4) retests of the Storage Capacity Test at any time upon five (5) days prior written notice to Buyer (or any shorter period reasonably acceptable to Buyer consistent with Good Utility Practice). Except for establishing the Storage Contract Capacity prior to the Commercial Operation Date, the Supplier may with Buyer's approval, fulfill the requirement to conduct a Storage Capacity Test by use of operational data from a Meter.

No later than five (5) days following any Storage Capacity Test, Supplier shall submit a testing report detailing results and findings of the test. The report shall include Meter readings and plant log sheets verifying the operating conditions and output of the Storage Facility. The actual capacity determined pursuant to a Storage Capacity Test shall become the new Storage Contract Capacity at the beginning of the day following the completion of the test for all purposes under this Agreement.

Supplier will perform a Storage Capacity Test generally in the following manner and utilizing the following steps:

1) Supplier may conduct any pre-capacity test activities required or recommended by the Storage Facility equipment suppliers, including charging or discharging the Storage Facility, prior to commencing step 2 below;

2) Supplier will fully charge the Storage Facility so that it is in a state that it is made commonly and typically available to Buyer as fully charged and dispatchable;

3) Supplier will discharge the Storage Facility at full capacity, over a duration of three and seven-tenths (3.7) consecutive hours;

4) Supplier will add the quantity of MWh produced by the Storage Facility during the three and seven-tenths (3.7) consecutive hours to produce a sum quantity of MWh for the three and seven-tenths (3.7) hour full discharge of the Storage Facility;

5) Supplier will divide the sum quantity of MWh produced over the three and seven-tenths (3.7) hour full discharge of the Storage Facility by a factor of three and seven-tenths (3.7), to produce a value that will become the Storage Contract Capacity for the Contract Year.

Example:
Hour 1 Discharge = 25 MWh
Hour 2 Discharge = 25 MWh
Hour 3 Discharge = 25 MWh
Partial Hour 4 Discharge = 17.5 MWh
25 + 25 + 25 + 17.5 = 92.5 MWh
92.5 MWh/3.7 hours = 25 MWh
Storage Contract Capacity = 25 MW

EXHIBIT 26

STORAGE AVAILABILITY LIQUIDATED DAMAGES

Availability Liquidated Damages

The Availability Liquidated Damages in Dispatch Availability Month (m) in which the Monthly Storage Availability is less than the Guaranteed Storage Availability shall be calculated as follows:

Availability Liquidated Damages_m = Undischarged Energy Price_m * Excess Undischarged Energy_m

Where:

Availability Liquidated Damages_m	=	Availability Liquidated Damages in Dispatch Availability Month (m) (in $)
Availability Liquidated Damages Monthly Cap (each Dispatch Availability Month)	=	$1,000,000
Undischarged Energy Price_m	=	simple average of the Market Price for the hours that the Storage Facility was unavailable in Dispatch Availability Month (m) (in $/MWh)
Undischarged Energy_m	=	The total amount of Discharging Energy in Dispatch Availability Month (m), excluding Excused Products, that Buyer could have scheduled and received at the Delivery Points pursuant to Section 14.3 from the Storage Facility but was unable to schedule and receive because the Storage Facility was, in whole or in part, mechanically out of service or otherwise not performing in accordance with the operational requirements specified in Exhibits 1 and 24, such amount of Discharging Energy to be reasonably determined by Supplier (i) during the period the Storage Facility was out of service, in whole or in part, or otherwise not performing in accordance with the operational requirements specified in Exhibits 1 and 24, and (ii) consistent with the Operating Procedures and operational requirements specified in Exhibits 1 and 24 (in MWh). During the months of January, February, March, April, October, November and December, an outage that is not a Planned Outage per Section 11, but for which Seller provided notice to Buyer prior to or included in the Availability Notice, shall not be considered as contributing to this calculation of Undischarged Energy_m provided the total hours of such Storage Facility unplanned

		outages when combined with those of Planned Outages in the same Contract Year (based on the potential Discharging Energy or Dispatch Availability Amounts, as applicable, for such Delivery Hours) shall not exceed four percent (4%) of the total annual Dispatch Availability Amounts for all hours in the applicable Contract Year (prorated for the Stub Period, if any) unless otherwise approved by Buyer.
Excess Undischarged $Energy_m$	=	Undischarged $Energy_m$ – 2% of the Storage Capacity at Point of $Delivery_m$.
Storage Capacity at Point of $Delivery_m$	=	the product of (a) Storage Contract Capacity for Dispatch Availability $Month_m$, multiplied by (b) three and seven-tenths (3.7) hours, multiplied by (c) the number of days in Dispatch Availability $Month_m$.
Monthly Storage Availability	=	$\frac{(\text{Storage Capacity at Point of Delivery}_m) - (\text{Undischarged Energy}_m)}{(\text{Storage Capacity at Point of Delivery}_m)}$

EXHIBIT 27

BACKCASTING TOOL GENERAL INPUTS

The main concepts of backcasting are broken into two parts: Resource-Adjusted Backcast Amount and Availability Backcast Amount. Both concepts are aimed at determining what the Generating Facility's solar generation capability, adjusted for various factors, would have been in cases where the actual solar output was dispatched lower than the Generating Facility's full capacity. Both are intended to calculate the energy that could have been generated by the Generating Facility and delivered to the Delivery Points, absent the use of the Storage Facility, except as relating to Buyer's rights in Section 14.3.2, in which case the Availability Backcast Amount should also include the energy that could have been used as Full Requirements Period Charging Energy (including otherwise clipped energy) and energy the Facility was available to deliver but could not deliver to the extent of any unavailability of the Facility resulting from one or more of the events described in this Section 3.6.6.

Final methodologies for backcasting shall be mutually developed and agreed upon no later than ninety (90) days prior to the Project Milestone described in Section 2(G) of Exhibit 6 based on industry-standard methodologies. The methodologies will be periodically reviewed to optimize operations, administrative efficiency and accuracy for the benefit of both parties. The Backcasting Tool will be calibrated one year after the Commercial Operation Date, and periodically thereafter, with actual measurements taken from the Generation Facility. Parties shall cooperate to integrate the systems and controls necessary to implement backcasting.

Backcasting will, in general, consist of a set of calculations and a mix of inputs to those calculations that include, but are not limited to, technical assumptions, real-time instrument measurements, historic instrument measurements, and data reported by Supplier. The inputs may include but are not limited to:

- As built designs;
- Generation Facility planned degradation as identified in Exhibit 1;
- Measured onsite plane of array (POA) irradiance;
- Measured module temperature;
- Measured onsite soiling conditions;
- All applicable losses to the Delivery Points including transformation and transmission losses from the PV array to points of delivery;
- Site controller and any ACG set-point limitations at the Delivery Points;
- Measurement uncertainties of equipment;
- Downtime/Planned Outages;
- Forced and maintenance outages
- Forced and maintenance derating of the Generating Facility
- Any non-production hours or standby loads

The Backcasting Tool outputs the hypothetical energy generation of the Generating Facility under certain weather conditions and Generating Facility operational status. Those outputs are then used throughout this Agreement to determine payments, shortfalls, dispatchability limits and damages (e.g. Un-Dispatched Amounts, Excused Product, etc.).

EXHIBIT 27

BACKCASTING TOOL GENERAL INPUTS

Resource-Adjusted Backcast Amount means an amount determined by the backcasting analysis that takes into account weather conditions including cloud cover, rain and snow impacting the solar resource, but assumes 100% mechanical availability of the Generating Facility.

Availability Backcast Amount means an amount determined by a backcasting analysis that takes into account both resource conditions and availability of the Generating Facility where availability, in this context, refers to the status of the Generating Facility's mechanical and electrical systems and equipment (e.g. operational capability of inverters, converters, transformers, etc.). The Availability Backcast Amount may be adjusted downwards from the Resource-Adjusted Backcast Amount by the amount of capacity lost due to these systems and equipment being impaired for any reason that is not a cause of Excused Product, as defined in Section 3.6.6. This calculation will include Supplier-reported derates and real-time status signals and calculations performed at the Generating Facility that are communicated to the Energy Management System (EMS) such that the EMS can send Automatic Generator Control (AGC) signals that are within the actual plant and weather conditions of the Generating Facility (reference Exhibit 16 Dispatchable Accuracy Rate).

Supplier shall provide Buyer its calculations and include all relevant back-up data and other information reasonably requested by Buyer.

If the Parties disagree on the calculation of the Resource Adjusted Backcast Amount or Availability Backcast Amount, then the Backcast Amount will be determined through the Dispute resolution provisions of Article 21.

REN-6-GS (b)

Technical Appendix REN-6-GS (b)

Summary of the Nevada Administrative Code sections applicable to Gemini Solar.

NAC 704.8885 (New renewable energy contracts: Review by Commission; criteria for approval) and NAC 704.8887 (New renewable energy contracts: Determination of whether price for electricity is reasonable) require that the Companies provide specific information regarding new renewable energy contracts for which they are seeking approval. The information responsive to NAC 704.8885 and 704.8887 is set forth below:

NAC 704.8885(2)(a) requires the Commission to determine the reasonableness of the price of electricity based on the factors set forth in NAC 704.8887, detailed in pertinent part as follows:

NAC 704.8887(1) instructs the utility to calculate the price for electricity acquired or saved pursuant to a new renewable energy contract or energy efficiency contract by calculating the levelized market price for the electricity.

The Levelized Cost of Energy ("LCOE") for the contract is $42.83/megawatt-hour ("MWh") including network upgrade costs. The rate is for the purchase of energy and portfolio credits ("PCs") at a blended rate, as well as the use and maintenance associated with the battery energy storage system.

NAC 704.8887(2)(a) requires the Commission to address whether the new renewable energy contract or energy efficiency contract comports with the utility provider's most recently approved plan to increase its supply of or decrease the demand for electricity.

This project is being proposed as part of the third amendment to the Companies' 2018 triennial integrated resource plan to increase its supply of electricity.

NAC 704.8887(2)(b) addresses the reasonableness of any price indexing provisions set forth in the new renewable energy contract or energy efficiency contract.

The price for renewable energy and PCs set forth in this contact is $24.79/MWh with no escalation for the term of the contract except during the hours ending 1700 through 2100 during the months of June, July and August when the price is $161.14/MWh.

The price for the storage portion of the PPA is included in the rates above for the term of 25 years.

NAC 704.8887(2)(c) addresses whether the new renewable energy systems will reduce environmental costs in this State as compared to competing facilities or energy systems that use fossil fuels.

The technology that the Gemini Solar project utilizes creates zero air emissions. When compared to a modern gas-fired combined cycle unit, the emissions avoided are shown in the table below.

Avoided Air Emissions [tons][1]					
Project	**S02**	**CO**	**VOC**	**NOX**	**PM**
Gemini Solar	4.61	10.75	0.23	49.55	16.90
1 Avoided Emissions derived from average heat rate for a state of the art combined cycle unit. This is a conservative assumption as avoided emissions are likely to be from higher heat rate market purchases or from older, less efficient units.					

The project uses de minimis amounts of water, creates no waste streams in its energy production and efficiently utilizes land for solar energy generation, and has minimal impacts on wildlife..

NAC 704.8887(2)(d) addresses the net economic impact and all environmental benefits and environmental costs to this State in accordance with NAC 704.9005 to 704.9525, inclusive.

According to the developer, the anticipated net economic impact of the project includes:

- *A temporary increase in workforce during the construction phase of the facility of an estimated 2,385 positions;*
- *A permanent long-term increase in the workforce for the operation and maintenance of the facility of an estimated 25 positions at an estimated average salary of $79,000 annually, and a total payroll of $63.2 million over 25 years;*
- *The environmental benefit will be a reduction in air emissions as shown in the table above.*

NAC 704.8887(2)(e) addresses any economic benefits that might inure to any sector of the economy of this State.

The economic benefits of the project include increased sales taxes from the purchase of local goods. Other benefits include an increase in short-term construction employment and long-term operations employment.

NAC 704.8887(2)(f) addresses the diversity of energy sources being used to generate electricity that is consumed in this State.

Commission approval of the PPA will increase the diversity of energy sources used to generate electricity that is consumed in Nevada. The portfolio of renewable energy will increase with a commensurate decrease in its reliance on fossil fuel generation.

NAC 704.8887(2)(g) addresses the diversity of energy suppliers generating or selling electricity in this State.

Solar Partners XI, LLC is a U.S.-based company, headquartered in Redwood City, CA. Its investor, Quinbrook Infrastructure Partners, has developed over 4GW of projects across the world, with a vast majority in the United States.

NAC 704.8887(2)(h) addresses the value of any price hedging or energy price stability associated with the new renewable energy contract or energy efficiency contract.

The agreement has a low starting price with no escalation over the term of the contract. The price is therefore known through the term of the contract and is not subject to fuel risk.

NAC 704.8887(2)(i) addresses the date on which each renewable energy system is projected to begin commercial operation.

The project's commercial operation date is estimated to be December 1, 2023.

NAC 704.8887(2)(j) addresses whether the utility provider has any flexibility concerning the quantity of electricity that the utility provider must acquire or save pursuant to the new renewable energy contract or energy efficiency contract.

The agreement permits Nevada Power Company ("NPC") the flexibility to economically dispatch the facility. During the hours ending 1700 through 2100 in June, July and August, the agreement calls for NPC to take all net energy, including any excess energy and PCs generated by the facility. Curtailment or re-dispatch of up to 100 percent of the expected output can be ordered by the transmission provider, electric system authority, or market operator. NPC has no obligation to pay for generation in excess of the maximum amount. Excess energy is paid for at fifty percent (50%) of the applicable product rate. NPC has flexibility in operation of the battery storage system which can be dispatched at the discretion of the Company.

NAC 704.8887(2)(k) addresses whether the new renewable energy contract or energy efficiency contract will result in any benefits to the transmission system of the utility provider.

The Large Generator Interconnection Agreement ("LGIA") and System Impact Study ("SIS") for this project have been completed. The studies did not identify any negative impacts to NPC's transmission grid that could not be mitigated by the transmission system additions proposed in the studies. The project generates electricity which will provide benefits to the transmission grid by providing real and reactive power at the point of interconnection. See Technical Appendices TRAN-3 and TRAN-4 for information on the LGIA and SIS.

NAC 704.8887(2)(l) addresses whether the electricity acquired or saved pursuant to the new renewable energy contract or energy efficiency contract is priced at or below the utility provider's long-term avoided cost rate.

When compared to the long-term avoided costs approved by the Commission in Docket No. 18-06003, the blended rate for energy and PCs is lower than the long-term avoided costs in year 2023 and years 2033 through 2048.

NAC 704.8887(3) addresses the price of electricity acquired or saved in a renewable energy contract or energy efficiency contract for the solar energy requirement of its portfolio standard to be evaluated separately.

The cost of power and PCs delivered from the project are competitive to both the prices NPC pays for its current portfolio of renewable projects and the other compliant bids submitted in the Fall 2018 Renewable Energy RFP.

NAC 704.8885(2)(b) addresses the term of the contract.

The term of the PPA is 25 years.

NAC 704.8885(2)(c) addresses the location of the portfolio [renewable] energy system or efficiency measure that is subject to the contract.

The project is located approximately 25 miles northeast of Las Vegas near the Apex Industrial Park in Clark County, Nevada.

NAC 704.8885(2)(d) addresses the use of natural resources by each renewable energy system that is subject to the contract.

The project utilizes irradiance from the sun gathered by solar panels. No water is consumed during the operation of the project other than the occasional cleaning of the panels.

NAC 704.8885(2)(e) addresses the firmness of the electricity to be delivered and the delivery schedule.

The project generates non-firm energy that will be delivered into the utility's grid which will be delivered through firm transmission pursuant to the designation of the facility as a network resource.

NAC 704.8885(2)(f) addresses the delivery point for the electricity.

The generating facility will be interconnected to the existing Crystal Substation. A one-line diagram depicting the interconnection can be found in Exhibit 5 of the PPA, Technical Appendix REN-6-GS (a).

NAC 704.8885(2)(g) addresses the characteristics of similar renewable energy systems.

The characteristics of the project are similar to those of NPC's other large scale PV systems such as Boulder Solar I and Techren I. The plant design is proven technology. The storage portion consists of lithium-ion battery and inverter technology in use in utility scale applications.

NAC 704.8885(2)(h) addresses the requirements for ancillary services.

Requirements for ancillary services are not affected by the PPA.

NAC 704.8885(2)(i) addresses the unit contingent provisions.

The energy from the facility is contingent upon the availability of the unit. If the unit is not producing within the performance specifications of the PPA, then energy will be replaced from other sources.

NAC 704.8885(2)(j) addresses the system peak capacity requirements of the utility provider.

The power purchase agreement will provide benefits to the system peak capacity requirements of NPC.

NAC 704.8885(2)(k) addresses the requirements for scheduling.

All net energy from the facility will be delivered directly to NPC's electric grid. The facility will be considered a network resource with NPC's system and output from the facility will be used to meet its native load.

NAC 704.8885(2)(l) addresses conditions and limitations on the transmission system.

The LGIA for the 230-kilovolt ("kV") portion of the facility has been executed and the SIS for the 525-kV portion of the facility is complete. Shared Network Upgrades associated with this project include a new 500-kV terminal position at the South Crystal substation, two 500-kV breakers and a new Harry Allen to Crysal 230-kV Line. This project will require transmission provider interconnection facilities, which includes associated protection, communications, and metering, that are directly paid for by the interconnection customer. The estimated cost for the shared Network Upgrades is $15,630,000.

NAC 704.8885(2)(m) addresses project insurance.

The PPA requires the supplier to provide workers compensation insurance of not less than $1 million per occurrence, general liability of not less than $5 million annual aggregate, and automobile liability insurance of at least $2 million aggregate.

NAC 704.8885(2)(n) addresses the costs for procuring replacement power in the event of non-delivery.

In the event the project does not meet certain performance requirements, the supplier is obligated to compensate NPC for shortfalls in energy and PCs. Compensation for an energy shortfall is based upon the difference between the cost of replacement power, as *specified in the PPA, and the PPA price. However, should the cost of replacement power be less than the contract price of power from supplier, the replacement cost will be $0.00. Compensation for a PC shortfall is determined by NPC exercising its reasonable discretion based on the estimated cost of purchasing PCs.*

NAC 704.8885(2)(o) addresses information verifying that each renewable energy system transmits or distributes or will transmit or distribute the electricity that it generates in accordance with the requirements of NRS 704.7815, as amended.

The generating facility uses renewable solar energy to generate electricity and transmits that energy to NPC. Therefore, the generating facility comports with NRS §§ 704.7815(1)(a) and 704.7815(1)(b).

NAC 704.8885(2)(p) addresses the total number of renewable energy systems that the owner of the renewable energy system is or has been associated with as an owner or operator.

Solar Partners XI, LLC is a U.S.-based company, headquartered in Redwood City, CA. Its investor, Quinbrook Infrastructure Partners, has developed over 4GW of renewable projects across the world, with a vast majority in the United States.

NAC 704.8885(2)(q) addresses the points of interconnection with the electric system of the utility.

The generating facility will be interconnected to the existing Crystal 230-kV and Crystal 525-kV substations. A one-line diagram depicting the interconnection can be found in Exhibit 5 of the PPA.

NAC 704.8885(2)(r) addresses the interconnection priority which has been established for the available transmission capacity of the utility provider for all proposed renewable energy systems that will interconnect and begin commercial operation within the three-year period immediately following the date on which the new renewable energy contract or energy efficiency contract is submitted for approval.

Commission approval of the project will not affect any pending Federal Energy Regulatory Commission ("FERC") interconnection priorities. Pursuant to the provisions of NPC's FERC-approved OATT, interconnection priority of a generator is determined based on the date the requesting customer submits a valid interconnection request.

NAC 704.8885(2)(s) addresses any requests for transmission service that have been filed with the utility provider.

A LGIA between NPC and Solar Partners XI was executed on June 11, 2018, for the 230-kV portion of the project. The in-service date is projected to be achieved October 1, 2020. An SIS for the 525-kV portion of the project was completed December 2018.

NAC 704.8885(2)(t) addresses any evidence that an environmental assessment, an environmental impact statement or an environmental impact report is being completed or has been completed with regard to the renewable energy system, or any evidence that a contract has been executed with an environmental contractor who will prepare such an assessment, statement or report within the 3-year period immediately preceding the date on which the renewable energy system is projected to begin commercial operation.

The facility and transmission are sited entirely on land managed by the Bureau of Land Management ("BLM"). The project will require preparation of an Environmental Impact Statement ("EIS") in compliance with National Environmental Policy Act ("NEPA") analysis. The BLM provided Gemini Solar with a schedule to have a Final EIS approved and Record of Decision ("ROD") in place by September 2019.

NAC 704.8885(2)(u) addresses permits required for the renewable energy systems within the 3-year period immediately preceding the date on which the renewable energy system is projected to begin commercial operation.

Permits necessary for the construction and operation of the Gemini Solar project are listed in Exhibit 10 and Exhibit 12 of the PPA, Technical Appendix REN-6-GS (a).

NAC 704.8885(2)(v) addresses applications for development rights with the appropriate Federal agencies (including BLM), where the granting of such developmental rights is not contingent upon a competitive bidding process.

Applications required from Federal agencies for the development of the Gemini Solar project are listed in Exhibit 10 and Exhibit 12 of the PPA, Technical Appendix REN-6-GS (a).

NAC 704.8885(2)(w) addresses any evidence that establishes rights of ownership, possession or use concerning land or natural resources, including, without limitation, deeds, land patents, leases, contracts, licenses or permits concerning land, geothermal drilling rights or other rights to natural resources.

The project developer, Arevia Power, obtained site control for the Gemini project through the NEPA BLM application process via Standard Form 299 (SF299). In April 2017, Quinbrook acquired Solar Partners XI, LLC, the entity that submitted the original SF299 to control the 44,000-acre Application Area.

NAC 704.8885(2)(x) addresses whether the utility provider has any economical dispatch rights.

The agreement permits NPC the flexibility to economically dispatch the facility. During the peak period hours ending 1700 through 2100 in June, July and August, the agreement calls for NPC to take all net energy, including any excess energy and PCs generated by the facility.

Power Purchase Agreement with Camino Solar, LLC

Riverside Public Utilities
Resource Operations and Strategic Analytics

Board of Public Utilities

November 25, 2019

WATER | ENERGY | LIFE

PUBLIC UTILITIES

LEGISLATIVE HISTORY

1. **SB X1-2 "California Renewable Energy Resources Act" (2011)**
   - 33% Renewable Portfolio Standard (RPS) Target by 2020
2. **SB 350 "Clean Energy and Pollution Reduction Act" (2015)**
   - Amends RPS target to 50% by 2030
3. **SB 32 "Global Warming Solutions Act" (2016)**
   - Greenhouse gas emissions reduced to 40% below the 1990 level by 2030
4. **SB 100 "100 Percent Clean Energy Act" (2018)**
   - Amends RPS target to 60% by 2030
5. **AB 2514 "Energy Storage Systems" (2010)**
   - Requires utilities to adopt an Energy Storage Procurement Target (ESPT)

RPU 2018 POWER SOURCE DISCLOSURE

	Net Purchases (MWh)	Percent of Total Retail Sales (MWh)
Specific Purchases		
Renewable	738,680	34%
Biomass & Biowaste	2,023	0%
Geothermal	399,457	18%
Eligible hydroelectric	-	0%
Solar	256,577	12%
Wind	80,623	4%
Coal	678,174	29%
Large Hydroelectric	29,527	1%
Natural Gas	101,933	4%
Nuclear	99,020	4%
Other	-	0%
Total Specific Purchases	**1,647,334**	**73%**
Unspecified Power (MWh)	**645,363**	**27%**
Total	**2,292,697**	**100%**
Total Retail Sales (MWh)	**2,165,453**	

Board and Council have approved over 230 MW of renewable contracts/extensions:

- Geothermal – 86 MW
- Wind- 46 MW
- Solar- > 100 MW

Riverside reached 34% renewables in 2018 – exceeding the 33% by 2020 RPS mandate.

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PUBLIC UTILITIES

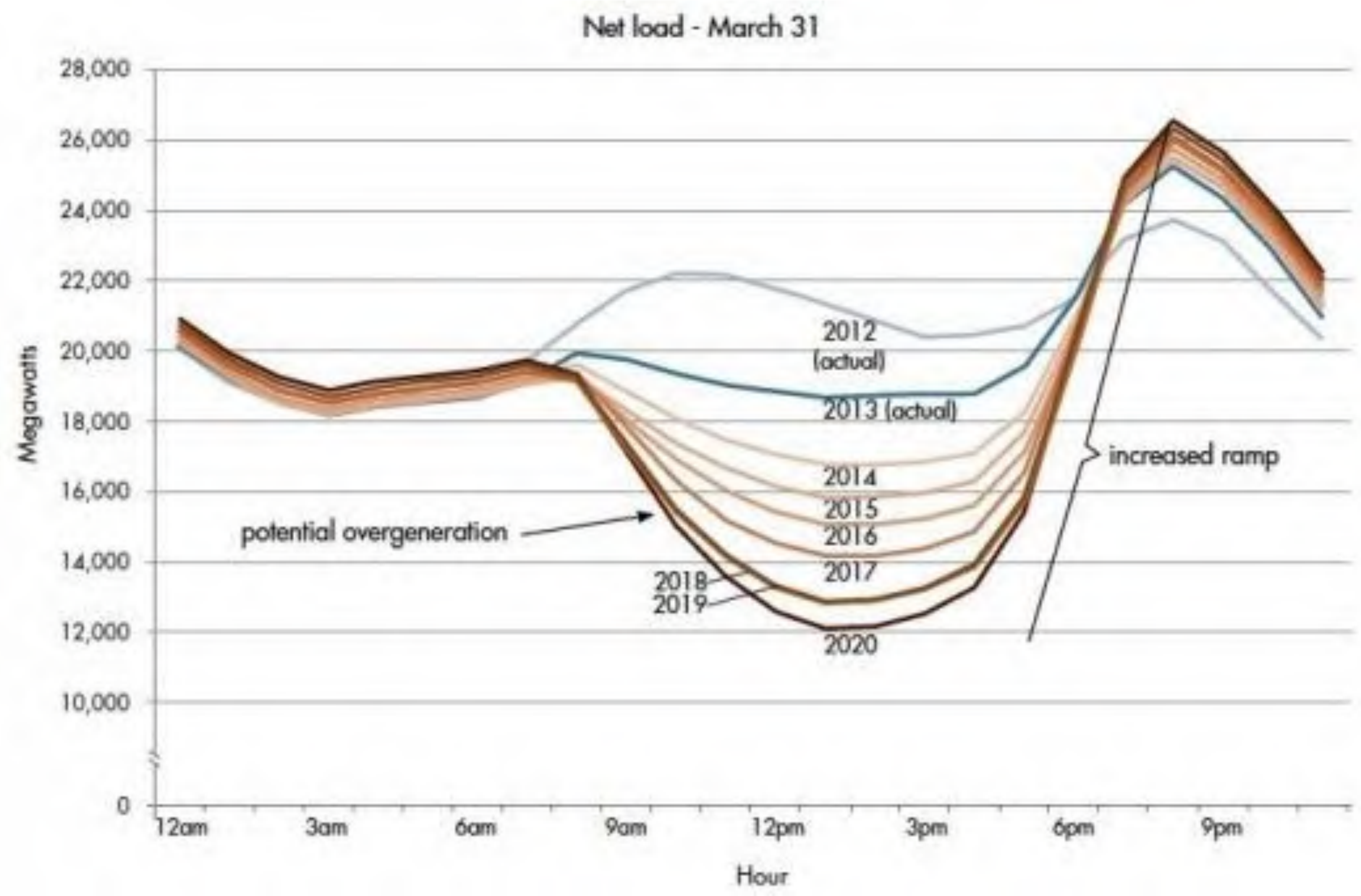
BACKGROUND

1. Solar penetration has greatly impacted the CAISO grid operation
   a. Mid-day net load has reduced
   b. Evening ramping has increased

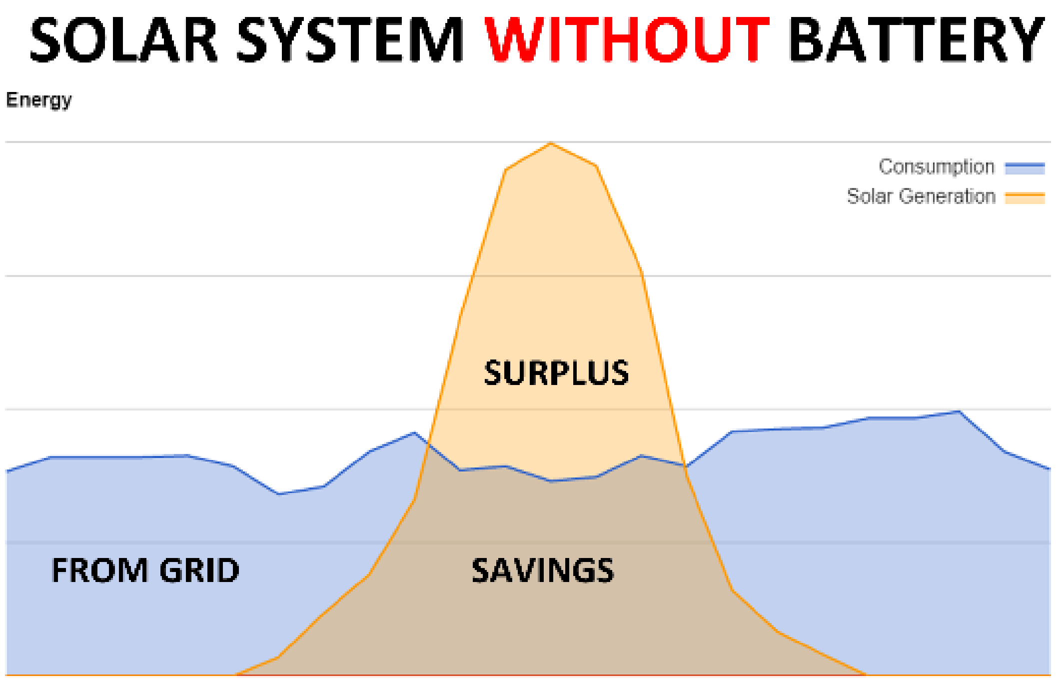
2. Negative energy pricing

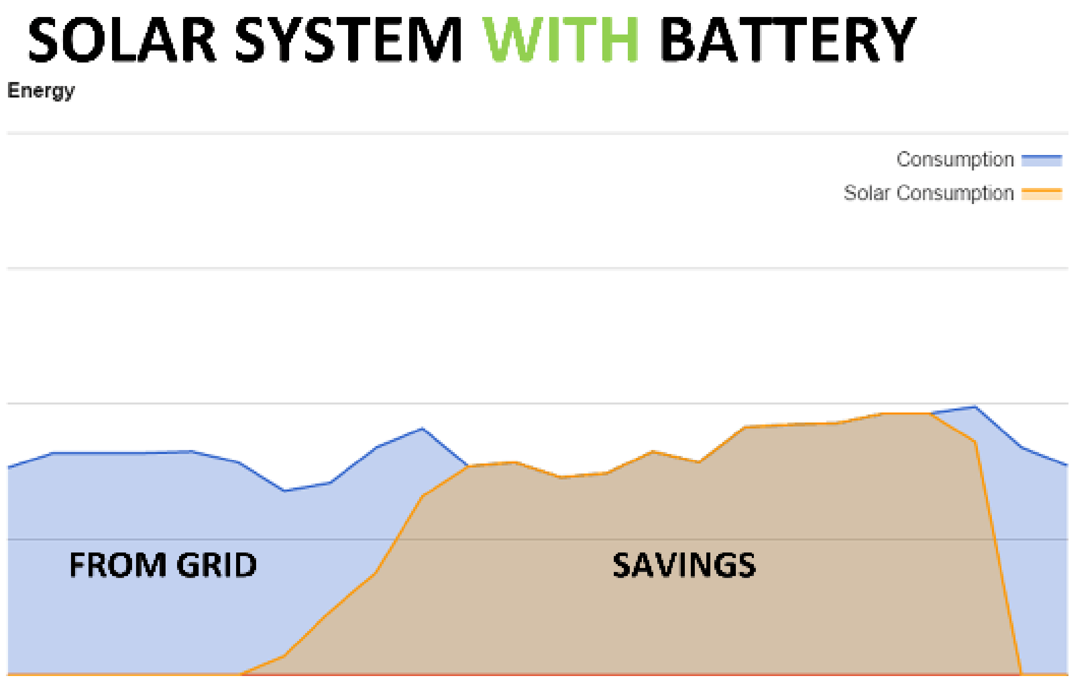
3. Undesirable generation curtailments

CAISO "DUCK CURVE"



DISCUSSION





1. Battery Energy Storage Benefits
   a) Load Shifting
   b) Reduce overproduction impacts on the grid

CAMINO SOLAR + STORAGE PPA

1. 15 year term – anticipated to start May of 2022

2. Solar Capacity and Price
   a. 44 MW at $27.70 per MWh

3. Battery Energy Storage Capacity Price
   a. 11 MW – 4 hour duration at $6.48 per kW-month (includes replenishment in years 5 and 10)

4. All-In System Price
   a. $33.75 per MWh

ADDITIONAL PPA CHARACTERISTICS

1. Performance Guarantees for both Solar and Battery

2. Mitigation for development delays - $14,850 per day

3. Development and Performance Security

4. Scheduling Coordinator Fee

5. Generation Limit

ECONOMIC ANALYSIS

1. Analysis based on detailed production cost modeling simulation analysis of the project
   a. Using CAISO market pricing
   b. Revenue assumptions consistent with the 2018 Integrated Resource Planning (IRP) process.
2. Camino Solar PV + BESS project should generate a positive net revenue stream of $36.74 Million dollars over the 15-year contract term

RECOMENDATIONS

That the Riverside Public Utilities Board recommend that the City Council:

1. Approve the Power Purchase Agreement with Camino Solar, LLC to provide renewable solar photovoltaic energy, battery energy storage, associated environmental attributes and capacity rights to the City for a term of fifteen years at an estimated average annual cost of $4,780,000;

2. Authorize the City Manager, or his designee, to execute or terminate the Power Purchase Agreement, as well as to execute future amendments to the Power Purchase Agreement under terms and conditions substantially similar or superior to the Power Purchase Agreement; and

3. Authorize the City Manager, or his designee, to execute any documents necessary to administer this Power Purchase Agreement.

THIS WORKING DRAFT DOES NOT CONSTITUTE A BINDING OFFER, SHALL NOT FORM THE BASIS FOR AN AGREEMENT BY ESTOPPEL OR OTHERWISE, AND IS CONDITIONED UPON EACH PARTY'S RECEIPT OF ALL REQUIRED MANAGEMENT APPROVALS (INCLUDING FINAL CREDIT AND LEGAL APPROVAL) AND ALL OTHER NECESSARY REGULATORY APPROVALS. ANY ACTIONS TAKEN BY A PARTY IN RELIANCE ON THE TERMS, CONDITIONS OR PRICES SET FORTH IN THIS WORKING DRAFT OR ON STATEMENTS MADE DURING NEGOTIATIONS PURSUANT TO THIS WORKING DRAFT SHALL BE AT THAT PARTY'S OWN RISK. UNTIL THIS AGREEMENT IS NEGOTIATED, APPROVED BY MANAGEMENT, SIGNED, DELIVERED AND APPROVED BY ALL REQUIRED REGULATORY BODIES, NO PARTY SHALL HAVE ANY OTHER LEGAL OBLIGATIONS, EXPRESSED OR IMPLIED, OR ARISING IN ANY OTHER MANNER UNDER THIS WORKING DRAFT OR IN THE COURSE OF NEGOTIATIONS.

POWER PURCHASE AGREEMENT

(RENEWABLE ENERGY – SOLAR)

BETWEEN

[__________________]

AND

PACIFICORP

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EXHIBITS

POWER PURCHASE AGREEMENT
(RENEWABLE ENERGY)

THIS POWER PURCHASE AGREEMENT (RENEWABLE ENERGY) (this "Agreement"), is entered into between [___________], a [___________] [____________] (the "Seller") and PacifiCorp, an Oregon corporation ("PacifiCorp"). Seller and PacifiCorp are sometimes hereinafter referred to collectively as the "Parties" and individually as a "Party."

WHEREAS, Seller intends to construct, own, operate and maintain a solar-powered generation facility for the generation of electric energy located in [______] County, [STATE] with an expected nameplate capacity rating of [__] MW (AC) (the "Facility").

WHEREAS, Seller expects that the Facility will deliver to PacifiCorp [________] MWh of Net Output in the first year of operation. Seller estimates that the Net Output will be delivered during each calendar year according to the estimates of monthly output set forth in Exhibit A. Seller acknowledges that PacifiCorp will include this amount of energy in PacifiCorp's resource planning.

WHEREAS, Seller desires to sell, and PacifiCorp desires to purchase, the Net Output delivered by the Facility in accordance with the terms and conditions hereof.

NOW, THEREFORE, in consideration of the foregoing and the mutual promises set forth below and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties mutually agree as follows:

SECTION 1
DEFINITIONS, RULES OF INTERPRETATION

1.1 Defined Terms. Unless otherwise required by the context in which any term appears, initially capitalized terms used herein shall have the following meanings:

"AAA" means the American Arbitration Association.

"AC" means alternating current.

"Abandonment" means (a) the relinquishment of all possession and control of the Facility by Seller, other than pursuant to a transfer permitted under this Agreement, or (b) if after commencement of the construction, testing, and inspection of the Facility, and prior to the Commercial Operation Date, there is a complete cessation of the construction, testing, and inspection of the Facility for ninety (90) consecutive days by Seller and Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default by PacifiCorp, a request by PacifiCorp, or an event of Force Majeure.

"Affiliate" means, with respect to any entity, each entity that directly or indirectly controls, is controlled by, or is under common control with, such designated entity, with "control" meaning the possession, directly or indirectly, of the power to direct management and policies, whether through the ownership of voting securities or by contract or otherwise. Notwithstanding the foregoing, with respect to PacifiCorp, Affiliate shall only include Berkshire Hathaway Energy Company and its direct, wholly owned subsidiaries.

"AGC" or "Automatic Generation Control" means the equipment and capability of an electric generation facility to automatically adjust the generation quantity.

"AGC Set-Point" means the analog or digital signal sent to the Facility by PacifiCorp, the Interconnection Provider, the Transmission Provider or the Market Operator representing the maximum Net Output for the Facility.

"Agreement" is defined in the Recitals.

"As-built Supplement" is a supplement to be added to Exhibit 6.1 that describes the Facility as actually built, pursuant to Section 6.1 and includes an American Land Title Association survey of the Premises.

"Book Value" means cost minus accumulated depreciation, and not deducting for debt or other encumbrances, calculated in accordance with generally accepted accounting principles consistently applied.

"Business Day" means any day on which banks in Salt Lake City, Utah, are not authorized or required by Requirements of Law to be closed, beginning at 6:00 a.m. and ending at 5:00 p.m. local time in Utah.

"Capacity Rights" means any current or future defined characteristic, certificate, tag, credit, ancillary service or attribute thereof, or accounting construct, including any of the same counted towards any current or future resource adequacy or reserve requirements, associated with the electric generation capability and capacity of the Facility or the Facility's capability and ability to produce energy. Capacity Rights are measured in MW and do not include any Tax Credits, or any other tax incentives existing now or in the future associated with the construction, ownership or operation of the Facility.

"Commercial Operation" means that not less than the Required Percentage of the Expected Nameplate Capacity Rating of the Facility is fully operational and reliable and the Facility is fully interconnected, fully integrated, and synchronized with the System, all of which shall be Seller's responsibility to receive or obtain, and without limiting Seller's other obligations under this Agreement, which occurs when all of the following events (a) have occurred, and (b) remain simultaneously true and accurate as of the date and moment on which Seller gives PacifiCorp notice that Commercial Operation has occurred:

(i) PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer that is licensed in the state of [INSERT STATE OF

LOCATION OF PROJECT] stating: (1) the Nameplate Capacity Rating of the Facility at the anticipated time of Commercial Operation, which must be at least the Required Percentage of the Expected Nameplate Capacity Rating; (2) that the Facility is able to generate electric energy reliably in amounts expected by this Agreement and in accordance with all other terms and conditions hereof; (3) Start-Up Testing of the Facility has been completed; and (4) all AGC equipment is installed and operational.

(ii) PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating that, in conformance with the requirements of the Generation Interconnection Agreement: (1) all required Interconnection Facilities have been constructed; (2) all required interconnection tests have been completed; and (3) the Facility is physically interconnected with the System in conformance with the Generation Interconnection Agreement and able to deliver energy consistent with the terms of this Agreement.

(iii) PacifiCorp has received a certificate from a Licensed Professional Engineer licensed in the state of [INSERT STATE OF LOCATION OF PROJECT] addressed to PacifiCorp stating that Seller has obtained or entered into all Permits and Required Facility Documents. Seller must provide copies of any or all Required Facility Documents requested by PacifiCorp.

(iv) PacifiCorp has received an opinion from a law firm or attorney registered or licensed in the State of [INSERT STATE OF LOCATION OF PROJECT] stating, after all appropriate and reasonable inquiry (1) Seller has obtained or entered into all Required Facility Documents; (2) neither Seller nor the Facility are in violation of or subject to any liability under any Requirements of Law; and (3) Seller has duly filed and had recorded all of the agreements, documents, instruments, mortgages, deeds of trust and other writings described in Section 8.4.1.

(v) PacifiCorp has received a certificate addressed to PacifiCorp from an authorized officer of Seller (i) stating that Seller has completed all of its obligations that would permit PacifiCorp to designate the Facility as a Network Resource and receive firm transmission service from the Transmission Provider in sufficient capacity to meet or exceed the Maximum Facility Delivery Rate; and (ii) that includes a document from the Transmission Provider confirming each of the items to which the Seller certifies in (i) above.

(vi) Seller has satisfied its obligation to pay for any required Network Upgrades as a Network Resource pursuant to the Generation Interconnection Agreement (as terms are defined in the Generation Interconnection Agreement).

(vii) PacifiCorp has received the Default Security, as applicable.

With respect to (i) through (iv) above, the certificate or opinion provided to PacifiCorp must come from a Licensed Professional Engineer or, in the case of (iv) above, an attorney that is not an employee of Seller (or any Affiliate) and has no financial interest in the Facility. Seller shall provide written notice to PacifiCorp stating when Seller believes that the Facility has achieved Commercial Operation and its Nameplate Capacity Rating accompanied by the certificates and opinions described above. PacifiCorp shall have ten (10) Business Days after receipt either to confirm to Seller that all of the conditions to Commercial Operation have been satisfied or have occurred, or to state with specificity what PacifiCorp reasonably believes has not been satisfied. If, within such ten (10) Business Day period, PacifiCorp does not respond or notifies Seller confirming that the Facility has achieved Commercial Operation, the original date of receipt of Seller's notice shall be the Commercial Operation Date. If PacifiCorp notifies Seller within such ten (10) Business Day period that PacifiCorp reasonably believes the Facility has not achieved Commercial Operation, Seller must address the concerns stated in PacifiCorp's notice to the satisfaction of PacifiCorp. In the event PacifiCorp provides notice of deficiency with regards to the information submitted to establish the Commercial Operation Date, then the Commercial Operation Date will be the date upon which Seller has addressed the concerns stated in PacifiCorp's notice to PacifiCorp's reasonable satisfaction. If Commercial Operation is achieved at less than 100 percent of the Expected Nameplate Capacity Rating and Seller informs PacifiCorp that Seller intends to bring the Facility to 100 percent of the Expected Nameplate Capacity Rating, Seller shall provide PacifiCorp, no later than ten (10) Business Days after the Commercial Operation Date, with a list of all items to be completed in order to achieve Final Completion ("Final Completion Schedule"). All items on the Final Completion Schedule must be completed on or before the ninetieth (90^{th}) day after the Commercial Operation Date. If a Final Completion Schedule is not provided to PacifiCorp within ten (10) Business Days following the Commercial Operation Date, then the date of Final Completion shall be the same as the Commercial Operation Date.

"Commercial Operation Date" means the date that Commercial Operation is achieved for the Facility but in no event earlier than thirty (30) days before the Scheduled Commercial Operation Date.

"Commission" means the [INSERT APPLICABLE STATE PUBLIC UTILITY COMMISSIONS WHICH WILL ULTIMATELY BE REQUIRED TO APPROVE OR ACKNOWLEDGE THE AGREEMENT].

"Compensable Curtailment Energy" has the meaning as described in Section 5.1.3.

"Compensable Curtailment Price" has the meaning as defined in Section 5.1.3(b).

"Confidential Business Information" is defined in Section 23.1.

"Contract Interest Rate" means the lesser of (a) the highest rate permitted under Requirements of Law or (b) 200 basis points per annum plus the rate per annum equal to the publicly announced prime rate or reference rate for commercial loans to large businesses in effect from time to time quoted by Citibank, N.A. as its "prime rate." If a Citibank, N.A. prime rate is not available, the applicable prime rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest is being paid.

"Contract Price" means the applicable price, expressed in $/MWh for Net Output, Green Tags and Capacity Rights stated in Section 5.1.

"Contract Year" means any consecutive 12-month period during the Term, commencing at 00:00 hours on the Commercial Operation Date or any of its anniversaries and ending at 24:00 hours on the last day of such 12-month period.

Credit Requirements" means a senior, unsecured long term debt rating (or corporate rating if such debt rating is unavailable) of (a) BBB+ or greater from S&P, or (b) Baa1 or greater from Moody's, and if such ratings are split, the lower of the two ratings must be at least 'BBB+' or 'Baa1' from S&P or Moody's, respectively; provided that if (a) or (b) is not available, an equivalent rating as determined by PacifiCorp through an internal process review and utilizing a proprietary credit scoring model developed in conjunction with a third party.

"Default Security" is defined in Section 8.2.1.

"Delay Damages" for any given day are equal to (a) the Expected Energy, expressed in MWhs per year, divided by 365, multiplied by (b) PacifiCorp's Cost to Cover.

"Deficit Damages" means a one-time payment equal to (a) the difference between (i) Expected Nameplate Capacity Rating and (ii) the Nameplate Capacity Rating of the Facility on the 120th day after the Guaranteed Commercial Operation Date, stated in MWs, multiplied by (b) $25,000.

"Effective Date" is defined in Section 2.1.

"Electric System Authority" means each of NERC, WECC, WREGIS, an RTO, a regional or sub-regional reliability council or authority, and any other similar council, corporation, organization or body of recognized standing with respect to the operations of the electric system in the WECC region, as such are applicable to the Seller or PacifiCorp.

"Energy Imbalance Market" means generation facilities electrically located within PacifiCorp's balancing authority areas that are, from time to time, bid in to or otherwise subject to dispatch instructions issued or originating from the Market Operator.

"Environmental Attributes" means any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (a) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (b) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change or any Governmental Authority to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere. Environmental Attributes do not include (i) the ITC or any other Tax Credits, or certain other tax incentives existing now or in the future associated with the construction, ownership or operation of the Facility, (ii) matters designated by PacifiCorp as sources of liability, or (iii) adverse wildlife or environmental impacts.

"Environmental Contamination" means the introduction or presence of Hazardous Materials at such levels, quantities or location, or of such form or character, as to constitute a violation of federal, state or local laws or regulations, and present a material risk under federal, state or local laws and regulations that the Premises will not be available or usable for the purposes contemplated by this Agreement.

"Event of Default" is defined in Section 11.1.

"Expansion Energy" is defined in Section 7.1.1.

"Expected Energy" means [_______] MWh of Net Output in the first full Contract Year, reduced by an annual degradation factor of [__] per Contract Year, measured at the Point of Delivery, which is Seller's best estimate of the projected long-term average annual Net Output production, based upon typical solar conditions at the Facility as determined by a Solar Performance Modeling Program, delivered to the Point of Delivery and the Expected Nameplate Capacity Rating. Seller estimates that the Net Output will be delivered during each Contract Year according to the estimates of monthly Net Output set forth in Exhibit A. If at Final Completion the Facility's Nameplate Capacity Rating is less than the Expected Nameplate Capacity Rating, Expected Energy shall be reduced proportionally per year for each full MW of Nameplate Capacity Rating below the Expected Nameplate Capacity Rating. Seller acknowledges that PacifiCorp will include Expected Energy in PacifiCorp's resource planning. PacifiCorp acknowledges that solar insolation is variable and that the Facility's actual annual output of Net Output in the ordinary course in any given year will be subject to variation caused by differences in the actual solar insolation at the Facility from year to year.

"Expected Nameplate Capacity Rating" means [__] MW (AC), the expected maximum instantaneous generation capacity of the Facility.

"Facility" is defined in the Recitals and is more fully described in attached Exhibit 6.1 and includes the photovoltaic power generating equipment, including panels, arrays, tracking system (if applicable), inverters, and all other equipment, devices, associated appurtenances owned, controlled, operated and managed by Seller in connection with, or to facilitate, the production, generation, transmission, delivery, or furnishing of electric energy by Seller to PacifiCorp and required to interconnect with the System.

"Facility Equity" is defined in Section 8.5.

"Facility Financing Date" means the closing date for the construction financing for the Facility between Seller or Seller's Affiliates and a Lender.

"Fair Market Value" means the fair market value of the Facility as determined pursuant to Section 7.2.

"FERC" means the Federal Energy Regulatory Commission.

"Final Completion" means the Facility is fully operational and reliable, at or greater than the Required Percentage of the Expected Nameplate Capacity Rating, and fully interconnected, fully integrated, and synchronized with the Transmission Provider's System, modified if necessary to reflect the Nameplate Capacity Rating and, if applicable, through completion of all the items set forth on the Final Completion Schedule.

"Final Completion Schedule" is defined in the definition of "Commercial Operation."

"Firm Market Price Index" means (a) the average price reported by Intercontinental Exchange, Inc. ("ICE") Day-Ahead [Palo Verde][1] On-Peak Index, for On-Peak Hours, and (b) the average price reported on the ICE Day-Ahead [Palo Verde] Off-Peak Index, for Off-Peak Hours. If either index is not available for a given period, for purposes of calculations hereunder, the Firm Market Price Index shall be deemed to equal the volumetrically-weighted average price derived from data published by ICE for the same number of days immediately preceding and immediately succeeding the period in which the index in question was not available, regardless of which days of the week are used for this purpose. If the Firm Market Price Index or its replacement or any component of that index or its replacement ceases to be published or available, or useful for its intended purpose hereunder, during the Term, the Parties shall agree upon a replacement Firm Market Price Index or component that, after any necessary adjustments, provides the most reasonable substitute quotation of the daily price of electricity for the applicable periods.

"Force Majeure" is defined in Section 14.1.

"Forced Outage" means NERC Event Types U1, U2 and U3, as set forth in attached Exhibit B, and specifically excludes any Maintenance Outage or Planned Outage.

