CITY OF ASHLAND

Council Communication
February 21, 2017, Business Meeting

"10 by 20" Ordinance - Project Update

FROM:
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SUMMARY
With direction provided by Council at the November 15, 2016 study session, staff has worked with two consulting firms to provide research, analysis and proposed schedule of tasks necessary to fully evaluate the feasibility of the use of the City owned Imperatrice property to construct a utility scale solar generation facility as one option to meet the requirements of the "10 by 20" ordinance (10% new, clean, local electricity generation by 2020).

BACKGROUND AND POLICY IMPLICATIONS:

10 by 20 Ordinance

A citizen initiative petition for a local ballot measure was submitted to the City Council on August 16, 2016 titled "Shall Ashland produce 10% of electricity used in the City by year 2020 from new, local and clean sources?"

On September 6, 2016, Council accepted and approved the ordinance language contained within the ballot measure verbatim, consistent with Oregon State Elections procedures (ORS 250.325 and 254.095)

With initial discussions at the November 1, 2016 Council meeting and subsequent discussions at the November 15, 2016 Council meeting, Council directed staff to develop a Request for Proposals (RFP) or a Request for Qualifications (RFQ) as a method of gathering the data necessary to properly evaluate the potential use of the Imperatrice property as a means of complying with the 10 by 20 ordinance requirements.

Council direction purposefully excluded several known variables in order to focus efforts on the technical and financial feasibility of the potential project with the intent and expectation that these variables would be integrated back into the evaluation process after the technical and financial elements of the project are better understood. These variables include:

- Potential need for a portion of the property for waste water treatment solutions (note: the property was originally purchased with waste water funds for waste water treatment solutions)
- Historical stated interest in a portion of the property to be reserved via conservation and/or trail easement for habitat and viewshed protection

- BPA wholesale electricity contract inclusion of a "take or pay" provision that requires the City to purchase all of its electricity needs through BPA. The current contract runs through 2028.

Imperatrice Property – Solar project analysis

Staff received assistance in the research, analysis and proposed schedule of tasks through its partnership with the Bonneville Environmental Foundation (BEF), a leading environmental non-profit with programs focused on solar and other renewable solutions.

Staff also relied heavily on OS Engineering, the City's electrical engineering consulting firm to provide key technical review, analysis on the ability and requirements of connecting a utility scale solar system directly to the City's distribution grid (called an interconnect).

Key Findings of this initial round of research and analysis include:

- Estimated total capital costs of a 12 MW system is likely between $15,000,000 and $20,000,000, resulting in a levelized cost of energy of $90 per Megawatt hour (+/- 10%) compared with current wholesale pricing of approximately $30/MWh
- Estimated interconnection cost of approximately $1,200,000 depending on final specifications
- A 12 MW system cannot be served by either of the two nearby sub-stations, requiring the interconnect to split the system to distribute the load to each of the existing sub-stations.
- Development of a smaller sized system that is scalable over time may provide benefits and avoid regulatory and financial obstacles.
- Additional opportunities to meet the 10 by 20 requirement should be evaluated concurrent with proposed next steps for the Imperatrice property

Staff has found this round of research and analysis invaluable in better understanding the issues specific to a large utility scale solar project and concur with the recommendations made by BEF on pages 2-3 of the attached report with key timeline items outlined briefly below:

- Spring 2017 - Conduct initial environmental review of site (flora/fauna survey)
- Spring 2017 – Submit new generator request to Pacific Power (6-18 month process)
- Summer/Fall 2017 – Begin application process for land use approval with Jackson County
- Summer/fall 2017 – Further address issues related to substation capacity and interconnection
- Ongoing – Continue to explore additional opportunities to develop renewable energy installations with City facilities, community/co-op solar projects, smaller (1 MW) utility owned/managed systems located within the local distribution grid system and other potential solutions that could meet the intent of the 10 by 20 ordinance

Pursuing the tasks listed above have been determined by both of our project research partners as needed steps prior to the issuance of a complete technical RFP/RFQ and also maintain the general timeline needed to realistically be able to advance the project through to completion by the end of 2020 as specified in the 10 by 20 ordinance.

COUNCIL GOALS SUPPORTED:

22. Prepare for the impact of climate change on the community.
    22.1 Develop and implement a community climate change and energy plan

FISCAL IMPLICATIONS:
The above described initial round of research and analysis was conducted with minimal City expenditure; a memorandum of understanding facilitated the work with BEF and the City's existing contract with OS Engineering was utilized for the technical research on the inter-connection aspect of the project at a cost of just over $3,000

The costs associated with pursuing the recommended initial environmental review of the site are not yet known, but is expected to be in the $10,000 to $20,000 range and would be funded from the contract services budget in the Electric Fund. Other listed tasks will involve staffing resources from both the Electric and Administration Departments.

STAFF RECOMMENDATION AND REQUESTED ACTION:
To pursue the project further, staff recommends that the initial environmental review of the site be conducted this spring to take advantage of the spring bloom that assists in the inventory component of the review. As staff assesses the needed scope of the review and the approximate costs, a determination can be made as to whether or not the contract for the desired services will necessitate Council approval.

Staff also recommends that Council consider directing staff to develop a proposed strategy document to assist Council, staff and the community as the "set aside" variables noted above integrate back into