"Generation Interconnection Agreement" means the large generator interconnection agreement to be entered into separately between Seller and Interconnection Provider concerning the Interconnection Facilities.

"Governmental Authority" means any supranational, federal, state or other political subdivision thereof, having jurisdiction over Seller, PacifiCorp or this Agreement, including any municipality, township or county, and any entity or body exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to government, including any corporation or other entity owned or controlled by any of the foregoing.

"Green Tags" means (a) the Environmental Attributes associated with all Output, together with (b) the Green Tag Reporting Rights associated with such energy and Environmental Attributes, however commercially transferred or traded under any or other product names, such as "Renewable Energy Credits," "Green-e Certified," or otherwise. One

[1] Note to Bidders – Palo Verde will be the reference hub for a facility proposed in Utah, Wyoming or Idaho. The reference hub will be Mid-C for a facility proposed in Oregon or Washington.

Green Tag represents the Environmental Attributes made available by the generation of one MWh of energy from the Facility.

"Green Tags Price Component" means: (1) the price for Green Tags determined by arithmetically averaging quotes for Green Tags from three nationally recognized independent Green Tag brokers selected by PacifiCorp pursuant to which PacifiCorp could reasonably purchase substitute Green Tags similar to those Green Tags that Seller failed to deliver, with delivery terms, vintage period and any renewable program certification eligibility that are similar to those contained herein, calculated as of the date of default or as soon as reasonably possible thereafter; or (2) if after the Effective Date a liquid market for Green Tags exists, the price established for Green Tags from the established liquid market for Green Tags in a form and location that PacifiCorp determines reasonably states the market value of the Green Tags delivered hereunder.

"Green Tag Reporting Rights" means the exclusive right of a purchaser of Environmental Attributes to report ownership of Environmental Attributes in compliance with federal or state law, if applicable, and to federal or state agencies or other parties at such purchaser's discretion, including under any present or future domestic, international, or foreign emissions trading program or renewable portfolio standard.

"Guaranteed Commercial Operation Date" means the date that is ninety (90) days after the Scheduled Commercial Operation Date.

"Hazardous Materials" means any waste or other substance that is listed, defined, designated or classified as or determined to be hazardous under or pursuant to any environmental law or regulation.

"Indemnified Party" is defined in Section 6.2.3(b).

"Interconnection Facilities" means all the facilities installed, or to be installed, for the purpose of interconnecting the Facility to the System, including electrical transmission lines, upgrades, transformers and associated equipment, substations, relay and switching equipment, and safety equipment.

"Interconnection Provider" means PacifiCorp Transmission.

"Inverter" means the equipment installed at the Facility to convert direct current from the Solar Panels to alternating current, as described in Exhibit 6.1.

"ITC" means the investment tax credit established pursuant to Section 48 of the Internal Revenue Code, as such law may be amended or superseded.

"KW" means kilowatt.

"KWh" means kilowatt hour.

"Leases" means the memoranda of lease and redacted leases recorded in connection with the development of the Facility, as the same may be supplemented, amended, extended, restated, or replaced from time to time.

"Lender" means an entity lending money or extending credit (including any financing lease, monetization of tax benefits, transaction with a tax equity investor, backleverage financing or credit derivative arrangement) to Seller or Seller's Affiliates (a) for the construction, term or permanent financing or refinancing of the Facility; (b) for working capital or other ordinary business requirements for the Facility (including for the maintenance, repair, replacement or improvement of the Facility); (c) for any development financing, bridge financing, credit support, and related credit enhancement or interest rate, currency, weather, or Environmental Attributes in connection with the development, construction or operation of the Facility; or (d) for the purchase of the Facility and related rights from Seller.

"Letter of Credit" means an irrevocable standby letter of credit in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder that:

(1) is issued by a Qualifying Institution;

(2) by its terms, permits PacifiCorp to draw up to the face amount thereof for the purpose of paying any and all amounts owing by Seller hereunder;

(3) permits PacifiCorp to draw the entire amount available thereunder if such letter of credit is not renewed or replaced at least thirty (30) Business Days prior to its stated expiration date;

(4) permits PacifiCorp to draw the entire amount available thereunder if such letter of credit is not increased or replaced as and when provided in Section 8;

(5) is transferable by PacifiCorp to any party to which PacifiCorp may assign this Agreement; and

(6) shall remain in effect for at least ninety (90) days after the end of the Term.

"Liabilities" is defined in Section 12.1.1.

"Licensed Professional Engineer" means a person proposed by Seller and acceptable to PacifiCorp in its reasonable judgment who (a) to the extent mandated by Requirements of Law is licensed to practice engineering in the appropriate engineering discipline for the required certification being made, in the United States, and in all states for which the person is providing a certification, evaluation or opinion with respect to matters or Requirements of Law specific to such state, (b) has training and experience in the engineering disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation or opinion, (c) has no economic relationship, association, or nexus with Seller and is not an employee of its members or Affiliates, other than with the prior written consent of PacifiCorp, for services previously or currently being rendered to Seller or its members or Affiliates, and (d) is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or a representative of a manufacturer or supplier of any equipment installed in the Facility.

"Maintenance Outage" means NERC Event Type MO, as set forth in attached Exhibit B, and includes any outage involving ten percent (10%) of the Facility's Net Output that is not a Forced Outage or a Planned Outage.

"Market Operator" means the California Independent System Operator or any other entity performing the market operator function for the Energy Imbalance Market.

"Maximum Delivery Rate" means the maximum hourly rate of delivery of Net Output in MWh from the Facility to the Point of Delivery, calculated on the basis of the Net Output delivered in an hour accruing at an average rate equivalent to the actual Nameplate Capacity Rating.

"Mediation Notice" is defined in Section 24.2.1.

"Mediation Procedures" is defined in Section 24.2.1(a).

"Moody's" means Moody's Investor Services, Inc.

"Mountain Prevailing Time" or "MPT" means Mountain Standard Time or Mountain Daylight Time, as applicable in Utah on the day in question.

"MW" means megawatt.

"MWh" means megawatt hour.

"Nameplate Capacity Rating" means the maximum installed instantaneous generation capacity of the completed Facility, expressed in MW (AC), when operated in compliance with the Generation Interconnection Agreement and consistent with the recommended power factor and operating parameters provided by the manufacturer of the Solar Panels and Inverters, as set forth in a notice from Seller to PacifiCorp delivered prior to the Commercial Operation Date and, if applicable, updated in a subsequent notice from Seller to PacifiCorp as required for Final Completion. The Nameplate Capacity Rating of the Facility shall not exceed [__] MW (AC).

"NERC" means the North American Electric Reliability Corporation.

"Net Output" means all energy and capacity produced by the Facility, less station use and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the Point of Delivery.

"Network Resource" is defined in the Tariff.

"Network Service Provider" means PacifiCorp Transmission, as a provider of network service to PacifiCorp under the Tariff.

"Non-Compensable Curtailment" has the meaning set forth in Section 4.4.1.

"Off-Peak Hours" or "LLH" means all hours ending 01:00:00 through 06:00:00 and hours ending 23:00:00 through 24:00:00, MPT, Monday through Saturday and hours ending 01:00:00 through 24:00:00, MPT, on Sundays and NERC designated holidays.

"On-Peak Hours" or "HLH" means all hours ending 07:00:00 through 22:00:00 MPT, Monday through Saturday, excluding NERC designated holidays.

"Option Confirmation Notice" is defined in Section 7.2.4.

"Output" means all energy produced by the Facility.

"Output Shortfall" is defined in Section 6.12.2.

"PacifiCorp" is defined in the Recitals, and explicitly excludes PacifiCorp Transmission.

"PacifiCorp Indemnitees" is defined in Section 12.1.1.

"PacifiCorp Representatives" is defined in Section 6.13.

"PacifiCorp Transmission" means PacifiCorp, an Oregon corporation, acting in its interconnection or transmission function capacity.

"PacifiCorp's Cost to Cover" means the positive difference, if any, between (a) the sum of (i) the time weighted average of the Firm Market Price Index for each day for which the determination is being made, plus (ii) the Green Tags Price Component, and (b) the Contract Price specified in Exhibit 5.1 in effect on such days, stated as an amount per MWh. If on a given day (or Contract Year in the case of calculating Output Shortfall) the difference between (a) minus (b) referenced above is zero or negative, then PacifiCorp's Cost to Cover shall be zero dollars ($0), and Seller shall have no obligation to pay any amount to PacifiCorp on account of Section 6.12.2 or Section 11.2.1 with respect to such day (or Contract Year in the case of calculating Output Shortfall). For any days prior to the Commercial Operation Date, the Contract Price applicable in the first Contract Year shall be utilized for purposes of clause (b).

"Party" and "Parties" are defined in the Recitals.

"Permits" means the permits, licenses, approvals, certificates, entitlements and other authorizations issued by Governmental Authorities required for the construction, ownership or operation of the Facility or occupancy of the Premises, and all amendments, modifications, supplements, general conditions and addenda thereto.

"Planned Outage" means NERC Event Type PO, as set forth in attached Exhibit B, and specifically excludes any Maintenance Outage or Forced Outage.

"Point of Delivery" means the point of interconnection between the Facility and the System, as specified in the Generation Interconnection Agreement and as further described in Exhibit 9.2.

"Potential Net Output" means the quantity of Net Output that Seller is capable of delivering at the Point of Delivery at any specific time. Potential Net Output will be calculated as the aggregate energy available for delivery at the Point of Delivery using the best available data obtained through commercially reasonable methods, and shall be dependent on solar insolation data at the Facility, cloud cover forecast models, Facility equipment availability, Solar Panels and Inverter performance guaranties provided by Seller to PacifiCorp in accordance with Exhibit 6.1, derates and transmission line losses, and any other adjustments necessary to accurately reflect the Facility's capability to produce and deliver energy at the Point of Delivery.

"Preliminary Interest Notice" is defined in Section 7.2.1.

"Premises" means the real property on which the Facility is or will be located, as more fully described on Exhibit 6.1.

"Project Development Security" is defined in Section 8.1.1.

"Prudent Electrical Practices" means any of the practices, methods and acts engaged in or approved by a significant portion of the independent electric power generation industry for solar facilities of similar size and characteristics or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition.

"Qualifying Institution" means a United States commercial bank or trust company organized under the laws of the United States of America or a political subdivision thereof having assets of at least $10,000,000,000 (net of reserves) and a credit rating on its long-term senior unsecured debt of at least "A" from S&P and "A2" from Moody's.

"Reporting Month" is defined in Section 6.10.1.

"Required Facility Documents" means the Permits and other authorizations, rights and agreements now or hereafter necessary for construction, ownership, operation, and maintenance of the Facility, and to deliver the Net Output to PacifiCorp in accordance with this Agreement and Requirements of Law, including those set forth in Exhibit 3.2.3.

"Required Percentage" means 93 percent.

"Requirements of Law" means any applicable and mandatory (but not merely advisory) federal, state and local law, statute, regulation, rule, action, order, code or ordinance enacted, adopted, issued or promulgated by any federal, state, local or other Governmental Authority or regulatory body (including those pertaining to electrical, building, zoning, environmental and wildlife protection and occupational safety and health).

"Rolling Period" is defined in Section 6.12.1.

"RTO" means any entity (including an independent system operator) that becomes responsible as system operator for, or directs the operation of, the System.

"S&P" means Standard & Poor's Rating Group (a division of S&P Global, Inc.).

"SCADA" means supervisory control and data acquisition.

"Scheduled Commercial Operation Date" means [_______________].

"Security Interests" is defined in Section 8.4.1.

"Seller" is defined in the Recitals.

"Seller Indemnitees" is defined in Section 12.1.2.

"Seller's Cost to Cover" means the positive difference, if any, between (a) the Contract Price per MWh specified in <u>Exhibit 5.1</u>, and (b) the net proceeds per MWh actually realized by Seller from the sale to a third party of Net Output not purchased by PacifiCorp as required hereunder. If on any given day the difference between (a) minus (b) referenced above is zero or negative, then Seller's Cost to Cover shall be zero dollars with respect to such day, and PacifiCorp shall have no obligation to pay any amount to Seller on account of Section 11.2.2. For any days prior to the Commercial Operation Date, the Contract Price applicable in the first Contract Year shall be utilized for purposes of clause (a).

"Senior Lenders" means Lenders being granted senior security interests on the Facility or its assets, or Seller or its equity, other than Affiliates of Seller.

"Seller Uncontrollable Minutes" means, for the Facility in any Contract Year, the total number of minutes during such Contract Year during which the Facility was unable to deliver Net Output to PacifiCorp (or during which PacifiCorp failed to accept such delivery) due to one or more of the following events, each as recorded by Seller's SCADA and indicated by Seller's electronic fault log: (a) an emergency or Force Majeure event; (b) to the extent not caused by Seller's actions or omissions, a Non-Compensable Curtailment in accordance with Section 4.4(b); (c) the System operating outside the voltage or frequency limits defined in the applicable operating manual for the Inverters installed at the Facility; (d) Planned Outages, but in no event exceeding thirty six (36) hours per Contract Year consistent with such operating manual; (e) Compensable Curtailment as provided in Section 5.1.3; (f) a default by PacifiCorp;

provided, however, that if any of the events described above in items (a) through (f) occur simultaneously, then the relevant period of time shall only be counted once in order to prevent double counting. Seller Uncontrollable Minutes shall not include minutes when (i) the Facility or any portion thereof was unavailable solely due to Seller's non-conformance with the Generation Interconnection Agreement or (ii) the Facility or any portion thereof was paused or withdrawn from use by Seller for reasons other than those covered in this definition.

“Solar Array” means one or more Solar Panels connected to the same Inverter.

“Solar Panels” means the photovoltaic energy generating panels installed at the Facility, as described in Exhibit 6.1.

“Solar Performance Modeling Program” means a commercially available computer modeling program that is generally accepted in the solar energy industry capable of modeling the Expected Energy and other similar outputs. Solar Performance Modeling Program includes, but is not limited to, the PVSYST program. If Seller elects a Solar Performance Modeling Program to which PacifiCorp does not have access, Seller, at its cost, shall provide PacifiCorp access to the Solar Performance Modeling Program in order for PacifiCorp to fully analyze all modeling provided by Seller under this Agreement.

“Start-Up Testing” means the start-up tests for the Facility as set forth in Exhibit C.

“Step-In Rights” means PacifiCorp’s rights under Section 11.8.

“System” means the electric transmission substation and transmission or distribution facilities owned, operated or maintained by Transmission Provider, which shall include, after construction and installation of the Facility, the circuit reinforcements, extensions, and associated terminal facility reinforcements or additions required to interconnect the Facility, all as set forth in the Generation Interconnection Agreement.

“Tariff” means the PacifiCorp FERC Electric Tariff Volume No. 11 Open Access Transmission Tariff, as revised from time to time.

“Tax Credits” means any state, local and/or federal production tax credit, tax deduction, and/or investment tax credit (including the ITC) specific to the production of renewable energy and/or investments in renewable energy facilities.

“Technical Expert” is defined in Section 24.2.2.

“Technical Dispute Notice” is defined in Section 24.2.2(a).

“Term” is defined in Section 2.1.

“Test Energy” means any Net Output during periods prior to the Commercial Operation Date and related Capacity Rights.

"Transmission Provider" means PacifiCorp Transmission, including the Grid Operations business unit.

"Transmission Service" means, if applicable, the transmission services pursuant to which the Transmission Provider transmits Output to the Point of Delivery, as applicable.

"WECC" means the Western Electricity Coordinating Council.

"WREGIS" means the Western Renewable Energy Generation Information System.

"WREGIS Certificate" or "Certificate" means "Certificate" as defined by the WREGIS Operating Rules.

"WREGIS Operating Rules" means the operating rules and requirements adopted by WREGIS.

1.2 Rules of Interpretation.

1.2.1 General. Unless otherwise required by the context in which any term appears, (a) the singular includes the plural and vice versa; (b) references to "Articles," "Sections," "Schedules," "Annexes," "Appendices" or "Exhibits" are to articles, sections, schedules, annexes, appendices or exhibits hereof; (c) all references to a particular entity or an electricity market price index include a reference to such entity's or index's successors; (d) "herein," "hereof" and "hereunder" refer to this Agreement as a whole; (e) all accounting terms not specifically defined herein shall be construed in accordance with generally accepted accounting principles, consistently applied; (f) the masculine includes the feminine and neuter and vice versa; (g) "including" means "including, without limitation" or "including, but not limited to"; (h) all references to a particular law or statute mean that law or statute as amended from time to time; (i) all references to energy or capacity are to be interpreted as utilizing alternating current, unless expressly stated otherwise; and (j) the word "or" is not necessarily exclusive. Reference to "days" shall be calendar days, unless expressly stated otherwise herein.

1.2.2 Terms Not to be Construed For or Against Either Party. Each term hereof shall be construed according to its fair meaning and not strictly for or against either Party. The Parties have jointly prepared this Agreement, and no term hereof shall be construed against a Party on the ground that the Party is the author of that provision.

1.2.3 Headings. The headings used for the sections and articles hereof are for convenience and reference purposes only and shall in no way affect the meaning or interpretation of the provisions hereof.

1.2.4 Examples. Example calculations and other examples set forth herein are for purposes of illustration only and are not intended to constitute a representation, warranty or covenant concerning the example itself or the matters assumed for purposes of such example. If there is a conflict between an example and the text hereof, the text shall control.

1.2.5 Interpretation with FERC Orders. Each Party conducts and shall conduct its operations in a manner intended to comply with FERC Order No. 717, Standards of Conduct for Transmission Providers, and its companion orders, requiring the separation of its transmission and merchant functions. Moreover, the Parties acknowledge that Interconnection Provider's transmission function offers transmission service on its system in a manner intended to comply with FERC policies and requirements relating to the provision of open-access transmission service. The Parties recognize that Seller will enter into the Generation Interconnection Agreement with the Interconnection Provider.

(a) The Parties acknowledge and agree that the Generation Interconnection Agreement shall be a separate and free standing contract and that the terms hereof are not binding upon the Interconnection Provider.

(b) Notwithstanding any other provision in this Agreement, nothing in the Generation Interconnection Agreement, nor any other agreement between Seller on the one hand and Transmission Provider or Interconnection Provider on the other hand, nor any alleged event of default thereunder, shall alter or modify the Parties' rights, duties, and obligation hereunder. This Agreement shall not be construed to create any rights between Seller and the Interconnection Provider or between Seller and the Transmission Provider,

(c) Seller expressly recognizes that, for purposes hereof, the Interconnection Provider and Transmission Provider each shall be deemed to be a separate entity and separate contracting party from PacifiCorp whether or not the Generation Interconnection Agreement is entered into with Interconnection Provider or an Affiliate thereof. Seller acknowledges that PacifiCorp, acting in its merchant capacity function as purchaser hereunder, has no responsibility for or control over Interconnection Provider or Transmission Provider, and is not liable for any breach of agreement or duty by Interconnection Provider or Transmission Provider.

SECTION 2
TERM; FACILITY DEVELOPMENT

2.1 Term. This Agreement shall become effective when it is executed and delivered by both Parties and, if necessary by any rules or guidance of a Commission, has been filed, acknowleged or approved, as applicable, by each such Commission ("Effective Date"). Unless earlier terminated as provided herein, this Agreement shall remain in effect until the [INSERT TERM LENGTH] (____th) anniversary of the Commercial Operation Date (the "Term").

2.2 [Reserved].

2.3 Milestones. Time is of the essence in the performance hereof, and Seller's completion of the Facility and delivery of Net Output and Green Tags by the Scheduled Commercial Operation Date is critically important. Therefore, Seller shall achieve the following milestones at the times indicated.

(a) On or before the thirtieth (30^{th}) day following the Effective Date, Seller shall post the Project Development Security in the amount described in Section 8.1;

(b) On or before the Commercial Operation Date, Seller shall provide Default Security required under Section 8.2;

(c) Seller shall provide PacifiCorp with documentation showing that Seller has obtained retail electric service for the Facility prior to the Commercial Operation Date;

(d) Seller shall cause the Facility to achieve Commercial Operation on or before the Guaranteed Commercial Operation Date; and

(e) If Commercial Operation of the Facility is achieved based on less than 100 percent of the Expected Nameplate Capacity Rating, then Seller may inform PacifiCorp, by written notice received no later than ten (10) Business Days after the Commercial Operation Date, that Seller intends to bring the Facility above the Required Percentage up to but not exceeding 100 percent of the Expected Nameplate Capacity Rating. Such notice from Seller shall include a Final Completion Schedule. After providing that notice, Seller shall cause the Facility to achieve Final Completion on or before the ninetieth (90^{th}) day after the Commercial Operation Date.

Notwithstanding the foregoing, the date for achieving each of the foregoing milestones shall be extended on a day for day basis for any delay due solely to PacifiCorp's delay in taking, or failure to take, any action required of it hereunder in breach of this Agreement.

Without limiting Seller's obligations under this Agreement, none of the following shall excuse in any respect Seller's failure to comply in all respects with any and all provisions in this Section 2.3 and Section 2.4, no matter what the source or reason: (i) any event of Force Majeure, actual or alleged; (ii) economic hardship, including lack of money or inability to obtain financing; (iii) inability to obtain any supply of any good or service, (iv) any breakdown or malfunction of any equipment; (v) costs or taxes; (vi) anything relating to any Required Facility Document; (vii) Requirements of Law; (viii) anything relating to the Transmission Provider, Network Service Provider, Interconnection Provider, or Generation Interconnection Agreement; or (ix) increased cost of electricity, steel, labor, or transportation.

2.4 Project Construction, Delay Damages and Deficit Damages.

(a) On or before the later of: (i) the Facility Financing Date or (ii) excavation of the first foundation for the photovoltaic panels, Seller shall provide to PacifiCorp a certificate from a Licensed Professional Engineer confirming that the Required Facility Documents including the material permits, consents and agreements necessary to operate and maintain the

Facility have been obtained by Seller.

(b) If Commercial Operation is not achieved on or before the Scheduled Commercial Operation Date, Seller shall pay to PacifiCorp Delay Damages from and after the Scheduled Commercial Operation Date up to, but not including, the date that the Facility achieves Commercial Operation.

(c) If the Facility does not achieve Commercial Operation by the Guaranteed Commercial Operation Date, PacifiCorp may terminate this Agreement pursuant to Section 11.

(d) If the Facility achieves Final Completion based on less than one hundred percent (100%) of the Expected Nameplate Capacity Rating, Seller shall pay to PacifiCorp Deficit Damages.

(e) After the date of Final Completion, any partially completed Solar Array shall not be part of the Facility, and Seller shall not undertake to add any such partially completed Solar Array or output from such partially completed Solar Array to the Facility without the prior written consent of PacifiCorp. Any output of such Solar Array or Capacity Rights associated with such output shall be treated as Net Output above the Maximum Delivery Rate and is subject to Section 6.8.

2.5 Damages Calculation. Each Party agrees and acknowledges that (a) the damages that PacifiCorp would incur due to Seller's delay in achieving Commercial Operation or failure to reach Final Completion based on 100 percent of the Expected Nameplate Capacity Rating would be difficult or impossible to predict with certainty, and (b) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages and Deficit Damages as agreed to by the Parties and set forth herein are a fair and reasonable calculation of such damages. The Parties agree that Delay Damages and Deficit Damages shall be PacifiCorp's exclusive remedy for a delay in achieving Commercial Operation or failure to reach Final Completion based on 100 percent of the Expected Nameplate Capacity Rating and believe that Delay Damages and Deficit Damages fairly represent actual damages. Subject to the foregoing sentence, this Section 2.5 shall not limit the amount of damages payable to PacifiCorp if this Agreement is terminated as a result of Seller's failure to achieve Commercial Operation by the Guaranteed Commercial Operation Date. Any such termination damages shall be determined in accordance with Section 11.5.

2.6 Damages Invoicing. By the tenth (10^{th}) day following the end of the calendar month in which Delay Damages begin to accrue or Deficit Damages are incurred, as applicable, and continuing on the tenth (10^{th}) day of each calendar month during the period in which Delay Damages accrue (and the following months, if applicable), PacifiCorp shall deliver to Seller an invoice showing PacifiCorp's computation of such damages and any amount due PacifiCorp in respect thereof for the preceding calendar month. No later than ten (10) days after receiving such an invoice and subject to Sections 10.3 and 10.4, Seller shall pay to PacifiCorp, by wire transfer of immediately available funds to an account specified in writing by PacifiCorp or by any other means agreed to by the Parties in writing from time to time, the amount set forth as due in such invoice.

2.7 PacifiCorp's Right to Monitor. During the Term, Seller shall permit PacifiCorp and its advisors and consultants to:

(a) Review and discuss with Seller and its advisors and consultants monthly status reports on the progress of the acquisition, design, financing, engineering, construction and installation of the Facility. Between the Effective Date and thirty (30) days following the date of Final Completion, Seller shall, on or before the tenth (10^{th}) day of each calendar month, provide PacifiCorp with a brief monthly status report for the preceding month.

(b) Monitor the status of the acquisition, land leasing, design, financing, engineering, construction and installation of the Facility and the performance of the contractors constructing the Facility.

(c) Monitor and receive monthly updates from Seller concerning (i) the progress of Seller's negotiation and execution of contracts for the acquisition, design, financing, engineering, construction and installation of the Facility, Premises, major equipment, and warranties, and (ii) the contractors' performance and achievement of contract deliverables and all performance and other tests required to achieve Commercial Operation or contemplated by the warranty agreements between Seller and a manufacturer of the Facility’s Solar Panels and Inverters and any other material items of Facility equipment that require testing for warranty agreements to be effective. Seller shall provide PacifiCorp with at least two (2) Business Days prior notice of each such test, with the understanding that if the performance of such test is dependent on the presence of sufficient solar insolation or other variables beyond the control of Seller, the date of such test may be postponed if, on the date specified in the related notice, there is insufficient solar insolation or other circumstances beyond the control of Seller that prevent the performance of such test on the scheduled date. Seller does not herein grant PacifiCorp the right to review, comment on or approve of the terms or conditions of any contract or negotiation between Seller and a third party, the terms and conditions of each such contract or negotiation being confidential and to be determined by Seller in its sole discretion. Conversely, nothing in this Agreement shall be construed to require PacifiCorp to review, comment on, or approve of any contract between Seller and a third party.

(d) Witness initial performance tests and other tests and review the results thereof; with Seller to make best efforts to provide PacifiCorp five (5) Business Days' advance notice of each such major test.

(e) Perform such examinations, inspections, and quality surveillance as, in PacifiCorp's reasonable judgment, are appropriate and advisable to determine that the Facility has been properly commissioned and Commercial Operation and Final Completion have been achieved.

With respect to PacifiCorp's right to monitor under this Section 2.7, (i) PacifiCorp is under no obligation to exercise any of these monitoring rights, (ii) such monitoring shall occur subject to reasonable rules developed by Seller regarding Facility construction, access, health, safety, and environmental requirements, and (iii) PacifiCorp shall have no liability to Seller for failing to advise it of any condition, damages, circumstances, infraction, fact, act, omission or disclosure discovered or not discovered by PacifiCorp with respect to the Facility or any contractor. Any review or monitoring of the Facility conducted by PacifiCorp hereunder shall be performed in a manner that does not impede, hinder, postpone, or delay Seller or its contractors in their performance of the engineering, construction, design or testing of the Facility. PacifiCorp shall maintain one or more designated representatives for purposes of the monitoring activities contemplated in this Section 2.7, which representatives shall have authority to act for PacifiCorp in all technical matters under this Section 2.7 as authorized by PacifiCorp but not to amend or modify any provision hereof. PacifiCorp's initial representatives and their contact information are listed in Exhibit 2.7. PacifiCorp may, by written notice to Seller, change its representatives or their contact information.

2.8 Tax Credits. Seller shall notify PacifiCorp whether Seller has elected to claim the ITC within thirty (30) days following the date that Seller (or Seller's Affiliate, on a consolidated basis) files its first tax return after the Commercial Operation Date. Seller shall bear all risks, financial and otherwise throughout the Term, associated with Seller's or the Facility's eligibility to receive the ITC or other Tax Credits, or to qualify for accelerated depreciation for Seller's accounting, reporting or tax purposes. The obligations of the Parties hereunder, including those obligations set forth herein regarding the purchase and price for and Seller's obligation to deliver Net Output, shall be effective regardless of whether the sale of Output or Net Output from the Facility is eligible for, or receives, the ITC or other Tax Credits during the Term.

SECTION 3
REPRESENTATIONS AND WARRANTIES

3.1 Mutual Representations and Warranties. Each Party represents, covenants, and warrants to the other that:

3.1.1 Organization. It is duly organized and validly existing under the laws of the State of its organization.

3.1.2 Authority. It has the requisite power and authority to enter this Agreement and to perform according to the terms hereof.

3.1.3 Corporate Actions. It has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance hereof and the consummation of the transactions contemplated hereby.

3.1.4 No Contravention. The execution and delivery hereof does not contravene any provision of, or constitute a default under, any indenture, mortgage, security instrument or undertaking, or other material agreement to which it is a party or by which it is bound, or any valid order of any court, or any regulatory agency or other Governmental Authority having authority to which it is subject.

3.1.5 Valid and Enforceable Agreement. This Agreement is a valid and legally binding obligation of it, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

3.1.6 Litigation. No litigation, arbitration, investigation or other proceeding is pending or, to the best of either Party's knowledge, threatened in writing against either Party or its members, with respect hereto and the transactions contemplated hereunder. No other investigation or proceeding is pending or threatened in writing against a Party, its members, or any Affiliate, the effect of which would materially and adversely affect the Party's performance of its obligations hereunder.

3.1.7 Eligible Contract Participant. It, and any guarantor of its obligations under this Agreement, is an "eligible contract participant" as that term is defined in the United States Commodity Exchange Act.

3.2 Seller's Further Representations and Warranties. Seller further represents, covenants, and warrants to PacifiCorp that:

3.2.1 Authority. Seller (a) has (or will have prior to the Commercial Operation Date) all required regulatory authority to make wholesale sales from the Facility; (b) has the power and authority to own and operate the Facility and be present upon the Premises for the Term; and (c) is duly qualified and in good standing under the laws of each jurisdiction where its ownership, lease or operation of property or the conduct of its business requires such qualification.

3.2.2 No Contravention. The execution, delivery, performance and observance by Seller of its obligations hereunder do not and will not:

(a) contravene, conflict with or violate any provision of any material Requirements of Law presently in effect having applicability to either Seller or any of Seller's members;

(b) require the consent or approval of or material filing or registration with any Governmental Authority or other person other than such consents and approvals which are (i) set forth in Exhibit 3.2.3 or (ii) required in connection with the construction or operation of the Facility and expected to be obtained in due course;

(c) result in a breach of or constitute a default under any provision of any security issued by any of Seller's members or managers, the effect of which would materially and adversely affect Seller's performance of, or ability to perform, its obligations hereunder, or any material agreement, instrument or undertaking to which either Seller's members or any Affiliates of Seller's members is a party or by which the property of any of Seller's members or any Affiliates of Seller's members is bound, the effect of which would materially and adversely affect Seller's performance of, or ability to perform, its obligations hereunder.

3.2.3 Required Facility Documents. All Required Facility Documents are listed on Exhibit 3.2.3. Pursuant to the Required Facility Documents, Seller holds as of the Effective Date, or will hold by the Commercial Operation Date (or such other later date as may be specified under Requirements of Law), and will maintain for the Term all Required Facility Documents. The anticipated use of the Facility complies with all applicable restrictive covenants affecting the Premises. Following the Commercial Operation Date, Seller shall promptly notify PacifiCorp of any additional Required Facility Documents.

3.2.4 Delivery of Energy. On or before the Commercial Operation Date, Seller shall hold rights sufficient to enable Seller to deliver Net Output at the Nameplate Capacity Rating from the Facility to the Point of Delivery pursuant to this Agreement throughout the Term.

3.2.5 Control of Premises. Seller has all legal rights necessary for the Seller to enter upon and occupy the Premises for the purpose of constructing, operating and maintaining the Facility for the Term. All leases of real property required for the operation of the Facility or the performance of any obligations of Seller hereunder are set forth and accurately described in Exhibit 3.2.5. Seller shall maintain all leases or other land grants necessary for the construction, operation and maintenance of the Facility as valid for the Term. Upon request by PacifiCorp, Seller shall provide copies of the memoranda of lease recorded in connection with the development of the Facility.

3.2.6 Undertaking of Agreement; Professionals and Experts. Seller has engaged those professional or other experts it believes necessary to understand its rights and obligations pursuant to this Agreement. All professionals or experts including engineers, attorneys or accountants, that Seller may have consulted or relied on in undertaking the transactions contemplated by this Agreement have been solely those of Seller. In entering into this Agreement and the undertaking by Seller of the obligations set forth herein, Seller has investigated and determined that it is capable of performing hereunder and has not relied upon the advice, experience or expertise of PacifiCorp in connection with the transactions contemplated by this Agreement.

3.2.7 Verification. All information relating to the Facility, its operation and output and the Premises provided to PacifiCorp and contained in this Agreement has been verified by Seller and is true and accurate.

3.2.8 Renewable Claims. Seller has at all times complied with the Federal Trade

Commission requirements set forth in 16 CFR Part 260 in any communications concerning the Output, the Facility and the Green Tags that have or may be generated from the Facility. Seller has not claimed the Green Tags, Environmental Attributes or other "renewable energy," "green energy," "clean energy" or similar attributes of the Output or the Facility as belonging to the Seller or any Seller Affiliate and is not aware of any such claims made by third parties with respect to the Facility or the Output.

3.3 No Other Representations or Warranties. Each Party acknowledges that it has entered into this Agreement in reliance upon only the representations and warranties set forth in this Agreement, and that no other representations or warranties have been made by the other Party with respect to the subject matter hereof.

3.4 Continuing Nature of Representations and Warranties; Notice. The representations and warranties set forth in this section are made as of the Effective Date and deemed repeated as of the Commercial Operation Date. If at any time during the Term, the Seller obtains actual knowledge of any event or information that would have caused any of the representations and warranties in Section 3 to be materially untrue or misleading at the time given, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. If at any time the Seller obtains actual knowledge that the representations and warranties in this Section 3 are not true, Seller shall provide written notice to PacifiCorp. The notice required pursuant to this section shall be given as soon as practicable after the occurrence of each such event.

SECTION 4
DELIVERIES OF NET OUTPUT AND GREEN TAGS

4.1 Purchase and Sale. Except as otherwise expressly provided herein, commencing on the Commercial Operation Date and continuing through the Term, Seller shall sell and make available to PacifiCorp, and PacifiCorp shall purchase and receive (a) the entire Net Output from the Facility at the Point of Delivery, and (b) all Green Tags associated with the Output or otherwise resulting from the generation of energy by the Facility. PacifiCorp shall be under no obligation to make any purchase hereunder other than Net Output and all Green Tags, as described above. PacifiCorp shall not be obligated to purchase, receive or pay for Output (or Green Tags associated with such Output) that is not delivered to the Point of Delivery. In addition, during the period between the Effective Date and the Commercial Operation Date, Seller shall sell and make available to PacifiCorp, and PacifiCorp shall purchase and receive, all Net Output and Green Tags from the Facility as Test Energy at the price specified in Section 5.1.1.

4.2 No Sales to Third Parties. During the Term, Seller shall not sell any Net Output, energy, Green Tags or Capacity Rights from the Facility to any party other than PacifiCorp; provided, however, that this restriction shall not apply during periods when PacifiCorp is in default hereof because it has failed to accept or purchase that Net Output or Green Tags as required hereunder.

4.3 Title and Risk of Loss of Net Output. Seller shall deliver Net Output, Green Tags and Capacity Rights free and clear of all liens, claims and encumbrances. Title to and risk of loss of all Net Output shall transfer from Seller to PacifiCorp upon its delivery to PacifiCorp at the Point of Delivery. Seller shall be deemed to be in exclusive control of, and responsible for, any damage or injury caused by, all Output up to and at the Point of Delivery. PacifiCorp shall be deemed to be in exclusive control of, and responsible for, any damages or injury caused by, Net Output after the Point of Delivery.

4.4 Curtailment.

4.4.1 Non-Compensable Curtailment. Except for Compensable Curtailment in accordance with Section 5.1.3, PacifiCorp shall not be obligated to purchase, receive, pay for, or pay any damages associated with, Net Output if such Net Output is not delivered to the System or Point of Delivery for any of the following reasons: (a) the interconnection between the Facility and the System is disconnected, suspended or interrupted, in whole or in part, consistent with the terms of the Generation Interconnection Agreement, (b) the Market Operator, Transmission Provider or Network Service Provider directs a general curtailment, reduction, or redispatch of generation in the area, (which would include the Net Output) for any reason (excluding curtailment of purchases for general economic reasons unilaterally directed by the Market Operator or PacifiCorp acting solely in its merchant function capacity), even if and no matter how such curtailment or redispatch directive is carried out by PacifiCorp, which may fulfill such directive by acting in its sole discretion; or if PacifiCorp curtails or otherwise reduces the Net Output in any way in order to meet its obligations to the Market Operator, Transmission Provider or Network Service Provider to operate within system limitations or otherwise, (c) the Facility's Output is not received because the Facility is not fully integrated or synchronized with the System, or (d) an event of Force Majeure prevents either Party from delivering or receiving Net Output ("Non-Compensable Curtailment").

4.4.2 Curtailed Amount. Seller will calculate the quantity of Non-Compensable Curtailment by determining the quantity of Net Output that would have been produced by the Facility and delivered to the Point of Delivery had its generation not been so curtailed under this Section 4.4. Seller shall determine the quantity of such curtailed energy based on (a) the time and duration of the Non-Compensable Curtailment and (b) solar conditions recorded at the Facility during the period of Non-Compensable Curtailment and the production estimate based on the Solar Panels and Inverter performance guaranties provided by Seller to PacifiCorp in accordance with Exhibit 6.1. Seller shall promptly provide PacifiCorp with access to such information and data as PacifiCorp may reasonably require to confirm to its reasonable satisfaction the amount of energy that was not generated or delivered because of a Non-Compensable Curtailment.

4.4.3 Compensable Curtailment. PacifiCorp shall pay Seller for Compensable Curtailment Energy as set forth in Section 5.1.3.

4.5 PacifiCorp as Merchant. Seller acknowledges that PacifiCorp, acting in its merchant capacity function as purchaser under this Agreement, has no responsibility for or control over PacifiCorp Transmission or any successor Transmission Provider.

4.6 Green Tags.

4.6.1 Title. Title to the Green Tags shall pass from Seller to PacifiCorp immediately upon the generation of the Output at the Facility that gives rise to such Green Tags.

4.6.2 Documentation. The Parties shall execute all additional documents and instruments reasonably requested by PacifiCorp in order to further document the transfer of the Green Tags to PacifiCorp or its designees. Without limiting the generality of the foregoing, Seller must, on or before the tenth (10th) day of each month, deliver to PacifiCorp a Green Tags Attestation and Bill of Sale, in the form attached in Exhibit 4.6(1), for all Green Tags delivered to PacifiCorp hereunder in the preceding month, along with any attestation that is then-current with the Center for Resource Solution's Green-e Program (or such successor program). Seller must, at its own cost and expense cause the Facility to maintain its registration in good standing with the Center for Resource Solution's Green-e Program (or such successor program) throughout the Term. Seller, at its own cost and expense, shall register with, pay all fees required by, and comply with, all reporting and other requirements of WREGIS relating to the Facility or Green Tags. Seller shall ensure that the Facility will participate in and comply with, during the Term, all aspects of WREGIS. Seller shall, at its sole expense, effectuate the transfer of WREGIS Certificates to PacifiCorp in accordance with WREGIS Operating Rules. Seller may either elect to enter into a Qualified Reporting Entity Services Agreement with PacifiCorp in a form similar to that in Exhibit 4.6(2) or elect to act as its own WREGIS-defined Qualified Reporting Entity. Unless the failure to deliver WREGIS Certificates was caused by action of PacifiCorp not acting in its capacity as Qualified Reporting Entity under the Qualified Reporting Entity Services Agreement, PacifiCorp shall be entitled to a refund of the Green Tags Price Component of Green Tags associated with any Output for which WREGIS Certificates are not delivered, and shall not transfer the affected Green Tags back to Seller, provided that Seller shall have thirty (30) days to correct any error and deliver such WREGIS Certificates to PacifiCorp or provide such refund payment. Seller shall promptly provide PacifiCorp copies of all documentation it submits to WREGIS. Further, in the event of the promulgation of a scheme involving Green Tags administered by a Governmental Authority, upon notification by such Governmental Authority that any transfers contemplated by this Agreement will not be recorded, the Parties shall promptly cooperate in taking all reasonable actions necessary so that such transfers can be recorded.

4.6.3 Publicity. Seller shall not make any public statement or report under any program that any of the Green Tags purchased by PacifiCorp hereunder belong to any person other than PacifiCorp. Seller shall reasonably cooperate in any registration by PacifiCorp of the Facility in the renewable portfolio standard or equivalent program in all such further states and programs in which PacifiCorp may wish to register or maintained registered the Facility by providing copies of all such information as PacifiCorp reasonably requires for such registration.

4.6.4 Renewable Claims. Seller will comply with the Federal Trade

Commission requirements set forth in 16 CFR Part 260 in any communications concerning the Output, the Facility and the Green Tags that are or may be generated from the Facility. Seller will not claim the Green Tags, Environmental Attributes or other "renewable energy," "green energy," "clean energy" or similar attributes of the Output or the Facility as belonging to the Seller or any Seller Affiliate.

4.7 Purchase and Sale of Capacity Rights. For and in consideration of PacifiCorp's agreement to purchase from Seller the Facility's Net Output and Green Tags on the terms and conditions set forth herein, Seller transfers to PacifiCorp, and PacifiCorp accepts from Seller, any right, title, and interest that Seller may have in and to Capacity Rights, if any, existing during the Term.

4.8 Representation Regarding Ownership of Capacity Rights. Seller represents that it has not sold, and covenants that during the Term it will not sell or attempt to sell to any other person or entity the Capacity Rights, if any. During the Term, Seller shall not report to any person or entity that the Capacity Rights, if any, belong to anyone other than PacifiCorp. PacifiCorp may at its own risk and expense report to any person or entity that Capacity Rights exclusively belong to it.

4.9 Authority to Make Sales. Seller covenants that during the Term it will maintain all required regulatory authority to make wholesale sales from the Facility.

4.10 Further Assurances. At PacifiCorp's request, the Parties shall execute such documents and instruments as may be reasonably required to effect recognition and transfer of the Net Output or Capacity Rights, if any, to PacifiCorp.

SECTION 5
CONTRACT PRICE; COSTS

5.1 Contract Price; Includes Green Tags and Capacity Rights. PacifiCorp shall pay Seller the prices stated below for all deliveries of Net Output, Green Tags and Capacity Rights, up to the Maximum Delivery Rate. The price provided for Test Energy in Section 5.1.1, the Contract Price provided for in Section 5.1.2, and the Compensable Curtailment Price provided for in Section 5.1.3 include the consideration to be paid by PacifiCorp to Seller for all Net Output, Green Tags, Capacity Rights and Test Energy, respectively, and Seller shall not be entitled to any compensation over and above the Contract Price or the Test Energy price, as the case may be, for the Green Tags and Capacity Rights associated therewith.

5.1.1 Test Energy and Net Output Before Later of Commercial Operation Date and Scheduled Operation Date. Between the Effective Date and the later to occur of the (i) Commercial Operation Date or (ii) the Scheduled Commercial Operation Date, Seller shall sell and deliver to PacifiCorp all Test Energy and Net Output. PacifiCorp shall pay Seller for such Test Energy and Net Output delivered at the Point of Delivery, an amount per MWh equal to seventy five percent (75%) of the Firm Market Price Index for the applicable hour on the applicable day in the applicable month, provided, however, that Seller's right to receive payment for such Test Energy and Net Output is subject to PacifiCorp's right of offset under Section 10.2

for, among other things, payment by Seller of any Delay Damages owed to PacifiCorp by Seller pursuant to Section 2.4.

5.1.2 Net Output After The Later of Commercial Operation Date and Scheduled Commercial Operation Date. For the period beginning on the later of (i) the Commercial Operation Date or (ii) the Scheduled Commercial Operation Date and thereafter during the Term, PacifiCorp shall pay to Seller the Contract Price per MWh of Net Output delivered to the Point of Delivery, as specified in Exhibit 5.1.

5.1.3 Compensable Curtailment. If, during the period beginning on the later of (i) the Commercial Operation Date or (ii) the Scheduled Commercial Operation Date and thereafter during the Term, Net Output is curtailed by PacifiCorp and such curtailment is not included as a Non-Compensable Curtailment ("Compensable Curtailment Energy"), then PacifiCorp shall pay to Seller the Compensable Curtailment Price for the Compensable Curtailment Energy, as determined below.

(a) The Parties will calculate the quantity of Compensable Curtailment Energy by determining the Potential Net Output (A) during those periods of time when the Facility is on AGC and the AGC Set-Point is set at a level that will not allow the entire Nameplate Capacity Rating to be deliverable by determining the difference between Potential Net Output and the delivered Net Output, and (B) during those periods of time when the Facility is not on AGC or the AGC Set-Point is set at a level that will allow the Nameplate Capacity Rating to be deliverable by determining the amount that would have been available for delivery had its generation not been so curtailed. Compensable Curtailment Energy shall equal the number of MWh represented by the Potential Net Output less the Net Output actually delivered to the Point of Delivery.

(b) PacifiCorp will pay Seller the Contract Price for each MWh of Compensable Curtailment Energy, net of any Non-Compensable Curtailments (the "Compensable Curtailment Price").

(c) For purposes of determining Compensable Curtailment Energy, the amount of Potential Net Output at any given time will be calculated using PacifiCorp's solar forecasting vendor.

5.2 Costs and Charges. Seller shall be responsible for paying or satisfying when due all costs or charges imposed in connection with the scheduling and delivery of Net Output up to and at the Point of Delivery, including transmission costs, Transmission Service, and transmission line losses, and any operation and maintenance charges imposed by Interconnection Provider and Transmission Provider for the Interconnection Facilities. PacifiCorp shall be responsible for all costs or charges, if any, imposed in connection with the delivery of Net Output at and from the Point of Delivery, including transmission costs and transmission line losses and imbalance charges or penalties. Without limiting the generality of the foregoing, Seller, in accordance with the Generation Interconnection Agreement, shall bear all costs associated with the modifications to Interconnection Facilities or the System (including system upgrades) caused by or related to (a) the interconnection of the Facility with the System and (b) any increase in generating capacity of the Facility.

5.3 Station Service. Seller shall be responsible for arranging and obtaining, at its sole risk and expense, any station service required by the Facility that is not provided by the Facility itself.

5.4 Taxes. Seller shall pay or cause to be paid when due, or reimburse PacifiCorp for, all existing and any new sales, use, excise, severance, ad valorem, and any other similar taxes, imposed or levied by any Governmental Authority on the Net Output, Capacity Rights or Green Tags up to and including, but not beyond, the Point of Delivery, regardless of whether such taxes are imposed on PacifiCorp or Seller under Requirements of Law. PacifiCorp shall pay or cause to be paid when due all such taxes imposed or levied by any Governmental Authority on the Net Output, Capacity Rights or Green Tags beyond the Point of Delivery, regardless of whether such taxes are imposed on PacifiCorp or Seller under Requirements of Law. The Contract Price shall not be adjusted on the basis of any action of any Governmental Authority with respect to changes to or revocations of sales and use tax benefits, rebates, exception or give back. In the event any taxes are imposed on a Party for which the other Party is responsible hereunder, the Party on which the taxes are imposed shall promptly provide the other Party notice thereof and such other information as such Party may reasonably request with respect to any such taxes. Seller shall be responsible for any and all sun and light severance taxes.

5.5 Costs of Ownership and Operation. Without limiting the generality of any other provision hereof and subject to Section 5.4, Seller shall be solely responsible for paying when due (a) all costs of owning and operating the Facility in compliance with existing and future Requirements of Law and the terms and conditions hereof, and (b) all taxes and charges (however characterized) now existing or hereinafter imposed on or with respect to the Facility, its operation, or on or with respect to emissions or other environmental impacts of the Facility, including any such tax or charge (however characterized) to the extent payable by a generator of such energy or Environmental Attributes.

5.6 Rates Not Subject to Review. The rates for service specified herein shall remain in effect until expiration of the Term, and shall not be subject to change for any reason, including regulatory review, absent agreement of the parties. Neither Party shall petition FERC pursuant to the provisions of Sections 205 or 206 of the Federal Power Act (16 U.S.C. § 792 et seq.) to amend such prices or terms, or support a petition by any other person seeking to amend such prices or terms, absent the agreement in writing of the other Party. Further, absent the agreement in writing by both Parties, the standard of review for changes hereto proposed by a Party, a non-party or the FERC acting sua sponte shall be the "public interest" application of the "just and reasonable" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and clarified by Morgan Stanley Capital Group. Inc. v. Public Util. Dist. No. 1 of Snohomish, 554 U.S. 527, 128 S. Ct. 2733 (2008).

SECTION 6
OPERATION AND CONTROL

6.1 As-Built Supplement. Within thirty (30) days of completion of construction of the Facility, Seller shall provide PacifiCorp the As-built Supplement. The As-built Supplement shall be deemed effective and shall be added to Exhibit 6.1 when it has been reviewed and approved by PacifiCorp, which approval shall not be unreasonably withheld or delayed. If the proposed As-built Supplement does not accurately describe the Facility as actually built or is otherwise defective as to form in any material respect, PacifiCorp may within fifteen (15) days after receiving the proposed As-built Supplement give Seller a notice describing what PacifiCorp wishes to correct. If PacifiCorp does not give Seller such a notice within the fifteen (15) day period, the As-built Supplement shall be deemed approved. If PacifiCorp provides a timely notice requiring corrections, Seller shall in good faith cooperate with PacifiCorp to revise the As-built Supplement to address PacifiCorp's concerns. Notwithstanding the foregoing, PacifiCorp shall have no right to require Seller to relocate, modify or otherwise change in any respect any aspect of the Facility as actually built.

6.2 Standard of Facility Operation.

6.2.1 General. At Seller's sole cost and expense, Seller shall build, operate, maintain and repair the Facility and the Interconnection Facilities in accordance with (a) the applicable and mandatory standards, criteria and formal guidelines of FERC, NERC, any RTO, and any other Electric System Authority and any successors to the functions thereof; (b) the Permits and Required Facility Documents; (c) the Generation Interconnection Agreement; (d) all Requirements of Law; (e) the requirements hereof; and (f) Prudent Electrical Practice. Seller acknowledges that it shall have no claims hereunder against PacifiCorp with respect to any requirements imposed by or damages caused by (or allegedly caused by) the Transmission Provider. Seller will have no claims against PacifiCorp under this Agreement with respect to the provision of station service.

6.2.2 Qualified Operator. From and after the Commercial Operation Date, Seller or an Affiliate of Seller shall itself operate and maintain the Facility or cause the Facility to be operated and maintained by an entity, approved by PacifiCorp (such approval not to be unreasonably withheld, conditioned or delayed), that has at least two years of experience in operation and maintenance of solar energy facilities of comparable size to the Facility. Seller shall provide PacifiCorp thirty (30) days prior written notice of any proposed change in the operator of the Facility.

6.2.3 Fines and Penalties.

(a) Without limiting a Party's rights under Section 6.2.3(b), each Party shall pay all fines and penalties incurred by such Party on account of noncompliance by such Party with Requirements of Law in respect to this Agreement, except where such fines and penalties are being contested in good faith through appropriate proceedings.

(b) If fines, penalties, or legal costs are assessed against or incurred by either Party (the “Indemnified Party”) on account of any action by any Governmental Authority due to noncompliance by the other Party (the “Indemnifying Party”) with any Requirements of Law or the provisions hereof, or if the performance of the Indemnifying Party is delayed or stopped by order of any Governmental Authority due to the Indemnifying Party's noncompliance with any Requirements of Law, the Indemnifying Party shall indemnify and hold harmless the Indemnified Party against any and all losses, liabilities, damages, and claims suffered or incurred by the Indemnified Party as a result thereof. Without limiting the generality of the foregoing, the Indemnifying Party shall reimburse the Indemnified Party for all fees, damages, or penalties imposed on the Indemnified Party by any Governmental Authority, other person or to other utilities for violations to the extent caused by a default by the Indemnifying Party or a failure of performance by the Indemnifying Party hereunder.

6.3 Interconnection. Seller shall be responsible for the costs and expenses associated with obtaining from the Transmission Provider network resource interconnection service for the Facility at its Nameplate Capacity Rating at the Point of Delivery. Seller shall have no claims hereunder against PacifiCorp, acting in its merchant function capacity, with respect to any requirements imposed by or damages caused by (or allegedly caused by) acts or omissions of the Transmission Provider or Interconnection Provider, in connection with the Generation Interconnection Agreement or otherwise.

6.4 Coordination with System. Seller shall be responsible for the coordination and synchronization of the Facility and the Interconnection Facilities with the System.

6.5 Outages.

6.5.1 Planned Outages. Except as otherwise provided herein, Seller shall not schedule a Planned Outage during daylight hours (sun up to sunset) during any portion of the months of November, December, January, February, June, July, and August, except to the extent a Planned Outage is reasonably required to enable a vendor to satisfy a guarantee requirement. Seller shall provide PacifiCorp with an annual forecast of Planned Outages for each Contract Year at least one month, but no more than three months, before the first day of that Contract Year, and shall promptly update such schedule, or otherwise change it, only to the extent that

Seller is reasonably required to change it in order to comply with Prudent Electrical Practices. Seller shall not schedule any maintenance of Interconnection Facilities during such months, without the prior written approval of PacifiCorp, which approval shall not be unreasonably withheld or delayed.

6.5.2 Maintenance Outages. If Seller reasonably determines that it is necessary to schedule a Maintenance Outage, Seller shall notify PacifiCorp of the proposed Maintenance Outage as soon as practicable but in any event at least five days before the outage begins (or such shorter period to which PacifiCorp may reasonably consent in light of then-existing solar conditions). Upon such notice, the Parties shall plan the Maintenance Outage to mutually accommodate the reasonable requirements of Seller and the service obligations of PacifiCorp; provided, however, that Seller shall take all reasonable measures consistent with Prudent Electrical Practices to not schedule any Maintenance Outage during the daylight hours of the following periods: November, December, January, February, June 15 through June 30, July, August, and September 1 through September 15. Notice of a proposed Maintenance Outage shall include the expected start date and time of the outage, the amount of generation capacity of the Facility that will not be available, and the expected completion date and time of the outage. Seller shall give PacifiCorp notice of the Maintenance Outage as soon as practicable after Seller determines that the Maintenance Outage is necessary. PacifiCorp shall promptly respond to such notice and may request reasonable modifications in the schedule for the outage. Seller shall use all reasonable efforts to comply with any request to modify the schedule for a Maintenance Outage provided that such change has no substantial impact on Seller. Seller shall notify PacifiCorp of any subsequent changes in generation capacity available to PacifiCorp as a result of such Maintenance Outage or any changes in the Maintenance Outage completion date and time. As soon as practicable, any notifications given orally shall be confirmed in writing. Seller shall take all reasonable measures consistent with Prudent Electrical Practices to minimize the frequency and duration of Maintenance Outages. Notwithstanding anything in this Section 6.5.2 to the contrary, Seller may schedule a Maintenance Outage at any time and without the requirement to notify PacifiCorp in advance during conditions of low solar insolation.

6.5.3 Forced Outages. Seller shall promptly provide to PacifiCorp an oral report, via telephone to a number specified by PacifiCorp (or other method approved by PacifiCorp), of any Forced Outage resulting in more than ten (10) percent of the Nameplate Capacity Rating of the Facility being unavailable. This report shall include the amount of the generation capacity of the Facility that will not be available because of the Forced Outage and the expected return date of such generation capacity. Seller shall promptly update the report as necessary to advise PacifiCorp of changed circumstances. As soon as practicable, the oral report shall be confirmed in writing by notice to PacifiCorp. Seller shall take all reasonable measures consistent with Prudent Electrical Practices to avoid Forced Outages and to minimize their duration.

6.5.4 Notice of Deratings and Outages. Without limiting the foregoing, Seller will inform PacifiCorp, via telephone to a number specified by PacifiCorp (or other method approved by PacifiCorp), of any major limitations, restrictions, deratings or outages known to Seller affecting the Facility for the following day (except curtailments pursuant to Section 4.4(b)) and will promptly update Seller's notice to the extent of any material changes in this information, with “major” defined as affecting more than five (5) percent of the Nameplate Capacity Rating of the Facility.

6.5.5 Effect of Outages on Estimated Output. Seller represents and warrants that the estimated monthly net output set forth on Exhibit A takes into account the Planned Outages, Maintenance Outages, and Forced Outages that Seller reasonably expects to encounter in the ordinary course of operating the Facility.

6.6 Scheduling.

6.6.1 Cooperation and Standards. With respect to any and all scheduling requirements hereunder, (a) Seller shall cooperate with PacifiCorp with respect to scheduling Net Output, and (b) each Party shall designate authorized representatives to communicate with regard to scheduling and related matters arising hereunder. Each Party shall comply with the applicable variable resource standards and criteria of any applicable Electric System Authority.

6.6.2 Schedule Coordination. If, as a result hereof, PacifiCorp is deemed by an RTO to be financially responsible for Seller's performance under the Generation Interconnection Agreement, due to Seller’s lack of standing as a “scheduling coordinator” or other RTO recognized designation, qualification or otherwise, then Seller shall acquire such RTO recognized standing (or shall contract with a third party who has such RTO recognized standing) such that PacifiCorp is no longer responsible for Seller's performance under the Generation Interconnection Agreement or RTO requirement.

6.7 Forecasting.

6.7.1 Long-Range Forecasts. For PacifiCorp’s planning purposes, Seller shall, by December 1 of each year during the Term (except for the last year of the Term), provide an annual update to the expected long-term monthly/diurnal mean net energy and net capacity factor estimates (12 X 24 profile). Seller shall prepare such forecasts by utilizing a solar prediction model or service that is satisfactory to PacifiCorp in the exercise of its reasonable discretion and comparable in accuracy to models or services commonly used in the solar industry. The forecasts provided by Seller must comply with all applicable Electric System Authority tariff procedures, protocols, rules and testing as necessary and as may be modified from time to time.

6.7.2 Day-Ahead Forecasts and Updates. At Seller’s expense, PacifiCorp shall solicit and obtain from a qualified solar energy production forecasting vendor forecast data and information with respect to the Facility, including day-ahead and real-time forecasting services and provision of real-time meteorological data necessary for compliance with applicable Electric System Authority procedures, protocols, rules and testing. Upon request by PacifiCorp, Seller shall provide a 24-hour telephone number that PacifiCorp may contact to determine the then-current status of the Facility. PacifiCorp shall present Seller with an invoice and documentation supporting the costs of obtaining such forecasting data. Seller shall pay the amount stated on the invoice within fifteen (15) days of receipt. PacifiCorp reserves the right to change the forecasting vendor in its sole discretion during the Term.

6.8 Increase in Nameplate Capacity Rating; New Project Expansion or Development. Without limiting Section 7.1.1 or any restrictions herein on Nameplate Capacity Rating, if Seller elects to increase, at its own expense, the ability of the Facility to deliver Net Output in quantities in excess of the Maximum Delivery Rate through any means, including replacement or modification of Facility equipment or related infrastructure, PacifiCorp shall not be required to purchase any Net Output or Green Tags above the Maximum Delivery Rate. Any such expansion or additional facility may not materially and adversely impact the ability of either Party to fulfill its obligations pursuant hereto.

6.9 Electronic Communications.

6.9.1 AGC.

(a) Beginning on the Commercial Operation Date, PacifiCorp will dispatch Facility through its AGC system installed by Seller.

(b) PacifiCorp may notify Seller, by telephonic communication or through use of the AGC Set-Point, to curtail the delivery of Net Output to PacifiCorp from the Facility and to the Point of Delivery, for any reason and in its sole discretion and Seller shall promptly comply with such notification.

(c) The AGC Set-Point is calculated by the Transmission Provider and communicated electronically through the SCADA system. Seller shall ensure that, throughout the Term, the SCADA signal is capable of functioning on all AGC Set-Points within the margin of error specified in the Facility control system manufacturer’s set point margin of error.

(d) Unless otherwise directed by PacifiCorp, Seller shall ensure that the Facility AGC is in “Remote” set-point control during normal operations.

6.9.2 Telemetering. Seller shall during the Term provide telemetering equipment and facilities capable of transmitting the following information concerning the Facility pursuant to the Generation Interconnection Agreement and to PacifiCorp on a real-time basis, and will operate such equipment when requested by PacifiCorp to indicate:

(a) instantaneous MW output at the Point of Delivery;

(b) Net Output; and

(c) the Facility's total instantaneous generation capacity.

Commencing on the date of initial delivery of Test Energy, Seller shall also transmit or cause to be transmitted to or make accessible to PacifiCorp any other data from the Facility that Seller receives on a real time basis, including meteorological data, solar insolation data and Net Output data. Such real time data shall be provided to or be made accessible to PacifiCorp on the same basis on which Seller receives the data (e.g., if Seller receives the data in four second intervals, PacifiCorp shall also receive the data in four second intervals). Seller must provide PacifiCorp access to Seller’s web-based performance monitoring system.

6.9.3 Transmission Provider Consent. Seller shall execute a consent, in the form required by Transmission Provider, to provide that PacifiCorp can read the meter and receive any and all data from the Transmission Provider relating to transmission of Output or other matters relating to the Facility without the need for further consent from Seller.

6.9.4 Dedicated Communication Circuit. Seller shall install a dedicated direct communication circuit (which may be by common carrier telephone) between PacifiCorp and the control center in the Facility's control room or such other communication equipment as the Parties may agree.

6.10 Reports and Records.

6.10.1 Monthly Reports. Commencing on the Commercial Operation Date, within thirty (30) days after the end of each calendar month during the Term (each, a "Reporting Month"), Seller shall provide to PacifiCorp a report in electronic format, which report shall include (a) summaries of the Facility's solar insolation and actual and predicted output data for the Reporting Month in intervals not to exceed one hour (or such shorter period as is reasonably possible with commercially available technology), including information from the Facility's computer monitoring system; (b) summaries of any other significant events related to the construction or operation of the Facility for the Reporting Month; and (c) any supporting information that PacifiCorp may from time to time reasonably request (including historical solar insolation data for the Facility).

6.10.2 Electronic Fault Log. Seller shall maintain an electronic fault log of operations of the Facility during each hour of the Term commencing on the Commercial Operation Date. Seller shall provide PacifiCorp with a copy of the electronic fault log within thirty (30) days after the end of the calendar month to which the fault log applies.

6.10.3 Other Information to be Provided to PacifiCorp. Seller shall provide to PacifiCorp the following information concerning the Facility:

(a) Upon the request of PacifiCorp, the manufacturers' guidelines and recommendations for maintenance of the Facility equipment;

(b) A report summarizing the results of maintenance performed during each Maintenance Outage, Planned Outage, and any Forced Outage, and upon request of PacifiCorp any of the technical data obtained in connection with such maintenance;

(c) Before Final Completion, a monthly progress report stating the percentage completion of the Facility and a brief summary of construction activity during the prior month;

(d) Before Final Completion, a monthly report containing a brief summary of construction activity contemplated for the next calendar month;

(e) From and after the Commercial Operation Date, a monthly report detailing the availability of the Facility; and

(f) At any time from the Effective Date, one year's advance notice of the termination or expiration of any material agreement, including Leases, pursuant to which the Facility or any material equipment relating thereto is upon the Premises; provided that the foregoing does not authorize any early termination of any land lease. In the event Seller has less than one year's advance notice of such termination or expiration, Seller shall provide the notice contemplated by this Section to PacifiCorp within fifteen (15) Business Days of Seller obtaining knowledge of the termination or expiration.

6.10.4 Information to Governmental Authorities. Seller shall, promptly upon written request from PacifiCorp, provide PacifiCorp with all data collected by Seller related to the construction, operation or maintenance of the Facility reasonably required by PacifiCorp or an Affiliate thereof for reports to, and information requests from, any Governmental Authority or Electric System Authority. Along with this information, Seller shall provide to PacifiCorp copies of all submittals to Governmental Authorities or Electric System Authorities directed by PacifiCorp and related to the operation of the Facility with a certificate that the contents of the submittals are true and accurate to the best of Seller's knowledge. Seller shall use best efforts to provide this information to PacifiCorp with sufficient advance notice to enable PacifiCorp to review such information and meet any submission deadlines imposed by the requesting organization or entity. PacifiCorp shall reimburse Seller for all of Seller's reasonable actual costs and expenses in excess of $10,000 per year, if any, incurred in connection with PacifiCorp's requests for information under this Section 6.10.4.

6.10.5 Data Request. Seller shall, promptly upon written request from PacifiCorp, provide PacifiCorp with data collected by Seller related to the construction, operation or maintenance of the Facility reasonably required for information requests from any Governmental Authorities, state or federal agency intervener or any other party achieving intervenor status in any PacifiCorp rate proceeding or other proceeding before any Governmental Authority. Seller shall use best efforts to provide this information to PacifiCorp sufficiently in advance to enable PacifiCorp to review it and meet any submission deadlines. PacifiCorp shall reimburse Seller for all of Seller's reasonable actual costs and expenses in excess of $10,000 per year, if any, incurred in connection with PacifiCorp's requests for information under this Section 6.10.5.

6.10.6 Documents to Governmental Authorities. After sending or filing any statement, application, and report or any document with any Governmental Authority or Electric System Authority relating to operation and maintenance of the Facility, Seller shall, within five (5) Business Days of such submission or filing, provide to PacifiCorp a copy of the same.

6.10.7 Environmental Information. Seller shall, promptly upon written request from PacifiCorp, provide PacifiCorp with all data reasonably requested by PacifiCorp relating to environmental information under the Required Facility Documents. Seller shall further provide PacifiCorp with information relating to environmental impact mitigation measures it is taking in connection with the Facility's construction or operation that are required by any Governmental Authority. PacifiCorp shall reimburse Seller for all of Seller's reasonable actual costs and expenses in excess of $10,000 per year, if any, incurred in connection with PacifiCorp's requests for the foregoing information under this Section 6.10.7. As soon as it is known to Seller, Seller shall disclose to PacifiCorp, the extent of any material violation of any environmental laws or regulations arising out of the construction or operation of the Facility, or the presence of Environmental Contamination at the Facility or on the Premises, alleged to exist by any Governmental Authority having jurisdiction over the Premises, or the present existence of, or the occurrence during Seller's occupancy of the Premises of, any enforcement, legal, or regulatory action or proceeding relating to such alleged violation or alleged presence of Environmental Contamination presently occurring or having occurred during the period of time that Seller has occupied the Premises.

6.10.8 Operational Reports. Seller shall provide PacifiCorp monthly operational reports in a form and substance reasonably acceptable to PacifiCorp, and Seller shall, promptly upon written request from PacifiCorp, provide PacifiCorp with all operational data requested by PacifiCorp with respect to the performance of the Facility and delivery of Net Output, Green Tags or Capacity Rights therefrom.

6.10.9 Notice of Material Adverse Events. Seller shall promptly notify PacifiCorp of receipt of written notice or actual knowledge by Seller or its Affiliates of the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller's ability to develop, construct, operate, maintain or own the Facility as provided herein.

6.10.10 Notice of Litigation. Following its receipt of written notice or actual knowledge of the commencement of any action, suit, or proceeding before any court or Governmental Authority against Seller or its members with respect to this Agreement or the transactions contemplated hereunder, Seller shall, within ten (10) days of such notice or knowledge, give notice to PacifiCorp of the same. Following its receipt of written notice or actual knowledge of the commencement of any action, suit or proceeding before any court or Governmental Authority against Seller, its members or any Affiliate, the effect of which would materially and adversely affect Seller's performance of its obligations hereunder, Seller shall, within ten (10) days of such notice or knowledge, give notice to PacifiCorp of the same.

6.10.11 Additional Information. Seller shall provide to PacifiCorp such other information respecting the condition or operations of Seller, as such pertains to Seller's performance of its obligations hereunder, or the Facility as PacifiCorp may, from time to time, reasonably request.

6.10.12 Confidential Treatment. The monthly reports and other information provided to PacifiCorp under this Section 6.10 shall be treated as Confidential Business Information if such treatment is requested in writing by Seller at the time the information is provided to PacifiCorp, subject to PacifiCorp's rights to disclose such information pursuant to Sections 6.10.4, 6.10.5, 6.10.7, 9.5, 9.6, 23.2 and 23.3, and pursuant to any applicable Requirements of Law. Seller shall have the right to seek confidential treatment of any such information from the Governmental Authority entitled to receive such information.

6.11 Financial and Accounting Information. If PacifiCorp or one of its Affiliates determines that, under (i) the Accounting Standards Codification (ASC) 810, Consolidation of Variable Interest Entities, and (ii) Requirements of Law that it may hold a variable interest in Seller, but it lacks the information necessary to make a definitive conclusion, Seller hereby agrees to provide, upon PacifiCorp's written request, sufficient financial and ownership information so that PacifiCorp or its Affiliate may confirm whether a variable interest does exist under ASC 810 and Requirements of Law. If PacifiCorp or its Affiliate determines that, under ASC 810, it holds a variable interest in Seller, Seller hereby agrees to provide, upon PacifiCorp's written request, sufficient financial and other information to PacifiCorp or its Affiliate so that PacifiCorp may properly consolidate the entity in which it holds the variable interest or present the disclosures required by ASC 810 and Requirements of Law. PacifiCorp shall reimburse Seller for Seller's reasonable costs and expenses, if any, incurred in connection with PacifiCorp's requests for information under this Section 6.11.

6.12 Output Guarantee.

6.12.1 Output Guarantee. Seller is obligated to deliver a quantity of Net Output during each Rolling Period which is equal to the Output Guarantee. For purposes of this Agreement, "Output Guarantee" for any Rolling Period means the sum of (i) 90% of the Expected Energy of the Facility for such Rolling Period, less (ii) any quantities of Output that were not delivered to the Point of Delivery (or accepted by PacifiCorp) in such Rolling Period during periods constituting Seller Uncontrollable Minutes (such quantity calculated on the basis of the Net Output capable of being delivered in an hour at an average rate equivalent to the actual Nameplate Capacity Rating). For purposes of this Agreement, "Rolling Period" means any two consecutive Contract Years occurring during the Term.

6.12.2 Liquidated Damages for Output Shortfall.

(a) If the quantity of Net Output delivered by the Facility during any Rolling Period is equal to or greater than the Output Guarantee for such Rolling Period, Seller's delivery obligation for such Rolling Period shall be deemed satisfied for such Rolling Period.

(b) If the quantity of Net Output delivered by the Facility during any Rolling Period is less than the Output Guarantee for such Rolling Period, the Seller shall determine the resulting shortfall, if any, for the first Contract Year occurring during such Rolling Period (the "Output Shortfall"). The Output Shortfall shall be expressed in MWh and calculated in accordance with the following formula:

Output Shortfall = (90% of the Expected Energy for the Contract Year).

less

Any quantities of Output that were not delivered to the Point of Delivery (or accepted by PacifiCorp) in such Contract Year during periods constituting Seller Uncontrollable Minutes (such quantity calculated on the basis of the Net Output capable of being delivered in an hour at an average rate equivalent to the actual Nameplate Capacity Rating),

less

The Net Output for the Contract Year

(c) If the product of the Output Shortfall calculation set forth in Section 6.12.2(b) is a positive number, Seller shall pay PacifiCorp liquidated damages equal to the product of (i) the Output Shortfall for that Contract Year, multiplied by (ii) PacifiCorp's Cost to Cover for that Contract Year. If the product of the Output Shortfall calculation set forth in Section 6.12.2(b) is a negative number, Seller shall not be obligated to pay PacifiCorp liquidated damages for such Contract Year.

(d) Each Party agrees and acknowledges that (i) the damages that PacifiCorp would incur due to the Facility's failure to achieve the Output Guarantee would be difficult or impossible to predict with certainty and (ii) the liquidated damages contemplated by this provision are a fair and reasonable calculation of such damages.

6.12.3 Annual Invoicing. On the thirtieth (30^{th}) day following the end of each Rolling Period, Seller shall deliver to PacifiCorp a report (and supporting data) detailing whether Seller achieved the Output Guarantee for the most recently completed Rolling Period. In the case of the Seller failing to achieve the Output Guarantee in the prior Rolling Period, Seller shall also provide a report (and supporting data) to PacifiCorp detailing the Output Shortfall for the first Contract Year occurring during such Rolling Period. Seller shall provide documentation to support all data and calculations used in each report to calculate the percent Expected Energy. Thirty (30) days after PacifiCorp has received the report and all support data, if there is an Output Shortfall, PacifiCorp shall deliver to Seller an invoice showing PacifiCorp's computation of liquidated damages calculated pursuant to Section 6.12.2. In preparing such invoices, PacifiCorp shall utilize the meter data provided to PacifiCorp for the Contract Year in question, but may also rely on historical averages and such other information as may be available to PacifiCorp at the time of invoice preparation, if the meter data for such Contract Year is then incomplete or otherwise not available. To the extent required, PacifiCorp shall true up any such invoice as promptly as practicable following its receipt of actual results for the relevant Contract Year. Seller shall pay to PacifiCorp, by wire transfer of immediately available funds to an account specified in writing by PacifiCorp or by any other means agreed to by the Parties in writing from time to time, the amount set forth as due in such invoice, and shall within thirty (30) days after receiving the invoice raise any objections regarding any disputed portion of the invoice. All disputes regarding such invoices shall be subject to Section 10.4. Objections not made by Seller within the thirty (30) day period shall be deemed waived.

6.13 Access Rights. Upon reasonable prior notice and subject to the prudent safety requirements of Seller, and Requirements of Law relating to workplace health and safety, Seller shall provide PacifiCorp and its authorized agents, employees and inspectors ("PacifiCorp Representatives") with reasonable access to the Facility: (a) for the purpose of reading or testing metering equipment, (b) as necessary to witness any acceptance tests, (c) to provide tours of the Facility to customers and other guests of PacifiCorp (not more than twelve (12) times per year), (d) for purposes of implementing Sections 2.7 or 10.5, and (e) for other reasonable purposes at the reasonable request of PacifiCorp. PacifiCorp shall release Seller from any and all Liabilities resulting from actions or omissions by any of the PacifiCorp Representatives in connection with their access to the Facility, except to the extent that such Liabilities are caused-by the intentional or negligent act or omission of Seller or its agents or Affiliates.

6.14 Facility Images. PacifiCorp shall be free to use any and all images from or of the Facility for promotional purposes, subject to Seller's consent (not to be unreasonably withheld or delayed, and which consent may consider Requirements of Law relating to Premises security, obligations to outside vendors (including any confidentiality obligations), and the corporate policies of Seller's Affiliates). Upon PacifiCorp's request and at PacifiCorp's expense, Seller shall install imaging equipment at the Facility as PacifiCorp may request, including video and or web-based imaging equipment subject to the prudent safety requirements of Seller, and Requirements of Law relating to workplace health and safety. PacifiCorp shall retain full discretion on how such images are presented including associating images of the Facility with a PacifiCorp-designated corporate logo.

SECTION 7
RIGHT OF FIRST OFFER AND PURCHASE OPTION

7.1 Right of First Offer on Facility Expansion.

7.1.1 Seller's Duty to Offer Expansion Energy. If, at any time during the Term, Seller or any Affiliate of Seller intends (a) to install equipment on the Premises in addition to the equipment included in the original Facility, and such installation is designed to increase the capacity of the Facility to more than the Nameplate Capacity Rating at Final Completion, or (b) to otherwise enable the Facility or any expansion thereof to produce more than the Maximum Delivery Rate, Seller shall first offer (or cause its Affiliate to offer) the excess above the Maximum Delivery Rate (the "Expansion Energy") to PacifiCorp. Such offer shall set forth the terms and conditions of the offer in writing and in reasonable detail. Seller shall promptly answer any questions that PacifiCorp may have concerning the offered terms and conditions and shall meet with PacifiCorp to discuss the offer.

7.1.2 PacifiCorp's Rejection of Offer; Revival of Offer. If PacifiCorp does not accept the offered terms and conditions within thirty (30) days after receiving Seller's offer, Seller (or the applicable Affiliate of Seller) may enter into an agreement to sell the Expansion Energy to a third party on terms and conditions no more favorable to the third party than those offered to PacifiCorp, provided such sale of Expansion Energy may not in any way impact or alter PacifiCorp's rights, obligations or entitlements under this Agreement. If Seller (or its Affiliate) wishes to enter into an agreement with a third party on terms more favorable to PacifiCorp than those previously offered to PacifiCorp under this section, Seller shall first offer (or cause its Affiliate to offer) the revised terms and conditions to PacifiCorp under this section.

7.1.3 PacifiCorp's Acceptance of Offer. If PacifiCorp accepts an offer made by Seller (or its Affiliate) under this section, the parties shall within sixty (60) days following such acceptance enter into a power purchase agreement in substantially the same form as this Agreement for the purchase and sale of such Expansion Energy (with appropriate provisions proportionally adjusted to account for the size of the proposed expansion relative to the Nameplate Capacity Rating of the Facility), but incorporating such changes as are expressly identified in the terms and conditions offered by Seller (or its Affiliate).

7.2 Purchase Option.[2]

7.2.1 Purchase Option. On the last day of the Term,[3] PacifiCorp shall have the option to purchase the Facility and all rights of Seller therein or relating thereto, for the Fair Market Value of the Facility, in accordance with the provisions set forth herein. PacifiCorp shall indicate its preliminary interest with respect to the option, if at all, by delivering to Seller a preliminary notice of its interest no less than two years prior to the last day of the Term (the "Preliminary Interest Notice"). If PacifiCorp fails to deliver such notice by such date, PacifiCorp's option shall terminate.

7.2.2 Determination of Fair Market Value of the Facility. Promptly following delivery of the Preliminary Interest Notice, the Parties shall mutually agree to the fair market value of the Facility. If PacifiCorp and Seller cannot mutually agree to a fair market value of the Facility within thirty (30) days of delivery of the Preliminary Interest Notice, then each of PacifiCorp and Seller shall select and retain, at each Party's own cost and expense, a nationally recognized independent appraiser with experience and expertise in appraising solar generation facilities to determine separately the value of the Facility. Subject to the appraisers' execution and delivery to Seller of a suitable confidentiality agreement in a form reasonably acceptable to Seller, Seller shall provide both appraisers access to the Facility and its books and records during business hours and upon prior written notice. The appraisers shall act reasonably and in good faith to determine the fair market value of the Facility and the Parties shall use their best efforts to cause the appraisers to complete such determination no later than sixty (60) days following delivery of the Preliminary Interest Notice. If for any reason (other than failure by Seller to provide access hereunder to PacifiCorp's appraiser), one of the appraisals is not completed within ninety (90) days following delivery of the Preliminary Interest Notice, the results of the other completed appraisal shall be deemed the Fair Market Value of the Facility. Each Party may provide to both appraisers a list of factors which the Parties suggest be taken into consideration when the appraisers generate their appraisals, consistent with industry standards prevailing at such time for appraising solar power generation facilities. Any information provided to an appraiser by a Party shall be provided to the other appraiser and the other Party at the same time, it being the intent of the Parties that the appraisers have access to the same information. PacifiCorp and Seller shall deliver the results of their respective appraisal to the other Party

[2] Note To Bidders – Providing a purchase option in favor of PacifiCorp is not a required condition to submitting a bid, nor will inclusion or failure to include a purchase option impact the overall scoring of a bid.

[3] Note To Bidders – PacifiCorp will entertain a mid-Term purchase option (or more than one mid-Term purchase option).

when completed. If so requested by either Party, the appraisals shall be exchanged simultaneously. After both appraisals are completed and exchanged, the Parties and their appraisers promptly shall confer and attempt to agree upon the Fair Market Value of the Facility.

7.2.3 Disagreement as to Value. If, within thirty (30) days after completion of both appraisals, the Parties cannot agree on the fair market value of the Facility, and the values of the appraisals are within ten percent (10%) of each other, the Fair Market Value of the Facility shall be the simple average of the two appraisals. If the values of the two appraisals differ by ten percent (10%) or more, the first two appraisers shall choose a third independent appraiser experienced in appraising solar power generation assets, or, if the first two appraisers fail to agree upon a third appraiser within ten (10) days after the expiration of the thirty (30) day period following completion of both appraisals, such appointment shall be made by the AAA upon application of either Party in accordance with the applicable rules and regulations of the AAA for such selection. The third appraiser shall have access to the same information as was available to the two other appraisers. The Parties shall direct the third appraiser to determine the fair market value of the Facility within sixty (60) days following his retention. The costs and expenses of such third appraiser shall be shared equally by the Parties. Upon completion of the fair market value of the Facility by such appraiser, the Fair Market Value of the Facility will be the simple average of the three appraisal values completed in accordance with this Section 7.2.

7.2.4 Exercise of Purchase Option. Within ninety (90) days following the determination of the Fair Market Value of the Facility pursuant to this Section 7.2, but in no event later than eighteen (18) months following delivery of a Preliminary Interest Notice, PacifiCorp shall notify Seller if PacifiCorp elects to exercise its option (an "Option Confirmation Notice").

7.2.5 Purchase and Sale. If PacifiCorp delivers a valid and timely Option Confirmation Notice, Seller shall sell, transfer, assign and convey to PacifiCorp all of the Facility and all rights of Seller therein or relating thereto, on an "AS IS, WHERE IS" basis, free and clear of all liens, claims, encumbrances, or rights of others arising through Seller on the last day of the Term, including good and valid title to the Facility and Seller's rights in the Premises. In connection with such sale, transfer, assignment and conveyance, Seller shall (a) assign or otherwise make available, to the extent permitted by Requirements of Law and not already assigned or otherwise transferred to PacifiCorp, Seller's interest in all applicable Required Facility Documents; (b) cooperate with all reasonable requests of PacifiCorp for purposes of enabling PacifiCorp to obtain any and all applicable Permits that are or will be required to be obtained by PacifiCorp in connection with the use, occupancy, operation or maintenance of the Facility or the Premises in compliance with Requirements of Law; (c) provide PacifiCorp copies of all documents, instruments, plans, maps, specifications, manuals, drawings and other documentary materials relating to the installation, maintenance, operation, construction, design, modification and repair of the Facility, as shall be in Seller's possession and shall be reasonably appropriate or necessary for the continued operation of the Facility.

SECTION 8

SECURITY AND CREDIT SUPPORT

8.1 Project Development Security. Seller shall provide within five (5) Business Days from receipt of a written request from PacifiCorp all reasonable financial records necessary for PacifiCorp to confirm Seller satisfies the Credit Requirements.

8.1.1 Form and Amount of Project Development Security. On or before the date specified in Section 2.3(a), Seller shall post and maintain in favor of PacifiCorp (a) a guaranty from a party that satisfies the Credit Requirements, in substantially the form attached hereto as Exhibit D, or (b) a Letter of Credit in favor of PacifiCorp, in a form acceptable to PacifiCorp in its reasonable discretion, equal in each case to two hundred dollars ($200) per kW of Expected Nameplate Capacity Rating (the "Project Development Security"). Seller and any entity providing a guaranty shall provide within five (5) Business Days from receipt of a written request from PacifiCorp all reasonable financial records necessary for PacifiCorp to confirm the guarantor satisfies the Credit Requirements.

8.1.2 Use of Project Development Security to Pay Delay Damages. If the Commercial Operation Date occurs after the Scheduled Commercial Operation Date and Seller has failed to pay any Delay Damages when due under Section 2.5, PacifiCorp shall be entitled to and shall draw upon the Project Development Security an amount equal to the Delay Damages until such time as the Project Development Security is exhausted. PacifiCorp shall also be entitled to draw upon the Project Development Security for other damages if this Agreement is terminated under Section 11 because of Seller's default.

8.1.3 Termination of Project Development Security. Seller shall no longer be required to maintain the Project Development Security after the Commercial Operation Date, if at such time no damages are owed to PacifiCorp under this Agreement. However, as of the Commercial Operation Date, Seller may elect to apply the Project Development Security toward the Default Security required by Section 8.2, including by the automatic continuation (as opposed to the replacement) thereof.

8.2 Default Security.

8.2.1 Duty to Post Default Security. On the date specified in Section 2.3(b), Seller shall post and maintain in favor of PacifiCorp (a) a guaranty from an entity that satisfies the Credit Requirements, in substantially the form attached hereto as Exhibit D, or (b) a Letter of Credit, each in the amount specified in Section 8.2.1 (the "Default Security"), as provided in this Section 8.2. Seller and any entity providing a guaranty shall provide within five (5) Business Days from receipt of a written request from PacifiCorp all reasonable financial records necessary for PacifiCorp to confirm the guarantor satisfies the Credit Requirements.

8.2.2 Amount of Default Security. The amount of the Default Security required by Section 8.2.1 shall be one hundred dollars ($100) per kW of Expected Nameplate Capacity Rating and will be held until the agreement expires.

8.3 [Reserved].

8.4 Subordinated Security Interests.

8.4.1 Security Interests. On or before the Effective Date, and simultaneously with the acquisition by Seller after the Effective Date of any additional real property in connection with the Facility, Seller shall execute, file and record such agreements, documents, instruments, mortgages, deeds of trust and other writings as PacifiCorp may reasonably request, all in the form attached hereto as Exhibit 8.4.1, to give PacifiCorp a perfected security interest in and lien on the Facility, the Premises, all present and future real property, personal property and fixtures therein and all other assets necessary or appropriate for the development, construction, ownership, operation or maintenance of the Facility, as security for Seller's performance and any amounts owed by Seller to PacifiCorp pursuant hereto (collectively the "Security Interests"). The Security Interests shall be subordinate in right of payment, priority and remedies only to (a) the interests of the Senior Lenders in any credit arrangements described in the definition of "Lenders," and (b) to the extent provided by applicable law, any workers', mechanics', suppliers', tax or similar liens arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within five (5) Business Days of the commencement of any proceeding to foreclose the lien.

8.4.2 Maintenance of Security Interests. Seller hereby authorizes the filing and recording of financing statements in the name of Seller as debtor thereunder and shall take such further action and execute such further instruments and other writings as shall be required by PacifiCorp to confirm and continue the validity, priority, and perfection of the Security Interests. The granting of the Security Interests shall not be to the exclusion of, nor be construed to limit the amount of any further claims, causes of action or other rights accruing to PacifiCorp by reason of any breach or default by Seller hereunder or the termination hereof prior to the expiration of the Term.

8.4.3 Transfer of Required Facility Documents. The Security Interests shall provide that if PacifiCorp acts to obtain title to the Facility pursuant to the Security Interests, Seller shall take all steps necessary to transfer all Required Facility Documents necessary to operate the Facility to PacifiCorp, and shall diligently prosecute and cooperate in such transfers.

8.5 Debt-to-Equity Ratio; Annual and Quarterly Financial Statements. Seller shall at all times during the Term, following the Commercial Operation Date, maintain the percentage of Facility Equity (as defined below) at no less than thirty percent (30%). Annually on March 1st, commencing after the Commercial Operation Date, Seller shall provide to PacifiCorp a certificate of Seller's Chief Financial Officer attesting to the maintenance of such Facility Equity percentage and the Facility's then-current Book Value. If requested by PacifiCorp from time to time, Seller shall within thirty (30) days provide PacifiCorp with copies of its most recent annual and quarterly financial statements and statement of the Facility's then-current Book Value. If, as of any such reporting date, the Facility Equity percentage is less than thirty (30) percent, then within sixty (60) days after such reporting date, Seller, in its discretion, will either (a) take the necessary action to cause the percentage of Facility Equity to be no less than thirty percent (30%) or (b) increase the amount of the Default Security by an amount equal to one percent (1%) (or pro rata portion thereof) of the then-current Book Value of the Facility for each percentage (or pro rata portion thereof) that Facility Equity falls below thirty percent (30%). PacifiCorp, in its sole discretion, may require that any required increase to the Default Security be provided in a form of Letter of Credit or cash, by providing written notice to Seller. For purposes of this section, "Facility Equity" means the aggregate amount, as of the Commercial Operation Date, of equity investment in the Facility by any owner, investor, or other party. The phrases "percentage of Facility Equity" or "Facility Equity percentage" means the ratio, expressed as a percentage, of the Facility Equity to the sum of (x) all indebtedness outstanding to third parties and (y) the amount of Facility Equity. Seller shall not grant a security interest to any third party in the Facility or any of its assets to support the obligations of any entity other than Seller or its Affiliates, or any obligations of Seller or its Affiliates other than obligations that relate directly to the Facility or Seller's or its Affiliates' other solar energy facilities. Without limiting the foregoing, Seller agrees to cause the contribution of Facility Equity whenever such contribution is required under Seller's and Seller's Affiliates agreements with Lenders.

8.6 Security is Not a Limit on Seller's Liability. The security contemplated by this Section 8 (a) constitutes security for, but is not a limitation of, Seller's obligations hereunder and (b) shall not be PacifiCorp's exclusive remedy for Seller's failure to perform in accordance with this Agreement. Seller shall maintain security as required by Sections 8.1, 8.2 and 8.3, as applicable per this Agreement. To the extent that PacifiCorp draws on any security, Seller shall, on or before the first day of the Contract Year following such draw, replenish or reinstate the security to the full amount then required under this Section 8. If at any time the Seller or Seller's credit support provider(s) fails to meet the Credit Requirements, then Seller shall provide replacement security meeting the requirements set forth in Section 8 within ten (10) Business Days after the earlier of (x) Seller's receipt of notice from any source that Seller or the credit support provider(s), as applicable, no longer meets the Credit Requirements or (y) Seller's receipt of written notice from PacifiCorp requesting the posting of alternate security.

SECTION 9
METERING

9.1 Installation of Metering Equipment. Metering equipment shall be designed, furnished, installed, owned, inspected, tested, maintained and replaced as provided in the Generation Interconnection Agreement; provided, however, that PacifiCorp acting in its merchant function capacity shall be under no obligation, pursuant hereto, to bear any expense relating to such metering equipment.

9.2 Metering. Metering shall be performed at the location and in the manner specified in Exhibit 9.2, the Generation Interconnection Agreement and as necessary to perform Seller's obligations hereunder. All quantities of Net Output purchased hereunder shall reflect the net amount of energy flowing into the System at the Point of Delivery.

9.3 Inspection, Testing, Repair and Replacement of Meters. PacifiCorp shall have the right to periodically inspect, test, repair and replace the metering equipment that are provided for in the Generation Interconnection Agreement, without PacifiCorp assuming any obligations thereunder. If any of the inspections or tests disclose an error exceeding 0.5 percent (0.5%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three months, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered. Such correction, when made, shall constitute full adjustment of any claim between Seller and PacifiCorp arising out of such inaccuracy of metering equipment. Nothing in this Agreement shall give rise to PacifiCorp, acting in its merchant function capacity hereunder, having any obligations to Seller, or any other person or entity, pursuant to or under the Generation Interconnection Agreement.

9.4 Metering Costs. To the extent not otherwise provided in the Generation Interconnection Agreement, Seller shall bear all costs (including PacifiCorp's costs) relating to all metering equipment installed to accommodate Seller's Facility.

9.5 Meter Data. Within ten (10) days of the Effective Date, Seller may request the Interconnection Provider or Transmission Provider in writing in a form similar to that found in Exhibit 9.5 to provide any and all meter or other data associated with the Facility or Net Output directly to PacifiCorp. Should Seller refuse to provide a release similar to that found in Exhibit 9.5, Seller shall establish a mechanism at its expense that allows PacifiCorp, in its merchant function, to obtain all necessary meter and other data to fully perform and verify Seller's performance under this Agreement. Notwithstanding any other provision hereof, PacifiCorp shall have the right to provide such data to any Electric System Authority.

9.6 WREGIS Metering. Seller shall cause the Facility to implement all necessary generation information communications in WREGIS, and report generation information to WREGIS pursuant to a WREGIS-approved meter that is dedicated to the Facility and only the Facility.

SECTION 10
BILLINGS, COMPUTATIONS AND PAYMENTS

10.1 Monthly Invoices. On or before the tenth (10^{th}) day following the end of each calendar month, Seller shall deliver to PacifiCorp a proper invoice showing Seller's computation of Net Output delivered to the Point of Delivery during such month. When calculating the invoice, Seller shall provide computations showing the portion of Net Output that was delivered during On-Peak Hours and the portion of Net Output that was delivered during Off-Peak Hours. If such invoice is delivered by Seller to PacifiCorp, then PacifiCorp shall send to Seller, on or before the later of the twentieth (20^{th}) day following receipt of such invoice or the thirtieth (30^{th}) day following the end of each month, payment for Seller's deliveries of Net Output and associated Green Tags to PacifiCorp.

10.2 Offsets. Either Party may offset any payment due hereunder against amounts owed by the other Party pursuant hereto. Either Party's exercise of recoupment and set off rights shall not limit the other remedies available to such Party hereunder.

10.3 Interest on Late Payments. Any amounts that are not paid when due hereunder shall bear interest at the Contract Interest Rate from the date due until paid.

10.4 Disputed Amounts. If either Party, in good faith, disputes any amount due pursuant to an invoice rendered hereunder, such Party shall notify the other Party of the specific basis for the dispute and, if the invoice shows an amount due, shall pay that portion of the statement that is undisputed, on or before the due date. Except with respect to invoices provided under Section 6.12.3, any such notice shall be provided within two (2) years of the date of the invoice in which the error first occurred. If any amount disputed by such Party is determined to be due the other Party, or if the Parties resolve the payment dispute, the amount due shall be paid within five (5) Business Days after such determination or resolution, along with interest at the Contract Interest Rate from the date due until the date paid.

10.5 Audit Rights. Each Party, through its authorized representatives, shall have the right, at its sole expense upon reasonable notice and during normal business hours, to examine and copy the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made hereunder or to verify the other Party's performance of its obligations hereunder. Upon request, each Party shall provide to the other Party statements evidencing the quantities of Net Output delivered at the Point of Delivery. If any statement is found to be inaccurate, a corrected statement shall be issued and any amount due thereunder will be promptly paid and shall bear interest at the Contract Interest Rate from the date of the overpayment or underpayment to the date of receipt of the reconciling payment. Notwithstanding the foregoing, no adjustment shall be made with respect to any statement or payment hereunder unless a Party questions the accuracy of such payment or statement within two (2) years after the date of such statement or payment.

SECTION 11
DEFAULTS AND REMEDIES

11.1 Defaults. The following events are defaults (each a “default” before the passing of applicable notice and cure periods, and an “Event of Default” thereafter) hereunder:

11.1.1 Defaults by Either Party.

(a) A Party fails to make a payment when due hereunder if the failure is not cured within ten (10) Business Days after the non-defaulting Party gives the defaulting Party a notice of the default.

(b) A Party (i) makes a general assignment for the benefit of its creditors; (ii) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (iii) becomes insolvent; or (iv) is unable to pay its debts when due.

(c) A Party breaches a representation or warranty made by it herein if the breach is not cured within thirty (30) days after the non-defaulting Party gives the defaulting Party a notice of the default; provided that if such default is not reasonably capable of being cured within the thirty (30) day cure period but is reasonably capable of being cured within a ninety (90) day cure period, the defaulting Party will have such additional time (not exceeding an additional sixty (60) days) as is reasonably necessary to cure, if, prior to the end of the thirty (30) day cure period the defaulting Party provides the non-defaulting Party a remediation plan, the non-defaulting party approves such remediation plan, and the defaulting Party promptly commences and diligently pursues the remediation plan.

(d) A Party otherwise fails to perform any material obligation hereunder for which an exclusive remedy is not provided hereunder and which is not addressed in any other Event of Default described in Section 11.1, if the failure is not cured within thirty (30) days after the non-defaulting Party gives the defaulting Party notice of the default; provided that if such default is not reasonably capable of being cured within the thirty (30) day cure period but is reasonably capable of being cured within a ninety (90) day cure period, the defaulting Party will have such additional time (not exceeding an additional sixty (60) days) as is reasonably necessary to cure, if, prior to the end of the thirty (30) day cure period the defaulting Party provides the non-defaulting Party a remediation plan, the non-defaulting party approves such remediation plan, and the defaulting Party promptly commences and diligently pursues the remediation plan.

11.1.2 Defaults by Seller.

(a) Seller fails to post, increase, or maintain the Project Development Security or Default Security as required under, and by the applicable dates set forth in, Section 2 and Section 8 and such failure is not cured within ten (10) Business Days after PacifiCorp gives Seller notice of default.

(b) Seller fails to (i) cause the Facility to achieve Commercial Operation on or before the Guaranteed Commercial Operation Date, or (ii) complete all items included on the Final Completion Schedule within ninety (90) days after the Commercial Operation Date.

(c) Seller sells Output, Green Tags or Capacity Rights from the Facility to a party other than PacifiCorp in breach of Section 4.2, or Seller makes a public statement or otherwise takes an action that any Governmental Authority or the Center for Resource Solutions determines is a retirement, double counting, double sale, double use or double claim of Green Tags, if Seller does not permanently cease such sale and compensate PacifiCorp for the damages arising from the breach within ten (10) days after PacifiCorp gives Seller a notice of default.

(d) PacifiCorp receives notice of foreclosure of the Facility or any part thereof by a Lender, mechanic or materialman, or any other holder, of an unpaid lien or other charge or encumbrance, if the same has not been stayed, paid, or bonded around within ten (10) days of the date of the notice received by PacifiCorp.

(e) After the Commercial Operation Date, Seller fails to maintain any Required Facility Documents or Permits necessary to own or operate the Facility and such failure continues for thirty (30) days after Seller’s receipt of written notice thereof from PacifiCorp; provided, however, that, upon written notice from Seller, the thirty (30) day period shall be extended by an additional sixty (60) days if (i) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (ii) the default is capable of being cured within the additional sixty (60) day period, and (iii) Seller commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

(f) Seller's Abandonment of construction or operation of the Facility and such failure continues for thirty (30) days after Seller’s receipt of written notice thereof from PacifiCorp.

(g) Seller fails to maintain insurance as required by the Agreement and such failure continues for ten (10) days after Seller's receipt of written notice thereof from PacifiCorp.

(h) Seller fails to meet the Output Guarantee for two (2) consecutive years.

11.2 Remedies for Failure to Deliver/Receive.

11.2.1 Remedy for Seller's Failure to Deliver. Upon the occurrence and during the continuation of a default of Seller under Section 11.1.2(c), Seller shall pay PacifiCorp within five (5) Business Days after invoice receipt, an amount equal to the sum of (a) PacifiCorp's Cost to Cover multiplied by the Net Output delivered to a party other than PacifiCorp, (b) additional transmission charges, if any, reasonably incurred by PacifiCorp in moving replacement energy to the Point of Delivery or if not there, to such points in PacifiCorp's control area as are determined by PacifiCorp, and (c) any additional cost or expense incurred as a result of Seller's default under Section 11.1.2(c), as determined by PacifiCorp in a commercially reasonable manner. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

11.2.2 Remedy for PacifiCorp's Failure to Purchase. If PacifiCorp fails to receive or purchase all or part of the Net Output and Green Tags required to be purchased pursuant hereto and such failure is not excused under the terms hereof or by Seller's failure to perform, then Seller shall first satisfy its obligations under Section 11.7 and then PacifiCorp shall pay Seller, on the earlier of the date payment would otherwise be due in respect of the month in which the failure occurred or within five (5) Business Days after invoice receipt, an amount equal to Seller's Cost to Cover multiplied by the amount of Net Output so not purchased, less amounts received by Seller pursuant to Section 11.7. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation thereof.

11.2.3 Remedy for Seller's Failure to Sell/Deliver Capacity Rights. Seller shall be liable for PacifiCorp's actual damages in the event Seller fails to sell or deliver all or any portion of the Capacity Rights to PacifiCorp.

11.3 Termination and Remedies. From and during the continuance of an Event of Default, the non-defaulting Party shall be entitled to all remedies available at law or in equity, and may terminate this Agreement by notice to the other Party designating the date of termination and delivered to the defaulting Party no less than one (1) Business Day before such termination date. The notice required by this Section 11.3 may be provided in the notice of default (and does not have to be a separate notice) so long as it complies with all other terms of this Section 11.3. As a precondition to Seller's exercise of this termination right, Seller must also provide copies of such notice to the notice addresses of the then-current President and General Counsel of PacifiCorp. Such copies shall be sent by registered overnight delivery service or by certified or registered mail, return receipt requested. In addition, Seller's termination notice shall state prominently therein in typefont no smaller than 14-point all-capital letters that “THIS IS A TERMINATION NOTICE UNDER A PPA. YOU MUST CURE A DEFAULT, OR THE PPA WILL BE TERMINATED,” and shall state therein any amount purported to be owed and wiring instructions. Notwithstanding any other provision of this Agreement to the contrary, Seller will not have any right to terminate this Agreement if the default that gave rise to the termination right is cured within fifteen (15) Business Days of PacifiCorp’s receipt of such notice. Further, from and after the date upon which Seller fails to remedy a default within the time periods provided in Section 11.1, and until PacifiCorp has recovered all damages incurred on account of such default by Seller, without exercising its termination right, PacifiCorp may offset its damages against any payment due Seller. Except in circumstances in which a remedy provided for in this Agreement is described as a Party's sole or exclusive remedy, upon termination, the non-defaulting Party may pursue any and all legal or equitable remedies provided by law, equity or this Agreement. The rights contemplated by this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. In the event of a termination hereof:

(a) Each Party shall pay to the other all amounts due the other hereunder for all periods prior to termination, subject to offset by the non-defaulting Party against damages incurred by such Party.

(b) The amounts due pursuant to Section 11.3(a) shall be calculated and paid within thirty (30) days after the billing date for such charges and shall bear interest thereon at the Contract Interest Rate from the date of termination until the date paid. The foregoing does not extend the due date of, or provide an interest holiday for any payments otherwise due hereunder.

(c) Before and after the effective date of termination, the non-defaulting Party may pursue, to the extent permitted by this Agreement, any and all legal or equitable remedies provided by law, equity or this Agreement.

(d) Without limiting the generality of the foregoing, the provisions of Sections 4.5, 5.4, 5.5, 6.10.4, 6.10.5, 6.10.7, 10.3, 10.4, 10.5, 11.3, 11.5, 11.6, 11.7, 11.8, 11.9 and Section 12, Section 13, Section 23, and Section 24 shall survive the termination hereof.

11.4 Intentionally Omitted.

11.5 Termination Damages. If this Agreement is terminated as a result of an Event of Default by one of the Parties, termination damages shall be determined. The amount of termination damages shall be calculated by the non-defaulting Party within a reasonable period after termination of the Agreement. Amounts owed pursuant to this section shall be due within five (5) Business Days after the non-defaulting Party gives the defaulting Party notice of the amount due. The non-defaulting Party shall under no circumstances be required to account for or otherwise credit or pay the defaulting Party for economic benefits accruing to the non-defaulting Party as a result of the defaulting Party's default.

11.6 Senior Lender Foreclosure. An exercise of remedies under the financing documents between Seller and Senior Lenders, in and of itself, is not an Event of Default under Section 11.1.2(d).

11.7 Duty/Right to Mitigate. Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance hereof. “Commercially reasonable efforts” (a) by Seller shall include requiring Seller to use commercially reasonable efforts to maximize the price for Net Output and associated Green Tags received by Seller from third parties, including entering into an enabling agreement with, or being affiliated with, one or more power marketers of nationally recognized standing to market such Net Output and associated Green Tags not purchased or accepted by PacifiCorp (only during a period PacifiCorp is in default), in each case only to the extent any of the foregoing actions are permitted under Requirements of Law and the Interconnection Agreement; and (b) by PacifiCorp shall include requiring PacifiCorp to use commercially reasonable efforts to minimize the price paid to third parties for energy and Green Tags purchased to replace Net Output and Green Tags not delivered by Seller as required hereunder.

11.8 Security. If this Agreement is terminated because of Seller's default, PacifiCorp may, in addition to pursuing any and all other remedies available at law or in equity, proceed against any security held by PacifiCorp in whatever form to reduce any amounts that Seller owes PacifiCorp arising from such default.

11.9 Step-In Rights.

11.9.1 Failure to Achieve Commercial Operation. If Seller fails to achieve Commercial Operation of the Facility by the Guaranteed Commercial Operation Date, PacifiCorp shall have the right to enter the Facility and do all such things as PacifiCorp may consider necessary or desirable to complete the Facility and cause Commercial Operation to occur. PacifiCorp shall, following the Commercial Operation Date (a) return the Facility to Seller upon execution of an indemnity and release by Seller of all claims arising out of the period of PacifiCorp’s entry on the Facility in a form reasonably acceptable to PacifiCorp or (b) failing the execution of such release or indemnity, operate the Facility for the Term pursuant to Section 11.9.2. PacifiCorp shall likewise return the Facility to Seller upon a showing by Seller that it is immediately ready, willing and able to achieve Commercial Operation of the Facility within a commercially and technically reasonable period of time.

11.9.2 License to Operate Facility. Seller hereby irrevocably grants to PacifiCorp the right, license, and authority to enter the Premises, operate and maintain the Facility, and to perform Seller's obligations hereunder for the Term during the continuance of an Event of Default by Seller under Sections 11.1.2(b), 11.1.2(c), 11.1.2(e), 11.1.2(f), or 11.1.2(h) (such rights along with those rights set forth in Section 11.9.1, "Step-In Rights"). PacifiCorp may, but shall not be obligated to, exercise its rights as licensee under this section in lieu of termination. During any period in which PacifiCorp is operating and maintaining the Facility pursuant to the license granted in this Section, Seller shall, upon request from PacifiCorp, reimburse PacifiCorp for all reasonable costs and expenses incurred by PacifiCorp to operate and maintain the Facility.

11.9.3 Indemnification; Standard of Care. Seller shall indemnify and hold PacifiCorp harmless from and against all losses, costs, charges and expenses reasonably incurred by PacifiCorp in connection with exercise of its rights under Section 11.9.1 or 11.9.2 whether to third parties or otherwise, other than losses, costs, charges and expenses attributable to the gross negligence or willful misconduct of PacifiCorp. During such time as PacifiCorp has custody of the Premises and Facility pursuant to this Section 11.9, it shall conduct all of its activities pursuant to Prudent Electrical Practices.

11.9.4 Records and Access. Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Electrical Practices. Upon PacifiCorp's notice of its intent to exercise Step-In Rights, PacifiCorp, its employees, contractors, or designated third parties shall have the right to enter the Premises and the Facility for the purpose of constructing or operating the Facility. Upon the exercise by PacifiCorp of the Step-In Rights, Seller shall cause the Facility operator (and any Person within the control of Seller) to give PacifiCorp access to and control of the operation and maintenance of the Facility to the extent reasonably necessary to enable PacifiCorp to exercise the Step-In Rights in respect of the part of the Facility so to be operated by PacifiCorp, and shall provide reasonable assistance and cooperation to PacifiCorp to effect safely the transfer of operational responsibility as may be requested by PacifiCorp. Seller shall execute such documents and take such other action as may be necessary for PacifiCorp to effectuate its rights under this Section 11.9.

11.9.5 Return. PacifiCorp may, at any time, terminate its exercise of the Step-In Rights whether or not the applicable event has been cured. If at any time after exercising its Step-In Rights, PacifiCorp elects to return such possession to Seller, PacifiCorp shall provide Seller with at least ten (10) days advance notice of the date PacifiCorp intends to return such possession, and upon receipt of such notice Seller shall take all measures necessary to resume possession of the Facility on such date.

11.9.6 No Assumption. PacifiCorp's exercise of its Step-In Rights shall not be deemed an assumption by PacifiCorp of any liability of Seller due and owing prior to the exercise of such rights. PacifiCorp shall not assume any liability of Seller for the period during which PacifiCorp exercises such Step-In Rights. During any period that PacifiCorp is exercising its Step-In Rights, Seller shall retain legal title to and ownership of the Facility and all of its other property and its revenues. When exercising its Step-In Rights, PacifiCorp shall assume possession, operation, and control of the Facility solely as agent for Seller. In no event shall PacifiCorp's election to exercise the Step-In Rights be deemed to constitute a transfer of ownership of or title to the Facility or any assets of Seller.

11.9.7 Costs and Expenses. Seller shall indemnify and hold harmless PacifiCorp from and against all losses, costs, charges and expenses incurred by PacifiCorp in connection with exercise of its Step-In Rights other than all losses, costs, charges and expenses attributable to the gross negligence or willful misconduct of PacifiCorp. In connection with its exercise of Step-In Rights, PacifiCorp shall have the right to recoup and set off all such losses, costs, charges and expenses against amounts otherwise owed by PacifiCorp hereunder. PacifiCorp's exercise of such recoupment and set off rights shall not limit the other remedies available to PacifiCorp hereunder or otherwise.

11.10 Cumulative Remedies. Except in circumstances in which a remedy provided for in this Agreement is described as a sole or exclusive remedy, the rights and remedies provided to PacifiCorp hereunder are cumulative and not exclusive of any rights or remedies of PacifiCorp.

SECTION 12
INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. To the extent permitted by Requirements of Law and subject to Section 12.1.5, Seller shall release, indemnify and hold harmless PacifiCorp, its divisions, Affiliates, and each of its and their respective directors, officers, employees, agents, and representatives (collectively, the "PacifiCorp Indemnitees") against and from any and all losses, fines, penalties, claims, demands, damages, liabilities, actions or suits of any nature whatsoever (including legal costs and attorneys' fees, both at trial and on appeal, whether or not suit is brought) (collectively, "Liabilities") actually or allegedly resulting from, or arising out of, or in any way connected with, the performance by Seller of its obligations hereunder, or relating to the Facility or Premises, for or on account of injury, bodily or otherwise, to, or death of, or damage to or destruction of property of, any person or entity, excepting only to the extent such Liabilities as may be caused by the gross negligence or willful misconduct of any person or entity within the PacifiCorp Indemnitees. Seller shall be solely responsible for (and shall defend and hold PacifiCorp harmless against) any damage that may occur as a direct result of Seller's breach of the Generation Interconnection Agreement.

12.1.2 Indemnity by PacifiCorp. To the extent permitted by Requirements of Law and subject to Section 12.1.5, PacifiCorp shall release, indemnify and hold harmless Seller, its Affiliates, and each of its and their respective directors, officers, employees, agents, and representatives (collectively, the "Seller Indemnitees") against and from any and all Liabilities actually or allegedly resulting from, or arising out of, or in any way connected with, the performance by PacifiCorp of its obligations hereunder for or on account of (a) injury, bodily or otherwise, to, or death of, or (b) for damage to, or destruction of property of, any person or entity within the Seller Indemnitees, excepting only to the extent such Liabilities as may be caused by the gross negligence or willful misconduct of any person or entity within the Seller Indemnitees.

12.1.3 Additional Cross Indemnity. Without limiting Sections 12.1.1 and 12.1.2, Seller shall release, indemnify and hold harmless the PacifiCorp Indemnitees from and against all Liabilities related to Net Output prior to its delivery by Seller at the Point of Delivery, and PacifiCorp shall release, indemnify and hold harmless the Seller Indemnitees from and against all Liabilities related to Net Output once delivered to PacifiCorp at the Point of Delivery as provided herein, except in each case to the extent such Liabilities are attributable to the gross negligence or willful misconduct or a breach of this Agreement by any member of the PacifiCorp Indemnitees or the Seller Indemnitees, respectively, seeking indemnification hereunder.

12.1.4 No Dedication. Nothing herein shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party. No undertaking by one Party to the other under any provision hereof shall constitute the dedication of PacifiCorp's facilities or any portion thereof to Seller or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.1.5 Consequential Damages. **NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE. THE PARTIES AGREE THAT ANY LIQUIDATED DAMAGES, DELAY DAMAGES, PACIFICORP AND SELLER COST TO COVER DAMAGES, SECTION 11.2.3 CAPACITY RIGHTS LOSS DAMAGES, OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR HEREIN, ARE NOT INTENDED BY THEM TO REPRESENT SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES.**

SECTION 13
INSURANCE

13.1 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller hereunder, Seller shall secure and continuously carry the insurance coverage specified on Exhibit 13 during the Term or longer period if specified in Exhibit 13.

13.2 Certificates of Insurance. Seller shall provide PacifiCorp with certificates of insurance within ten (10) days after the date by which such policies are required to be obtained (as set forth in Exhibit 13). Seller shall provide a certificate of insurance (in ACORD or similar industry form) to PacifiCorp within ten (10) days of the effective date of any insurance policy required under this Agreement. The certificates shall indicate that the insurer shall provide thirty (30) days prior written notice of cancellation. If any coverage is written on a “claims-made” basis, the certification accompanying the policy shall conspicuously state that the policy is "claims made."

SECTION 14
FORCE MAJEURE

14.1 Definition of Force Majeure. "Force Majeure" or "an event of Force Majeure" means an event that (a) is not reasonably anticipated as of the date hereof, (b) is not within the reasonable control of the Party affected by the event, (c) is not the result of such Party's negligence or failure to act, and (d) could not be overcome by the affected Party's use of due diligence in the circumstances. Force Majeure includes, but is not restricted to, events of the following types (but only to the extent that such an event, in consideration of the circumstances, satisfies the tests set forth in the preceding sentence): acts of God; civil disturbance; sabotage; strikes; lock-outs; work stoppages; and action or restraint by court order or public or Governmental Authority (as long as the affected Party has not applied for or assisted in the application for, and has opposed to the extent reasonable, such court or government action). Notwithstanding the foregoing, none of the following constitute Force Majeure: (i) Seller's ability to sell, or PacifiCorp's ability to purchase energy, capacity or Green Tags at a more advantageous price than is provided hereunder; (ii) the cost or availability of fuel or motive force to operate the Facility; (iii) economic hardship, including lack of money; (iv) any breakdown or malfunction of the Facility"s equipment (including any serial equipment defect) that is not caused by an independent event of Force Majeure, (v) the imposition upon a Party of costs or taxes allocated to such Party under Section 5, (vi) delay or failure of Seller to obtain or perform any Required Facility Document unless due to a Force Majeure event, (vii) any delay, alleged breach of contract, or failure by the Transmission Provider, Network Service Provider or Interconnection Provider unless due to a Force Majeure event, (viii) maintenance upgrade or repair of any facilities or right of way corridors constituting part of or involving the Interconnection Facilities, whether performed by or for Seller, or other third parties (except for repairs made necessary as a result of an event of Force Majeure); (ix) Seller's failure to obtain, or perform under, the Generation Interconnection Agreement, or its other contracts and obligations to transmission owner, Transmission Provider or Interconnection Provider, unless due to a Force Majeure event; or (x) any event attributable to the use of Interconnection Facilities for deliveries of Net Output to any party other than PacifiCorp. Notwithstanding anything to the contrary herein, in no event will the increased cost of electricity, steel, labor, or transportation constitute an event of Force Majeure.

14.2 Suspension of Performance. After the Commercial Operation Date, but not before, neither Party shall be liable for any delay or failure in its performance under this Agreement, nor shall any delay, failure, or other occurrence or event become an Event of Default, to the extent such delay, failure, occurrence or event is substantially caused by conditions or events of Force Majeure during the continuation of the event of Force Majeure, for the same number of days that the event of Force Majeure has prevailed, provided that:

(a) the Party affected by the Force Majeure, shall, within five (5) days after the occurrence of the event of Force Majeure, give the other Party written notice describing the particulars of the event; and

(b) the suspension of performance shall be of no greater scope and of no longer duration than is required to remedy the effect of the Force Majeure; and

(c) the affected Party shall use diligent efforts to remedy its inability to perform.

14.3 Force Majeure Does Not Affect Other Obligations. No obligations of either Party that arose before the Force Majeure causing the suspension of performance or that arise after the cessation of the Force Majeure shall be excused by the Force Majeure. No obligation of Seller arising before the Commercial Operation Date may be excused by Force Majeure.

14.4 Strikes. Notwithstanding any other provision hereof, neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.5 Right to Terminate. If a Force Majeure event prevents a Party from substantially performing its obligations hereunder for a period exceeding 180 consecutive days (despite the affected Party's effort to take all reasonable steps to remedy the effects of the Force Majeure with all reasonable dispatch), then the Party not affected by the Force Majeure event, with respect to its obligations hereunder, may terminate this Agreement by giving ten (10) days prior notice to the other Party. Upon such termination, neither Party will have any liability to the other with respect to the period following the effective date of such termination; provided, however, that this Agreement will remain in effect to the extent necessary to facilitate the settlement of all liabilities and obligations arising hereunder before the effective date of such termination.

SECTION 15
SEVERAL OBLIGATIONS

Nothing contained herein shall be construed to create an association, trust, partnership or joint venture or to impose a trust, partnership or fiduciary duty, obligation or liability on or between the Parties.

SECTION 16
CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the State of [______],[4] applying any choice of law rules that may direct the application of the laws of another jurisdiction.

SECTION 17
PARTIAL INVALIDITY

The Parties do not intend to violate any laws governing the subject matter hereof. If any of the terms hereof are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms hereof shall remain in effect. The Parties shall use best efforts to amend this Agreement to reform or replace any terms determined

[4] Note to Bidders – The laws of the state in which the facility is located will apply, provided it is a state in which PacifiCorp is engaged in utility operations (e.g., Wyoming, Utah, Washington, Oregon and Idaho).

to be invalid, illegal or void, such that the amended terms (a) comply with and are enforceable under applicable law, (b) give effect to the intent of the Parties under this Agreement, and (c) preserve the balance of the economics and equities contemplated by this Agreement in all material respects.

SECTION 18
NON-WAIVER

No waiver of any provision hereof shall be effective unless the waiver is set forth in a writing that (a) expressly identifies the provision being waived, and (b) is executed by the Party waiving the provision. A Party's waiver of one or more failures by the other Party in the performance of any of the provisions hereof shall not be construed as a waiver of any other failure or failures, whether of a like kind or different nature.

SECTION 19
GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those Governmental Authorities having control over either Party or this Agreement. During the Term, Seller shall maintain all Permits required, as applicable, for the construction, operation, or ownership of the Facility.

SECTION 20
SUCCESSORS AND ASSIGNS

20.1 Restriction on Assignments. Except as expressly provided in this Section 20, neither Party may assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the other Party.

20.2 Permitted Assignments. Notwithstanding Section 20.1, either Party may, without the need for consent from the other Party (but with notice to the other Party, including the names of the assignees): (a) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds therefrom in connection with project financing for the Facility; or (b) transfer or assign this Agreement to an Affiliate meeting the requirements of this Agreement; provided, however, that Seller shall not transfer, sell, encumber or assign this Agreement or any interest herein to any Affiliate of PacifiCorp without the prior written consent of PacifiCorp. Except with respect to collateral assignments for financing purposes in every assignment permitted under this Section 20.2, the assignee must agree in writing to be bound by the terms and conditions hereof and must possess the same or similar experience, and possess the same or better creditworthiness, as the assignor. PacifiCorp may assign this Agreement in whole or in part without the consent of Seller to any person or entity in the event that PacifiCorp ceases to be a load-serving entity, in which event PacifiCorp shall be released from liability hereunder upon approval of PacifiCorp ceasing to be a load-serving entity by the Commission. The Party seeking to assign or transfer this Agreement shall be solely responsible for paying all costs of assignment.

SECTION 21
ENTIRE AGREEMENT

This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding the subject matter hereof. No modification hereof shall be effective unless it is in writing and executed by both Parties.

SECTION 22
NOTICES

22.1 Addresses and Delivery Methods. All notices, requests, statements or payments shall be made to the addresses set out below. In addition, copies of a notice of termination of this Agreement under Section 11.3 shall contain the information required by Section 11.3 and shall be sent to the then-current President and General Counsel of PacifiCorp. Notices required to be in writing shall be delivered by letter, facsimile or other tangible documentary form. Notice by overnight mail or courier shall be deemed to have been given on the date and time evidenced by the delivery receipt. Notice by hand delivery shall be deemed to have been given when received or hand delivered. Notice by facsimile is effective as of transmission to each and all of the telefacsimile numbers provided below for a Party, but must be followed up by notice by registered mail or overnight carrier to be effective. Notice by overnight mail shall be deemed to have been given the Business Day after it is sent, if sent for next day delivery to a domestic address by a recognized overnight delivery service (e.g., Federal Express or UPS). Notice by certified or registered mail, return receipt requested, shall be deemed to have been given upon receipt.

To Seller:	[________________] [________________] [________________]
with a copy to:	[________________] [________________] [________________]
To PacifiCorp:	PacifiCorp 825 NE Multnomah, Suite 600 Portland, Oregon 97232- 2315 Attn: Director, Valuation & Commercial Business Telefacsimile (503) 813-6260
with a copy to:	PacifiCorp 825 NE Multnomah, Suite 600 Portland, Oregon 97232- 2315

Attn: Contract Administration
Telefacsimile (503) 813-6291
Email: cntadmin@pacificorp.com

with copies to:

PacifiCorp Legal Department
825 NE Multnomah, Suite 1800
Portland, Oregon 97232- 2315
Attn: Assistant General Counsel
Telefacsimile (503) 813-6761

and termination notices to PacifiCorp:

PacifiCorp
1407 West North Temple
Suite 320
Salt Lake City, Utah 84116
Attn: President

and to:

PacifiCorp
1407 West North Temple
Suite 320
Salt Lake City, Utah 84116
Attn: General Counsel

22.2 Changes of Address. The Parties may change any of the persons to whom notices are addressed, or their addresses, by providing written notice in accordance with this section.

SECTION 23
CONFIDENTIALITY

23.1 Confidential Business Information. The following constitutes "Confidential Business Information," whether oral or written: (a) the Parties' proposals and negotiations concerning this Agreement, made or conducted prior to the Effective Date, (b) the actual charges billed to PacifiCorp hereunder, and (c) any information delivered by PacifiCorp to Seller prior to the Effective Date relating to the market prices of energy or Green Tags and methodologies for their determination or estimation. Seller and PacifiCorp each agree to hold such Confidential Business Information wholly confidential, except as otherwise expressly provided in this Agreement. "Confidential Business Information" shall not include information that (x) is in or enters the public domain through no fault of the Party receiving such information, or (y) was in the possession of a Party prior to the Effective Date, other than through delivery thereof as specified in subsections (a) and (c) above. A Party providing any Confidential Business Information under this Agreement shall clearly mark all pages of all documents and materials to be treated as Confidential Business information with the term "Confidential" on the front of each page, document or material. If the Confidential Business Information is transmitted by electronic means the title or subject line shall indicate the information is Confidential Business Information. All Confidential Business Information shall be maintained as confidential, pursuant to the terms of this Section 23, for a period of two (2) years from the date it is received by the receiving Party unless otherwise agreed to in writing by the Parties.

23.2 Duty to Maintain Confidentiality. Each Party agrees not to disclose Confidential Business Information to any other person (other than its Affiliates, accountants, auditors, counsel, consultants, lenders, prospective lenders, employees, officers and directors), without the prior written consent of the other Party, provided that: (a) either Party may disclose Confidential Business Information, if and to the extent such disclosure is required (i) by Requirements of Law, (ii) in order for PacifiCorp to receive regulatory recovery of expenses related to this Agreement, (iii) pursuant to an order of a court or regulatory agency, or (iv) in order to enforce this Agreement or to seek approval hereof, and (b) notwithstanding any other provision hereof, PacifiCorp may in its sole discretion disclose or otherwise use for any purpose in its sole discretion the Confidential Business Information described in Sections 23.1(b) or 23.1(c). In the event a Party is required by Requirements of Law to disclose Confidential Business Information, such Party shall to the extent possible promptly notify the other Party of the obligation to disclose such information.

23.3 PacifiCorp Regulatory Compliance. The Parties acknowledge that PacifiCorp is required by law or regulation to report certain information that is or could otherwise embody Confidential Business Information from time to time. Such reports include models, filings, reports of PacifiCorp's net power costs, general rate case filings, power cost adjustment mechanisms, FERC-required reporting such as those made on FERC Form 1 or Form 714, market power and market monitoring reports, annual state reports that include resources and loads, integrated resource planning reports, reports to entities such as NERC, WECC, Pacific Northwest Utility Coordinating Committee, WREGIS, or similar or successor organizations, forms, filings, or reports, the specific names of which may vary by jurisdiction, along with supporting documentation. Additionally, in regulatory proceedings in all state and federal jurisdictions in which it does business, PacifiCorp will from time to time be required to produce Confidential Business Information. PacifiCorp may use its business judgment in its compliance with all of the foregoing and the appropriate level of confidentiality it seeks for such disclosures. PacifiCorp may submit Confidential Business Information in regulatory proceedings without notice to Seller.

23.4 Irreparable Injury; Remedies. Each Party agrees that violation of the terms of this Section 23 constitutes irreparable harm to the other, and that the harmed Party may seek any and all remedies available to it at law or in equity, including injunctive relief.

23.5 News Releases and Publicity. Except as otherwise provided in Section 6.14, before either Party issues any news release or publicly distributed promotional material regarding the Facility that mentions the Facility, such Party shall first provide a copy thereof to the other Party for its review and approval. Any use of either Party's name in such news release or promotional material must adhere to such Party's publicity guidelines then in effect; any use of Berkshire Hathaway's name requires PacifiCorp's prior written consent.

SECTION 24
DISAGREEMENTS

24.1 Negotiations. Prior to proceeding with formal dispute resolution procedures as provided below in this Section 24, the Parties must first attempt in good faith to resolve all disputes arising out of, related to or in connection with this Agreement promptly by negotiation, as follows. Any Party may give the other Party written notice of any dispute not resolved in the normal course of business. Executives of both Parties at levels one level above those employees who have previously been involved in the dispute must meet at a mutually acceptable time and place within ten (10) days after delivery of such notice, and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the dispute. If the matter has not been resolved within thirty (30) days after the referral of the dispute to such senior executives, or if no meeting of such senior executives has taken place within fifteen (15) days after such referral, either Party may initiate any legal remedies available to the Party. All negotiations pursuant to this clause are confidential.

24.2 Mediation; Technical Expert.

24.2.1 Mediation. If the dispute is not resolved within thirty (30) days after the referral of the dispute to senior executives, or if no meeting of senior executives has taken place within fifteen (15) days after such referral, either Party may request that the matter be submitted to non-binding mediation. If the other Party agrees, the mediation will be conducted in accordance with the Construction Industry Arbitration Rules and Mediation Procedures (Including Procedures for Large, Complex Construction Disputes) of the AAA, as amended and effective on the date a Party requests mediation, and except as modified in this Section 24 (the "Mediation Procedures").

(a) The Party requesting the mediation, may commence the mediation process with AAA by notifying AAA and the other Party in writing ("Mediation Notice") of such Party's desire that the dispute be resolved through mediation, including therewith a copy of the Dispute Notice and the response thereto, if any, and a copy of the other Party's written agreement to such mediation.

(b) The mediation shall be conducted through, by and at the office of AAA located in Salt Lake City, Utah.

(c) The mediation shall be conducted by a single mediator. The Parties may select any mutually acceptable mediator. If the Parties cannot agree on a mediator within five (5) days after the date of the Mediation Notice, then the AAA's arbitration administrator shall send a list and resumes of three (3) available mediators to the Parties, each of whom shall strike one name, and the remaining person shall be appointed as the mediator. If more than one name remains, either because one or both Parties have failed to respond to the AAA's arbitration administrator within five (5) days after receiving the list or because one or both Parties have failed to strike a name from the list or because both Parties strike the same name, the AAA's arbitration administrator will choose the mediator from the remaining names. If the designated mediator shall die, become incapable or, unwilling to, or unable to serve or proceed with the mediation, a substitute mediator shall be appointed in accordance with the selection procedure described above in this Section 24.2.1, and such substitute mediator shall have all such powers as if he or she has been originally appointed herein.

(d) The mediation shall consist of one or more informal, non-binding meetings between the Parties and the mediator, jointly and in separate caucuses, out of which the mediator will seek to guide the Parties to a resolution of the Dispute. The mediation process shall continue until the resolution of the dispute, or the termination of the mediation process pursuant to Section 24.2.1(f). The costs of the mediation, including fees and expenses, shall be borne equally by the Parties.

(e) All verbal and written communications between the Parties and issued or prepared in connection with this Section 24 shall be deemed prepared and communicated in furtherance, and in the context, of dispute settlement, and shall be exempt from discovery and production, and shall not be admissible in evidence (whether as admission or otherwise) in any litigation or other proceedings for the resolution of the dispute.

(f) The initial mediation meeting between the Parties and the mediator shall be held within twenty (20) days after the Mediation Notice. Either Party may terminate the mediation process upon or after the earlier to occur of (i) the failure of the initial mediation meeting to occur within twenty (20) days after the date of the Mediation Notice, (ii) the passage of thirty (30) days after the date of the Mediation Notice without the dispute having been resolved, or (iii) such time as the mediator makes a finding that there is no possibility of resolution through mediation.

(g) All deadlines specified in this Section 24.2.1 may be extended by mutual agreement.

24.2.2 Technical Expert. If the dispute regards (a) whether or not Commercial Operation has been achieved, or (b) the disputed amount of any invoice, the Parties may, in lieu of mediation, have such dispute resolved pursuant to this Section 24.2.2. Any such dispute will be determined by an independent technical expert, who shall be a mutually acceptable third party with training and experience in the disciplines relevant to the matters with respect to which such person is called upon to provide a certification, evaluation or opinion (the "Technical Expert"), which determination shall be (x) except as otherwise provided in this Section 24.2.2, made in accordance with the Construction Industry Arbitration Rules and Mediation Procedures (Including Procedures for Large, Complex Construction Disputes) of the AAA, as amended and effective on the date a Party provides notice of its intent to submit the dispute to a technical expert, and (y) binding upon the Parties.

(a) Either Party may commence the technical dispute process with AAA by notifying AAA and the other Party in writing ("Technical Dispute Notice") of such Party's desire that the dispute be resolved through a determination by a technical expert.

(b) The determination shall be conducted by a sole Technical Expert. The Parties may select any mutually acceptable Technical Expert. If the Parties cannot agree on a Technical Expert within five (5) days after the date of the Technical Dispute Notice, then the AAA's arbitration administrator shall send a list and resumes of three (3) available technical experts meeting the qualifications set forth in Section 24.2.2 to the Parties, each of whom shall strike one name, and the remaining person shall be appointed as the Technical Expert. If more than one name remains, either because one or both Parties have failed to respond to the AAA's arbitration administrator within five (5) days after receiving the list or because one or both Parties have failed to strike a name from the list or because both Parties strike the same name, the AAA's arbitration administrator will choose the Technical Expert from the remaining names. If the designated Technical Expert shall die, become incapable or, unwilling to, or unable to serve or proceed with the determination, a substitute technical expert shall be appointed in accordance with the selection procedure described above, and such substitute Technical Expert shall have all such powers as if he or she has been originally appointed herein.

(c) Within thirty (30) days of the appointment of the Technical Expert pursuant to the foregoing sub-section, each Party shall submit to the Technical Expert a written report containing its position with respect to the dispute, and arguments therefor together with supporting documentation and calculations. Discovery shall be limited to Facility documentation relating to the disputed matter. Within sixty (60) days from receipt of such submissions, the Technical Expert shall select one or the other Party's position with respect to the dispute, whereupon such selection shall be a binding determination upon the Parties for all purposes hereof. The costs of the determination by the Technical Expert of any dispute, including fees and expenses, shall be borne by the Party whose position was not selected by the Technical Expert. If the Technical Expert fails to render a decision within ninety (90) days from receipt of each Party's submissions, either Party may initiate litigation in accordance with the provisions herein.

(d) All verbal and written communications between the Parties and issued or prepared in connection with this Section 24.2.2 shall be deemed prepared and communicated in furtherance, and in the context, of dispute settlement, and shall be exempt from discovery and production, and shall not be admissible in evidence (whether as admission or otherwise) in any litigation or other proceedings for the resolution of the dispute.

(e) All deadlines specified in this Section 24.2.2 may be extended by mutual agreement of the Parties.

24.3 Choice of Forum. Each Party irrevocably consents and agrees that any legal action or proceeding arising out of this Agreement or the actions of the Parties leading up to the Agreement shall be brought exclusively in the [United States District Court for the District of Utah in Salt Lake City, Utah, or if such court does not have jurisdiction, in the 3rd Judicial District (Salt Lake County) Court of the State of Utah].[5] By execution and delivery hereof, each Party (a) accepts the exclusive jurisdiction of such court and waives any objection that it may now or hereafter have to the exercise of personal jurisdiction by such court over each Party for the purpose of any proceeding related to this Agreement, (b) irrevocably agrees to be bound by any final judgment (after any and all appeals) of any such court arising out of such documents or actions, (c) irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of venue of any suit, action or proceedings arising out of such documents brought in such court (including any claim that any such suit, action or proceeding has been brought in an inconvenient forum) in connection herewith, (d) agrees that service of process in any such action may be effected by mailing a copy thereof by registered or certified mail, postage prepaid, to such Party at its address as set forth herein, and (e) agrees that nothing herein shall affect the right to effect service of process in any other manner permitted by law.

23.4 Settlement Discussions. No statements of position or offers of settlement made in the course of the dispute process described in this section will be offered into evidence for any purpose in any litigation between the Parties, nor will any such statements or offers of settlement be used in any manner against either Party in any such litigation. Further, no such statements or offers of settlement shall constitute an admission or waiver of rights by either Party in connection with any such litigation. At the request of either Party, any such statements and offers of settlement, and all copies thereof, shall be promptly returned to the Party providing the same.

23.5 Waiver of Jury Trial. EACH PARTY KNOWINGLY, VOLUNTARILY, INTENTIONALLY AND IRREVOCABLY WAIVES THE RIGHT TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED ON THIS AGREEMENT, OR ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT AND ANY AGREEMENT EXECUTED OR CONTEMPLATED TO BE EXECUTED IN CONJUNCTION WITH THIS AGREEMENT, OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER VERBAL OR WRITTEN) OR ACTIONS OF ANY PARTY HERETO. THIS PROVISION IS A MATERIAL INDUCEMENT TO EACH OF THE PARTIES FOR ENTERING HEREINTO. EACH PARTY HEREBY WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR IN CONNECTION WITH THIS AGREEMENT OR ANY OTHER AGREEMENT EXECUTED OR CONTEMPLATED TO BE EXECUTED IN CONJUNCTION WITH THIS AGREEMENT, OR ANY MATTER ARISING HEREUNDER OR THEREUNDER, WITH ANY PROCEEDING IN WHICH A JURY TRIAL HAS NOT OR CANNOT BE WAIVED. THIS PARAGRAPH WILL SURVIVE THE EXPIRATION OR TERMINATION OF THIS AGREEMENT.

[5] Note to Bidders – Choice of forum to be revised based on the proposed location of the project.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed in their respective names as of the date last written below.

[SELLER]		PACIFICORP	
By:	______________________	By:	______________________
Name:	______________________	Name:	______________________
Title:	______________________	Title:	______________________
Date:	______________________	Date:	______________________

EXHIBIT A

ESTIMATED MONTHLY OUTPUT

EXPECTED ENERGY - FIRST FULL CONTRACT YEAR			
PERIOD	ON-PEAK (MWh)	OFF-PEAK (MWh)	TOTAL (MWh)
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			
First Year Total			

EXPECTED ENERGY - ANNUAL REDUCTION	
PERIOD	**EXPECTED ENERGY (MWh)**
Year 0-1	
Year 1-2	
Year 2-3	
Year 3-4	
Year 4-5	
Year 5-6	
Year 6-7	
Year 7-8	
Year 8-9	
Year 9-10	
Year 10-11	
Year 11-12	
Year 12-13	
Year 13-14	
Year 14-15	
Year 15-16	
Year 16-17	
Year 17-18	
Year 18-19	
Year 19-20	
Year 20-21	
Year 21-22	
Year 22-23	
Year 23-24	
Year 24-25	

Under separate cover, Seller will also provide PacifiCorp one (1) electronic and hard copy of the solar plant performance estimation report using a Solar Performance Modeling Program no later than ninety (90) days prior to the start of construction. This report will include, at a minimum, estimated hourly MW generation output in MWh/h for the site and Facility, and shall set forth additional losses related to availability, AC-side collection, transformers, substation and no-load/overnight losses. On or prior to the Commercial Operation Date, Seller shall provide an updated Exhibit A and solar plant performance estimation report based on completed construction.

Upon the date of Final Completion, if different than the Commercial Operation Date, Seller shall provide an updated Exhibit A and solar plant performance estimation report based on the final completed construction.

EXHIBIT B

NERC EVENT TYPES

Event Type	**Description of Outages**
U1	Unplanned (Forced) Outage—Immediate – An outage that requires immediate removal of a unit from service, another outage state or a Reserve Shutdown state. This type of outage results from immediate mechanical/electrical/hydraulic control systems trips and operator-initiated trips in response to unit alarms.
U2	Unplanned (Forced) Outage—Delayed – An outage that does not require immediate removal of a unit from the in-service state but requires removal within six (6) hours. This type of outage can only occur while the unit is in service.
U3	Unplanned (Forced) Outage—Postponed – An outage that can be postponed beyond six hours but requires that a unit be removed from the in-service state before the end of the next weekend. This type of outage can only occur while the unit is in service.
SF	Startup Failure – An outage that results from the inability to synchronize a unit within a specified startup time period following an outage or Reserve Shutdown. A startup period begins with the command to start and ends when the unit is synchronized. An SF begins when the problem preventing the unit from synchronizing occurs. The SF ends when the unit is synchronized or another SF occurs.
MO	Maintenance Outage – An outage that can be deferred beyond the end of the next weekend, but requires that the unit be removed from service before the next planned outage. (Characteristically, a MO can occur any time during the year, has a flexible start date, may or may not have a predetermined duration and is usually much shorter than a PO.)
ME	Maintenance Outage Extension – An extension of a maintenance outage (MO) beyond its estimated completion date. This is typically used where the original scope of work requires more time to complete than originally scheduled. Do not use this where unexpected problems or delays render the unit out of service beyond the estimated end date of the MO.
PO	Planned Outage – An outage that is scheduled well in advance and is of a predetermined duration, lasts for several weeks and occurs only once or twice a year. (Boiler overhauls, turbine replacement or inspections are typical planned outages.)
PE	Planned Outage Extension – An extension of a planned outage (PO) beyond its estimated completion date. This is typically used where the original scope of work requires more time to complete than originally scheduled. Do not use this where unexpected problems or delays render the unit out of service beyond the estimated end date of the PO.

EXHIBIT C

START-UP TESTING[6]

[To be completed]

[6] Note to Bidders – Initial start-up testing procedures to be provided by Seller for PacifiCorp's review before PPA is finalized.

EXHIBIT D

FORM OF GUARANTY — CREDIT SUPPORT OBLIGATION

EXHIBIT 2.7

PACIFICORP'S INITIAL DESIGNATED REPRESENTATIVES

Authorized Representatives:

PacifiCorp:	Director, Valuation & Commercial Business PacifiCorp 825 NE Multnomah St., Suite 600 Portland, OR 97232-2315 Fax 503-813-6260
With a copy to:	Contract Administration PacifiCorp Energy Supply Management 825 NE Multnomah St., Suite 600 Portland, OR 97232-2315 Fax 503-813-6291 Email: cntadmin@pacificorp.com

EXHIBIT 3.2.3

REQUIRED FACILITY DOCUMENTS

1. <u>Obtained Required Facility Documents</u>:

<u>Permits</u>:

<u>Land Rights</u>:

2. <u>To Be Obtained (Prior to Commercial Operation) Required Facility Documents</u>:

<u>Licenses, Permits and Authorizations</u>:

Evidence of market-based rate authority under Section 205 of the Federal Power Act or evidence of qualifying facility certification under the Public Utility Regulatory Policies Act

Access road easement

Electrical Permit

Land Use Permit

Environmental Permit

Building Permit

Interconnection approval

Utility easement

<u>Construction and Operations and Maintenance</u>:

Contract for the Sale of Power Generation Equipment and Related Services between ______and Seller

Generator Interconnection Agreement

Retail Electric Service Agreement

Proof of Insurance

<u>Construction Agreements</u>:

Balance of Plant/Construction Services Agreement
<u>Operations and Maintenance Agreements</u>:

Warranty, Service and Maintenance Agreement

SUCH LIST MAY BE UPDATED PURSUANT TO SECTION 3.2.3

EXHIBIT 3.2.5

LEASES

EXHIBIT 4.6(1)

GREEN TAG ATTESTATION AND BILL OF SALE

EXHIBIT 4.6(2)

QUALIFIED REPORTING ENTITY SERVICES AGREEMENT

EXHIBIT 5.1

CONTRACT PRICE

EXHIBIT 6.1

Description of Seller's Facility

[To be populated based on the information provided by Bidder in response to RFP.]

EXHIBIT 6.1 — Attachments

1. _______________ Site Map
2. As-Builts
3. Manufacturer’s performance warranties
5. [Other]

EXHIBIT 8.4.1

FORM OF SUBORDINATED MORTGAGE

EXHIBIT 9.2

POINT OF DELIVERY/INTERCONNECTION FACILITIES

[Seller to provide its own diagram and description]

Instructions to Seller:

1. Include description of point of metering, and Point of Interconnection

2. Include description of Point of Delivery

3. Provide interconnection single line drawing of Facility including any transmission facilities on Seller's side of the Point of Interconnection.

4. Provide transmission single line drawing of the transmission path from the Point of Interconnection to the Point of Delivery as the path is defined in the Transmission Agreement(s). Specify any changes of ownership along the transmission path. Specify the Transmission Agreement(s) governing each segment of Seller's transmission path, from the Point of Interconnection to the Point of Delivery.

5. Describe Seller's arrangements for station service to the Facility and show on one-line diagram how station service will be provided and metered.

6. Specify the maximum hourly rate (MW) at which Seller is permitted to deliver energy to the Point of Delivery and in compliance with Seller's transmission rights between the Point of Interconnection and the Point of Delivery ("Maximum Transmission Rate"):

__________MW.

EXHIBIT 9.2 – Attachments

1. Substation Metering One-Line Diagram

EXHIBIT 9.5

SELLER AUTHORIZATION TO RELEASE GENERATION DATA TO PACIFICORP

[DATE]

Director, Transmission Services
PacifiCorp
825 NE Multnomah, Suite 1600
Portland, OR 97232

To Whom it May Concern:

________________________ ("Seller") hereby voluntarily authorizes PacifiCorp's Transmission business unit to share Seller's interconnection information with marketing function employees of PacifiCorp, including but not limited to those in Energy Supply Management. Seller acknowledges that PacifiCorp did not provide it any preferences, either operational or rate-related, in exchange for this voluntary consent.

____

EXHIBIT 13

REQUIRED INSURANCE

1.1 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than “A-/VII” by the A.M. Best Company the insurance coverage specified below:

1.1.1 Workers’ Compensation. Seller shall comply with any applicable laws or statutes, state or federal jurisdiction, where Seller performs work.

1.1.2 Employers’ Liability. Seller shall maintain employers’ liability insurance with minimum limits covering bodily injury for: $1,000,000 – each accident, $1,000,000 by disease – each employee, and $1,000,000 by disease – policy limit.

1.1.3 Commercial General Liability. Seller shall maintain insurance to include premises and operations, contractual liability, with a minimum single limit of $1,000,000 each occurrence to protect against and from loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

1.1.4 Business Automobile Liability. Seller shall secure and continuously carry business automobile liability insurance with a minimum single limit of $1,000,000 each accident covering bodily injury and property damage with respect to Seller’s vehicles whether owned, hired or non-owned.

1.1.5 Umbrella/excess Liability. Seller shall maintain umbrella or excess liability insurance on an occurrence and following form basis with a minimum limits as follows:

(a) Facility Capacity Rating under 200 KW - $1,000,000

(b) Facility Capacity Rating at or above 200 KW - $5,000,000

1.1.6 Property Insurance. Seller shall maintain property insurance covering equipment and structures in an amount at least equal to the full replacement value for "all risks" of physical loss or damage, including coverage for earth movement, flood, boiler and machinery, and business interruption. The policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. Property insurance will be maintained in accordance with terms available in the insurance market for similar facilities.

1.2 Additional Provisions or Endorsements:

1.2.1 Except for workers’ compensation and property insurance, the policies required herein shall include provisions or endorsements as follows:

(a) naming PacifiCorp, parent, divisions, officers, directors and employees as additional insureds;

(b) include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and

(c) cross liability coverage or severability of interest.

1.2.2 Unless prohibited by applicable law, all required insurance policies shall contain provisions that the insurer will have no right of recovery or subrogation against PacifiCorp.

1.3 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system if delivery to PacifiCorp is to be accomplished by wheeling, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) confirming Seller's compliance with the insurance requirements hereunder. Insurance certificate confirming compliance shall be provided to PacifiCorp by Seller at least annually and each time a new insurance policy is issued or becomes effective.

1.4 Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate, and Seller shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

1.5 Periodic Review. PacifiCorp may review this schedule of insurance as often as once every two (2) years. PacifiCorp may in its discretion require Seller to make reasonable changes to the policies and coverages described in this Exhibit to the extent reasonably necessary to cause such policies and coverages to conform to the insurance policies and coverages typically obtained or required for power generation facilities comparable to the Facility at the time PacifiCorp's review takes place.

STANDARD RENEWABLE IN-SYSTEM VARIABLE POWER PURCHASE AGREEMENT

THIS AGREEMENT is between ____ ______ ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties") and is effective upon execution by both Parties ("Effective Date"). The Parties agree this Agreement is a [choose one]:

☐ **Option A**: Standard Renewable Price Agreement [generally available to solar qualifying facilities with nameplate capacity no greater than 3 MW and other qualifying facilities with nameplate capacity no greater than 10 MW; if this option is selected then Option A will apply under Section 1.6, Section 3.1.14, and Section 4.3, and there will be no Exhibit E]; or

☐ **Option B:** Solar Standard Terms and Negotiated Price Agreement [generally available to solar qualifying facilities with nameplate capacity above 3 MW but no greater than 10 MW; if this option is selected then Option B will apply under Section 1.6, Section 3.1.14, and Section 4.3, and there will be an Exhibit E containing the negotiated prices agreed to by the Parties].

Eligibility for a Standard Renewable Price Agreement (Option A) or a Solar Standard Terms and Negotiated Price Agreement (Option B) is governed by the Schedule and applicable Commission orders.

RECITALS

Seller intends to construct, own, operate and maintain a ____________________ facility for the generation of electric power located in _____________________________ County, ______________________ with a Nameplate Capacity Rating of ______________ kilowatt ("kW"), as further described in Exhibit A ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller shall sell and PGE shall purchase the entire Net Output, as such term is defined in Section 1.21, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1. "As-built Supplement" means the supplement to Exhibit A provided by Seller in accordance with Section 4.3 following completion of construction of the Facility, describing the Facility as actually built.

1.2. “Base Hours” is defined as the total number of hours in each Contract Year (8,760 or 8,784 for leap year).

1.3. "Billing Period" means a period between PGE’s readings of its power purchase billing meter at the Facility in the normal course of PGE’s business. Such periods may vary and may not coincide with calendar months; however, PGE shall use best efforts to read the power purchase billing meter in 12 equally spaced periods per year.

1.4. “Cash Escrow” means an agreement by two parties to place money into the custody of a third party for delivery to a grantee only after the fulfillment of the conditions specified.

1.5. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable. PGE may, at its discretion, require, among other things, that all of the following events have occurred:

1.5.1. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from a Licensed Professional Engineer (“LPE”) acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in accordance with the terms and conditions of this Agreement (certifications required under this Section 1.5 can be provided by one or more LPEs);

1.5.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.36;

1.5.3. (facilities with nameplate under 500 kW exempt from following requirement) After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement and was continuously mechanically available for operation for a minimum of 120 hours. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the mechanical availability of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility shall promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;

1.5.4. (facilities with nameplate under 500 kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that in accordance with the Generation Interconnection Agreement, all required interconnection facilities have been constructed all required interconnection tests have been completed; and the Facility is physically interconnected with PGE's electric system.

1.5.5. (facilities with nameplate under 500kW exempt from following requirement) PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;

1.6. “Contract Price” means (see the selection made in the first paragraph of this Agreement to determine whether Option A or Option B applies – only one option applies):

Option A: “Contract Price” means the applicable price, including on-peak and off-peak prices, as specified in the Schedule. For the first 15 years measured from the date in Section 2.2.2, the Contract Price will be the Renewable Fixed Price Option under the Schedule; thereafter and for the remainder of the Term, the Contract Price will be equal to the Mid-C Index Price.

Option B: “Contract Price” means: (i) the negotiated price, including on-peak and off-peak prices, as specified in Exhibit E; or (ii) the Mid C Index Price. For the first 15 years measured from the date in Section 2.2.2, the Contract Price will be the negotiated price specified in Exhibit E; thereafter and for the remainder of the Term, the Contract Price will be equal to the Mid-C Index Price. The negotiated price established in Exhibit E is not necessarily the same as the Standard Fixed Price Option or the Renewable Fixed Price Option established in the Schedule.

1.7. "Contract Year" means each twelve (12) month period commencing upon the Commercial Operation Date or its anniversary during the Term, except the final contract year will be the period from the last anniversary of the Commercial Operation Date during the Term until the end of the Term.

1.8. “Effective Date” has the meaning set forth in Section 2.1.

1.9. “Environmental Attributes” shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), and other greenhouse gasses (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth’s climate by trapping heat in the atmosphere.

1.10. "Facility" has the meaning set forth in the Recitals.

1.11. “Generation Interconnection Agreement” means the generation interconnection agreement to be entered into separately between Seller and PGE, providing for the construction, operation, and maintenance of interconnection facilities required to accommodate deliveries of Seller's Net Output.

1.12. “Generation Unit” means each separate electrical generator that contributes towards Nameplate Capacity Rating included in Exhibit A. For solar facilities, a generating unit is a complete solar electrical generation system within the Facility that is able to generate and deliver energy to the Point of Delivery independent of other Generation Units within the same Facility.

1.13. "Letter of Credit" means an engagement by a bank or other person made at the request of a customer that the issuer will honor drafts or other demands for payment upon compliance with the conditions specified in the letter of credit.

1.14. "Licensed Professional Engineer" or "LPE" means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.

1.15. "Lost Energy" means ((the Guarantee of Mechanical Availability as set forth in 3.1.10 / MAP) X Net Output for a Calendar Year) – Net Output for the Calendar Year. Lost Energy shall be zero unless the result of the calculation in this subsection results in a positive number.

1.16. "Lost Energy Value" means Lost Energy X the excess of the annual time-weighted average Mid-C Index Price for On-Peak and Off-Peak Hours over the time-weighted average Contract Price for On-Peak and Off-Peak Hours for the corresponding time period (provided that such excess shall not exceed the Contract Price and further provided that Lost Energy is deemed to be zero prior to reaching the Commercial Operation Date) plus any reasonable costs incurred by PGE to purchase replacement power and/or transmission to deliver the replacement power to the Point of Delivery. (For Start-Up Lost Energy Value see Section 1.35).

1.17. "Mechanical Availability Percentage" or "MAP" shall mean that percentage for any Contract Year for the Facility calculated in accordance with the following formula:

MAP = 100 X (Operational Hours) /(Base Hours X Number of Units)

1.18. "Mid-C Index Price" means the Day Ahead Intercontinental Exchange ("ICE") index price for the bilateral OTC market for energy at the Mid-C Physical for Average On Peak Power and Average Off Peak Power found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

1.19. "Nameplate Capacity Rating" means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which shall not exceed 10,000 kW.

1.20. "Net Dependable Capacity" means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.

1.21. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses. Net Output does not include any environmental attributes.

1.22. “Number of Units” means the number of Generating Units in the Facility described in Exhibit A.

1.23. “Off-Peak Hours” has the meaning provided in the Schedule.

1.24. “On-Peak Hours” has the meaning provided in the Schedule.

1.25. “Operational Hours” for the Facility means the total across all Generating Units of the number of hours each of the Facility’s Generating Units are potentially capable of producing power at its Nameplate Capacity Rating regardless of actual weather, season and time of day or night, without any mechanical operating constraint or restriction, and potentially capable of delivering such power to the Point of Delivery in a Contract Year. During up to, but not more than, 200 hours of Planned Maintenance during a Contract Year for each Generation Unit and hours during which an event of Force Majeure exists, a Generation Unit shall be considered potentially capable of delivering such power to the Point of Delivery. For example, in the absence of any Planned Maintenance beyond 200 hours on any Generation Unit of Event of Force Majeure, the Operational Hours for a wind farm with five separate two MW turbines would be 43,800 for a Contract Year.

1.26. “Planned Maintenance” means outages scheduled 90 days in advance, with PGE’s prior written consent, which shall not be unreasonably withheld.

1.27. "Point of Delivery" means the high side of the generation step up transformer(s) located at the point of interconnection between the Facility and PGE's distribution or transmission system, as specified in the Generation Interconnection Agreement.

1.28. “Pre-Commercial Operation Date Minimum Net Output” shall mean, unless such MWh is specifically set forth by Seller in Exhibit A, an amount in MWh equal to seventy-five percent (75%) of the Nameplate Capacity Rating X thirty percent (30%) for a wind or other renewable QF or fifty percent (50%) for a solar QF X (whole months since the date selected in Section 2.2.1 / 12) X (8760 hours – 200 hours (assumed Planned Maintenance)) for each month. If Seller has provided specific expected monthly Net Output amounts for the Facility in Exhibit A, “Pre-Commercial Operation Date Minimum Net Output” shall mean seventy-five (75%) X expected Net Output set forth in Exhibit A for each month.

1.29. “Prime Rate” means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.

1.30. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.

1.31. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, interconnection, and maintenance of the Facility including without limitation those set forth in Exhibit B.

1.32. “RPS Attributes” means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with “qualifying electricity,” as that term is defined in Oregon’s Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

1.33. Schedule” shall mean PGE Schedule 201 filed with the Oregon Public Utilities Commission (“Commission”) in effect on the Effective Date of this Agreement and attached hereto as Exhibit D, the terms of which are hereby incorporated by reference.

1.34. Senior Lien” means a prior lien which has precedence as to the property under the lien over another lien or encumbrance.

1.35. “Start-Up Lost Energy Value” means for the period after the date specified in Section 2.2.2 but prior to achievement of the Commercial Operation Date: zero, unless the Net Output is less than the pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable delay period, and the time-weighted average of the delay period’s Mid-C Index Price for On-Peak Hours and Off-Peak Hours is greater than the time-weighted average of the delay period’s Contract Price for On-Peak Hours and Off-Peak Hours, in which case Startup Lost Energy Value equals: (pro-rated Pre-Commercial Operation Date Minimum Net Output for the applicable period - Net Output for the applicable period) X (the lower of: the time-weighted average of the Contract Price for On-Peak hours and Off-Peak Hours during the applicable period; or (the time-weighted average of the Mid-C Index Price for On-Peak Hours and Off-Peak Hours during the applicable period – the time-weighted average of the Contract Price for On-Peak Hours and Off-Peak Hours during the applicable period)). The time-weighted average in this section will reflect the relative proportions of On-Peak Hours and Off-Peak Hours in each day.

1.36. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit C.

1.37. “Step-in Rights” means the right of one party to assume an intervening position to satisfy all terms of an agreement in the event the other party fails to perform its obligations under the agreement.

1.38. “Term” shall mean the period beginning on the Effective Date and ending on the Termination Date.

1.39. “Test Period” shall mean a period of sixty (60) days or a commercially reasonable period determined by the Seller.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1. This Agreement shall become effective upon execution by both Parties (“Effective Date”).

2.2. Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,

2.2.1 By ________ [*date to be determined by the Seller*] Seller shall begin initial deliveries of Net Output; and

2.2.2 By ________ [*date to be determined by the Seller subject to Section 2.2.3 below*] Seller shall have completed all requirements under Section 1.5 and shall have established the Commercial Operation Date.

2.2.3 Unless the Parties agree in writing that a later Commercial Operation Date is reasonable and necessary, the Commercial Operation Date shall be no more than three (3) years from the Effective Date. PGE will not unreasonably withhold agreement to a Commercial Operation Date that is more than three (3) years from the Effective date if the Seller has demonstrated that a later Commercial Operation Date is reasonable and necessary.

2.3. This Agreement shall terminate on _________, ____ [*date to be chosen by Seller but not to exceed 20 years from the date contained in Section 2.2.2*], or the date the Agreement is terminated in accordance with Section 9 or 11, whichever is earlier (“Termination Date”).

SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1. Seller and PGE represent, covenant, and warrant as follows:

3.1.1. Seller warrants it is a ___________ duly organized under the laws of ___________.

3.1.2. Seller warrants that the execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.1.3. Seller warrants that the Facility is and shall for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.

3.1.4. Seller warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this Agreement current on all of its financial obligations.

3.1.5. Seller warrants that during the Term of this Agreement, all of Seller's right, title and interest in and to the Facility shall be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond acceptable to PGE posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

3.1.6. Seller warrants that it will design and operate the Facility consistent with Prudent Electrical Practices.

3.1.7. Seller warrants that the Facility has a Nameplate Capacity Rating not greater than 10,000 kW.

3.1.8. Seller warrants that Net Dependable Capacity of the Facility is ____________ kW.

3.1.9. Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is __________ kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.

3.1.10. Seller represents and warrants that the Facility shall achieve the following Mechanical Availability Percentages ("Guarantee of Mechanical Availability"):

3.1.10.1 Ninety percent (90%) beginning in the first Contract Year and extending through the Term for the Facility, if the Facility was operational and sold electricity to PGE or another buyer prior to the Effective Date of this Agreement; or

3.1.10.2 Ninety percent (90%) beginning in Contract Year three and extending throughout the remainder of the Term.

3.1.10.3 Annually, within 90 days of the end of each Contract Year Seller shall send to PGE a detailed written report demonstrating and providing evidence of the actual MAP for the previous Contract Year.

3.1.10.4 Seller's failure to meet the Guarantee of Mechanical Availability in a Calendar Year shall result in damages payable to PGE by Seller equal to the Lost Energy Value. PGE shall bill Seller for such damages in accordance with Section 8.

3.1.11. Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of _______ kWh of Net Output during each Contract Year ("Maximum Net Output").

3.1.12. By the Commercial Operation Date, Seller has entered into a Generation Interconnection Agreement for a term not less than the term of this Agreement.

3.1.13. PGE warrants that it has not within the past two (2) years been the debtor in any bankruptcy proceeding, and PGE is and will continue to be for the Term of this Agreement current on all of its financial obligations.

3.1.14. (See the selection made in the first paragraph of this Agreement to determine whether Option A or Option B applies – only one option applies):

Option A: Seller warrants that (i) the Facility satisfies the eligibility requirements for the Renewable Fixed Price Option specified in the section of PGE's Schedule entitled "Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Fixed Price Option or the Renewable Fixed Price Option under the Standard PPA" and (ii) Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the eligibility requirements for the Renewable Fixed Price Option specified in the section of PGE's Schedule entitled "Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Fixed Price Option or the Renewable Fixed Price Option under the Standard PPA." Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Public Utility Commission of Oregon upon the Commission's request.

Option B: Seller warrants that (i) the Facility satisfies the eligibility requirements for a Standard PPA specified in the section of PGE's Schedule entitled "Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Fixed Price Option or the Renewable Fixed Price Option under the Standard PPA" and (ii) Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the eligibility requirements for a Standard PPA specified in the section of PGE's Schedule entitled "Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Fixed Price Option or the

Renewable Fixed Price Option under the Standard PPA." Seller will provide, upon request by PGE not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. PGE agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PGE will provide all such confidential information to the Public Utility Commission of Oregon upon the Commission's request.

3.1.15. Seller warrants that it will comply with all requirements necessary for all Transferred RECs (as defined in Section 4.5) associated with Net Output to be issued, monitored, accounted for, and transferred by and through the Western Renewable Energy Generation System consistent with the provisions of OAR 330-160-0005 through OAR 330-160-0050. PGE warrants that it will reasonably cooperate in Seller's efforts to meet such requirements, including, for example serving as the qualified reporting entity for the Facility if the Facility is located in PGE's balancing authority.

SECTION 4: DELIVERY OF POWER, PRICE AND ENVIRONMENTAL ATTRIBUTES

4.1. Commencing on the Effective Date and continuing through the Term of this Agreement, Seller shall sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.

4.2. PGE shall pay Seller the Contract Price for all delivered Net Output.

4.3. (See the selection made in the first paragraph of this Agreement to determine whether Option A or Option B applies – only one option applies):

Option A: Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility pursuant to this section to no more than 3,000 kW (if the Facility produces Net Output through solar generation), or to no more than 10,000 kW (if the Facility does not produce Net Output through solar generation), PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating of the Facility to greater than 3,000 kW and the Facility produces Net Output through solar generation, then Seller shall be required to enter into a new power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 3,000 kW. In the event Seller increases the Nameplate Capacity Rating of the Facility to greater than 3,000 kW but no greater than 10,000 kW and the Facility produces Net Output through solar generation, the new power purchase agreement will be (at Seller's choice) either a standard (Schedule 201) power purchase agreement or a negotiated (Schedule 202) power purchase agreement and neither option is eligible for Schedule 201 prices. In the event the Seller increases the Nameplate Capacity Rating to greater than 10,000 kW and the Facility produces Net Output through solar generation, then Seller shall be required to enter into a new negotiated (Schedule 202) power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 3,000 kW. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW and the Facility produces Net Output through means other than solar generation, then Seller shall be required to enter into a new negotiated (Schedule 202) power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.

Option B: Upon completion of construction of the Facility, Seller shall provide PGE an As-built Supplement to specify the actual Facility as built. Seller shall not increase the Nameplate Capacity Rating above that specified in Exhibit A or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.11 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with prior written notice to PGE. In the event Seller increases the Nameplate Capacity Rating of the Facility to no more than 10,000 kW pursuant to this section, PGE shall pay the Contract Price for the additional delivered Net Output. In the event Seller increases the Nameplate Capacity Rating to greater than 10,000 kW, then Seller shall be required to enter into a new negotiated (Schedule 202) power purchase agreement for all delivered Net Output proportionally related to the increase of Nameplate Capacity above 10,000 kW.

4.4. To the extent not otherwise provided in the Generation Interconnection Agreement, all costs associated with the modifications to PGE's interconnection facilities or electric system occasioned by or related to the interconnection of the Facility with PGE's system, or any increase in generating capability of the Facility, or any increase of delivery of Net Dependable Capacity from the Facility, shall be borne by Seller.

4.5. From the start of the Renewable Resource Deficiency Period through the remainder of the Term of this Agreement, Seller shall provide and PGE shall acquire the RPS Attributes for the Contract Years as specified in the Schedule and Seller shall retain ownership of all other Environmental Attributes (if any). During the Renewable Resource Sufficiency Period, Seller shall retain all Environmental Attributes in accordance with the Schedule. The Contract Price includes full payment for the Net Output and any RPS Attributes transferred to PGE under this Agreement. With respect to Environmental Attributes not transferred to PGE under this Agreement ("Seller-Retained Environmental Attributes") Seller may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to Seller any of the Seller-Retained Environmental Attributes, and PGE shall not report under such program that such Seller-Retained Environmental Attributes belong to it. With respect to RPS Attributes transferred to PGE under this Agreement ("Transferred RECs"), PGE may report under §1605(b) of the Energy Policy Act of 1992 or under any applicable program as belonging to it any of the Transferred RECs, and Seller shall not report under such program that such Transferred RECs belong to it.

SECTION 5: OPERATION AND CONTROL

5.1. Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE shall have no obligation to purchase Net Output from the Facility to the extent the interconnection of the Facility to PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's noncompliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

5.2. Seller agrees to provide sixty (60) days advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time.

5.3. If the Facility ceases operation for unscheduled maintenance, Seller immediately shall notify PGE of the necessity of such unscheduled maintenance, the time when such maintenance has occurred or will occur, and the anticipated duration of such maintenance. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 6: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller shall immediately notify PGE and shall promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: Senior Lien, Step-in Rights, a Cash Escrow or Letter of Credit. The amount of such default security that shall be acceptable to PGE shall be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Net Dependable Capacity). Notwithstanding the foregoing, in the event Seller is not current on construction related financial obligations, Seller shall notify PGE of such delinquency and PGE may, in its discretion, grant an exception to the requirements to provide default security if the QF has negotiated financial arrangements with the construction loan lender that mitigate Seller's financial risk to PGE.

SECTION 7: METERING

7.1. PGE shall design, furnish, install, own, inspect, test, maintain and replace all metering equipment at Seller's cost and as required pursuant to the Generation Interconnection Agreement.

7.2. Metering shall be performed at the location and in a manner consistent with this Agreement and as specified in the Generation Interconnection Agreement. All Net Output purchased hereunder shall be adjusted to account for electrical losses, if any, between the point of metering and the Point of Delivery, so that the purchased amount reflects the net amount of power flowing into PGE's system at the Point of Delivery.

7.3. PGE shall periodically inspect, test, repair and replace the metering equipment as provided in the Generation Interconnection Agreement. If any of the inspections or tests discloses an error exceeding two (2%) percent of the actual energy delivery, either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) months, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered. Such correction, when made, shall constitute full adjustment of any claim between Seller and PGE arising out of such inaccuracy of metering equipment.

7.4. To the extent not otherwise provided in the Generation Interconnection Agreement, all of PGE's costs relating to all metering equipment installed to accommodate Seller's Facility shall be borne by Seller.

SECTION 8: BILLINGS, COMPUTATIONS AND PAYMENTS

8.1. On or before the thirtieth (30th) day following the end of each Billing Period, PGE shall send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement, the Generation Interconnection Agreement, and any other agreement related to the Facility between the Parties or otherwise. On or before the thirtieth (30^{th}) day following the end of each Contract Year, PGE shall bill for any Lost Energy Value accrued pursuant to this Agreement.

8.2. Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 9: DEFAULT, REMEDIES AND TERMINATION

9.1. In addition to any other event that may constitute a default under this Agreement, the following events shall constitute defaults under this Agreement:

9.1.1. Breach by Seller or PGE of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.

9.1.2. Seller's failure to provide default security, if required by Section 6, prior to delivery of any Net Output to PGE or within 10 days of notice.

9.1.3. Seller's failure to meet the Guarantee of Mechanical Availability established in Section 3.1.10 for two consecutive Contract Years or Seller's failure to provide any written report required by that section.

9.1.4. If Seller is no longer a Qualifying Facility.

9.1.5. Failure of PGE to make any required payment pursuant to Section 8.1.

9.1.6. Seller's failure to meet the Commercial Operation Date.

9.2. In the event of a default under Section 9.1.6, PGE may provide Seller with written notice of default. Seller shall have one year in which to cure the default during which time the Seller shall pay PGE damages equal to the Lost Energy Value. If Seller is unable to cure the default, PGE may immediately terminate this Agreement as provided in Section 9.3. PGE's resource sufficiency/deficiency position shall have no bearing on PGE's right to terminate the Agreement under this Section 9.2.

9.3. In the event of a default under this Agreement, except as otherwise provided in this Agreement, the non-defaulting party may immediately terminate this Agreement at its sole discretion by delivering written notice to the other Party. In addition, the non-defaulting party may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. A termination hereunder shall be effective upon the date of delivery of notice, as provided in Section 20. The rights provided in this Section 9 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights.

9.4. If this Agreement is terminated as provided in this Section 9 PGE shall make all payments, within thirty (30) days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of receipt of notice of default. PGE shall not be required to pay Seller for any Net Output delivered by Seller after such notice of default.

9.5. In the event PGE terminates this Agreement pursuant to this Section 9, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.

9.6. Sections 9.1, 9.4, 9.5, 10, and 19.2 shall survive termination of this Agreement.

SECTION 10: INDEMNIFICATION AND LIABILITY

10.1. Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this

Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.

10.2. PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.

10.3. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.

10.4. NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 11: INSURANCE

11.1. Prior to the connection of the Facility to PGE's electric system, provided such Facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance shall include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance or self-insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of insurance interest clause; and provisions that such policies shall not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section shall be $1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

11.2. Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller shall secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "B+" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly shall notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination shall be effective upon receipt by PGE of written notice from Seller. Seller shall waive its insurers' rights of subrogation against PGE regarding Facility property losses.

11.3. Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller shall provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 12: FORCE MAJEURE

12.1. As used in this Agreement, “Force Majeure” or “an event of Force Majeure” means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility, changes in market conditions that affect the price of energy or transmission, wind or water droughts, and obligations for the payment of money when due.

12.2. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

12.2.1. the non-performing Party shall, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

12.2.2. the suspension of performance shall be of no greater scope and of no longer duration than is required by the Force Majeure; and

12.2.3. the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.

12.3. No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the Force Majeure.

12.4. Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 13: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 14: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 15: PARTIAL INVALIDITY AND PURPA REPEAL

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

In the event the Public Utility Regulatory Policies Act (PURPA) is repealed, this Agreement shall not terminate prior to the Termination Date, unless such termination is mandated by state or federal law.

SECTION 16: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 17: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PGE.

SECTION 18: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 19: ENTIRE AGREEMENT

19.1. This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

19.2. By executing this Agreement, Seller releases PGE from any third party claims related to the Facility, known or unknown, which may have arisen prior to the Effective Date.

SECTION 20: NOTICES

20.1. All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller: ______________________________
____
____
____

with a copy to: ______________________________
____
____
____

To PGE: Contracts Manager

QF Contracts, 3WTC0306
PGE - 121 SW Salmon St.
Portland, Oregon 97204

20.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 20.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the Effective Date.

PGE

By: ______________________
Name:____________________
Title: _____________________
Date:_____________________

____
(Name Seller)

By: ______________________
Name:____________________
Title: _____________________

Date:_____________________

EXHIBIT A
DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

[Sellers may include reasonable expected monthly Net Output for purposes of Section 1.35 (Start-Up Lost Energy Value). Amounts may vary by month and shall be assumed repeated for each Contract Year, unless amounts for each Contract Year of this Agreement are set forth in this Exhibit A. Such amounts, if provided, shall exceed zero, and shall be established in accordance with Prudent Electrical Practices and documentation supporting such a determination shall be provided to PGE upon execution of this Agreement. Such documentation shall be commercially reasonable, and may include, but is not limited to, documents used in financing the project, and data on output of similar projects operated by seller, PGE or others.]

EXHIBIT B
REQUIRED FACILITY DOCUMENTS

[Seller list all permits and authorizations required for this project]

Sellers Generation Interconnection Agreement

EXHIBIT C
START-UP TESTING

[Seller identify appropriate tests]

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable):

1. Pressure tests of all steam system equipment;
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;
3. Operating tests of all valves, operators, motor starters and motor;
4. Alarms, signals, and fail-safe or system shutdown control tests;
5. Insulation resistance and point-to-point continuity tests;
6. Bench tests of all protective devices;
7. Tests required by manufacturer of equipment; and
8. Complete pre-parallel checks with PGE.

Required start-up test are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PGE's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;
3. Brake tests;
4. Energization of transformers;
5. Synchronizing tests (manual and auto);
6. Stator windings dielectric test;
7. Armature and field windings resistance tests;
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load;
9. Heat runs;
10. Tests required by manufacturer of equipment;
11. Excitation and voltage regulation operation tests;
12. Open circuit and short circuit; saturation tests;
13. Governor system steady state stability test;
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;
15. Auto stop/start sequence;
16. Level control system tests; and
17. Completion of all state and federal environmental testing requirements

EXHIBIT D
SCHEDULE

[Attach currently in-effect Schedule 201]

EXHIBIT E
NEGOTIATED CONTRACT PRICES

[Attach On-Peak and Off-Peak Negotiated Contract Prices if Option B is selected in the first paragraph of the Agreement, otherwise delete Exhibit E]

RFF REPORT

Decommissioning US Power Plants

Decisions, Costs, and Key Issues

Daniel Raimi

OCTOBER 2017

RESOURCES FOR THE FUTURE

Decommissioning US Power Plants: Decisions, Costs, and Key Issues

Daniel Raimi*

Abstract

In recent years, hundreds of large power plants have retired across the United States, with hundreds more nearing the end of their useful lives. At the same time, large-scale growth in natural gas, wind, and solar power is changing the nation's electricity mix. Although much research has been carried out on the decommissioning of nuclear power plants, far less work has examined what happens to plant sites when generating units that burn coal, oil, or natural gas are retired or when wind or solar facilities reach the end of their lives. This report describes the options faced by plant owners after a plant has been retired. It examines the costs associated with decommissioning different plant types and highlights key issues that present opportunities and challenges for generating companies, regulators, local governments, and communities. Key issues include the large costs of environmental remediation and monitoring for coal-fired power plants and their combustion residuals, whether companies in deregulated markets are adequately saving for decommissioning, state and local policies for wind and solar decommissioning, and the economic and fiscal impacts of decommissioning power plants in rural areas.

Key Words: power plant decommissioning, power plant retirement, decommissioning costs, coal combustion residuals

JEL Codes: H23, H32, H71, H77, Q28, Q38, Q40, Q48, Q52, Q58

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Contents

Acronyms and abbreviations

AROs asset retirement obligations

BLM Bureau of Land Management

CCRs coal combustion residuals

CERCLA Comprehensive Environmental Response, Compensation, and Liability Act

CSP concentrated solar power

ELT environmental liability transfer

GW gigawatts

MSA metropolitan statistical area

MW megawatt

NGCC natural gas combined cycle

NGST natural gas steam turbine

PCBs polychlorinated biphenyls

PV [solar] photovoltaic

RCRA Resource Conservation and Recovery Act

TVA Tennessee Valley Authority

1. Introduction

As of 2015, roughly 6,300 electric generating units aged 40 years or older were operating in the United States. These units represent roughly 350 gigawatts (GW) of electric generating capacity, or approximately one-third of the nation's total generating capacity. In the coming years and decades, many of the older units at these plants will retire, with important implications for electricity markets, investors, and communities where plants operate.[1]

At the same time, the generating fleet is changing, as the number of natural gas, wind, and solar plants grows rapidly. For wind and solar facilities, most utilities, regulators, and communities have virtually no experience decommissioning utility-scale installations. Although most of these facilities will operate for decades to come, understanding the key issues associated with decommissioning new power generation can help mitigate any negative impacts for ratepayers, investors, and communities.

Once units retire, plant owners are faced with choices over how to repurpose each site. This report examines key issues that arise when owners decide to decommission an individual unit or an entire plant, including the following: What choices do plant owners face? What policies and market incentives affect each option, and how do they vary across states? What are the costs of decommissioning, and who bears them? What are the local economic and fiscal implications of decommissioning power plants?

Because a rich literature exists examining decommissioning issues associated with nuclear and conventional hydroelectric plants, those sources are excluded from this analysis. Instead, it focuses on those that have recently experienced large-scale retirements (coal, petroleum, and natural gas), along with those that are currently seeing widespread deployment (wind and solar) and will face decommissioning in the decades to come.

1.1. Structure of This Report

This report begins with an overview of recent power plant retirements in the United States, along with a brief analysis of where future retirements are likely to occur in the coming decades. Section 3 offers a framework to describe key decision points for power plant owners after a plant retires, discussing the rationale and risks behind each major option. Section 4 describes the cost of decommissioning for different fuel types by aggregating hundreds of cost estimates, primarily from regulatory filings. This section examines the key cost drivers for decommissioning plants of each fuel type and identifies areas where existing accounting protocols may not reflect the true costs of decommissioning. Section 5 synthesizes and discusses in detail the key issues facing plant owners, regulators, and communities as they consider how to decommission retired facilities. The discussion focuses on three topics: (1) how planning for decommissioning costs varies across market structures (i.e., traditionally regulated versus deregulated states); (2) the potential economic and fiscal

[1] Throughout this paper, *units* refers to individual generating units such as natural gas combustion turbines, coal-fired boilers, or individual wind turbines. *Plants* refers to the facilities where these individual units are located, often including multiple generating units and incorporating transmission equipment, fuel processing facilities, and other infrastructure. The bulk of this analysis focuses on the retirement of plants.

impacts for communities where decommissioning occurs; and (3) the differences between decommissioning plants in rural and urban locations. Section 6 concludes and offers suggestions for future research.

1.2. Key Findings and Recommendations

1.2.1. Key Findings

- Hundreds of large power plants have retired in recent years, and hundreds more will retire over the coming decades. Planning properly for the decommissioning of these facilities is essential to minimize negative impacts to local environments, economies, electricity ratepayers, and taxpayers.
- Partly because of recently enacted federal regulations, decommissioning of coal-fired power plants and management of waste materials will be more costly than most had anticipated. A 2009 study estimates that closing all the nation's 155 "wet" ash impoundments would cost roughly $39 billion over 10 years, and billions more will likely be needed for long-term monitoring and remediation. Existing decommissioning savings funds may not be sufficient to manage these costs for some utilities.
- In certain locations, particularly in some states with deregulated power markets, no local, state, or federal policy ensures adequate funding for decommissioning. In these locations, plant owners may not be adequately saving for decommissioning, potentially exposing shareholders, ratepayers, and/or taxpayers to unanticipated costs in the coming years.
- When power plants are sold, environmental liabilities typically transfer to the new owner. However, if the new owner goes bankrupt in the future, environmental liabilities may revert to the original plant owner if they are not fully addressed in bankruptcy proceedings. This issue will tend to arise more frequently in states where decommissioning funds are not accrued in advance of plant retirement.
- Full decommissioning often involves extensive environmental remediation, the costs of which are uncertain until work has begun. This may incentivize some plant owners to delay decommissioning and its associated costs, in some cases for years, which could lead to increased environmental damage as plant conditions deteriorate.
- Decommissioning of power plants has important economic and employment implications in the communities where they have operated. Although the decommissioning process requires dozens of temporary workers, the retirement of a power plant can displace hundreds of long-term employees.
- The local fiscal implications of decommissioning can also be significant. In some regions, particularly sparsely populated rural areas, large power plants can make up a sizable portion of the local tax base. In these locations, decommissioning can substantially reduce revenues for local governments and school districts.
- Numerous federal, state, and local programs incentivize decommissioning and redevelopment of industrial property. These programs are often beneficial for communities where they occur but can shift the cost of decommissioning and remediation from shareholders and ratepayers to taxpayers.
- Although data on decommissioning costs are limited, on a per-megawatt (MW) basis, it appears that the highest decommissioning costs are for offshore wind and coal plants. Natural gas plants on average have the lowest decommissioning costs, followed by petroleum. Solar and onshore wind fall in between the two (Table 1).

TABLE 1. DECOMMISSIONING COST ESTIMATES PER MEGAWATT OF CAPACITY

		2016$ (thousands)		
Fuel type	No. of estimates	Minimum	Mean	Maximum
Offshore wind	7	$123	$212	$342
Coal	28	$21	$117	$466
Concentrated solar power (CSP)	5	$24	$94	$138
Solar photovoltaic (PV)	22	–$89*	$57	$179
Onshore wind	18	$2	$51	$222
Petroleum/petroleum + gas	19	$2	$31	$103
Gas (various types)	28	$1	$15	$50

*Negative cost estimates indicate that the salvage value of plant materials exceeds decommissioning costs.

1.2.2. Recommendations

- To mitigate against large unplanned decommissioning costs, prudent policy would require plant owners to either: (1) provide adequate financial assurance for decommissioning before construction of a plant; (2) accrue decommissioning funds over the life of the power plant, or both.
- In some states, particularly those with traditional cost-of-service regulations, such policies are currently in place. In states where these policies are not in place, state governments and regulators could move to implement such policies for existing plants.
- Because plant owners have more information about historical environmental issues than do potential buyers, and because environmental liabilities may not be uncovered until after a plant is decommissioned, extensive due diligence by potential buyers is advisable.
- In locations where power plants provide a large share of the local employment or tax base, careful planning between the plant owner and state and local officials will be crucial to minimize negative economic and fiscal impacts of decommissioning.

2. Background

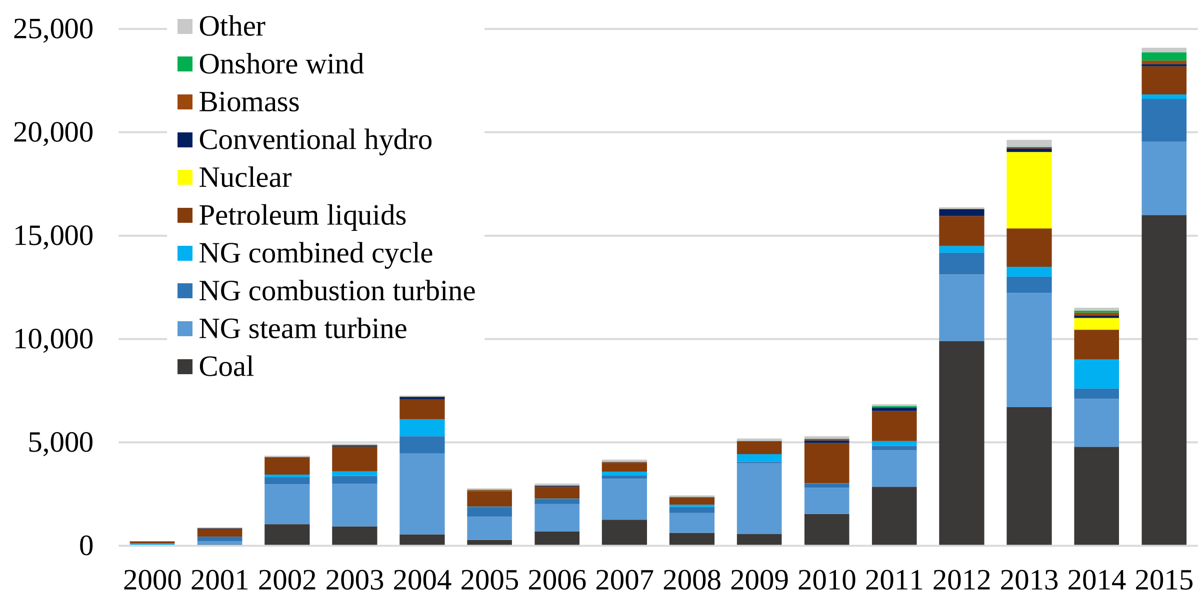
Since the year 2000, roughly 3,300 generating units totaling roughly 115 GW of capacity have been retired across the United States. The bulk of these retirements have come from coal (accounting for 40 percent of retired capacity), natural gas steam turbine (29 percent), and petroleum liquids (13 percent) units. Because petroleum liquid generators tend to be smaller than most coal- or gas-fired units, the greatest number of retired units (1,054) have been those fueled by petroleum, followed by 545 coal units, 372 natural gas steam turbines, and 310 natural gas combustion turbines (Table 2).

TABLE 2. ELECTRICITY RETIREMENT SUMMARY STATISTICS BY FUEL TYPE, 2000–2015

Unit type	Capacity of retirements (MW)	Number of units retired	Average age when retired	Average retired unit size (MW)
Coal	49,936	545	54	92
Natural gas (all)	42,513	995	38	43
Combined cycle	3,981	109	30	39
Combustion turbine	6,508	310	34	21
Combustion engine	307	204	37	2
Steam turbine	31,717	372	51	86
Petroleum liquids	14,677	1,054	38	14
Nuclear	4,188	5	35	838
Conventional hydro	1,281	174	70	8
Biomass	655	63	41	10
Onshore wind	565	37	15	15
Municipal solid waste	173	13	17	13
Solar PV	7	11	10	1
All other	1,106	396	40	12
Total	115,103	3,293	40	35

Source: Data from EIA (2016).

FIGURE 1. CAPACITY OF UNITS RETIRED (MW)



Source: Data from EIA (2016).
Note: In the early 2000s, a large amount of natural gas steam turbine capacity was retired, along with a substantial number of petroleum units. Since 2010, the majority of retirements have come from coal-fired plants, though retirements of natural gas and petroleum units have also been substantial.

Notably, retirement and decommissioning have different meanings. When a generating unit or an entire plant is retired, it no longer produces electricity. However, the assets of the plant, such as buildings, turbines, boilers, and other equipment, may remain in place. Decommissioning takes place only after a unit or plant retires and refers to the process of environmental remediation, dismantlement, and restoration of the site. Data on retired units are provided here because the US Energy Information Administration (EIA) does not collect data on the type and timing of decommissioning.

In recent years, coal retirements in particular have accelerated (Figure 1), driven by increased competition from low-priced natural gas, lower projections for future electricity demand, and to a lesser extent, environmental regulations (Burtraw et al. 2012).

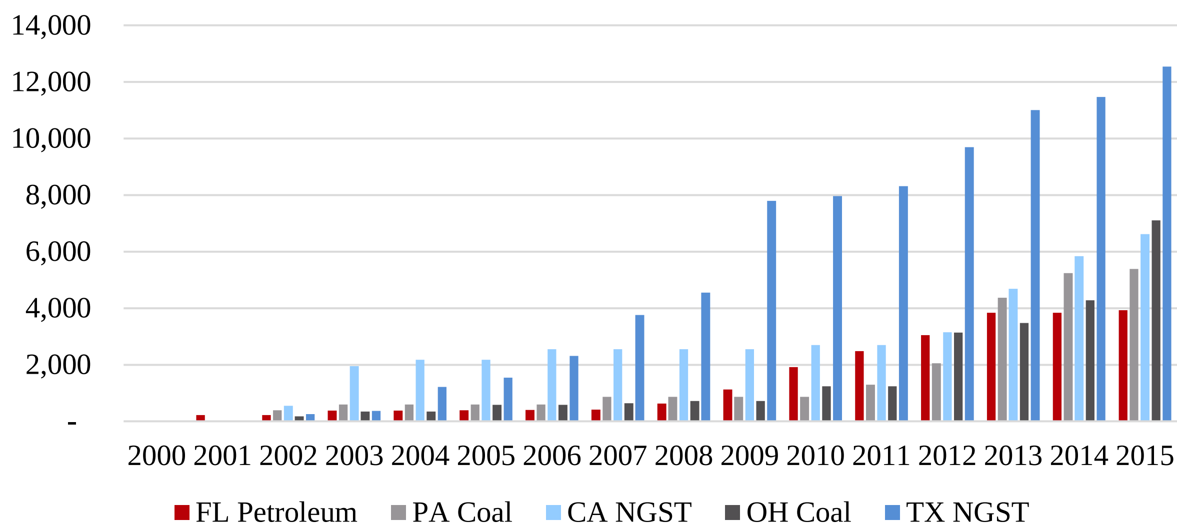
2.1. Regional Trends

Among states, Texas has seen the most capacity retired (14,657 MW) since 2000. The bulk of these retirements have come from 62 natural gas steam turbines (NGST), totaling 12,224 MW of capacity. California is home to the largest number of retired units (299) and the second-greatest retired capacity (12,118 MW). As with Texas, most of California's retirements (6,810 MW) have been NGST units. California has also seen 2,150 MW of nuclear capacity retired.

California and Texas are the two leading states for renewables retirement, with 441 MW and 64 MW of onshore wind retiring, respectively. Although little solar photovoltaic (PV) capacity has been retired to date (7 MW), the bulk of these retirements (6 MW) have occurred in California.

In Florida, the state with the third-largest number of retirements, 67 petroleum-fired units totaling 4,017 MW of capacity have retired, followed by 71 natural gas–fired units totaling just over 2,000 MW. Large-scale retirements of coal-fired units have occurred in over a dozen states, led by Ohio (7,518 MW), Pennsylvania (5,468 MW), and 15 other states with more than 1,000 MW of coal-fired retirements. Figure 2 highlights the states and fuels where the most retirements have occurred since 2000.

FIGURE 2. CUMULATIVE RETIRED CAPACITY (MW) FOR SELECTED FUELS IN SELECTED STATES

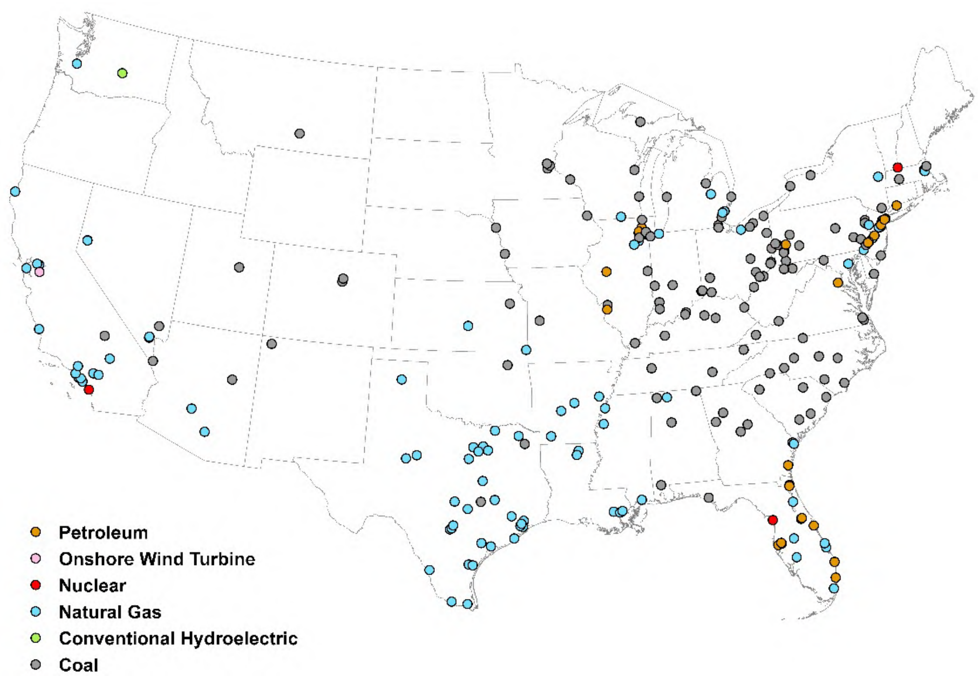


Source: Data from EIA (2016).
Note: This figure highlights the most substantial retirements by state and fuel type, showing that the largest single source of retirements since 2000 has been natural gas steam turbines (NGST) in Texas. Retirements have also been driven by coal in Ohio and Pennsylvania, NGST in California, and petroleum units in Florida.

Figure 3 provides a nationwide overview of plant retirements since the year 2000, mapping just those plants where generating capacity exceeded 100 MW. Along with the trends highlighted above, the figure illustrates the prevalence of coal-fired retirements in the Midwest and Southeast and the retirement of petroleum-fired plants in Florida, New Jersey, and New York.

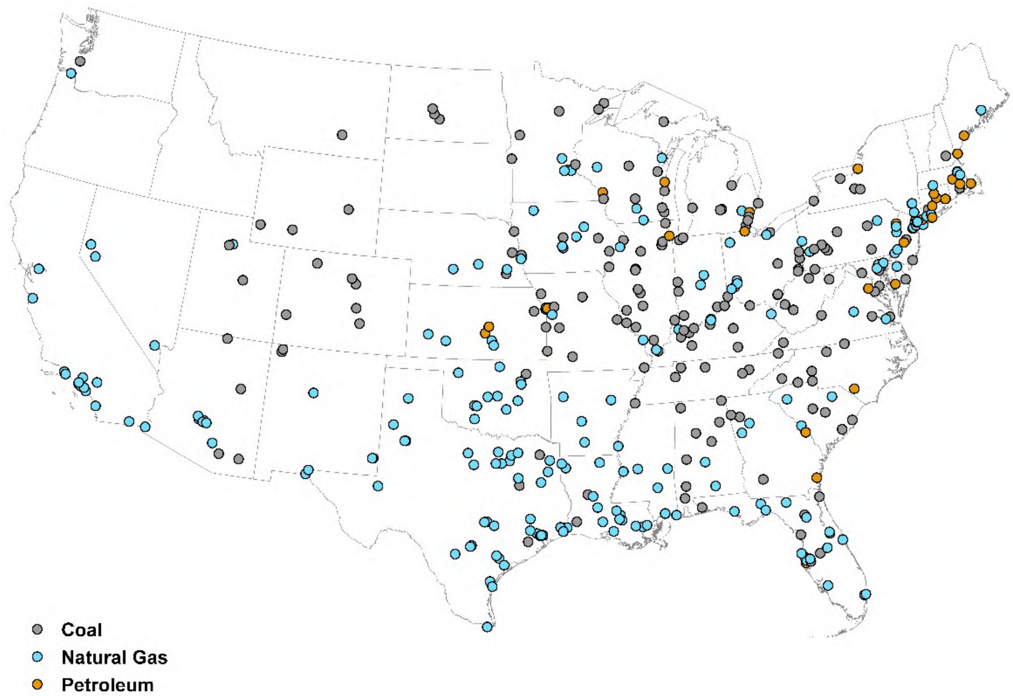
Looking forward, the oldest operating power plants follow similar geographic and fuel-specific trends. Figure 4 shows all operating fossil fuel–fired plants that are 40 years old or older, with most aging coal plants concentrated in the Midwest and Southeast, while older petroleum plants are located primarily in the Northeast. Older natural gas plants are distributed broadly across the United States but show concentrations in Texas, California, Oklahoma, the Northeast, and along the Gulf Coast. The figure does not show nuclear or hydroelectric plants, as they are not the focus of this report, nor does it show wind or solar facilities, as just one wind facility and zero solar plants are older than 40 years.

FIGURE 3. POWER PLANT RETIREMENTS (>100 MW), 2000–2015



Source: Data from EIA (2016).
Note: This figure shows where large plant retirements have taken place from 2000 through 2015 and highlights the prevalence of natural gas retirements in Texas and California, coal retirements in the Midwest and Southeast, and petroleum retirements in Florida and the Northeast. Some plants use multiple fuels. Plants with any nuclear or coal units are labeled as such. For facilities with both petroleum- and gas-fired units, the plant is labeled according to which fuel source provided the dominant generating capacity.

FIGURE 4. OPERATING COAL, GAS, AND PETROLEUM PLANTS 40 YEARS OR OLDER (>100 MW), 2015



Source: Data from EIA (2016).
Note: This figure shows the location of large fossil fuel–fired power plants aged 40 years or older. It highlights the broad distribution and large number of plants that will need to be retired in the coming decades, with particular concentrations of natural gas in Texas, California, Oklahoma, the Northeast, and along the Gulf Coast; coal plants in the Midwest and Southeast; and petroleum plants in the Northeast. Some plants use multiple fuels. Plants with any nuclear or coal units are labeled as such. For facilities with both petroleum- and gas-fired units, the plant is labeled according to which fuel source provided the dominant generating capacity.

3. Key Decisions

Perhaps the most important single decision associated with decommissioning is how the plant site will ultimately be used. For example, when plants are located in city centers or near other amenities that create strong demand for land, financial incentives encourage owners to either sell the site or fully decommission and remediate for residential, commercial, or industrial development. For plants located in rural areas or other locations with weak demand for land, owners have less financial incentive to fully decommission and remediate a site, sometimes resulting in extended periods of the facility sitting idle. In other locations, preexisting access to natural gas pipelines, electricity transmission, or other infrastructure may incentivize owners to repower (i.e., construct new generating units) at the site.

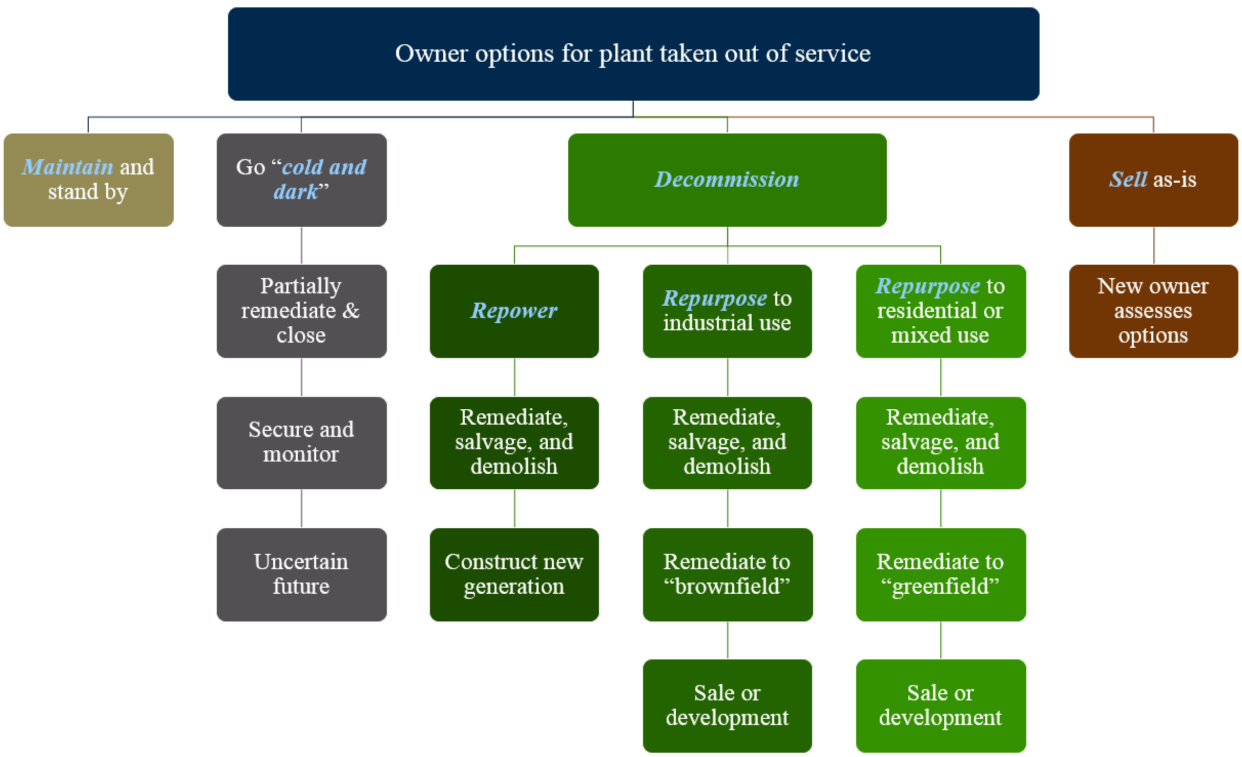
Regardless of location, plant owners will assess the value of their existing assets alongside the costs they may face under each of the four options described below and presented in Figure 5.

1. Maintain the plant for potential restart. If not restarted (or after restart), the owner ultimately decides from the other three options. With proper maintenance, plants can be kept in this condition for years.
2. Take the plant to a "cold and dark" condition. Under this option, the owner conducts limited environmental remediation and perhaps partial demolition, then retains and secures the site. The bulk of the facility is left as-is, with an uncertain future. The plant owner

retains environmental liabilities and financial obligations.

3. Decommission and repower or repurpose the site. The desired end use of the facility will determine the extent of demolition and environmental remediation.
4. Sell the plant as-is. Depending on the condition of the units, other structures, and the site itself, the plant owner may find a buyer who will decide how and when to repurpose the site. The new owner assumes environmental liabilities and financial obligations associated with the site. However, if the new owner goes bankrupt in the future, environmental liabilities could revert to the original plant owner.

FIGURE 5. DECOMMISSIONING DECISION TREE



3.1. Assess Options for Decommissioning

Once an owner has decided to retire individual units or an entire plant, the decision of how to decommission will depend on the potential value of the assets, including plant equipment, transmission equipment, land, permits, and other assets. Owners must also evaluate and consider the costs of remediating environmental issues, along with the risks of potential future liability associated with those environmental concerns.

To thoroughly assess their options, experts suggest that owners examine five key areas that can vary substantially among plants:

1. Above-ground costs: those costs associated with managing regulated materials above-ground (e.g., asbestos, polychlorinated biphenyls (PCBs), mercury)
2. Below-ground costs: those costs associated with managing surface and below-ground environmental issues (e.g., coal pile, coal combustion residual impoundments, petroleum releases)
3. Demolition and land reclamation costs
4. Salvage value of plant equipment and scrap
5. Property value of site

Because power plant owners' area of expertise is producing electricity rather than developing property, they may have little appetite for conducting a detailed analysis on the potential for redevelopment at a given site. However, such an evaluation is essential to determine the potential opportunities and liabilities in each case, as conditions can vary widely from plant to plant.

3.2. Maintain and Put on Standby

In some cases, plant owners may defer the decision of whether to retire a plant, instead idling the facility and ceasing the bulk of operations, but leaving it with the ability to restart in a period of days or weeks. The plant would retain its environmental permits unless it undergoes major changes, in which case it may become subject to new regulations under US Environmental Protection Agency (EPA) guidelines, potentially requiring new permitting.

The plant is kept in good working order, and although it is not available for dispatch, routine maintenance would mean ongoing costs for the owner. In general, maintaining is not a decommissioning option, but instead a temporary period when the plant is neither operating nor in the process of being decommissioned. This may be a preferred option when substantial uncertainty exists surrounding issues such as electricity markets or environmental regulations, and owners are uncertain whether a given plant will be needed or profitable in years to come.

Once a unit or plant is put into this state, the owner may either restart or retire it, then follow any of the three options described below: sell as-is, go cold and dark, or decommission. The decision of whether to restart or decommission is similar to the set of issues plant owners face when deciding whether to keep a plant in service or retire it. Because the focus of this report is on the set of decisions faced by owners once they decide to decommission a plant or generating unit, it does not cover putting a plant on standby.

3.3. Sell As-Is

Plant owners may wish to sell a plant as-is, the simplest of the four options examined here. Potential buyers of these properties are primarily those wishing to redevelop the site and use the location's existing assets. The buyers of the property will face the same set of decisions as the original plant owners but often bring different expertise to the redevelopment process.

As noted above, power plant operators are in the business of generating and selling electricity, not real estate development. In some locations, such as densely populated urban areas where land is valuable, real estate developers may seize on the opportunity to purchase a site, demolish the existing plant, remediate any contamination, and redevelop. Such developers will bring expertise in the local real estate market but are unlikely to have the experience of power plant owners with regard to managing environmental liabilities (see Section 3.3.1).

Power plants often have assets attractive to a range of developers. For those interested in residential, commercial, or mixed-use development, particularly in regions with strong real estate markets, the value of the land can be substantial. In addition, a plant's main buildings are sometimes local landmarks, sturdily constructed and offering appealing aesthetic traits such as aged brick and high ceilings.

For developers interested in light industrial activity such as logistics, plants often have access to transportation infrastructure such as highways, waterways, and rail lines. For heavier industrial purposes, power plant sites offer access to electrical substations. In addition, plant owners may be able to transfer valuable water rights or permits to new owners, lowering costs for new or modified industrial operations.

Some firms specialize in acquiring, decommissioning, and redeveloping industrial sites with environmental liabilities. These companies, known as environmental liability transfer (ELT) firms, typically have expertise in assessing and remediating industrial facilities, then repurposing those sites. Such sales typically are not overseen by state or federal regulators, though they may come under scrutiny if a sale occurs in the context of bankruptcy.

In some cases, ELTs will purchase a facility as-is and assume its environmental liabilities because the potential redevelopment value of the site exceeds the costs of remediation. In other cases, ELTs may be paid a fee by companies to take on the responsibility of a property and assume its environmental liabilities. For example, if a facility has an estimated redevelopment value of $7 million and estimated environmental liabilities of $10 million, an ELT may acquire the property in exchange for a $3 million payment. Because ELTs often have more experience with environmental remediation than other buyers, their participation could improve sales terms for sellers.

3.3.1. Concerns Associated with As-Is Sales

While the option to sell a power plant as-is offers the potential for speedy redevelopment, a number of issues may arise that can affect sellers, buyers, and communities. For sellers, the sale of a site and transfer of environmental liabilities may not absolve them of all future liability risk. For example, the postsale discovery of unanticipated environmental hazards may pose new liabilities for the previous owner. Under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund, EPA can pursue claims against the owner at the time the environmental damage occurred. (It can also pursue claims against the current owner or others in the chain of title.) This financial risk points to the importance of a thorough presale examination of the property by the original plant owner.

Another risk arises if the plant buyer goes bankrupt or is otherwise unable to cover the costs of known environmental liabilities. While EPA or state authorities, or both, will pursue claims against the bankrupt firm if environmental remediation is needed, liabilities may return to the plant seller under CERCLA. This risk generally encourages plant owners to sell only to entities with large financial assets that have little risk of entering bankruptcy in the foreseeable future, as plant owners would not want to see environmental liabilities returned to them. Community stakeholders such as local businesses and governments may also wish to see plant sites owned by well-capitalized firms, thereby reducing risks of blight or any further environmental degradation.

In some cases, local governments may have an interest in acquiring a site. Because they are typically well capitalized, there is little risk that local governments would be unable to manage the costs associated with environmental remediation. Governments may be in a position to acquire the site from plant owners at a low price, presenting opportunities for redevelopment as green space or other community development efforts. However, local governments may not be in a position to understand the extent of the environmental liabilities associated with these sites. If environmental remediation requirements are extensive, local taxpayers may ultimately bear the burden of cleaning up sites.

As one example, in 1990, the city of Allentown, Pennsylvania, received a 280,000-square-foot riverfront industrial facility from a local donor, who had bought the property years earlier for $250,000. The city accepted the donation with the intention of redeveloping the structure and integrating it into a mixed-use development (Hernan 1990). However, environmental liabilities, among other issues, delayed the project for more than 10 years, with the costs of remediating the site and rehabilitating the structure estimated at roughly $17 million, according to press reports (Wittman 2003). Ultimately, the site was remediated and a museum constructed with $12.4 million in state and federal contributions (Nerl 2002).

3.4. Go "Cold and Dark"

Under some circumstances, plant owners may choose not to sell or fully decommission, but instead partially decommission the plant and retain key structures. In these cases, some—but not all—equipment is removed and some environmental liabilities are remediated. The facility will typically be physically secured with fencing and other measures to prevent vandalism or theft and limit liability risks. Owners may also hire a security firm to monitor the location.

When a plant is "cold and dark," the owner continues to carry the costs associated with property taxes and site security. According to one decommissioning expert, these costs are often in the range of $1 million per year for a medium-size coal-fired power plant, depending on the design of local property tax laws (Malley 2017).

Table 3 shows the current status of 238 retired fossil fuel–powered generating units based on data from 22 states provided by an industry expert (the EIA does not track the status of retired plants). Of these 238 units, roughly 38 percent are currently cold and dark, 55 percent have been demolished, and no data is available for the remainder.

TABLE 3. SELECTED RETIRED GENERATING UNITS BY STATUS

Fuel type	Units retired	Cold and dark	Demolished	Uncertain
Coal	102	37	55	10
Natural gas	86	37	45	4
Petroleum	50	16	31	3
Total	238	90	131	17

Source: Data by email from Ed Malley, TRC Solutions, July 2017.

Examining these data (which are not comprehensive) shows that the greatest number of cold and dark units are located in New Jersey (37), Ohio (13), Pennsylvania (11), Indiana (7), and Illinois (6). The bulk of these units have retired since 2014. However, 9 units identified in this dataset have sat cold and dark for more than 10 years, raising concerns over blight and potentially loss of structural integrity.

Multiple factors may lead a plant owner to go cold and dark. First, there may be little interest in redeveloping the site, and the plant owner may not want to invest the capital needed to fully decommission the plant. In locations where land values are low, the potential return on such an investment may be small or negative. As discussed further in Section 5.1, this situation tends to arise more often in competitive power markets, as utilities in cost-of-service regions typically build decommissioning costs into their rate bases.

Another factor that may perversely incentivize going cold and dark is the presence of uncertain environmental liabilities. As discussed in Section 3.5, full decommissioning frequently involves extensive environmental remediation, the costs of which are often uncertain until work has begun. By leaving the plant cold and dark, owners do not uncover unanticipated environmental issues such as oil leaks, asbestos-containing materials, PCBs, and other hazards that must be remediated. As noted in previous reports focused on decommissioning power plants, the unanticipated presence of such environmental hazards is common (e.g., Armor 2004; Brown et al. 2017).

3.4.1. Concerns Associated with Going "Cold and Dark"

Four major concerns arise when plants are left in this uncertain condition, two from the plant owner's perspective and two from the community's perspective. First, the closure of a power plant can have significant local economic and social impacts in nearby communities (see Section 5.2). For plant owners, which are often leading employers in communities where they operate, the reputational risks of these negative impacts are substantial. In addition, reputational risks could be exacerbated if the plant, left cold and dark, physically deteriorates into a blighted state. Second, fully securing large sites such as power plants is difficult and costly. Despite efforts to secure a site, vandalism, theft, or other criminal activity may be difficult to prevent completely, particularly when valuable materials such as copper are present. Plant owners also remain liable for accidents that occur on the site. As the condition of the plant deteriorates over time, the risk increases that plant visitors (whether authorized or unauthorized) could slip or fall, leading to injuries.

From the community's perspective, the risk of blight (as noted above) from a plant left cold and dark for a number of years may be substantial, lowering nearby property values and raising the risk of vandalism or other crime at the site. In addition, environmental damage from unremediated spills or leaching tends to increase over time. For example, leaks from petroleum storage tanks that have not been fully remediated could spread deeper into soil, increasing ultimate cleanup costs as well as risks to groundwater. Structural issues such as a collapsed roof could make a site more hazardous by releasing previously sequestered materials such as asbestos or lead.

Until recently, perhaps the most important long-term environmental risk associated with leaving a plant cold and dark was posed by coal combustion residuals (CCRs). Risks of ground and surface water pollution from wet or dry ash impoundments that are not closed or properly maintained will tend to increase over time, as underground contaminants migrate. Recent regulations under the Resource Conservation and Recovery Act (RCRA) require that all CCR impoundments managing wet ash comply with detailed groundwater monitoring protocols, mitigating some of these risks. Any ponds found to be contaminating nearby groundwater will be required to close by 2019. However, CCR landfills that do not manage wet ash are not subject to these regulations unless they receive new CCRs after October 2015 (US EPA 2015). These legacy landfills could pose risks if not properly constructed or maintained. These regulations and their cost implications, which are substantial, are explored in Sections 4.1.3 and 4.1.4.

3.5. Decommission

Full decommissioning indicates that generating units will be completely dismantled, and in most cases, other capital at the plant site such as fuel-processing facilities and transmission equipment will also be dismantled and closed. (If repowering occurs, some of this equipment may remain.) This option includes environmental remediation, though the extent of remediation will vary depending on the desired end use of the property.

In cases where plant assets clearly outweigh expected demolition and remediation costs, or in traditionally regulated regions where decommissioning costs are built into rate bases, owners will typically proceed with decommissioning. Depending on the value of the property and the extent of contamination, a site may be remediated to conditions that suit different types of development. For example, remediation costs may be prohibitive for restoring land to a “greenfield” (pre-project) condition where residential development might occur. In such cases, plant owners may choose to restore the site to “brownfield” condition, suitable for development of an industrial facility or repowering.

3.5.1. Deciding On An End Use

Multiple factors go into deciding on the end use of a power plant site. Although no two plants are alike in terms of their liabilities and assets, several common principles guide the decision-making process.

3.5.1.1. Location and Value of Land and Assets

As noted above, some power plants have a variety of attractive features that encourage redevelopment of the site, whereas others offer less opportunity for profitable redevelopment. Chief among these factors is the physical location of the plant. This section provides a brief overview, and the issue is examined in depth in Section 5.3.

When plants are in locations with strong real estate markets, such as in growing cities or along attractive waterfronts, the value of land may be substantial. In these situations, if the plant owner does not wish to sell the site as-is, they will likely have strong financial incentives to quickly decommission the plant and remediate the site so that it can be redeveloped. In addition to the value of the land, power plant infrastructure such as buildings may be attractive to potential developers. In these cases, decommissioning will involve removal of key pieces of equipment but leave other structures, such as facades or entire buildings, intact.

Along with the characteristics of the plant itself, the location of the facility may provide attractive access to key infrastructure or transportation. For example, many retired and aging coal-fired power plants sit along rivers that offer access to shipping lanes and typically have ready connections to railways. Access to such infrastructure may be appealing for developers seeking to site new industrial facilities.

3.5.1.2. *Access to Transmission and Market Factors*

In some cases, access to electricity transmission and favorable market or regulatory conditions will encourage owners to repower the site. For example, Florida Power & Light (FPL), a traditionally regulated utility operating in Florida, has retired 14 petroleum-fired units totaling roughly 2,700 MW of capacity in recent years (US Energy Information Administration 2016). At many of those sites, FPL has installed new natural gas combined-cycle (NGCC) units, which, because of the low cost of natural gas in recent years, have reduced operating costs (NextEra Energy 2016).

Repowering efforts in some cases may be supported by federal policy. For example, in recent years, EPA has offered the RE-Powering America's Land Initiative, which encourages the development of renewable energy projects on contaminated sites. The program provides technical assistance, project guidance, and coordination with potential partners, though it does not offer direct financial incentives (US EPA 2016a). Through October 2016, the program had supported deployment of 190 projects represented 1.1 GW of capacity across 38 states. Most of these projects have occurred at landfill sites, but other brownfield sites also have been eligible (US EPA 2016b).

3.5.1.3. *Costs of Different Options*

The potential value of the factors discussed above must be weighed against the costs associated with different decommissioning options. As discussed in detail in Section 4, costs range widely because of a variety of factors, including location (urban or very remote plants will tend to cost more), extent of environmental remediation required, salvage value, and more.

Under all circumstances, some level of environmental remediation will be required, and the desired end use of the site will ultimately determine the level of remediation undertaken by the plant owner. Owners may decommission a facility and (1) remediate the site to brownfield status and repower; (2) remediate the site to brownfield status, suitable for industrial development, and sell; or (3) remediate the site to greenfield status, suitable for residential or commercial development, and sell. Because it requires the greatest level of environmental remediation, the third option will tend to be the costliest.

Plant owners typically examine the costs and benefits of each of these three options, often consulting with law firms, demolition companies, and others with expertise on decommissioning. After determining the end use of the site, the owner will begin planning for execution. Key decisions during this stage include the selection of contractors to characterize on-site safety risks, hazardous and regulated materials, salvage value, permit issues, and structural issues. Owners also solicit bids from contractors to carry out environmental remediation, demolition, and waste management. Once dismantlement and remediation are complete, the owner (or contractor) closes out the project by conducting a final site assessment, closing out contracts and permits, and archiving records.

3.5.1.4. *Local Stakeholders*

Because of the major economic and, in some cases, cultural contributions of power plants to the communities where they operate, the decision of how to repurpose a plant site can have substantial impacts on a community's character and economic prospects. As a result, plant owners often have a reputational incentive to see the site redeveloped, whether by them or by another party. Plant owners and contractors may also seek to enhance community support by hiring local workers, engaging local labor leaders, or subcontracting with local businesses.

Regardless of the site's end use, extensive engagement with plant employees and other local, state, regional, and federal stakeholders is cited by industry experts as an essential component of any successful decommissioning effort. In some cases, plant owners convene a community advisory board to keep stakeholders abreast of plans and developments, as well as to gather external feedback and address concerns as they arise (Electric Power Research Institute 2010a, b; Malley 2016).

3.5.2. Decommissioning the Plant

Once an end use has been determined, the plant owner develops and implements a plan for decommissioning. For many newer power plants, including most wind and solar farms, decommissioning plans are developed and approved by local or state authorities, or both, before initial construction of the project. But for older power plants, decommissioning plans must in most cases be developed and implemented after decades of operations. In addition, many older plants were constructed using asbestos, lead paint, or other regulated materials, the handling of which has become more stringent over decades.

Broadly speaking, decommissioning consists of four major phases: site assessment, project planning, project implementation, and project closure. Based on previous experience, the Electric Power Research Institute has developed reports that guide plant owners by providing a great level of detail on establishing workflows to accomplish objectives (Electric Power Research Institute 2010a, b). Each step in the process involves extensive planning and dozens of individual steps. Table 4 summarizes key elements.

While all decommissioning activities involve the steps above, different plant types and desired end uses require different levels of activity, particularly with regard to environmental remediation and site restoration. The costs and implications of these issues for different fuel types are discussed in Section 4.

TABLE 4. KEY DECOMMISSIONING STEPS

Site assessment
Gather historical information
Conduct on-site assessment for detailed information
Project planning
Develop remediation and closure plan
Communicate with stakeholders
Develop contracts and select contractors
Project implementation
Asbestos removal and other above-ground environmental remediation
Equipment removal and salvage
Demolition and salvage
Below-ground environmental remediation
Waste removal and disposal
Project closure
CCR landfill/impoundment closure and monitoring (coal plants)
Site grading and restoration: brownfield or greenfield

Source: Adapted from EPRI (2010a, b)

3.5.2.1. Decommissioning to Brownfield for Repowering or Sale/Redevelopment

Because power plants have access to existing electricity transmission infrastructure and often other features such as rail connections, natural gas pipelines, or access to water bodies for cooling, plant owners have opted to repower in many cases, decommissioning older generating units, then constructing new units at the same site.

After decommissioning, repowering typically requires that a site is remediated to brownfield status. As defined by federal statute, a brownfield is "a property, the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant."[2] After decommissioning, major issues of concern for power plant brownfields include soil contamination from leaks of petroleum or other liquids, CCR-related soil or groundwater contamination, and the presence of asbestos, PCBs, lead, or other regulated materials.

If a brownfield property is sold, liability is transferred under CERCLA to the new owner, providing prospective purchasers with a strong incentive to conduct a detailed site assessment. However, if the site is to be repowered by the same owner, no liability transfer occurs, and a detailed environmental assessment becomes less necessary. Although such an outcome results in lower costs for the plant owner, it may also increase ultimate site cleanup costs if subsurface contamination becomes worse over time.

3.5.2.2. Decommissioning to Greenfield for Sale or Redevelopment

In some cases, plant owners may wish to remediate a plant site to greenfield status. While the concept of a greenfield is straightforward, the precise definition will vary depending on local government requirements. For example, decommissioning plans for most wind and solar farms require developers to restore the site to preconstruction conditions (see Sections 4.3 and 4.5). For older fossil-fired plants, greenfield status may instead indicate remediation of a site suitable for residential redevelopment, where the extent of environmental cleanup satisfies local requirements but does not return a site to preconstruction conditions.

Although in theory plant owners could take on redevelopment efforts at a greenfield site, most owners are not interested in moving away from their core business of producing electricity and toward commercial or residential development. As a result, greenfield sites typically are sold to developers with knowledge of local real estate markets or in some cases donated by the plant owners for use as parkland or other civic purposes.

4. Fuel-Specific Decommissioning Processes and Costs

The costs of decommissioning power plants vary widely based on a variety of factors (Figure 6). These include the extent of environmental remediation required to meet the desired (or regulated) end state, the physical location of the plant, and the potential salvage value of equipment and scrap. Generally speaking, costs increase

[2] Small Business Liability Relief and Brownfields Revitatlization Act, Public Law 107-118, Section 211, 107th US Congress (2002).

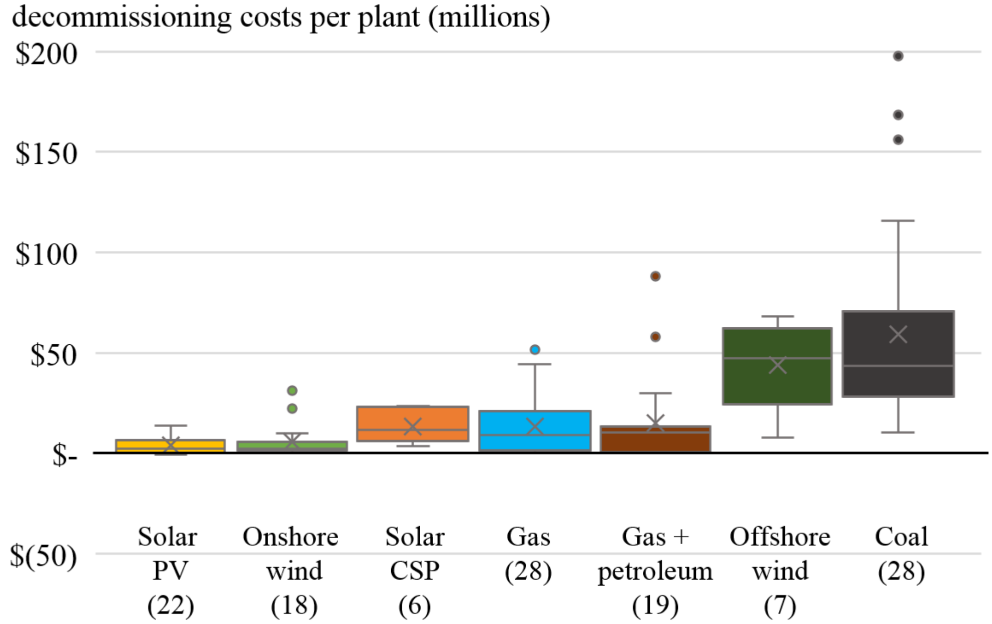
when environmental remediation needs are greater; when plants are in densely populated cities, highly remote areas, or other locations that create logistical challenges; and when salvage values (which are driven by prices in volatile metals markets) are low. Because they are often relatively modest in physical size, and because of the absence of fuel storage facilities or combustion residuals, solar PV and onshore wind facilities tend to have lower costs for decommissioning than other plants. Concentrated solar power (CSP) plants, which tend to be larger than PV facilities and are often located in remote regions, typically entail higher decommissioning costs. Natural gas and petroleum plants both show wide ranges, with costs generally scaling with plant capacity. Estimates for offshore wind tend to be relatively high because of the logistical challenges of decommissioning at sea, though costs remain highly uncertain because no US facilities have been decommissioned.

Finally, coal plants tend to show the highest overall costs because of their age, large size, and various environmental remediation requirements. In particular, the costs associated with managing CCRs are substantial and contribute to a large share of the cost estimates provided in Figure 6. However, each of these estimates was made before the implementation of EPA's rule on CCRs under RCRA and other state laws mandating the closure and monitoring of CCR impoundments and landfills. As discussed in more detail in Section 4.1, these costs are substantial, in some cases reaching $200 million or more for a single large CCR impoundment. As a result, Figures 6 and 7 likely underestimate the ultimate cost of decommissioning coal-fired plants. Figures 6 and 7 use box-and-whisker plots to illustrate estimated decommissioning costs gathered from dozens of sources for 127 power plants.[3] Some estimates, such as those for projects on Bureau of Land Management (BLM) land, have been reviewed and approved by regulators. Others, including several wind and solar PV projects, are not subject to regulatory review and are therefore unverified estimates.

On a per-MW basis, the costs of decommissioning shift. The highest estimates for decommissioning come from offshore wind farms, where remote locations and offshore operations increase costs relative to onshore wind. Coal plants are also relatively costly to decommission on a per-MW basis, due largely to waste management costs and the need to remediate legacy environmental issues. Cost estimates are also relatively high for CSP plants, which are large-scale projects often sited in remote locations on federal land.

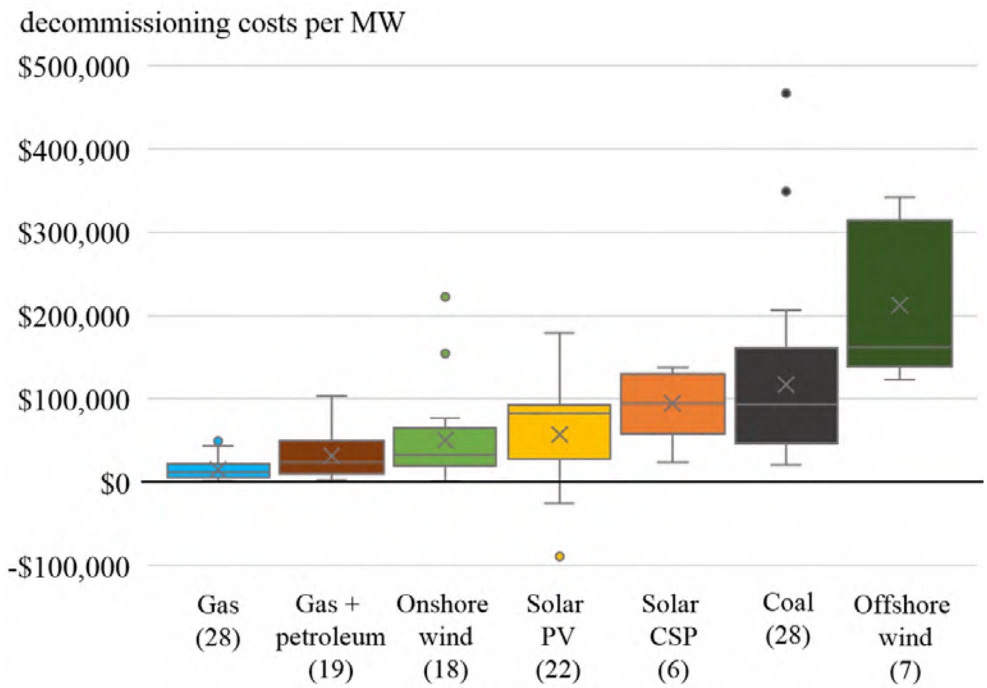
[3] In these figures, boxes represent the two central quartiles of the estimates, with an X marking the mean value and a horizontal line marking the median. Whiskers extend to the largest or smallest data point within 150 percent of the interquartile range (Q3 – Q1). Estimates beyond this range are shown as individual points.

FIGURE 6. DECOMMISSIONING COST ESTIMATES FOR VARIOUS PLANTS (2017$)



Sources: Onshore wind: (EDP Renewables 2006; Ripley-Westfield Wind LLC 2010; State of Vermont Public Service Board 2010a, b, 2011a, b; EDP Renewables 2015a, b; McCarthy 2015; Algonquin Power Co. 2016; Invenergy 2016; State of Minnesota ND). Solar PV and CSP: (CH2MHill 2010; US Bureau of Land Management 2010-2016; Belectric 2011; EMC Planning Group Inc. 2012; Maryland Solar 2013; Michael Brandman Associates 2013; Apple One LLC 2014; Birdseye Renewable Energy 2015; RBI Solar 2015; Cypress Creek Renewables 2016; New York State Energy Research and Development 2016). Offshore wind: (Deepwater Wind 2012; Kaiser & Snyder 2012a; Levitan & Associates 2016). Solar PV, petroleum, gas (various), gas and petroleum, and coal estimates in Florida: (Progress Energy Florida 2009; Florida Power and Light 2016) . Onshore wind, gas (various), and coal estimates in Colorado: (Burns & McDonnell 2014). Onshore wind, gas and petroleum, and coal estimates in Minnesota: (Xcel Energy 2015; Minnesota Power 2016).
Note: This figure shows the estimated decommissioning costs for a variety of plant types across the United States. Offshore wind estimates are based on preconstruction filings with state utility commissions and modeling exercises. Fossil plant estimates entail decommissioning and site remediation to brownfield status, suitable for industrial redevelopment. Wind and solar estimates entail decommissioning and site remediation to greenfield status, returning the sites to predevelopment condition.

FIGURE 7. DECOMMISSIONING COST ESTIMATES PER MW OF PLANT CAPACITY (2017$)



Sources: See Figure 6.
Note: This figure shows the estimated decommissioning costs on a per-MW basis for a variety of plant types across the United States. Offshore wind estimates are based on preconstruction filings with state utility commissions and modeling exercises. Fossil plant estimates entail decommissioning and site remediation to brownfield status, suitable for industrial redevelopment. Wind and solar estimates entail decommissioning and site remediation to greenfield status, returning the site to predevelopment condition.

The cost estimates underpinning the figures above are drawn from specific jurisdictions where plant owners are required to submit cost estimates either when the project is built (most new wind and solar facilities) or when filing with public utility commissions to recover rates for decommissioning (in some cost of service regions). In competitive regions, plant owners are typically not required to file decommissioning cost estimates with state regulators (though they may be required to make these estimates for local jurisdictions when building new facilities). However, publicly listed plant owners assess the future cost of decommissioning plants as asset retirement obligations (AROs), often filed as part of an annual financial report (see Section 5.1.2.1). Although AROs provide some indication of expected future decommissioning costs, they do not include plant-specific estimates, preventing detailed analysis.

4.1. Coal-Fired Plants

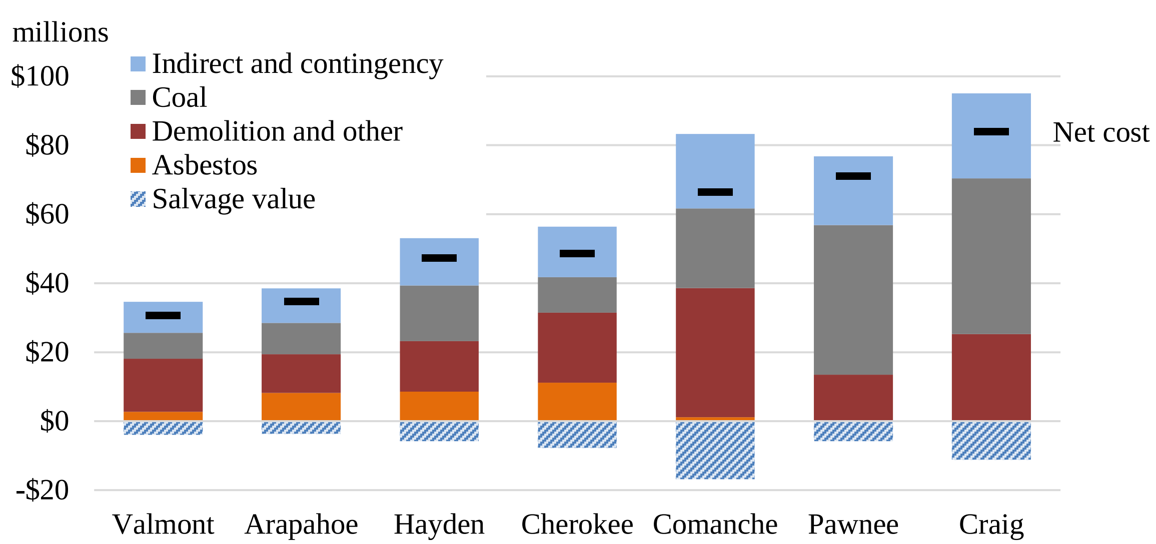
In recent years, the largest amount of retired capacity has come from coal-fired plants, with 433 units representing more than 45,000 MW going offline since 2005. For the 911 coal-fired units that continue to operate in the United States, the average age is 43 years, with 298 units aged 50 years or older. As of 2015, 60 coal plants had announced planned retirement dates (US Energy Information Administration 2016).

Because of the large number of coal plants retired in recent years, owners have invested substantial time in considering options for decommissioning. Once an owner decides to retire a coal plant, perhaps the most important decision is how the site will be used in the future (see Section 3). Depending on this decision, the plant and site will undergo different levels of the following activities: pre-demolition environmental characterization and remediation, demolition and salvage, post-demolition remediation, and in many cases, long-term monitoring.

A variety of environmental concerns are associated with decommissioning coal plants, but the most substantial and most uncertain costs are typically from closing coal ash facilities. These costs are likely to increase in the coming years, largely as a result of the introduction of new federal regulations of CCRs under RCRA (see Section 4.1.4).

Figure 8 illustrates the leading cost components of decommissioning a selection of coal-fired plants. In some cases, particularly for older plants, predemolition environmental remediation such as asbestos abatement constitutes a large share of costs. Demolition and other costs vary widely from site to site and are typically driven by the complexities of safely demolishing smokestacks, boilers, and other large infrastructure. Management costs of CCRs and other coal-related environmental issues (such as cleaning up coal storage areas) can be substantial, in some cases exceeding 50 percent of total project costs. Finally, contractors typically include indirect costs (15 percent in the figure below), along with contingency funds to prepare for unanticipated environmental or other costs (20 percent in the figure below).

FIGURE 8. ESTIMATED KEY COMPONENTS OF COAL DECOMMISSIONING FOR SELECT COLORADO PLANTS



Source: Data from Burns & McDonnell (2014).
Note: This figure shows the key components of estimated decommissioning costs for a selection of coal-fired plants in Colorado. It highlights the wide variability in costs for demolition, salvage values, asbestos abatement, and coal residual management.

4.1.1. Environmental Characterization and Remediation

When a plant is fully decommissioned, substantial time is invested in pre-demolition environmental remediation. This process begins with a detailed site characterization study, in which environmental hazards are identified and cataloged. These may include asbestos, PCBs, lead paint, hydrocarbon storage tanks, and contaminated soils, which must be removed, handled, and disposed of properly. As environmental standards have grown more stringent over time, remediation costs have increased. If environmental standards become more stringent in the future, delaying site remediation will tend to lead to higher costs (Oostdyk et al. 2017).

As Figure 8 highlights, asbestos abatement can be a major cost, adding $10 million or more to some projects. Other costs, including remediation of soils affected by petroleum spills and disposal of PCBs or other regulated materials such as mercury, are also substantial.

4.1.2. Demolition and Salvage

Plant owners hire contractors to plan for and implement demolition plans. These activities often begin with removing components that can be reused or sold for scrap, such as turbines or copper. In some cases, contracts specify that plant owners share in the proceeds from the resale of these materials; in other cases, contractors retain scrap revenues.

After valuable components have been removed, contractors will demolish key structures such as buildings and supporting infrastructure. Depending on the desired end use of the site, they may crush concrete foundations on-site and either remove or recycle the resulting waste streams. Smokestacks are often the final components to be demolished, and this tends to attract crowds from the surrounding area. Although it is the most dramatic phase of demolition, stack demolition is typically less costly than other demolition activities, such as demolishing boilers or buildings. Along with the direct costs of demolition, each of these activities requires mitigation of the resulting dust or other materials, which can also be costly, particularly in urban areas where community concerns may be high.

After demolition, the remaining scrap metal will be removed from the site and sold to local purchasers. As discussed in more detail in Sections 4.3 and 4.5, scrap values can be substantial but are also volatile because of their connection with globally set metals prices.

4.1.3. Coal Ash Management

As noted above, managing CCRs has become the costliest aspect of decommissioning many coal-fired power plants. During operations, CCRs generated by burning coal, which include fly ash and bottom ash, are stored in dry landfills or wet "ash ponds" at or near the plant site. In the wake of high-profile releases of ash from such ponds, along with evidence of groundwater contamination from unlined ponds (Harkness et al. 2016), EPA regulations finalized in 2015 now regulate CCRs under RCRA. These rules set standards for existing CCR impoundments, require the closure of ash ponds if they are contaminating groundwater, and require the closure of ponds or landfills that do not meet certain criteria, such as those that lack structural integrity or are in sensitive locations (US EPA 2015).

Wet CCR impoundments may be closed in two different ways. The first, closure-in-place, requires owners to first "dewater" the pond, then close the remaining landfill containing dry CCRs. (Closure of landfills is discussed below.) A key cost associated with this option is managing the wastewater produced during dewatering (EOP Group 2009).

The second option for closing coal ash ponds also involves dewatering, followed by excavation of the CCRs and transportation to a landfill for ultimate disposal. This option tends to be costlier than closure-in-place because of the transportation costs of moving CCRs by rail or truck. As a result, closure-in-place tends to be the preferred option for plant owners, though in some cases, such as in North Carolina, excavation and removal of CCRs has been implemented following a high-profile release from an ash pond (Duke Energy Corporation 2017a).

A 2009 study commissioned by the federal Office of Management and Budget estimated that closing every one of the 155 wet ash impoundment in the United States through closure-in-place would include large capital, operating, and stranded costs, totaling roughly $39 billion over 10 years (EOP Group 2009). For reference, $39 billion represents roughly 10 percent of total revenue generated by electricity sales in the United States in 2016 (US Energy Information Administration 2017a). However, interviews with industry experts suggest that these costs may ultimately be higher because of monitoring and remediation requirements imposed by new regulations on CCRs under RCRA (see Section 4.1.4).

The costs of closing ash ponds vary for a number of reasons. First, groundwater conditions are different in each location; in some cases, groundwater movements may enhance the likelihood of CCR-related contaminants reaching a receptor (such as a private water well), potentially requiring costly remediation from the facility owner. Second, the operational needs of a plant may increase the costs of closure. For example, closing a CCR impoundment at a plant that continues operations will entail more logistical challenges than at a site where the plant is retired. Finally, the physical location of the impoundment affects costs. In some cases, ponds may be located in hard-to-reach locations, increasing logistical and transportation costs.

A series of studies carried out by the Tennessee Valley Authority (TVA) illustrates this range, with estimated closure-in-place costs ranging from $3.5 million for a 22-acre pond to $200 million for a 350-acre site (Tennessee Valley Authority 2016a, b, c, d, e, f). Excavation and removal of CCRs to landfills was estimated to cost between 270 and 2,200 percent more than closure-in-place for different sites. On aggregate and on per-unit terms, the costs of closure vary widely, as shown in Table 5.

Table 5. Costs of Closure-In-Place at Six TVA Wet Coal Ash Impoundments

Plant name	Impoundment size (acres)	CCR volume (yd^3)	Total cost	Cost per acre	Cost per yd^3
Allen	22	250,000	$3,500,000	$159,000	$14
Bull Run	38.5	3,500,000	$13,000,000	$338,000	$4
Colbert	52	3,200,000	$10,000,000	$192,000	$3
Sevier	42	770,000	$13,000,000	$310,000	$17
Kingston	31	700,000	$40,000,000	$1,290,000	$57
Widow’s Creek	350	25,000,000	$200,000,000	$571,000	$8
Total	536	33,420,000	$279,500,000	$521,942	$8

Sources: Data from TVA (Tennessee Valley Authority 2016a, b, c, d, e, f).

Duke Energy, the nation's largest electric power utility, is currently closing all its CCR basins (both wet and dry) in the Carolinas. Due in part to state legislation enacted in 2016, a number of these basins are being excavated and removed to landfills, leading to higher costs per acre than closure-in-place.[4] Although Duke has not publicly issued estimated closure costs for these landfills, in 2016 it did report AROs associated with CCR basins in North and South Carolina of $4.2 billion. For reference, Duke Energy Carolinas' net income in 2016 was $1.2 billion (Duke Energy Corporation 2016). As Table 6 shows, these estimates imply closure costs of roughly $1.6 million per acre, well above the average per-acre costs noted above for the TVA.

Dry ash landfills containing CCRs are typically closed by installing a cover system, such as liners topped with landscaping, which minimizes erosion and runoff. Modern landfills include underground protections to prevent seepage and limit environmental risks to surrounding areas. However, some older CCR landfills do not have such protections and may pose increased risks to nearby groundwater resources.

Like coal ash ponds, closure of landfills containing CCRs can also be very costly. For example, landfill closure costs at one 1,270 MW coal plant in Florida were recently estimated at $44.5 million, plus several million more for closure of smaller impoundments at the site (Florida Power and Light 2016). Another estimate from American Electric Power (AEP) for the closure of a 53-acre facility in Ohio estimates total costs of $8.2 million (~$154,000/acre). AEP also estimates costs of $4.4 million over 15 years associated with maintenance of the landfill cover system, along with monitoring for contamination to groundwater, surface water, and other risks (American Electric Power 2016).

TABLE 6. DUKE ENERGY ASSET RETIREMENT OBLIGATIONS AND COAL ASH IN THE CAROLINAS

State	No. of ash basins (wet and dry)	Acreage	Ash volume (tons)	AROs	AROs per acre
NC	31	2,543	111,135,000		
SC	4	176	4,716,000		
Total	35	2,719	115,851,000	$4.24 billion	$1,559,765

Sources: Duke Energy (2016, 2017b).
Note: Duke Energy does not estimate state-specific AROs for North or South Carolina.

[4] Drinking Water Protection/Coal Ash Cleanup Act, Session Law 2016-95, House Bill 630, General Assembly of North Carolina (2016).

4.1.4. Postdecommissioning Activities

After decommissioning and closure of CCR impoundments, hundreds of coal plant sites around the United States will require decades of monitoring and mitigation of any negative impacts to groundwater sources. Under EPA's 2015 CCR rule issued under RCRA (US EPA 2015), owners or operators of impoundments must install a groundwater monitoring system and complete the development of a groundwater sampling and testing program approved by a professional engineer by mid-2019. This program requires owners or operators to establish baseline groundwater quality levels (based on sampling from wells up-gradient of the impoundment), then monitor for statistically significant changes to water quality at down-gradient locations over the course of 30 years (statistical guidelines are provided in Section 257.93 of the rule).

Under the rule, owners or operators prepare annual groundwater monitoring reports, note results, and describe any corrective action taken. If changes in groundwater quality are detected over this period, owners or operators are required to begin corrective action. Any such actions are required to protect human health and the environment, meet certain groundwater quality criteria, eliminate or mitigate the source of contamination, and remediate the affected area to the extent possible (Sections 257.97–257.98). Satisfaction of these criteria must be determined by a professional engineer.

Because these rules have yet to go into effect, and the long-term extent of contamination is uncertain, no reliable cost estimates exist for these monitoring programs. Impoundment closure costs cited above in Table 5 include the installation of groundwater monitoring networks, but because the long-term liabilities arising from any detections of groundwater contamination are unknown, the potential range of costs is large.

The Resource Conservation and Recovery Act (RCRA)

RCRA, passed by Congress in 1976, gives EPA authority to develop regulations related to hazardous and nonhazardous solid waste. States develop and carry out programs according to the guidelines established by EPA and may establish stricter regulations if they so choose. These guidelines include standards, monitoring, and corrective action protocols for municipal and industrial landfills, as well as "cradle-to-grave" requirements for hazardous wastes.

CCRs had not been subject to regulations under RCRA, though other fuel waste such as used motor oils have been regulated as hazardous wastes for decades. Other energy infrastructure such as underground petroleum storage tanks are also regulated under RCRA.

RCRA focuses on active and future sites, whereas abandoned or historical sites are the focus of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), often referred to as Superfund.

In 2010, EPA proposed to regulate CCRs under RCRA, examined several alternative approaches, and determined that it would regulate CCRs as nonhazardous solid waste, under subtitle D of the statute. After final publication of the rule in 2015, states began submitting management plans for approval to EPA, with the rule slated to take effect in late 2017. For more information on the rule, see https://www.epa.gov/coalash/coal-ash-rule.

4.1.5. Aggregate Cost Estimates

As demonstrated by the wide range of estimates, the costs of decommissioning a coal plant vary according to a number of location-specific factors. However, there is a correlation between the size of a plant and its decommissioning costs. As Figure 9 shows, larger plants tend to be less costly on a per-MW basis, as the incremental costs of planning for, carrying out, and completing decommissioning tend to decrease with scale. In addition, a number of the smaller plants included in the figure are old compared with the larger, newer plants. As noted above, older plants often use more hazardous materials such as asbestos and may have treated CCRs less carefully, resulting in higher ultimate cleanup costs

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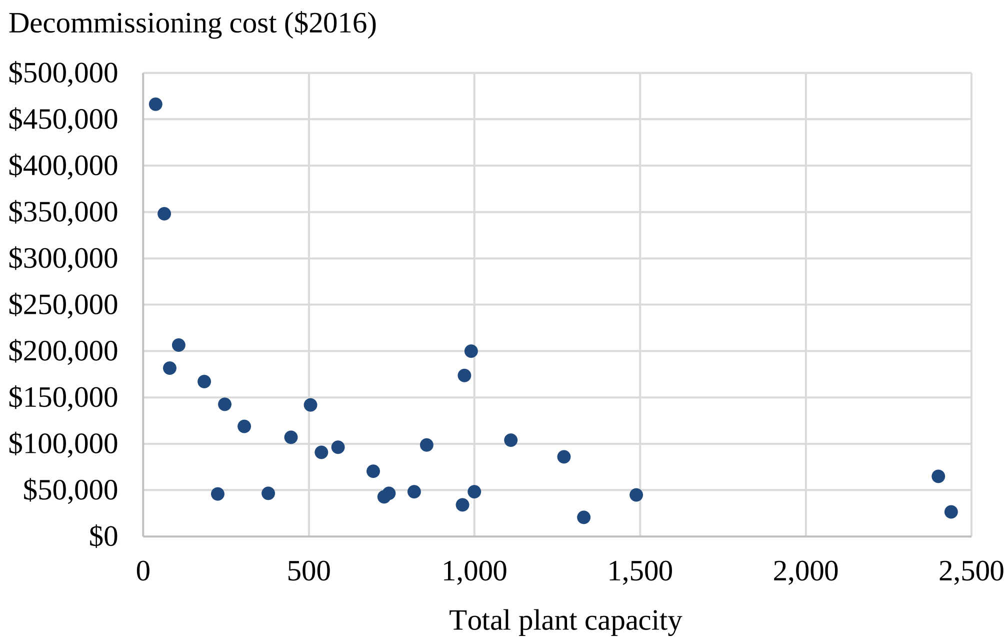
FIGURE 9. COAL DECOMMISSIONING COSTS BY PLANT SIZE



Sources: See Figure 6.
Note: This figure shows estimated decommissioning costs for coal plants in select regions and highlights the correlation between plant capacity and per-MW decommissioning costs. In short, larger plants tend to be less costly to decommission on a per-MW basis. Figure does not include costs of compliance with 2015 EPA rules related to CCR management and monitoring.

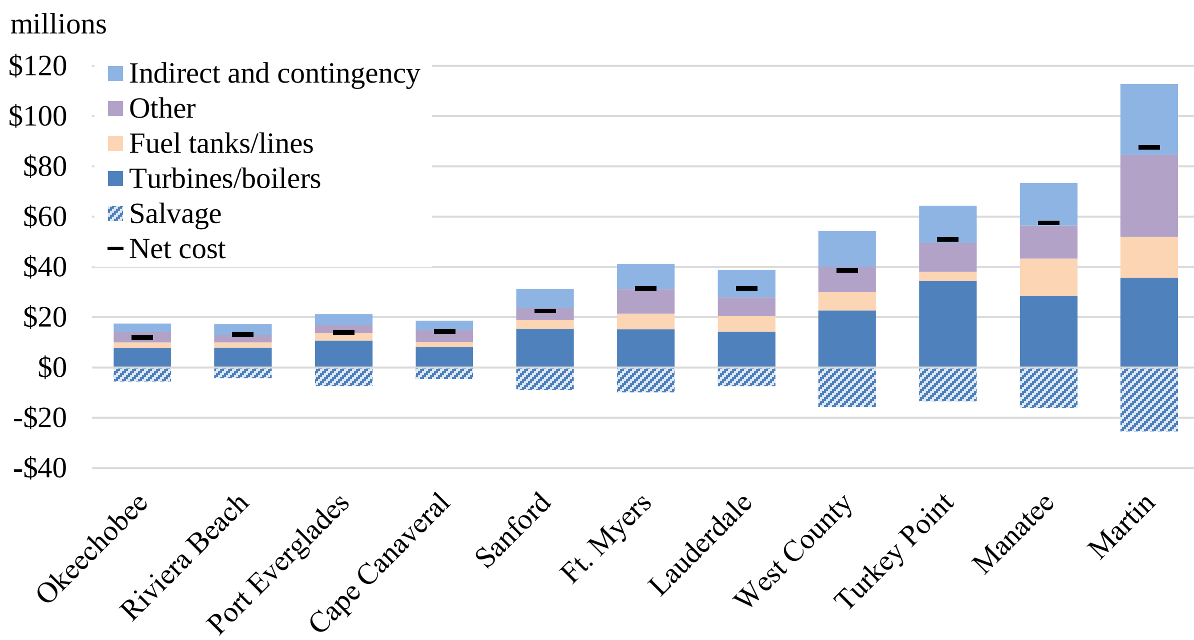
4.2. Natural Gas and Petroleum-Fired Plants

As noted in Section 2, the greatest number of recently retired generating units have been fueled by petroleum or natural gas. While recent years have seen a substantial increase in the number of NGCC units, less efficient types of natural gas generation, particularly NGST units, have seen increased retirements. Since 2005, 816 natural gas units and 791 petroleum-fired units have retired. On average, natural gas units have operated for 40 years before going offline, and petroleum units have averaged 38 years before retirement. As of 2015, 535 operating natural gas units (306 of which were NGST units) were aged 50 or older, and 133 (66 of which were NGST units) had announced retirement dates; 518 operating petroleum units were 50 years or older, with 42 having announced retirement.

Decommissioning gas and petroleum plants requires not only dismantling the generating units but also removing and managing fuel storage tanks, petroleum or gas pipelines, and other equipment at the plant.

Figure 10 highlights the major cost drivers for decommissioning petroleum and gas plants in Florida, where a large number of petroleum and gas retirements have occurred since 2000. Typically, the largest costs are associated with dismantling turbines (for gas plants) and boilers (for petroleum plants). The salvage value of scrap steel can be substantial, reaching above $20 million for larger plants. Owners of both gas and petroleum plants also spend considerable sums cleaning and removing fuel storage equipment such as tanks and transportation lines. Finally, contractors add fees and contingency budgets to protect against unforeseen expenses.

Figure 10. Decommissioning Costs for Select Gas and Petroleum Power Plants in Florida



Source: Data from FPL (2016).
Note: This figure shows estimated cost drivers for decommissioning natural gas and petroleum-fired power plants in Florida. It highlights that costs tend to be relatively uniform across different plant types and typically scale with plant size. Turkey Point estimates do not include nuclear power facilities.

4.2.1. Environmental Assessment and Remediation

The major steps of decommissioning a gas or oil plant are similar to those for a coal plant, but without the challenges associated with managing CCRs. Asbestos abatement costs for these power plants also tend to be lower than those of coal-fired plants, primarily because of their younger age. However, in some cases, older petroleum plants will contain substantial levels of asbestos, resulting in additional remediation costs amounting to millions of dollars. For example, the costs of asbestos abatement at several older petroleum plants in Minnesota are estimated at $1.5 million to $3 million (Minnesota Power 2016).

Natural gas and petroleum plants also require removal of fuel waste, though these costs tend to be less substantial than for coal-fired plants. For example, the dismantling, cleaning, and disposal of fuel oil storage tanks and other components was estimated to cost between $5 million and $17 million for several large natural gas and petroleum-fired plants in Florida (Florida Power and Light 2016). In some cases, leaking fuel storage tanks may create additional costs, as contaminated soil must be removed and properly disposed of.4.2.2. Demolition, Salvage, and Postdemolition Activities

As noted above, the largest cost components for decommissioning natural gas and petroleum plants are often for dismantling turbine or boiler systems. The scrap metal generated from this equipment can be valuable, but it is not sufficient to offset demolition costs. Along with dismantling turbine and boiler systems, decommissioning involves breaking up and disposing or recycling concrete foundations.

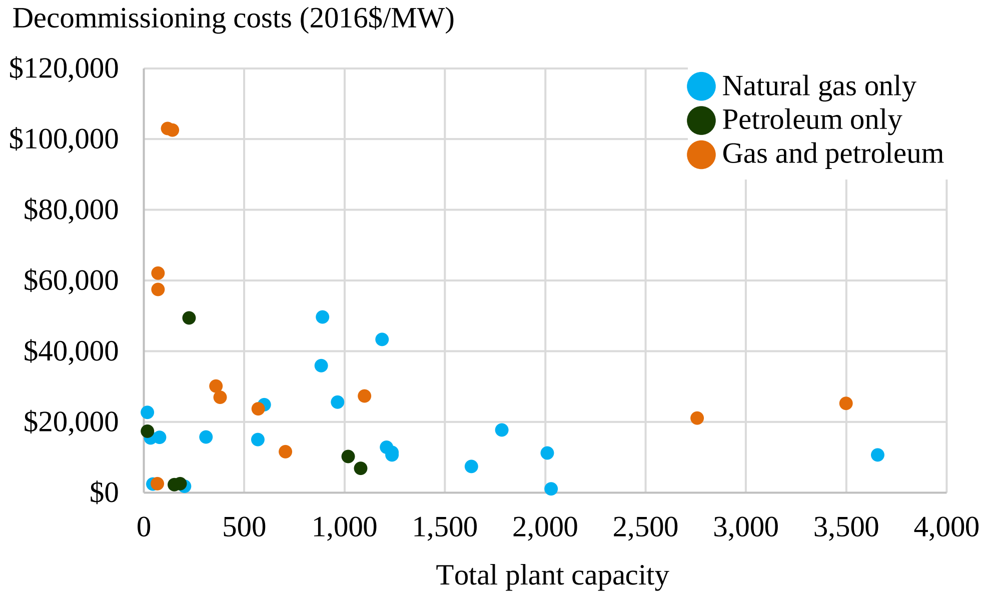
Pipelines and storage tanks that are not removed may be retired in place. To retire this infrastructure, concrete is pumped in to seal off equipment and minimize risks of future degradation, similar to the “plugging” of abandoned oil and natural gas production wells.

Following the demolition phase, the plant site will be graded and restored to the desired end state. In most cases, long-term monitoring will not be required.

4.2.3. Aggregate Cost Estimates

Figure 11 shows the range of decommissioning costs for different plant sizes. There is little correlation between the size of a plant and its decommissioning costs on a per-MW basis. Neither is there a clear distinction between the costs of decommissioning gas-fired plants and petroleum-fueled plants. As noted above, older plants will be more likely to contain health hazards such as asbestos or lead paint.

FIGURE 11. DECOMMISSIONING COSTS FOR NATURAL GAS AND PETROLEUM POWER PLANTS



Sources: See Figure 6.
Note: This figure shows estimated decommissioning costs for natural gas and petroleum-fired plants in select regions and indicates a limited correlation between plant capacity and per-MW decommissioning costs.

4.3. Onshore Wind

In the United States, onshore wind energy has grown rapidly in recent years, with net generation increasing more than 10-fold over a decade, from 18 TWh in 2005 (0.4 percent of total net generation) to 191 TWh in 2015 (nearly 5 percent of the total) (US Energy Information Administration 2017b). Installed wind capacity has grown from roughly 9,000 to 82,000 MW from 2005 to 2015, with more than 52,000 utility-scale turbines operating across 40 states (American Wind Energy Association 2017b).

Because relatively few wind farms have reached the end of their useful lives, industry experience with decommissioning these facilities is extremely limited. Indeed, operating facilities were just eight years old on average as of 2015 (US Energy Information Administration 2016). Because they are often relatively small in terms of generating capacity, decommissioning cost estimates for wind units tend to be lower than those for most other plants. And because they do not use or store on site large quantities of fuel or other potential pollutants such as oils or CCRs, estimates of decommissioning costs are also relatively low on a per-MW basis.

Utility-scale wind farms require substantial industrial equipment. One representative project using 2.3 MW turbines entails 262-foot-tall steel towers, with rotor diameters of 381 feet and each unit weighing roughly 275 tons (Invenergy 2016). Turbines sit atop steel-reinforced concrete pads that may be 30 to 50 feet wide and reach several feet below the surface (Ferrell & DeVuyst 2013). Other key pieces of infrastructure include transformers, roads, and below-ground electrical lines. Decommissioning plans for these facilities typically include removing all equipment, regrading the affected land, and restoring the site to preconstruction conditions (e.g., EDP Renewables 2006, 2015a, b; Algonquin Power Co. 2016; Invenergy 2016).

In some cases, decommissioned wind farms may be repowered, with developers removing and updating foundations, towers, and turbines. Newer turbines operate with longer blades and taller towers, increasing capacity factors relative to older, smaller turbines. As a result, repowered wind farms may result in greater output without an increase in land use. For example, a recent update to the Altamont Pass wind farm in California replaced roughly 1,500 smaller turbines with 82 larger units that provide the same amount of electricity, according to the American Wind Energy Association, an industry trade group (Hunt 2017).

4.3.1. Landowner Agreements and Relevant Policies

Unlike large, centralized power plants, whose owners typically purchased land on which to site their facilities, most wind farms are sited on land that is leased by the project developer. Although state and local governments often have requirements for decommissioning wind facilities, most modern leases also include provisions for decommissioning, providing the landowners some assurance that their properties will be returned to preconstruction conditions after retirement of the facilities.

Typically, leasing language stipulates that decommissioning occur within some reasonable time frame (e.g., six months) after all operations at the facility have ceased. Leases commonly require that all structures such as towers and turbines, concrete pads, and underground wiring are removed, followed by site grading and reseeding. In some cases, leases stipulate that the developer post a bond for the expected decommissioning costs. However, given the limited experience with decommissioning to date, it is not clear whether decommissioning is typically completed to the satisfaction of landowners or whether project developers have the financial capacity to properly carry out decommissioning when a project reaches the end of its useful life.

Along with these private decommissioning terms, many local governments and some states require developers to prepare decommissioning plans and cost estimates when they submit permits to build a facility. In Connecticut, Ohio, and Oklahoma, legislatively established commissions require decommissioning plans and cost estimates prior to development, along with the establishment of financial assurance for ultimate decommissioning (Heibel & Durkay 2016). In New York State, similar requirements mandate wind farms with capacities of 25 MW or more to submit plans and expected funding requirements to a state board.[5] In other states, particularly in traditionally regulated regions, state utility commissions effectively require such planning by mandating that regulated power producers create and regularly update decommissioning plans, then recover the projected costs through rates (Progress Energy Florida 2009; Burns & McDonnell 2014; Minnesota Power 2016).

For projects on BLM land, developers submit decommissioning plans to the bureau before construction. These plans, which typically entail returning the site to greenfield condition, are reviewed and, if necessary, modified in accordance with BLM standards. The developer then provides financial assurance (typically a bond) based on the estimated decommissioning costs. Bond levels are reviewed by the BLM every five years to ensure adequacy (US Bureau of Land Management 2015).

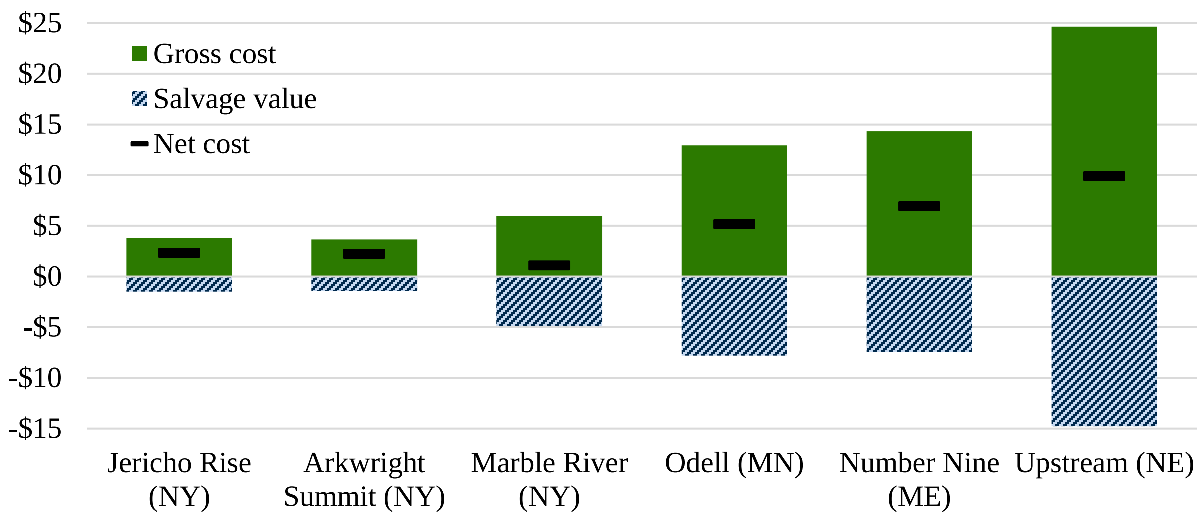
[5] Article 10 Regulations under the Power NY Act of 2011, Section 1001.29, New York State Board on Electric Generation Siting and the Environment (2011).

In states with deregulated electricity markets, or for independent power producers in traditionally regulated states, local governments such as counties are primarily responsible for permitting wind facilities, including decommissioning requirements. In some cases, local governments may not have the ability to set detailed standards for construction of these facilities. For example, the state of Texas is the largest wind power producer in the United States, with over 21,000 MW of installed capacity and nearly 12,000 active turbines (American Wind Energy Association 2017a). However, this study found no evidence of local regulations pertaining to wind decommissioning in Texas. As a result, it is possible that not all wind developers in these regions have made financial preparations for decommissioning.

4.3.2. Decommissioning Cost Estimates

One key element in the decommissioning of wind farms is the estimated value of scrap materials generated by dismantlement of towers and turbines. In many cases, plant owners estimate that the ultimate cost of decommissioning will be offset by 50 percent or more from the sale of these materials (Figure 12).

Figure 12. Decommissioning Cost Estimates for Select Onshore Wind Farms (millions)

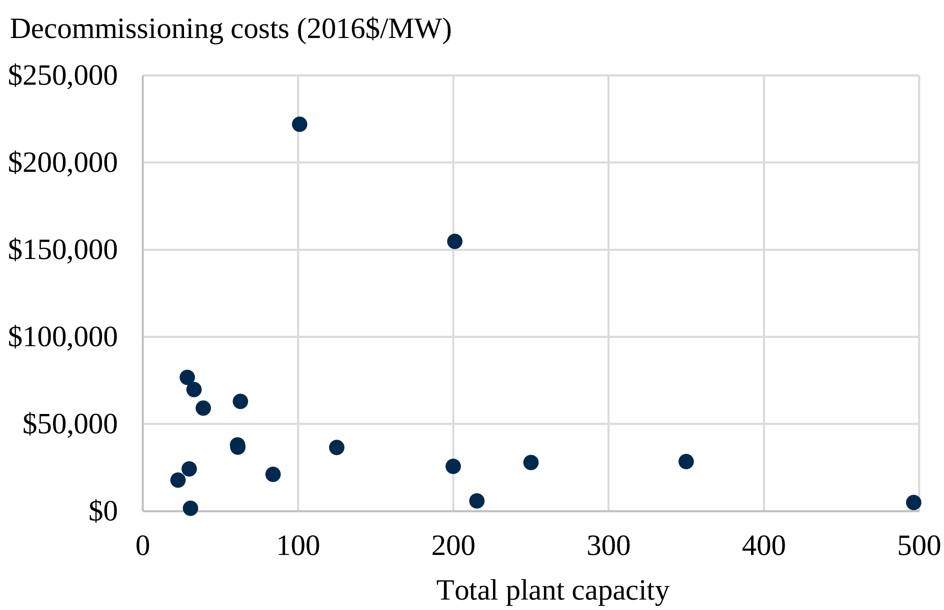


Sources: (EDP Renewables 2006, 2015a, b; Algonquin Power Co. 2016; Invenergy 2016; Patriot Renewables ND).
Note: This figure highlights the importance of salvage value for the net costs of decommissioning wind plants, with salvage values estimated to recover more than half the costs of decommissioning in some cases.

These estimates raise concerns over whether project developers are adequately accounting for future decommissioning costs. Prices for steel and other metals can be highly volatile, but the cost estimates cited above rely on commodity prices based on a single day (Algonquin Power Co. 2016) or an annual average (Invenergy 2016). In other cases, regulatory filings of developers do not provide sources for their estimates of commodity prices (EDP Renewables 2006) or state in these filings that values associated with decommissioning are unlikely to change substantially from year to year (EDP Renewables 2015a).

For decommissioning cost estimates that do provide salvage values, price estimates range from $150 to $236/ton. For a 215 MW wind farm, which includes 109 towers each weighing 200 tons (EDP Renewables 2006), this difference in expected prices for steel scrap implies salvage values ranging from $3.27 million to $5.14 million, a difference of $1.87 million in net decommissioning costs. As Figure 13 illustrates, steel prices are volatile and have ranged from lows of near $100/ton in 2009 to more than $400/ton in 2012 (Steel Benchmarker 2017). This range in steel prices implies a potential difference of $6.54 million in the estimated net decommissioning costs for the hypothetical wind farm described above.

FIGURE 14. ONSHORE WIND DECOMMISSIONING COSTS BY PLANT SIZE



Sources: See Figure 6.
Note: This figure shows estimated decommissioning costs for onshore wind plants in select regions and highlights a modest correlation between plant capacity and per-MW decommissioning costs.

Although decommissioning costs for most projects are well below $100,000 per MW, two plants in Minnesota show substantially higher costs. These higher cost estimates, prepared by the contractor TLG Services, appear to be driven by relatively high costs for grading and landscaping at the site following demolition and removal (Minnesota Power 2016). The underlying cause of these higher remediation costs is unclear.

4.4. Offshore Wind

As of this writing, just one offshore wind farm, the Block Island project off Rhode Island, is operating in the United States. The decommissioning process for offshore wind projects tends to be more challenging and costly than for onshore projects. On a per-MW basis, decommissioning cost estimates for offshore wind projects are higher than for any other fuel type. These higher costs are driven primarily by the challenges of working in offshore environments, along with the costs associated with maritime transportation. In addition, offshore wind projects are often substantially larger than their onshore cousins, employing larger towers and turbines. However, because of the lack of experience with decommissioning of these facilities, domestic cost estimates are based on modeling and projections, rather than experience.

The major steps of offshore wind decommissioning include turbine removal, foundation removal, electrical cable removal, scour protection (preventing damage to the seafloor), and salvage or disposal of materials (Kaiser & Snyder 2012b). Different types of turbine foundations will also incur different levels of decommissioning costs. Turbines may be driven directly into the seabed (such foundations are called “monopiles”) or may rest on foundations made of concrete, steel tripods, or other designs. A variety of other designs have been proposed, including floating foundations. For monopole or tripod designs, owners cut and remove equipment below the seabed using water jets, explosives, or other techniques. For concrete designs, underwater demolition is also required.

Costs for decommissioning will vary according to several key factors. First, facilities located farther from shore will be costlier to dismantle because of logistical requirements. In particular, the distance between equipment and onshore staging areas, rather than the mere presence of coastline, will play an important role in determining these costs. Second, facilities with older and less powerful turbines will generally have higher per-MW costs. Kaiser and Snyder (2012a) provide a useful example of these two factors by modeling costs for two 150-MW wind farms, one off the coast of Texas and another off the coast of New Jersey. As Table 7 shows, decommissioning of the New Jersey facility, which would employ smaller turbines and is located farther from the nearest serviceable port, is estimated to cost roughly twice as much on a per-MW basis.

Table 7. Decommissioning Cost Estimates for Two Offshore Wind Farms

Wind farm	Capacity (MW)	No. of turbines	Distance to port (nautical miles)	Net cost (millions)	Cost per MW
Coastal Point (TX)	150	60	20	$23	$156,000
Garden State (NJ)	150	96	80	$45	$302,000

Source: Kaiser and Snyder (2012a).

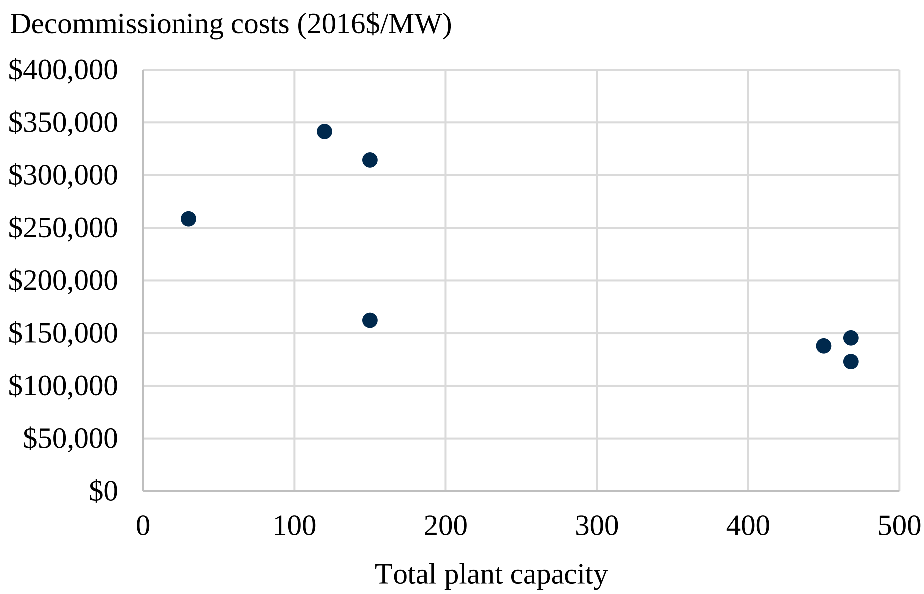
4.4.1. Federal Policies

For wind farms constructed in federal waters, federal regulations require that operators begin decommissioning at the end of commercial operations, with all equipment removed within two years of the termination of the lease, right-of-way, or right-of-use grant. Federal waters begin 3 nautical miles from shore for most states and 9 nautical miles from the coast of Texas and the west coast of Florida (Bureau of Ocean Energy Management 2017). In federal waters, developers post a bond or other financial assurance based on estimated decommissioning costs. Federal rules require removal of all equipment at the surface, on the seafloor, and up to 15 feet below the seafloor "mudline." On a case-by-case basis, regulators may allow developers to leave certain infrastructure in place.[6]

4.4.2. Decommissioning Cost Estimates

Figure 15 illustrates a range of estimated decommissioning costs for six proposed and one constructed offshore wind farm in the United States, showing that larger plants are generally less costly to decommission on a per-MW basis than smaller plants. However, given the limited experience with offshore decommissioning coupled with the small number of estimates available, it is difficult to say whether this correlation would hold under real-world conditions.

FIGURE 15. OFFSHORE WIND DECOMMISSIONING COSTS BY PLANT SIZE



Sources: See Figure 6.
Note: This figure shows estimated decommissioning costs for offshore wind plants in the United States. Because no offshore wind plants have been decommissioned in the United States (only one plant is currently operating), these estimates are highly uncertain and come from preconstruction filings with state utility commissions and modeling exercises.

[6] Renewable Energy Alternate Uses of Existing Facilities on the Outer Continental Shelf, 30 CFR 285, 43 U.S.C. 1331 and 1337 (2011).

4.5. Solar Photovoltaic and Concentrated Solar Power

Like onshore wind generation, utility-scale solar electricity generation has increased rapidly in recent years, growing from 550 GWh in 2005 to nearly 25,000 GWh in 2015 (though it accounted for just 0.6 percent of total generation in 2015) (US Energy Information Administration 2017b).[7] As of 2016, 1,734 utility-scale solar PV and 19 CSP plants were operating across 37 states. On average, PV facilities were just 3 years old, with CSP averaging 2.3 years (US Energy Information Administration 2016). The useful lives of most solar PV cells are expected to be 20 to 30 years.

Because few solar facilities have reached the end of their useful lives, industry experience with decommissioning these facilities is extremely limited. As a result, cost estimates for decommissioning solar sites are not based on experience, but instead are projections. Solar PV units, because they are often relatively small in terms of generating capacity, generally have lower decommissioning cost estimates than larger fossil-powered plants. However, CSP units are often quite large (>100 MW), resulting in higher overall cost estimates. On a per-MW basis, cost estimates for CSP facilities tend to be higher than those for solar PV. Both are higher on average than those for gas, petroleum, or onshore wind but lower than those for coal or offshore wind.

For both PV and CSP facilities, decommissioning involves three major steps: dismantling the equipment, managing the resulting waste streams, and restoring the site. In each of the decommissioning studies and regulatory filings reviewed for this study, project owners are required to return the site to greenfield (i.e., preconstruction) condition.

Although there are some concerns associated with regulated materials from solar PV cells, the environmental remediation requirements for decommissioning these facilities is limited compared with those for older fossil-fired plants, which often require asbestos abatement and management of soils contaminated by hydrocarbons or CCRs. However, contractors handling waste streams from solar decommissioning must handle certain materials carefully and comply with relevant waste and recycling guidelines.

4.5.1. Landowner Agreements and Relevant Policies

When negotiating with landowners, solar developers sometimes include language related to decommissioning and site restoration in the lease agreement (Clark 2016). However, such language is not typically required by state or local regulations, and it is unclear how common decommissioning terms are in private lease agreements.

In locations where decommissioning cost estimates are required by local, state, or federal authorities, owners are also required to provide some type of financial assurance for this reclamation. For solar development on federal land, decommissioning plans and financial assurance are required by the BLM. Along with BLM requirements, 10 states have statewide policies on solar decommissioning, though most do not require financial assurance. For the 40 states without policies, rules and requirements may be applied by utility commissions or local jurisdictions (North Carolina Clean Energy Technology Center 2016).

[7] Distributed solar power generated an additional 14,139 GWh in 2015, increasing solar's total share of the power mix to roughly 1 percent.

Developers in some regions may not be required to submit any decommissioning plans. For example, this study was unable to find evidence of decommissioning plans or financial assurance for dozens of solar PV projects currently in operation or under development across several counties in western Texas.

Managing waste streams from solar PV projects has the potential to be challenging because of the hazardous materials contained in solar cells, including cadmium, lead, and selenium. These issues will arise at the end of a project's life or if equipment is rendered unusable by high winds, hail, or other damage. If not properly disposed of, these materials may cause risks to the environment or human health, though existing research suggests that such risks are relatively modest (Sinha et al. 2014). A number of recycling programs will accept retired PV modules for no charge, but private incentives to recycle may not always be sufficient to induce this behavior (McDonald & Pearce 2010).

4.5.2. Decommissioning Cost Estimates

Because PV and CSP facilities are composed of hundreds or thousands of individual modules, dismantling them is time- and labor-intensive. Removing each module, dismantling its support structure, removing electrical wiring, and breaking up concrete accounts for the bulk of decommissioning costs in most cases. For example, one estimate of solar PV decommissioning costs prepared by the state of New York estimates that roughly 90 percent of costs arise from dismantling and removing equipment, while just 10 percent come from postdismantling activities such as site grading and restoration (Table 8).

In some cases, particularly in environmentally sensitive locations, the costs of land restoration are more substantial. For example, decommissioning plans for the Ivanpah CSP facility in California, which sits on federal land, involve costly site remediation programs, along with a 10-year monitoring and maintenance plan estimated to cost more than $9 million (CH2MHill 2010). As with other power plants, the physical location of solar projects also plays an important role in ultimate decommissioning costs. Notably, projects in more remote locations (such as CSP projects in deserts) will tend to be costlier to decommission than projects in more densely populated regions because of high transportation costs and limited local labor supply.

TABLE 8. ESTIMATED DECOMMISSIONING COSTS FOR A 2 MW SOLAR PV FACILITY

Task	Estimated cost
Remove rack wiring	$2,459
Remove panels	$2,450
Dismantle racks	$12,350
Remove electrical equipment	$1,850
Breakup and remove concrete pads or ballasts	$1,500
Remove racks	$7,800
Remove cable	$6,500
Remove ground screws and power poles	$13,850
Remove fence	$4,950
Removal costs subtotal	*$53,709*
Grading	$4,000
Seed disturbed areas	$250
Truck to recycling center	$2,250
Postremoval costs subtotal	*$6,500*
Grand total	**$60,209**

Source: NYSERDA (2016).

Table 9 shows a wide range of net costs for decommissioning these plants, with larger plants being more costly overall. However, there is not a clear pattern in terms of relative costs, with net costs per MW of capacity varying from $177,000 to –$88,000. As noted above, the drivers of these costs are typically location and the sensitivity of the natural habitat. In addition, similarly to wind farms, decommissioning costs for solar PV projects are substantially affected by the potential to recycle or sell equipment and scrap metal. The negative costs in the table indicate that the estimated resale value of scrap metal exceeds all decommissioning costs.

North Carolina, like most other states, currently has no statewide standards for the preparation of decommissioning plans or cost estimates. Large utilities in cost-of-service states such as North Carolina submit decommissioning plans to experts at state public utility commissions during rate cases. However, independent project developers are not required to submit such plans. Instead, they may not prepare decommissioning plans or may submit plans to local authorities such as county planning officials, who may not have the expertise or resources to adequately assess the plausibility of those plans.

A key difference between decommissioning cost estimates in North Carolina and other states examined in this study is that with the North Carolina projects listed in Table 9, developers assumed substantial salvage values for solar panels at the end of a project's life. Whereas other cost estimates assumed $0 salvage value, these projects in North Carolina forecast hundreds of thousands of dollars in revenue from the salvage of solar panels. For example, one decommissioning plan for a 5 MW facility projects that the salvage value in 2065 (50 years after the project began operation) of 23,000 solar panels will be $14 each, totaling $316,000 (Apple One LLC 2014). Another plan for a 5 MW facility forecasts $256,000 in salvage value from panels. In addition, this project's cost estimates for dismantlement are well below those of other, similar-size facilities in the area; does not include costs for site restoration; and bases its projected salvage value for steel and aluminum on market spot prices on a single day (RBI Solar 2015). In contrast, a 2017 regulatory filing by Duke Energy with the North Carolina Utilities Commission estimates $0 salvage value for solar panels (Burns & McDonnell 2017).

TABLE 9. NET DECOMMISSIONING COSTS FOR SELECT SOLAR PV PROJECTS

Project name	State	Capacity (MW)	Net cost/MW	Net cost
Desert Sunlight 300	CA (BLM)	300	$45,976	$13,792,776
Desert Sunlight 250	CA (BLM)	250	$50,992	$12,748,075
Dry Lake	NV (BLM)	100	$101,915	$10,191,455
Quinto	CA	110	$43,583	$4,794,180
Vega	CA	20	$177,000	$3,540,000
Maryland Solar Park	MD	20	$105,000	$2,100,000
Luning	NV (BLM)	50	$35,027	$1,751,357
Fleshman/Kost Rd.	CA	3	$73,333	$220,000
NYSERDA estimate	MA	2	$30,100	$60,200
Longneck	NC	5	–$1,253	–$6,263
Rock Barn	NC	5	–$24,902	–$124,508
Sonne Two	NC	5	–$84,676	–$423,382
Apple One	NC	5	–$88,076	–$440,381

Sources: See Figure 6.
Note: All cost estimates include returning sites to greenfield condition.

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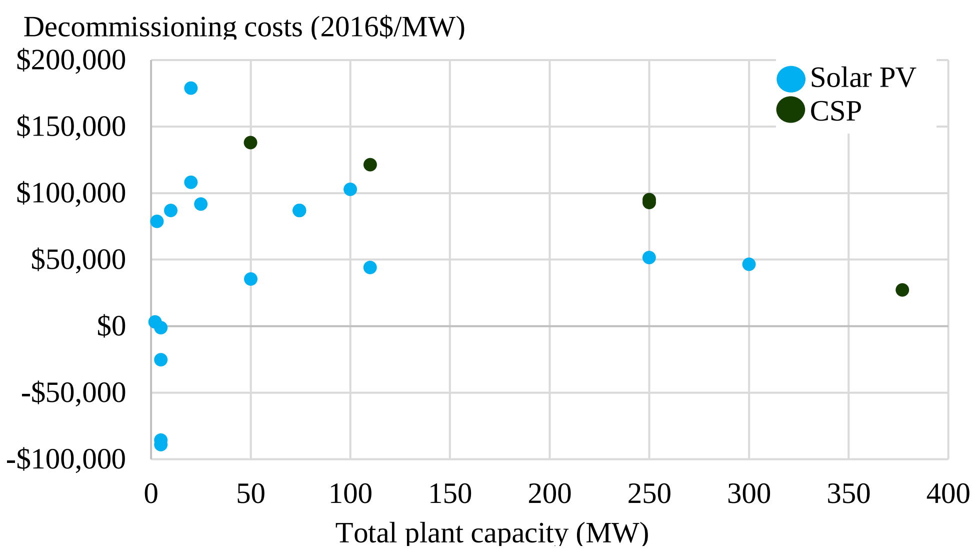
Figure 16 shows the distribution of costs across a range of PV and CSP facilities. Although there is a modest negative correlation between plant size and decommissioning costs per MW, the limited amount of data and presence of negative estimates for plants in North Carolina makes it difficult to generalize.

FIGURE 16. SOLAR DECOMMISSIONING COSTS BY PLANT SIZE



Sources: See Figure 6.
Note: This figure shows estimated decommissioning costs for solar plants in select regions. It also shows several plants where project developers estimate negative net costs, with salvage values exceeding decommissioning expenditures. These estimates all come from solar PV projects in North Carolina and appear to be driven by optimistic assumptions about the resale value of solar PV panels on retirement. When these negative estimates are excluded, there is a clear negative correlation between plant size and decommissioning costs per MW.

percent for the future development contingency. However, Applicant maintains that 3 percent for each add-on provides the Council with adequate cushion should it ever be in the unlikely position of overseeing facility decommissioning. Applicant provides the following reasons.

ODOE's role in overseeing facility decommissioning would entail converting Table W-1 into a scope of work for bids, identifying and retaining one or more contractors, legal review and costs associated with contracting, reviewing progress reports on decommissioning and relaying information to Lake County and one underlying landowner (the Department of State Lands) with whom Applicant has a land use (all other land is owned fee title by an affiliate of Applicant). Actual on the ground, day-to-day project management and administration, including permitting for the decommissioning activities, would be conducted by the decommissioning contractor and there is already a 3 percent add-on in the decommissioning amount for that management work. There is no evidence that ODOE will incur more costs for managing decommissioning than will the contractor actually overseeing the work. There is only evidence that EFSC has a 10 percent project management mark-up in the past, but no evidence that EFSC has ever needed or used that financial cushion. In fact, there is no evidence of an EFSC project being abandoned in the history of EFSC projects.

With respect to future development contingency, Applicant has included a 3 percent future development contingency in its decommissioning estimate. In addition to that, Applicant proposes that the Council add another 3 percent future development contingency. This would bring the total financial cushion to account for future uncertainties to $1,437,323 (over and above the add-on for project administration and management). The intention of this future contingency add-on is to provide for the potential for regulatory and environmental changes and changes in costs at a rate that exceeds the standard inflation adjustment. Rather than adjust this amount annually during the life of the project, when there is a PPA in place and little risk of actual decommissioning, Applicant proposes that the Council approve annual adjustments to the amount(s) beginning closer to when the project might actually be decommissioned. Specifically:

<u>Construction to COD:</u>

From the beginning of construction to the date of commencement of operations (COD), there is very little risk of changes that would severely impact that accuracy of the cost estimates, particularly because construction is required to be completed within the relatively short time frame set forth in the site certificate. For this period, Applicant proposes to provide financial security in the full amount of $25,3933,00.

<u>COD to 3 Years Left in PPA</u>

Once the facility has reach COD, Applicant proposes to reduce the amount of the bond or letter of credit to $1.00 and maintain it at that level until the year(s) that is three years prior to the expiration of the facility's power purchase agreement(s) (PPA). During the fourth year before the expiration of the PPA, certificate holder would update the estimates reflected in Table W-1 based on current data and information and use that revised amount, with the approval of ODOE, for the financial decommissioning costs through rates. Instead, costs must be planned for and incorporated as a cost of doing business. However, it is not clear whether all companies properly account for such costs.

Publicly listed companies file annual reports estimating these decommissioning costs (Section 5.1.2.1), but it is unclear whether smaller generating companies do the same. For example, this study was unable to find any evidence of planning for decommissioning costs for fossil or renewable plants operated by municipal or other smaller entities in Texas.

In recent years, low electricity prices in many regions have reduced the profitability of many generators, which may further reduce the ability of firms to properly account and plan for ultimate decommissioning of plants.

5.1.2.1. Asset Retirement Obligations

In their annual financial reports to the US Securities and Exchange Commission known as 10-Ks, publicly listed generating companies report AROs. An asset retirement obligation is defined as "an environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset (e.g., the obligation to decontaminate a nuclear power plant site or cap a landfill)" (Ernst & Young 2016). Until recently, nuclear assets have constituted the bulk of ARO funds. However, increased awareness of environmental risks and new regulatory requirements have increased anticipated costs of decommissioning for other plant types. In particular, the anticipated costs of retiring CCR impoundments at coal-fired power plants have grown dramatically in recent years and are likely to affect financial obligations for plant owners.

AROs may change over time as the definition of "the normal operation of a long-lived asset" changes. In particular, certain environmental liabilities that are now understood to be common have not always been included in reported AROs.

Issued in April 2015, EPA's CCR rule requires firms to include the environmental remediation obligations associated with coal ash in their AROs. For example, NRG, a large independent power producer, reports in its 2015 10-K filing that it has set aside funds to manage coal combustion waste because of this rule (though it does not report the dollar total). NRG's total AROs for 2015 are reported as $945 million, $643 million of which is associated with nuclear decommissioning liabilities (NRG Energy 2016).

However, AROs for some utilities may underestimate the actual costs of remediation, particularly related to CCRs. As noted in Section 4.1, Duke Energy, the nation's largest electric power utility, reported AROs for closure of coal ash impoundments in the Carolinas at $4.24 billion (Duke Energy Corporation 2016). In 2013, prior to a release from a CCR impoundment in North Carolina, Duke did not report any AROs specifically designated for closure and remediation of CCR facilities (Duke Energy Corporation 2013).

Because most decommissioning cost studies were carried out before the enactment of new EPA rules regarding CCRs, associated AROs are likely to increase for most utilities that own regulated impoundments. If the ARO revisions made by Duke Energy are at all representative of the future costs of safely closing CCR basins, AROs for other companies owning ash basins are likely to grow by billions of dollars.

If companies in deregulated regions are underestimating their AROs in internal and external accounting protocols, funds may not be available to adequately remediate any legacy environmental issues, and if those costs are sufficient to result in bankruptcy, they may be transferred to ratepayers or taxpayers.

Although this is unlikely to be a concern for large, well-capitalized companies, it may pose risks for smaller companies with substantial remediation and monitoring requirements associated with CCRs.

5.2. Local Economic and Fiscal Considerations

Power plants are key economic assets in many communities where they operate. When plants retire and are not repowered or repurposed for other economic uses, local employment and income may be substantially affected. Although this issue arises most prominently when a plant is retired, the different options available to plant owners after retirement each have implications for communities and local economies. This section focuses on these issues.

In 2016, an estimated 94,100 people were employed in fossil-fired power plants, roughly 60 percent of the total number employed by electricity generators (US Bureau of Labor Statistics 2017). Although 95,000 is a relatively small number measured against the 140 million employees across all sectors of the economy, certain communities are heavily reliant on employment and income driven by large fossil-fired power plants.

For example, Montana's 2,100 MW coal-fired Colstrip power plant and the nearby mine that supplies it directly employ 730 people, according to press reports (Puckett 2017). Two of the plant's four units have been slated for closure by 2022, with large potential economic impacts for the city of Colstrip, population 2,200, and the surrounding county of Rosebud, population 9,000. In response, Montana policymakers filed legislation to require that plant owners submit decommissioning plans to state environmental regulators, including plans to compensate nearby residents and local governments for negative economic and fiscal impacts (not environmental impacts), which would likely run into the tens of millions of dollars.[10]

The bill passed the state senate but not the house, and similar legislation may be reintroduced in future sessions. Although the legality of this legislation is uncertain, it illustrates the severity of potential economic impacts for communities heavily reliant on large power plants.

Along with broader economic impacts, the fact that power plants often make up a large share of the local tax base can mean additional local economic impacts from decommissioning. However, the valuation methods for power plants varies from state to state, resulting in a wide range of assessed values for plants.

In Texas, for example, plants are assessed using a market-based income model. This method for appraisal accounts for the current price of electricity along with fuel, operating, and capital costs to estimate annual revenues and profit. In other states, such as Florida or Pennsylvania, plants may be assessed for property tax purposes on the estimated resale value of their physical assets, including the land they occupy. As Table 10 shows, plants with similar physical characteristics may receive very different valuations depending on local assessment methods.

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[10] Coal-Fired Generating Unit Mitigated Retirement Act, S. 338, Montana 65th Leg. (2016).

TABLE 10. ASSESSED VALUE OF SELECT POWER PLANTS IN 2015

Plant name	State	Fuel	Capacity (MW)	Taxable value	Taxable value/MW
WA Parish	TX	Coal	3,675	$865,390,820	$235,480
Sandy Creek	TX	Coal	937	$427,491,427	$456,234
Monticello	TX	Coal	1,880	$373,540,150	$198,692
Tolk	TX	Coal	1,067	$310,607,100	$291,103
Turkey Point	FL	Nuclear, gas/oil	3,330	$61,160,648	$18,367
Fort Myers	FL	Gas/oil	2,080	$6,188,296	$2,975
Sanford	FL	Gas/oil	1,912	$13,203,355	$6,906
Hatfield's Ferry	PA	Coal	1,710	$13,616,100	$7,963

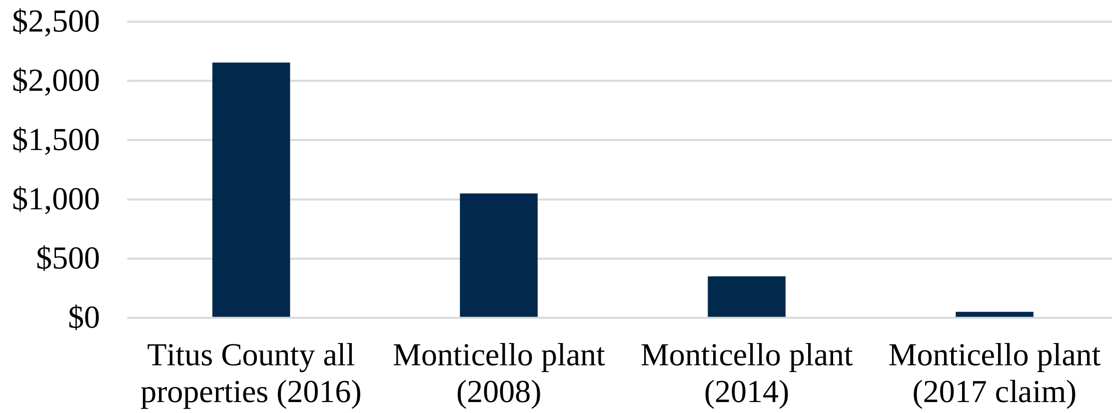
Sources: Texas: local appraisal districts; Florida: local assessors' offices; Pennsylvania: Greene County Department of Finance.

In Texas, state valuation methods appear to lead to higher assessed values than in Pennsylvania or Florida. However, this method also can result in greater volatility in valuation, as the profitability of a plant may vary widely from year to year based on prevailing electricity prices, fuel costs, and other factors. For example, one large coal-fired power plant, the Monticello plant in Titus County, Texas, has seen its valuation change from over $1 billion in 2008 to $350 million in 2014 (Titus County Appraisal District 2017). In 2017, the plant's owner filed suit against the county appraisal district, arguing that the plant should instead be valued at $50 million (Carpenter 2017). For reference, the total taxable value of all properties in Titus County was roughly $2.2 billion in 2016 (Figure 17).

In states where plants are assessed based on the estimated resale value of their capital and the land they occupy, local governments tend to see less volatility in assessed values. However, plant closure and decommissioning can lead to unusual incentives for local governments that have become reliant on power plants to provide tax revenue.

For example, in Greene County, Pennsylvania, the recently retired Hatfield's Ferry power plant is appraised at $14 million, accounting for roughly 1 percent of the county tax base. Because Pennsylvania property tax law assesses properties based on the resale value of equipment and land, the retirement did not affect the plant's valuation (whereas in Texas, for example, it would have had a major effect). However, if the plant were torn down or its major components sold, the valuation would drop considerably and include only the value of the remaining land and other assets. This provides an incentive, at least in theory, for local governments to delay or prevent the demolition of the plant or repurpose the property. The longer a facility sits idle, the more degraded it will become and the worse contamination issues will become, leading eventually to higher mitigation costs when the site is ultimately decommissioned.

FIGURE 17. PROPERTY VALUATIONS IN TITUS COUNTY, TEXAS



Source: Data from Titus County Appraisal District (2017).
Note: This figure highlights the volatility of power plant valuations in Texas and shows the importance of one particular plant to the tax base of Titus County.

TABLE 11. LOCATION OF OLDER AND RETIRED FOSSIL FUEL POWER PLANTS, 100 MW OR LARGER

Location	Operating, older than 40 years	Retired
Urban/suburban (inside MSA)	332 (72%)	195 (78%)
Rural (outside MSA)	118 (26%)	52 (21%)
Highly rural (>50 miles from MSA)	12 (2%)	2 (1%)
Total	462	249

Sources: Data from EIA (2016) and US Census Bureau (2016).

5.3. Decommissioning in Rural and Urban/Suburban Areas

Since 2000, most large plant retirements have occurred in and around urban or suburban regions. Of the 249 plants that have been retired with capacities of greater than 100 MW, 195 (78 percent) have been within a metropolitan statistical area (MSA), with 54 (22 percent) located outside MSAs. Looking forward, most large operating coal, petroleum, or natural gas–fired plants that are 40 years old or older are also found in urban or suburban regions, as illustrated in Table 11.

5.3.1. Decommissioning in Urban and Suburban Areas

As decades-old power plants have retired in and around major US cities, redevelopment opportunities have emerged for plant owners and local developers. In recent years, a number of these retired power plants have been repurposed for mixed-use development. Such facilities are often desirable for developers because of their large footprint and vast floor space, high ceilings, proximity to urban centers or waterways, sturdy construction, and unique architectural features.

5.3.1.1. Federal, State, and Local Incentives

From 1997 through 2011, federal tax incentives offered full expensing of cleanup costs for redeveloping brownfields associated with any industrial facility (US EPA 2011), with annual costs in the range of $100 million (US Joint Committee on Taxation 2008). Currently, EPA provides grants and technical assistance for local governments interested in assessing environmental damage, cleaning up sites, and providing related job training programs, with grants totaling roughly $59 million in 2017 (US EPA 2017).

State and local governments also offer a variety of policies to encourage redevelopment of former industrial and brownfield sites. For example, the state of New York offers a refundable tax credit for redevelopment of brownfields properties worth up to $45 million (New York State Department of Taxation and Finance 2017). Baltimore offers brownfield developers a reduction in city property tax rates (Baltimore Development Corporation 2017).

Developers may also benefit from retired power plants obtaining status as historic buildings. For example, the Delaware River Generating Station in Philadelphia, which retired in 2004, was added to the National and Philadelphia Registers of Historic Places in 2016. Certification on these registries enables redevelopers to take advantage of income tax credits offered by the federal government of up to 20 percent (US National Parks Service 2012) and, in some locations, credits against state income or local property taxes (San Francisco Planning Department 2010; Pennsylvania Dept. of Community & Economic Development 2014; New York State Dept. of Parks Recreation and Historic Preservation 2017). A variety of state and local tax and nontax incentives are described in a series of reports by Bartsch and Wells (2005, 2006a, b, c), though many provisions are likely out of date over a decade after publication.

Dozens of projects have benefited from these types of financing opportunities. One project located along the Hudson River in Yonkers, New York, would convert the Glenwood Power Station, which retired in the 1960s but was never fully decommissioned, to an “arts-focused event complex,” with expansion plans including restaurants, a 90-room hotel, and a 22-slip marina. According to news reports, the $150 million project could benefit from up to $45 million in state tax credits (Hughes 2014). The developer describes the building, which it acquired in 2012, as currently undergoing restoration and redevelopment (Lela Goren Group 2017).

In Austin, Texas, a large retired power plant in the city’s downtown has been redeveloped into a mixed-use residential and commercial space, including a grocery store and hundreds of apartments. The redevelopment of the plant was enabled in part by changes in property tax treatment of the facility (City of Austin Texas 2008).

As described in a report by the American Clean Skies Foundation (2011), numerous other large-scale power plant redevelopment projects have been carried out, including in Chicago; Portland, Oregon; Providence, Rhode Island; Queens, New York; and Sacramento. Project costs have ranged from less than $10 million for small plants to more than $150 million for larger projects. Another report describes 25 redevelopment projects, noting that the average time between plant closure and sale was 16 years, and the average time between plant closure and the completion of redevelopment was 27 years (Delta Institute 2014). Notably, every major redevelopment project identified in these reports (and in this review) has taken place in or around a major city.

5.3.1.2. Challenges of Urban Redevelopment

For project owners and contractors, decommissioning in urban areas may pose additional challenges. Although major development projects in urban areas are by no means unusual, dismantlement and demolition of power plants in dense urban areas tend to be costlier than in other locations such as an industrial park. Hazardous materials removed from the site (typically by truck) need to pass through populated areas, increasing risks and associated costs. Demolition activities also have to be more carefully managed in light of local concerns and regulations regarding noise, dust, and light.

Utilities or project developers typically have strong incentives to meet the expectations of the surrounding communities. For utilities, reputational concerns come to the fore, as these companies will continue to operate other plants and serve their customers. If new developers have assumed responsibility for the project, those developers also have an interest in being seen as good neighbors in their communities.

5.3.2. Decommissioning in Rural Areas

Since 2000, 52 plants greater than 100 MW have been retired outside of MSAs, and 130 plants aged 40 years or more and with capacities greater than 100 MW sit outside of MSAs (Table 11). In these rural areas, or in other locations where there is a lack of private sector interest in redeveloping a site, owners may see little financial incentive to fully decommission retired plants. Particularly in deregulated regions, where decommissioning costs are not built into the rate base, the costs of decommissioning are borne by shareholders, and the return on fully decommissioning a plant may be zero. As discussed in Section 3.4.1, this dynamic may lead some plants to go “cold and dark” for an uncertain period of time, potentially leading to issues of blight, reduced property values, crime, and other concerns.

In other cases, new economic development opportunities may arise. For example, in 2016, a 568 MW coal-fired power plant was demolished along the Ohio River in eastern Ohio, where production of liquids-rich natural gas from the Utica and Marcellus Shale plays has grown dramatically in recent years. After demolition and restoration, the property was transferred to an international company interested in constructing an ethane “cracker,” which uses ethane, a natural gas liquid, as a feedstock in the production of ethylene, a key component of plastics and other products (First Energy 2016). Such plants often entail investments of $4 billion or more.

5.3.2.1. Federal, State, and Local Incentives

In some locations, retired plant sites may offer significant value because of their proximity to electricity transmission infrastructure. EPA administers a program known as RE-Powering America’s Land, which provides technical assistance for developers interested in building renewable energy facilities on brownfield sites. This may encourage some plant owners to fully decommission and repower their facilities. However, the bulk of these projects have occurred at landfills rather than brownfields (US EPA 2016b).

The US Department of Commerce, under its Economic Development Association, launched Partnerships for Opportunity and Workforce and Economic Revitalization, or the POWER Initiative, in 2016. This program provides funding and expertise to support local workforce development programs in communities negatively affected by declining coal production and consumption, including decommissioned coal-fired power plants (US Economic Development Association 2017).

In Pennsylvania, for example, the state Department of Community and Economic Development has partnered with the POWER Initiative to commission a series of studies to assess the economic potential for retired coal plant sites, predominantly in rural parts of the state. Because power generation companies may not have the expertise to evaluate real estate opportunities associated with retired plants, these studies are designed to highlight for owners the reuse options for their sites, which may have substantial value.

6. Conclusions

This report provides an overview of the key issues facing plant owners as they decide how to decommission retired power plants fueled by coal, oil, natural gas, wind, or the sun. It provides a framework for understanding key decision points, assesses the major cost drivers of decommissioning for different plant types, and identifies key issues that warrant attention from plant owners, regulators, communities, and other stakeholders. It also makes recommendations for state policymakers and regulators and provides information on decommissioning costs and other key issues that can inform the implementation of these recommendations. Conclusions and suggestions for additional research are provided below.

6.1. Costs of Decommissioning

- The costs of decommissioning power plants can be large, especially for coal plants managing CCRs under a new regulatory framework. In some regions, it appears that utilities and regulators have not adequately planned for these costs, which will ultimately be borne by shareholders, ratepayers, or taxpayers.
- The costs of decommissioning onshore wind and solar PV appear to be modest, but existing accounting protocols may underestimate these costs. In particular, optimistic assumptions about the salvage value of scrap steel and other equipment may lead to inadequate financial preparation.
- The costs of decommissioning offshore wind appear high relative to other fuels, but substantial uncertainty remains because of limited experience.
- The costs of decommissioning natural gas– and oil-fired power plants appear to be modest in most cases.

6.2. Planning and Saving for Decommissioning

- In traditionally regulated states, public utility commissions typically require plant owners to plan for decommissioning and recoup the associated costs through rates.
- In some deregulated states, notably Texas, there was a lack of evidence that state or local regulators require any planning (financial or otherwise) for decommissioning.
- Federal, state, and local programs incentivize decommissioning and redevelopment of industrial property. These programs are often beneficial for communities where they occur, but they can shift the costs of decommissioning and remediation from shareholders and ratepayers to taxpayers.

6.3. Community Impacts of Decommissioning

- In regions with strong demand for land, plant owners often have financial incentives to decommission and sell a property. In rural regions, financial incentives to decommission may be weaker and—unless decommissioning is planned for and funded in advance—plant sites may sit idle for years or decades, with negative environmental and community impacts.
- Decommissioning a plant can provide temporary employment opportunities in the community where a plant has operated. However, the loss of long-term employment at the plant will tend to outweigh these opportunities.
- Power plants are often an important part of the local tax base, particularly in rural communities. Decommissioning a power plant can have a major impact on revenues for school districts, counties, and other local governments.

6.4. Suggestions for Future Research

This report raises numerous questions that warrant further investigation, the answers to which will be important to utilities, regulators, and communities as they plan for decommissioning hundreds of power plants in the coming years. These questions include the following:

- What are the potential costs to plant owners of complying with EPA's coal ash rule, particularly with regard to long-term monitoring and remediation?
- What are the social costs (such as environmental contamination or blight) of a plant sitting idle for years or decades in urban and rural settings?
- Across all 50 states, what policies are currently in place with regard to planning and saving for power plant decommissioning?
- Are landowner lease agreements sufficient to provide for timely and thorough decommissioning of wind and solar facilities?

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To	Oregon Department of Energy
From	Tetra Tech, Inc.
Date	February 21, 2020
Subject	Bakeoven Solar Project – Tetra Tech Response to the Golder November 5, 2019 Technical Memorandum: *Review of Bakeoven Solar Project, Exhibit W: Retirement and Financial Assurance*
Attachments	Attachment A – SteelBenchmarker Scrap Price Attachment B – New York Solar Panel Decommissioning Guidebook Attachment C – Example Product Data Sheets and Power Output Warranties

This technical memorandum provides a discussion in response to the review of Exhibit W of the Bakeoven Solar Project's (the Facility) Application for Site Certificate performed by Golder, submitted November 5, 2019 to the Oregon Department of Energy (ODOE) (Golder 2019)[1]. This technical memorandum focuses on Section 1 of Golder's review, regarding scrap value of facility components, and provides a subsection by subsection commentary regarding Tetra Tech's professional opinion to Golder's review.

Section 1.1 – A Summary of the Councils Current Policy Regarding Scrap Value

ODOE appears to be basing its current policy based on this statement from the Stateline Wind Project Final Order on Amendment #4, as quoted by Golder (2019:2):

> The Department concluded that there was a significant risk that third party creditors or other parties could assert a claim against the scrap or salvage value that might result in that value being unavailable to the State to offset site restoration costs.

As such, the current ODOE policy is based on the concerns Council members had in 2006: that the availability of scrap value offset was at risk due to third party claims, and that the actual value was not in question. It is our opinion that measures can be taken to mitigate this risk while still allowing a valuable commodity to be used to offset a portion of the overall decommissioning cost. Measures

[1] Golder. 2019. *Review of Bakeoven Solar Project, Exhibit W: Retirement and Financial Assurance Technical Memorandum*. Submitted to ODOE November 5, 2019.

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could include a perfected security interest in Facility components, or liens on Facility real estate. ODOE's cost to implement mitigation measures could be recovered in the ODOE management fee already included in the decommissioning estimate.

Section 1.2 – Fluctuation in Scrap Value

Golder's review of historical scrap value focused on short-term trends. Tetra Tech understands that to accurately develop a trend that represents the 30-plus year life span of a renewable energy project, the long-term trend is a more appropriate method. As published by SteelBenchmarker (Attachment A), the long-term trend represents a substantial increase in value: from a January 2002 value of $70 a ton, to the January 2020 value of $261 per ton. At the time of Golder's review, they noted a September 2019 value of $206 per ton (Golder 2019:3). This demonstrates that short-term fluctuations are not accurate in predicting long term trends, as the price is currently $261. Long-term trends clearly show a steady increase in scrap value, and with increasing demand and tightening environmental regulations, Tetra Tech assumes this trend will continue.

Section 1.3 – Practices or Policies Regarding Scrap Value in Other Jurisdictions

All of the examples that Golder cited in their review were unrelated to renewable energy projects (Golder 2019:3-4). For Golder's review of California's regulations, the focus was on solid and hazardous waste facilities. For Golder's review of Alaska and British Columbia, the focus was on mine reclamation projects. For Golder's review of Alberta, the focus was on waste, hazardous waste, and mine reclamation projects. In reviewing Washington State requirements, there is acknowledgement that scrap value is accepted for renewable energy facilities, but the law cited (denying scrap credit) was for a coal-fired power plant, not a renewable energy facility. We believe that not addressing the differences between renewable and non-renewable facilities indicates an inadequate review of the subject.

The statement in Golder's summary is that none of the policies reviewed explicitly allowed the use of scrap value, and that some expressly disallowed it (Golder 2019:4). It is our opinion that where expressly disallowed, it is disallowed for facilities that present a great risk of substantial and long-term environmental damage, where future environmental remediation cost can be considerable. The proposed Facility does not have the potential to cause long-term environmental damage and will maintain a non-hazardous condition throughout its life cycle. Furthermore, the absence of a written policy expressly permitting the use of scrap value for renewable energy facilities is not evidence that scrap value credits are not accepted. As an example, the State of New York has published a Solar Guidebook (Attachment B) for decommissioning solar systems. Section 1, para 1.2, lists resale of components in decommissioning estimates. The State of New York does not have a published policy on scrap value, but as evidenced by their guidebook, they allow it. Tetra Tech has developed and updated decommissioning cost estimates in at least 10 states, and without exception, all allow the use of scrap credit to offset decommissioning costs. These include California, Vermont, New York, South Dakota, Wyoming, Minnesota, Oklahoma, Colorado, Arizona and Virginia. In addition to these states, the Federal Bureau of Land Management, in their Solar Energy Program, Western Solar Plan (BLM 2017)[2], specifically states they will consider salvage value of material when determining bond amount.

Section 1.4 – Recommendation

Tetra Tech does not agree with Golder's recommendation to not accept scrap value. Golder recommends $100 per ton as a reasonable floor price, which they refer to as the value in November 2008, the beginning of the Great Recession (Golder 2019:4-5). The Great Recession began in December 2007 and ended June 2009. In December 2007, the value was $268 per ton. In June 2009, the value was $195 per ton, and recovered to pre-recession value soon after. Industry standard for demolition contractors is to sell when the market is favorable. During the short-term drops noted by Golder, contractors will typically stage or stockpile material to sell during periods of recovery, effectively treating this material considered more favorably than cash payment due to the possibility of a short term market driven windfall.

Final Observations

Tetra Tech understands ODOE's reluctance to accept scrap and salvage value in renewable energy decommissioning estimates. It demonstrates a responsible and firm commitment to protect the citizens of Oregon from financial harm. We acknowledge that ODOE has likely been presented with decommissioning estimates that were overly simplistic and optimistic when it comes to the cost required to decommission a facility. Therefore, Tetra Tech takes a very conservative approach to decommissioning estimates, as described in Exhibit W of the Final Application for Site Certificate, and discussed further below.

Two terms that are often used interchangeably are "scrap value" and "salvage value." For calculating credits, Tetra Tech considers salvage value as the value received by selling a product in a secondary market as it was originally designed. We consider salvage a very risky assumption, as a market and future pricing for this material cannot be identified at the time a facility enters construction. Instead, Tetra Tech only assumes credit for scrap value, where the market is mature and established, and long-term trends can easily be determined.

We anticipate that a salvage market will develop in the future, but until that market can be identified and substantiated, we assume it does not currently exist. An example of a potential future salvage market would be the re-sale of solar modules. Tier 1 modules will retain 82–83 percent (Attachment C) of their initial generating capacity at the end of the project's lifespan, so Tetra Tech

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[2] BLM (U.S. Bureau of Land Management). 2017. Solar Energy Program Western Solar Plan website. http://blmsolar.anl.gov/program/authorization-policies/bond/.

anticipates that at the time of decommissioning, a market will exist for the modules, which will result in additional value available to offset the decommissioning cost. To take the conservative approach a step further, Tetra Tech calculated all scrap as steel scrap, and we do not assume an increased credit for nonferrous metals.

When preparing the estimate for Exhibit W, all tasks and steps in the decommissioning work were clearly detailed and outlined, allowing a reviewer to easily follow the work from start to finish. Scrap value was listed separately by item, and the cost to prepare, load, and ship the scrap was captured separately. Our goal was to provide a clear and accurate estimate, leaving nothing to the reviewer's interpretation.

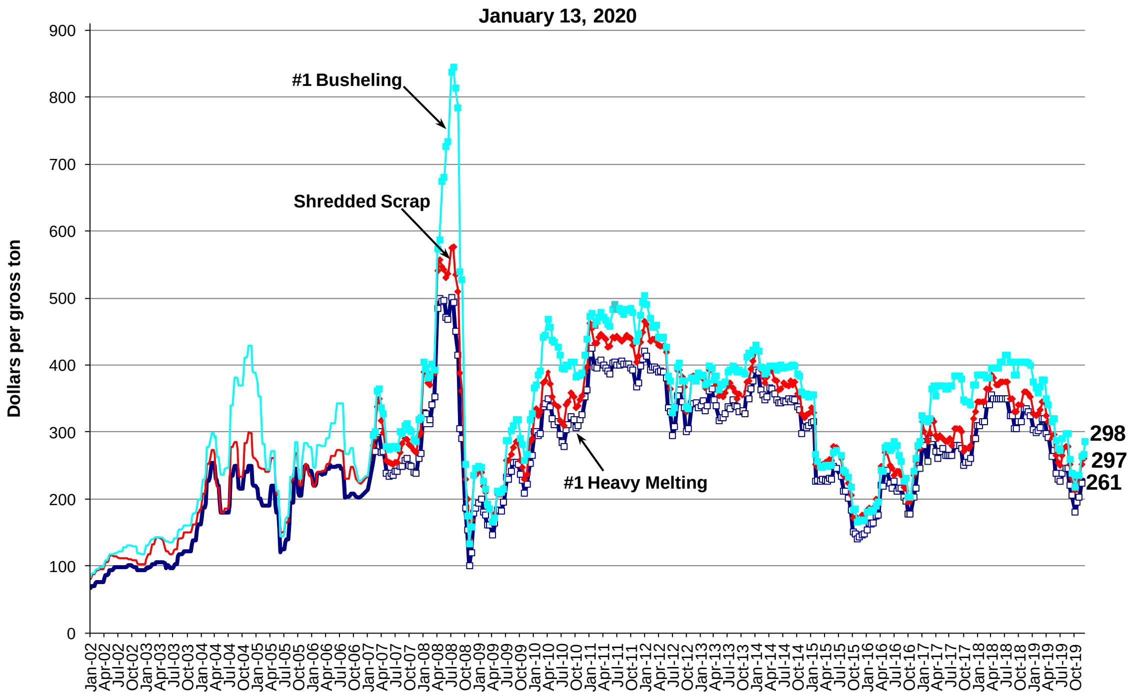
While Golder bases their recommendation to not accept scrap value on ODOE's objective to minimize risk to the State of Oregon (Golder 2019:4-5), Tetra Tech believes that this technical memorandum provides ample justification for the value we have assigned to scrap in the Facility's decommissioning estimate in Exhibit W, and have provided numerous examples of jurisdictions where scrap value is accepted. Decommissioning a solar facility is a standard clean demolition project, and the sale of recyclable material is standard practice. It is our opinion that the appropriate place to address the risk associated with scrap value is through the Retirement and Financial Assurance Standard (Oregon Administrative Rules 345-022-0050), not by denying the credit for scrap value.

Attachment A – SteelBenchmarker Scrap Price

SteelBenchmarker™ Scrap Price

USA, delivered to steel plant

(AMM scrap price data, Jan. 2002 - Jan. 2007; SteelBenchmarker data begins Feb. 2007)



SteelBenchmarker™

USA

delivered to steel plant

Dollars per Gross Ton

	Steel Scrap**								
	#1 Heavy Melting			Shredded Scrap			#1 Busheling		
	Price	Dlr Chng	Pct Chng	Price	Dlr Chng	Pct Chng	Price	Dlr Chng	Pct Chng
27-Aug-18	325	0	0.0%	350	0	0.0%	405	0	0.0%
10-Sep-18	305	-20	-6.2%	330	-20	-5.7%	385	-20	-4.9%
24-Sep-18	305	0	0.0%	330	0	0.0%	385	0	0.0%
8-Oct-18	315	10	3.3%	340	10	3.0%	405	20	5.2%
22-Oct-18	315	0	0.0%	340	0	0.0%	405	0	0.0%
12-Nov-18	335	20	6.3%	360	20	5.9%	405	0	0.0%
26-Nov-18	335	0	0.0%	360	0	0.0%	405	0	0.0%
10-Dec-18	331	-4	-1.2%	357	-3	-0.8%	403	-2	-0.5%
24-Dec-18	325	-6	-1.8%	352	-5	-1.4%	400	-3	-0.7%
14-Jan-19	303	-22	-6.8%	328	-24	-6.8%	375	-25	-6.3%
28-Jan-19	299	-4	-1.3%	324	-4	-1.2%	366	-9	-2.4%
11-Feb-19	302	3	1.0%	327	3	0.9%	358	-8	-2.2%
25-Feb-19	307	5	1.7%	333	6	1.8%	368	10	2.8%
11-Mar-19	320	13	4.2%	345	12	3.6%	378	10	2.7%
25-Mar-19	320	0	0.0%	345	0	0.0%	378	0	0.0%
8-Apr-19	298	-22	-6.9%	324	-21	-6.1%	350	-28	-7.4%
22-Apr-19	292	-6	-2.0%	315	-9	-2.8%	340	-10	-2.9%
13-May-19	264	-28	-9.6%	293	-22	-7.0%	315	-25	-7.4%
27-May-19	272	8	3.0%	296	3	1.0%	320	5	1.6%
10-Jun-19	238	-34	-12.5%	265	-31	-10.5%	287	-33	-10.3%
24-Jun-19	229	-9	-3.8%	255	-10	-3.8%	276	-11	-3.8%
8-Jul-19	226	-3	-1.3%	250	-5	-2.0%	272	-4	-1.4%
22-Jul-19	238	12	5.3%	265	15	6.0%	290	18	6.6%
12-Aug-19	246	8	3.4%	279	14	5.3%	298	8	2.8%
26-Aug-19	246	0	0.0%	278	-1	-0.4%	297	-1	-0.3%
9-Sep-19	220	-26	-10.6%	251	-27	-9.7%	259	-38	-12.8%
23-Sep-19	206	-14	-6.4%	231	-20	-8.0%	238	-21	-8.1%
14-Oct-19	181	-25	-12.1%	214	-17	-7.4%	218	-20	-8.4%
28-Oct-19	195	14	7.7%	229	15	7.0%	236	18	8.3%
11-Nov-19	202	7	3.6%	233	4	1.7%	236	0	0.0%
25-Nov-19	223	21	10.4%	252	19	8.2%	263	27	11.4%
9-Dec-19	229	6	2.7%	261	9	3.6%	267	4	1.5%
20-Dec-19	247	18	7.9%	280	19	7.3%	286	19	7.1%
13-Jan-20	261	14	5.7%	297	17	6.1%	298	12	4.2%

Notes: ** Steel scrap delivered to steel plant
#1 heavy melting – demolition scrap that is at least ¼" thick. This grade does not include the heavy "p & s" (plate and structural) category that includes the very thick scrap items.
Shredded – largely old cars and some appliances – for all but the West Coast (CA, OR & WA).
#1 busheling – new sheet steel scrap.

Prices released on Wednesdays following the 2nd and 4th Mondays of the month at 9:00 AM to Price Assessment Providers. If a price is not indicated, fewer than ten (10) price inputs were received at that time. The first price release was for Feb.12, 2007 for data go to steelbenchmarker.com/files/history2.pdf.

For product specifications refer to last page, or go to steelbenchmarker.com/specifications.

Attachment B – New York Solar Panel Decommissioning Guidebook

Decommissing Solar Panel Systems

Information for local governments and landowners on the decommissioning of large-scale solar panel systems.

NEW YORK STATE OF OPPORTUNITY. | NYSERDA

Solar Guidebook for Local Governments
NYSERDA 17 Columbia Circle Albany, NY 12203

Section Contents

Overview

We provide information for local governments and landowners on the decommissioning of large-scale solar panel systems through the topics of decommissioning plans and costs and financial and non-financial mechanisms in land-lease agreements.

As local governments develop solar regulations and landowners negotiate land leases, it is important to understand the options for decommissioning solar panel systems and restoring project sites to their original status.

From a land use perspective, solar panel systems are generally considered large-scale when they constitute the primary use of the land and can range from less than one acre in urban areas to 10 or more acres in rural areas. Depending on where they are sited, large-scale solar projects can have habitat, farmland, and aesthetic impacts. As a result, large-scale systems must often adhere to specific development standards.

1. Abandonment and Decommissioning

Abandonment occurs when a solar array is inactive for a certain period of time.

- Abandonment requires that solar panel systems be removed after a specified period of time if they are no longer in use. Local governments establish timeframes for the removal of abandoned systems based on aesthetics, system size and complexity, and location. For example, the Town of Geneva, NY, defines a solar panel system as abandoned if construction has not started within 18 months of site plan approval, or if the completed system has been nonoperational for more than one year.[22]
- Once a local government determines a solar panel system is abandoned and has provided thirty (30) days prior written notice to the owner it can take enforcement actions, including imposing civil penalties/fines, and removing the system and imposing a lien on the property to recover associated costs.

Decommissioning is the process for removing an abandoned solar panel system and remediating the land.

- When describing requirements for decommissioning sites, it is possible to specifically require the removal of infrastructure, disposal of any components, and the stabilization and re-vegetation of the site.

1.1 Decommissioning Plans

Local governments may require having a plan in place to remove solar panel systems at the end of their lifecycle, which is typically 20-40 years. A decommissioning plan outlines required steps to remove the system, dispose of or recycle its components, and restore the land to its original state. Plans may also include an estimated cost schedule and a form of decommissioning security (see Table 1).

[22] Town of Geneva, N.Y. CODE § 130-4(D)(5) (2016):

1.2 Estimated Cost of Decommissioning

Given the potential costs of decommissioning and land reclamation, it is reasonable for landowners and local governments to proactively consider system removal guarantees. A licensed professional engineer, preferably with solar development experience, can estimate decommissioning costs, which vary across the United States. Decommissioning costs will vary depending upon project size, location, and complexity. Table 1 provides an estimate of potential decommissioning costs for a ground-mounted 2-MW solar panel system. Figures are based on estimates from the Massachusetts solar market. Decommissioning costs for a New York solar installation may differ. Some materials from solar installations may be recycled, reused, or even sold resulting in no costs or compensation. Consider allowing a periodic reevaluation of decommissioning costs during the project's lifetime by a licensed professional engineer, as costs could decrease, and the required payment should be reduced accordingly.

Table 1: Sample list of decommissioning tasks and estimated costs

Tasks	Estimated Cost ($)
Remove Rack Wiring	$2,459
Remove Panels	$2,450
Dismantle Racks	$12,350
Remove Electrical Equipment	$1,850
Breakup and Remove Concrete Pads or Ballasts	$1,500
Remove Racks	$7,800
Remove Cable	$6,500
Remove Ground Screws and Power Poles	$13,850
Remove Fence	$4,950
Grading	$4,000
Seed Disturbed Areas	$250
Truck to Recycling Center	$2,250
Current Total	**$60,200**
Total After 20 Years (2.5% inflation rate)	**$98,900**

2. Ensuring Decommissioning

Landowners and local governments can ensure appropriate decommissioning and reclamation by using financial and regulatory mechanisms. However, these mechanisms come with tradeoffs. Including decommissioning costs in the upfront price of solar projects increases overall project costs, which could discourage solar development. As a result, solar developers are sometimes hesitant to provide or require financial surety for decommissioning costs.

It is also important to note that many local governments choose to require a financial mechanism for decommissioning. Although similar to telecommunications installations, there is no specific authority to do so as part of a land use approval for solar projects (see Table 2). Therefore, a local government should consult their municipal attorney when evaluating financial mechanisms.

The various financial and regulatory mechanisms to decommission projects are detailed below.

Table 2: Relevant Provisions of General City, Town, and Village Laws Relating to Municipal Authority to Require Conditions, Waivers, and Financial Mechanisms

Site Plan Review	General City Law	Town Law	Village
Conditions	27-a (4)	274-a (4)	7-725-a (4)
Waivers	27-a (5)	274-a (5)	7-725-a (5)
Performance bond or other security	27-a (7)	274-a (7)	7-725-a (7)
Subdivision	**General City Law**	**Town Law**	**Village Law**
Waivers	33 (7)	277 (7)	7-730 (7)
Performance bond or other security	33 (8)	277 (9)	7-730 (9)
Special	**General City Law**	**Town Law**	**Village Law**
Conditions	27-b (4)	274-b (4)	7-725-b (4)
Waivers	27-b (5)	274-b (5)	7-725-b (5

Source: Referenced citations may be viewed using the NYS Laws of New York Online

Excerpts from these statutes are also contained within the "Guide to Planning and Zoning Laws of New York State," New York State Division of Local Governments Services, June 2011: https://www.dos.ny.gov/lg/publications/Guide_to_planning_and_zoning_laws.pdf

2.1 Financial mechanisms

Decommissioning Provisions in Land-Lease Agreements. If a decommission plan is required, public or private landowners should make sure a decommissioning clause is included in the land-lease agreement. This clause may depend on the decommissioning preferences of the landowner and the developer. The clause could require the solar project developer to remove all equipment and restore the land to its original condition after the end of the contract, or after generation drops below a certain level, or it could offer an option for the landowner to buy-out and continue to use the equipment to generate electricity. The decommissioning clause should also address abandonment and the possible failure of the developer to comply with the decommissioning plan. This clause could allow for the landowner to pay for removal of the system or pass the costs to the developer.

Decommissioning Trusts or Escrow Accounts. Solar developers can establish a cash account or trust fund for decommissioning purposes. The developer makes a series of payments during the project's lifecycle until the fund reaches the estimated cost of decommissioning. Landowners or third-party financial institutions can manage these accounts. Terms on individual payment amounts and frequency can be included in the land lease.

Removal or Surety Bonds. Solar developers can provide decommissioning security in the form of bonds to guarantee the availability of funds for system removal. The bond amount equals the decommissioning and reclamation costs for the entire system. The bond must remain valid until the decommissioning obligations have been met. Therefore, the bond must be renewed or replaced if necessary to account for any changes in the total decommissioning cost.

Letters of credit. A letter of credit is a document issued by a bank that assures landowners a payment up to a specified amount, given that certain conditions have been met. In the case that the project developer fails to remove the system, the landowner can claim the specified amount to cover decommissioning costs. A letter of credit should clearly state the conditions for payment, supporting documentation landowners must provide, and an expiration date. The document must be continuously renewed or replaced to remain effective until obligations under the decommissioning plan are met.

2.2 Nonfinancial mechanisms

Local governments can establish nonfinancial decommissioning requirements as part of the law. Provisions for decommissioning large-scale solar panel systems are similar to those regulating telecommunications installations, such as cellular towers and antennas. The following options may be used separately or together.

- **Abandonment and Removal Clause.** Local governments can include in their zoning code an abandonment and removal clause for solar panel systems. These cases effectively become zoning enforcement matters where project owners can be mandated to remove the equipment via the imposition of civil penalties and fines, and/or by imposing a lien on the property to recover the associated costs. To be most effective, these regulations should be very specific about the length of time that constitutes abandonment. Establishing a timeframe for the removal of a solar panel system can be based on system aesthetics, size, location, and complexity. Local governments should include a high degree of specificity when defining "removal" to avoid ambiguity and potential conflicts
- **Special Permit Application.** A local government may also mandate through its zoning code that a decommissioning plan be submitted by the solar developer as part of a site plan or special permit application. Having such a plan in place allows the local government, in cases of noncompliance, to place a lien on the property to pay for the costs of removal and remediation.
- **Temporary Variance/Special Permit Process.** As an alternative to requiring a financial mechanism as part of a land use approval, local governments could employ a temporary variance/special permit process (effectively a re- licensing system). Under this system, the locality would issue a special permit or variance for the facility for a term of 20 or more years; once expired (and if not renewed), the site would no longer be in compliance with local zoning, and the locality could then use their regular zoning enforcement authority to require the removal of the facility.

2.3 Examples of abandonment and decommissioning provisions

The New York State Model Solar Energy Law provides model language for abandonment and decommissioning provisions in the Model Law section of this Guidebook.

The following provide further examples that are intended to be illustrative and do not confer an endorsement of content:

- Town of Geneva, N.Y., § 130-4(D): ecode360 .com/28823382
- Town of Olean, N.Y., § 10.25.5: https://www.cityofolean.org/council/minutes/ccmin2015-04-14.pdf

2.4 Checklist for Decommissioning Plans

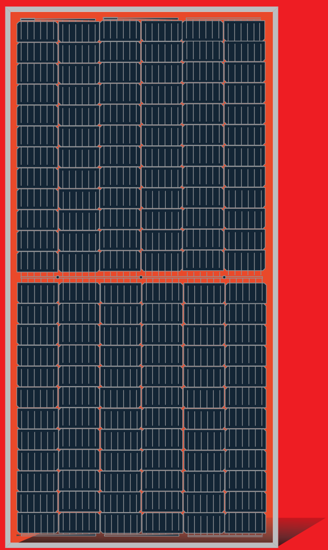
The following items are often addressed in decommissioning plans requirements:

- Defined conditions upon which decommissioning will be initiated (i.e., end of land lease, no operation for 12 months, prior written notice to facility owner, etc.).
- Removal of all nonutility owned equipment, conduit, structures, fencing, roads, and foundations.
- Restoration of property to condition prior to solar development.
- The timeframe for completion of decommissioning activities.
- Description of any agreement (e.g., lease) with landowner regarding decommissioning.
- The party responsible for decommissioning.
- Plans for updating the decommissioning plan.
- Before final electrical inspection, provide evidence that the decommissioning plan was recorded with the Register of Deeds.

Questions?

If you have any questions regarding the decommissioning of solar panels, please email questions to cleanenergyhelp@nyserda.ny.gov or request free technical assistance at nyserda.ny.gov/SolarGuidebook. The NYSERDA team looks forward to partnering with communities across the state to help them meet their solar energy goals.

Attachment C – Example Product Data Sheets and Power Output Warranties

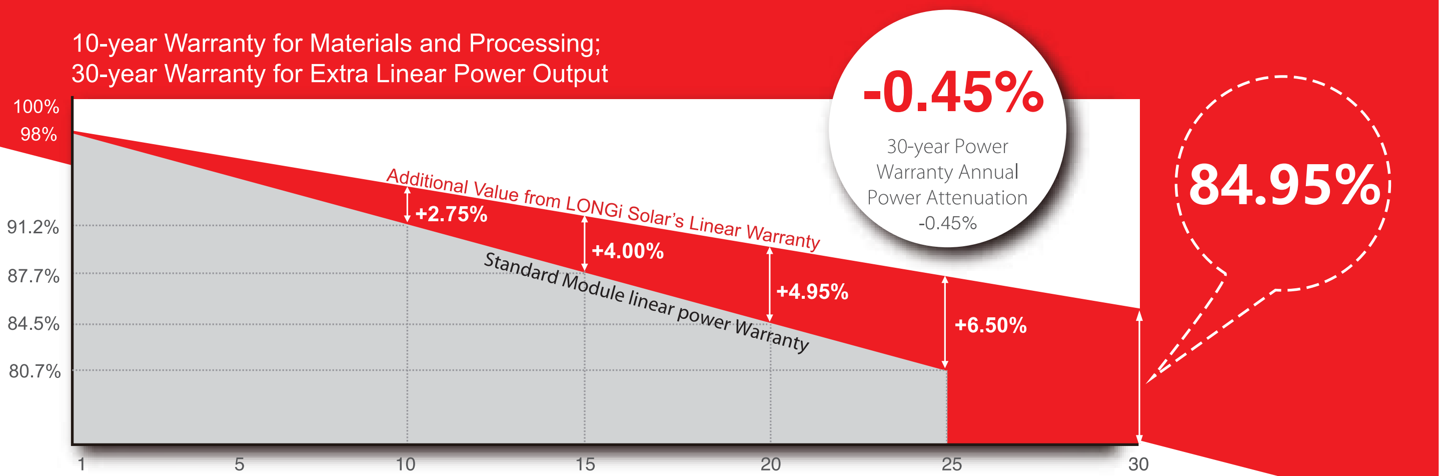


LR4-72HIBD
415~435M

Hi-MO 4

High Efficiency
Low LID Bifacial PERC with
Half-cut Technology

10-year Warranty for Materials and Processing;
30-year Warranty for Extra Linear Power Output



Complete System and Product Certifications

IEC 61215, IEC61730, UL1703

ISO 9001:2008: ISO Quality Management System

ISO 14001: 2004: ISO Environment Management System

TS62941: Guideline for module design qualification and type approval

OHSAS 18001: 2007 Occupational Health and Safety

* Specifications subject to technical changes and tests. LONGi Solar reserves the right of interpretation.

Front side performance equivalent to conventional low LID mono PERC:
- High module conversion efficiency (up to 19.4%)
- Better energy yield with excellent low irradiance performance and temperature coefficient
- First year power degradation <2%

Bifacial technology enables additional energy harvesting from rear side (up to 25%)

Glass/glass lamination ensures 30 year product lifetime, with annual power degradation < 0.45%, 1500V compatible to reduce BOS cost

35mm frame design enables easy installation and robust mechanical strength

Solid PID resistance ensured by solar cell process optimization and careful module BOM selection

Reduced resistive loss with lower operating current

Higher energy yield with lower operating temperature

Reduced hot spot risk with optimized electrical design and lower operating current

LONGi Solar

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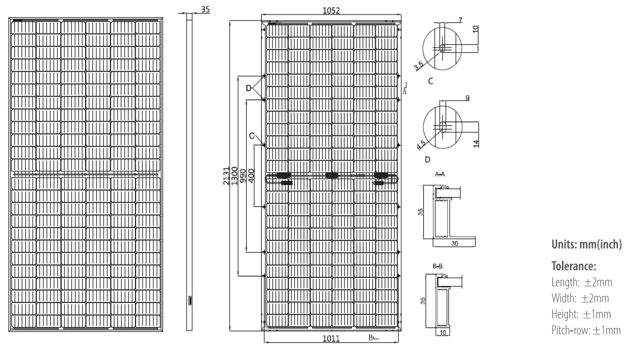
Note: Due to continuous technical innovation, R&D and improvement, technical data above mentioned may be of modification accordingly. LONGi Solar have the sole right to make such modification at anytime without further notice; Demanding party shall request for the latest datasheet for such as contract need, and make it a consisting and binding part of lawful documentation duly signed by both parties.

LR4-72HIBD **415~435M**

Design (mm)



Mechanical Parameters

Cell Orientation: 144 (6×24)
Junction Box: IP68, three diodes
Output Cable: 4mm², 300mm in length, length can be customized
Glass: Dual glass 2.0mm coated tempered glass
Frame: Anodized aluminum alloy frame
Weight: 29.5kg
Dimension: 2131×1052×35mm
Packaging: 30pcs per pallet
150pcs per 20'GP
600pcs per 40'HC

Operating Parameters

Operational Temperature: -40℃ ~ +85℃
Power Output Tolerance: 0 ~ +5 W
Voc and Isc Tolerance: ±3%
Maximum System Voltage: DC1500V (IEC/UL)
Maximum Series Fuse Rating: 20A
Nominal Operating Cell Temperature: 45±2℃
Safety Class: Class Ⅱ
Fire Rating: UL type 6
Bifaciality: Glazing 65±5%

Electrical Characteristics

Test uncertainty for Pmax: ±3%

Model Number	LR4-72HIBD-415M		LR4-72HIBD-420M		LR4-72HIBD-425M		LR4-72HIBD-430M		LR4-72HIBD-435M	
Testing Condition	STC	NOCT	STC	NOCT	STC	NOCT	STC	NOCT	STC	NOCT
Maximum Power (Pmax/W)	415	308.6	420	312.3	425	316.0	430	319.7	435	323.5
Open Circuit Voltage (Voc/V)	49.0	45.6	49.2	45.8	49.4	46.0	49.6	46.2	49.8	46.4
Short Circuit Current (Isc/A)	10.73	8.69	10.80	8.74	10.86	8.80	10.93	8.85	11.00	8.91
Voltage at Maximum Power (Vmp/V)	40.6	37.7	40.8	37.9	41.0	38.1	41.2	38.2	41.4	38.4
Current at Maximum Power (Imp/A)	10.23	8.19	10.30	8.25	10.37	8.30	10.44	8.36	10.51	8.42
Module Efficiency(%)	18.5		18.7		19.0		19.2		19.4	

STC (Standard Testing Conditions): Irradiance 1000W/m², Cell Temperature 25℃, Spectra at AM1.5

NOCT (Nominal Operating Cell Temperature): Irradiance 800W/m², Ambient Temperature 20℃, Spectra at AM1.5, Wind at 1m/S

Electrical characteristics with different rear side power gain (reference to 425W front)

Pmax /W	Voc/V	Isc /A	Vmp/V	Imp /A	Pmax gain
446	49.4	11.41	41.0	10.88	5%
468	49.4	11.95	41.0	11.40	10%
489	49.5	12.49	41.1	11.92	15%
510	49.5	13.04	41.1	12.44	20%
531	49.5	13.58	41.1	12.96	25%

Temperature Ratings (STC)

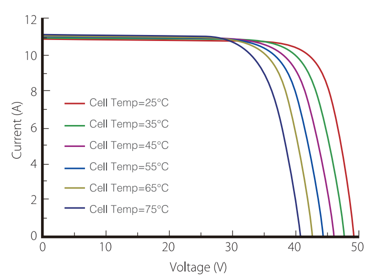
Temperature Coefficient of Isc	+0.060%/℃
Temperature Coefficient of Voc	-0.300%/℃
Temperature Coefficient of Pmax	-0.370%/℃

Mechanical Loading

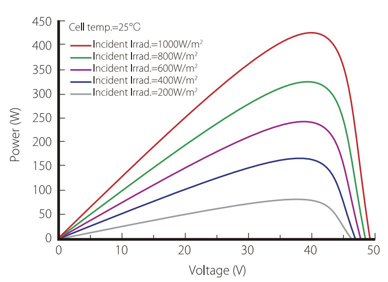
Front Side Maximum Static Loading	5400Pa
Rear Side Maximum Static Loading	2400Pa
Hailstone Test	25mm Hailstone at the speed of 23m/s

I-V Curve

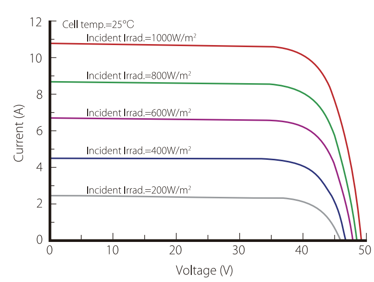
Current-Voltage Curve (LR4-72HIBD-425M)



Power-Voltage Curve (LR4-72HIBD-425M)



Current-Voltage Curve (LR4-72HIBD-425M)



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Note: Due to continuous technical innovation, R&D and improvement, technical data above mentioned may be of modification accordingly. LONGi Solar have the sole right to make such modification at anytime without further notice; Demanding party shall request for the latest datasheet for such as contract need, and make it a consisting and binding part of lawful documentation duly signed by both parties.

Preliminary

Attachment 3

Harvest the Sunshine

390W Bifacial Mono PERC Double Glass Module

Mono

JAM72D09 370-390/BP Series

Introduction

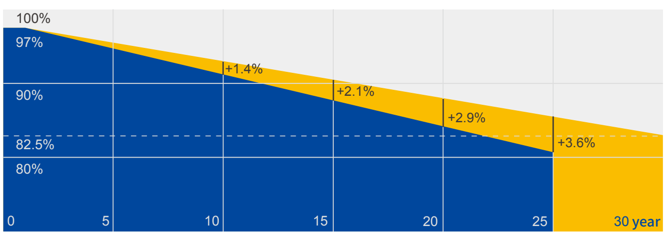
These double-glass modules assembled with bifacial PERCIUM cells have the capability of converting lights incident on their rear side into electricity on top of what is being generated by the front side, making them the best-performed and the most cost-effective modules in terms of solar energy generation as well as tolerance for harsh environment and extreme weather conditions.

- 3%~15%more energy generation
- framed design, ease of transportation and installation
- Superior low irradiance performance
- Excellent temperature dependent performance

Superior Warranty

- 12-year product warranty
- 30-year linear power output warranty

0.5% Annual Degradation Over 30 years



■ Additional Value From 30-Year Warranty ■ JA Standard

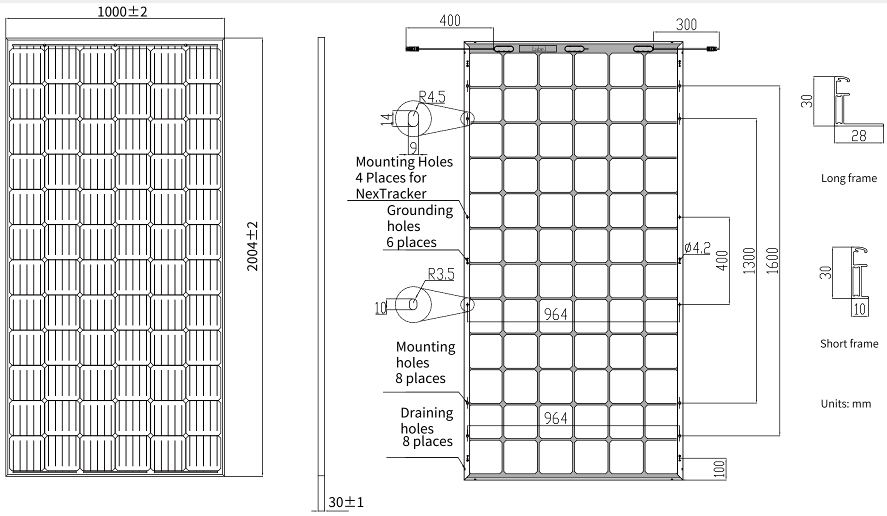
Comprehensive Certificates

- IEC 61215, IEC 61730
- ISO 9001: 2015 Quality management systems
- ISO 14001: 2015 Environmental management systems
- OHSAS 18001: 2007 Occupational health and safety management systems
- IEC TS 62941: 2016 Terrestrial photovoltaic (PV) modules – Guidelines for increased confidence in PV module design qualification and type approval

JA SOLAR

JAM72D09 370-390/BP Series

MECHANICAL DIAGRAMS



Remark: customized frame color and cable length available upon request

SPECIFICATIONS

Cell	Mono
Weight	29.8kg±3%
Dimensions	2004±2mm×1000±2mm×30±1mm
Cable Cross Section Size	4mm²
No. of cells	72(6x12)
Junction Box	IP68, 3 diodes
Connector	QC 4.10-35
Packaging Configuration	34 Per Pallet

ELECTRICAL PARAMETERS AT STC

TYPE	JAM72D09 -370/BP	JAM72D09 -375/BP	JAM72D09 -380/BP	JAM72D09 -385/BP	JAM72D09 -390/BP
Rated Maximum Power(Pmax) [W]	370	375	380	385	390
Open Circuit Voltage(Voc) [V]	48.20	48.51	48.81	49.11	49.42
Maximum Power Voltage(Vmp) [V]	39.41	39.73	40.02	40.33	40.63
Short Circuit Current(Isc) [A]	9.91	9.97	10.03	10.09	10.14
Maximum Power Current(Imp) [A]	9.39	9.44	9.50	9.55	9.60
Module Efficiency [%]	18.5	18.7	19.0	19.2	19.5
Power Tolerance	0~+5W				
Temperature Coefficient of Isc(α_Isc)	+0.060%/°C				
Temperature Coefficient of Voc(β_Voc)	-0.300%/°C				
Temperature Coefficient of Pmax(γ_Pmp)	-0.370%/°C				
STC	Irradiance 1000W/m², cell temperature 25°C, AM1.5G				

Remark: Electrical data in this catalog do not refer to a single module and they are not part of the offer.They only serve for comparison among different module types.
The efficiency of the bifacial PERC glass-glass modules at 200W/m² to that at 1000W/m² is 98%.
*Bifaciality=Pmax,rear/Rated Pmax,front

ELECTRICAL CHARACTERISTICS WITH DIFFERENT REAR SIDE POWER GAIN(REFRENCE TO 385W FRONT)

Backside Power Gain	5%	10%	15%	20%	25%
Rated Max Power(Pmax) [W]	404	424	443	462	481
Open Circuit Voltage(Voc) [V]	49.11	49.11	49.11	49.21	49.21
Max Power Voltage(Vmp) [V]	40.33	40.33	40.33	40.43	40.43
Short Circuit Current(Isc) [A]	10.59	11.10	11.60	12.11	12.61
Max Power Current(Imp) [A]	10.02	10.51	10.98	11.43	11.90

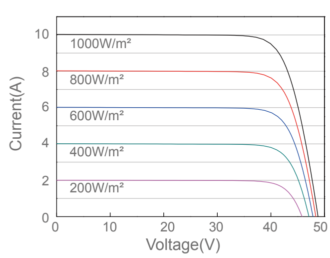
*For NexTracker installations static loading performance: front load measure 2400Pa, while back load measures 2400Pa.

OPERATING CONDITIONS

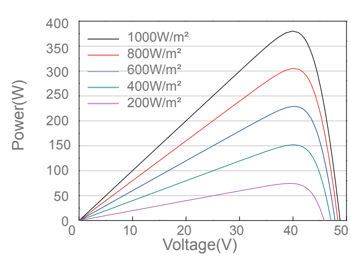
Maximum System Voltage	1500V DC(IEC)
Operating Temperature	-40°C~+85°C
Maximum Series Fuse	20A
Maximum Static Load,Front* Maximum Static Load,Back*	5400Pa 2400Pa
NOCT	45±2°C
Bifaciality*	70%±5%

CHARACTERISTICS

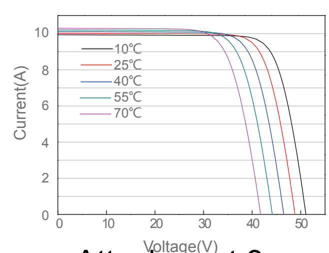
Current-Voltage Curve JAM72D09-380/BP



Power-Voltage Curve JAM72D09-380/BP



Current-Voltage Curve JAM72D09-380/BP



Preliminary

GCL-M8/72GDF

Bifacial Dual Glass Monocrystalline Module

410-435W

435W
Maximum Power Output

19.5%
Maximum Module Efficiency

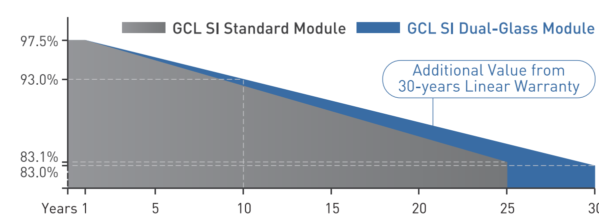
0~+5W
Power Output Guarantee

- Ideal choice for large scale ground installation
- More evenly distributed soldering points and better reliability and lower hot spot risk
- Selected encapsulating material and stringent production process control ensure the product is highly PID resistant and snail trails free
- Additional safety, Fire class Acertified
- Withstand up to 1500V system voltage effectively reduce BOS cost
- Sand blowing test, salt mist test and ammonia test passed to endure harsh environments

GCL Delivers Reliable Performance Over Time

- World-class manufacturer of crystalline silicon photovoltaic modules
- Fully automatic facility and world-class technology
- Rigorous quality control to meet the highest standard: ISO9001:2015, ISO14001: 2015 and OHSAS: 18001 2007
- Tested for harsh environments (salt mist, ammonia corrosion and sand blowing test: IEC 61701, IEC 62716, DIN EN 60068-2- 68)
- Long term reliability tests
- 2×100% EL inspection ensuring defect-free modules

Linear Performance Warranty



12 Years Product Warranty 30 Years Linear Power Warranty

* Please refer to GCL standard warranty for details

Additional Insurance Backed by Swiss RE

* Please refer to GCL for details

Preliminary

GCL-M8/72GDF

Bifacial Dual Glass Monocrystalline Module 410-435W

Electrical Specification (STC*)

Test Condition		Front	Rear	Front	Rear	Front	Rear	Front	Rear	Front	Rear	Front	Rear
Maximum Power	Pmax(W)	410	287	415	291	420	294	425	298	430	301	435	305
Maximum Power Voltage	Vmp(V)	39.16	39.56	39.49	39.89	39.78	40.18	40.10	40.50	40.38	40.78	40.70	41.10
Maximum Power Current	Imp(A)	10.47	7.25	10.51	7.28	10.56	7.32	10.60	7.35	10.65	7.38	10.69	7.41
Open Circuit Voltage	Voc(V)	46.60	45.90	46.93	46.23	47.22	46.52	47.54	46.84	47.82	47.12	48.14	47.44
Short Circuit Current	Isc(A)	10.96	7.69	11.00	7.72	11.05	7.76	11.09	7.79	11.14	7.82	11.18	7.85
Module Efficiency	(%)	18.4	12.9	18.6	13.0	18.8	13.2	19.0	13.3	19.3	13.5	19.5	13.6
Power Output Tolerance	(W)	0~+5											

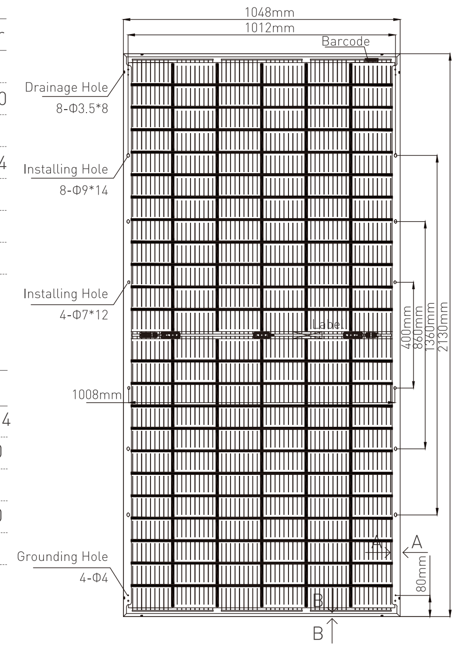
* Irradiance 1000W/m², Module Temperature 25°C, Air Mass 1.5

Electrical Specification (NOCT*)

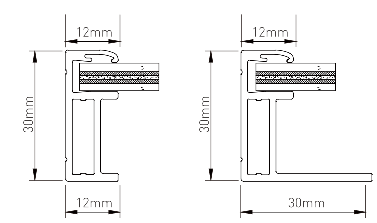
Test Condition		Front	Rear	Front	Rear	Front	Rear	Front	Rear	Front	Rear	Front	Rear
Maximum Power	Pmax (W)	306.34	213.67	309.96	216.16	313.58	218.66	317.20	221.15	320.81	223.65	324.43	226.14
Maximum Power Voltage	Vmp (V)	36.60	36.40	36.90	36.70	37.20	37.00	37.50	37.30	37.80	37.60	38.10	37.90
Maximum Power Current	Imp (A)	8.37	5.87	8.40	5.89	8.43	5.91	8.46	5.93	8.49	5.95	8.52	5.97
Open Circuit Voltage	Voc(V)	43.50	42.80	43.80	43.10	44.10	43.40	44.40	43.70	44.70	44.00	45.00	44.30
Short Circuit Current	Isc (A)	8.86	6.21	8.89	6.24	8.92	6.27	8.95	6.30	8.98	6.33	9.01	6.36

* Irradiance 800W/m², Ambient Temperature 20°C, Wind Speed 1m/s

Module Dimension



Back View



Short Frame B-B

Long Frame A-A

Mechanical Data

Number of Cells	144 Cells (6×24)
Dimensions of Module L*W*H (mm)	2130×1048×30mm (83.86×41.26×1.18 inches)
Weight (kg)	27.5 kg
Front Side Glass	High transparency solar glass 2.0mm (0.08 inches)
Back Side Glass	High transparency solar glass 2.0mm (0.08 inches)
Frame	Silver, anodized aluminium alloy
J-Box	IP68 Rated
Cable	4.0mm² (0.006 inches²), Portrait: 200/200mm (7.87 inches)
Number of diodes	3
Wind/ Snow Load	2400Pa/ 5400Pa*
Connector	MC Compatible

* For more details please check the installation manual of GCLSI

Temperature Ratings

Nominal Operating Cell Temperature (NOCT)	43±2°C
Temperature Coefficient of Isc	+0.06%/°C
Temperature Coefficient of Voc	-0.30%/°C
Temperature Coefficient of Pmax	-0.38%/°C

Maximum Ratings

Operational Temperature	-40~+85°C
Maximum System Voltage	1500V DC
Max Series Fuse Rating	20A

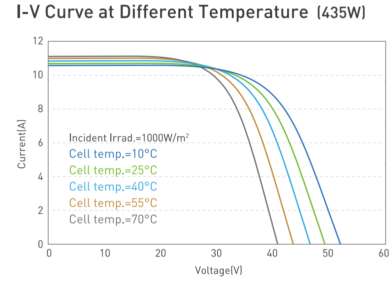
Optional

Connector:	☐ Original MC4

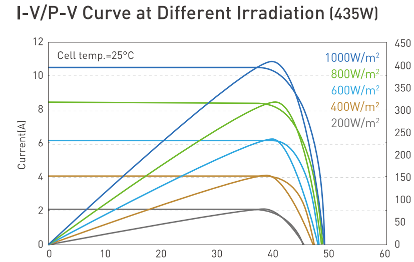
Packaging Configuration

Module per box	26 pieces
Module per 40' container	520 pieces

I-V Curve at Different Temperature (435W)



I-V/P-V Curve at Different Irradiation (435W)



CAUTION: READ INSTALLATION MANUAL BEFORE USING THE PRODUCT

Contact Us for More Information

website: www.gclsi.com email: gclsisales@gclsi.com

Obsidian Solar Center - Decommissioning Estimates Cost Estimate Component	Quantity	Unit	Per Unit Cost	Cost Estimate	Assumption
SWPPP & Dust Control Measures					
Stabilized Construction Entrances	1	Each	$ 3,287	$ 3,287	
Perimter Silt Fencing	95,040	Linear Ft	$ 0.74	$ 70,330	
Spill Kits (Emergency Equipment Cleanup)	2	Each	$ 324	$ 648	
Dust Control Watering (Water Truck)	250	Day	$ 787	$ 196,750	250 works days for decommissioning
				$ 271,015	
500 kV Step-Up Substation and Transmission Line					
Substation Step-up Transformer Removal	2	Each	$ 40,205	$ 80,410	
Haul and Recycle/Dispose of Transformer Oil	2	Each	$ 48,207	$ 96,414	50,000 gallons
Substation Circuit Breaker Removal	2	Each	$ 40,205	$ 80,410	500kv breakers
Remove and Recycle/Disponse of Fencing	1,200	Linear Ft	$ 2.50	$ 3,000	1,200 ft; 8 ft tall barbed chain link
Remove and Recycle Gate	28	Linear Ft	$ 6.75	$ 189	one metal access gate 8 ft by 20 ft
Remove and Recycle Access and Maintenance Lighting	1	Day	$ 1,051	$ 1,051	
Remove and Recycle Control Building Structure	1	Each	$ 2,432	$ 2,432	
Remove and Recycle Control/Communications Equipment	1	Each	$ 1,051	$ 1,051	
Remove and Recycle HV Above Ground Transmission Line	10,560	Feet	$ 36.61	$ 386,602	
Remove Gentie Foundations to Subgrade	37	Each	$ 15,333	$ 567,321	
				$ 1,218,880	
Four Collector Substations					
Remove and Recycle Collector Cables	60	Days	$ 4,000	$ 240,000	4 person crew, 60 days, $4,000/day
Remove Step up Transformers and Oil	4	Each	$ 172,250	$ 689,000	
Haul and Recycle/Dispose of Transformer Oil	20	Trips	$ 1,000	$ 20,000	
Remove Foundations to Subgrade	4	Each	$ 25,000	$ 100,000	
Remove Substation Junction Boxes and Foundations	4	Each	$ 212,500	$ 212,500	
				$ 1,261,500	
Solar Array					
Remove and Recycle Photovoltaic Modules	1,742,572	Panels	$ 3.98	$ 6,935,437	
Hauling and Disposal of Modules	34,851	Ton	$ 30	$ 1,045,543	
Remove Racking	22,689	Each	$ 47	$ 1,072,055	$105/row@22,689 module rows; 45%
Hauling and Disposal of Racking	22,689	Ton	$ 58	$ 1,310,290	removal and 55% hauling and disposal
Remove Posts	246,444	Each	$ 4.50	$ 1,108,998	$10/post@246,444 posts; 45%
Hauling and Disposal of Posts	246,444	Each	$ 6	$ 1,355,442	removal and 55% hauling and disposal
Remove and Recycle Inverters and Transformers	160	Each	$ 1,200	$ 192,000	
Dispose of Inverters and Transformers	3,040	Ton	$ 30	$ 91,200	
Disconnect and Remove Combiner Boxes and Switches	2,240	Each	$ 1,100	$ 2,464,000	14 combiner boxes for each inverter
Remove SCADA and Met Stations	1	Each	$ 1,051	$ 1,051	
Remove Fences/Gates	95,040	Linear Ft	$ 2.50	$ 237,600	18 miles
Restore Site (Primarily Re-Seeding Disturbed Areas)	1,300	Acres	$ 200	$ 260,000	
				$ 16,073,616	
O&M Facilities					
Remove O&M facility (per building)	2	Each	$ 40,000	$ 80,000	2 buildings
				$ 80,000	
Battery System					
Disconnect battery and prepare for removal	134	Each	$ 4,000	$ 536,000	134 buildings
Remove Buildings and Foundations (Demolition and Hauling)	134	Each	$ 1,000	$ 134,000	134 buildings
Haul Batteries Containing Electrolyte Fluid	67	Trips	$ 1,000	$ 67,000	2 buildings per trip
Dispose of Electrolyte Fluid	50	MW	$ 100	$ 5,000	14,000 gallons per MW
Disposal of Battery System Inverters and Switchyard	70	Each	$ 4,100	$ 287,000	
Disposal of Battery System Switchyard	1	Each	$ 9,100	$ 9,100	
Restore Battery Building Site	25	Acres	$ 2,600	$ 65,000	includes application of manure,scarifying , and blending
Hauling and Disposal	67	Trips	$ 1,000	$ 67,000	67 trips
				$ 1,170,100	
Road Restoration					
Remove Service Roads	3,696,000	SF	$ 0.08	$ 295,680	50 miles
				$ 295,680	
Restore Additional Areas Distributed by Facility Removal					
Restore and seed temporary disturbance areas	25	Acres	$ 2,600	$ 65,000	includes application of manure, scarifying, and blending
				$ 65,000	
General Costs					
Haul charges and disposal fees (per load)	250	Trips	$ 1,000	$ 250,000	250 loads
Permits, Inspections and Fees				$ 10,000	
				$ 260,000	
Subtotal				$ 20,695,790	
Mobilization and Supervisory				$ 206,958	1%
Subcontractor Bonding/Liability Insurance				$ 310,437	1.50%
General Conditions				$ 258,697	1.25%
Performance Bond				$ 206,958	1%
Administration and Project Mgmt				$ 620,874	3%
General Overhead and Profit				$ 1,034,789	5%
Future Developments Contingency				$ 620,874	3%
Total Site Restoration Cost (current dollars)				$ 23,955,377	
Total Site Restoration Cost (rounded to nearest $1,000)				**$ 23,955,000**	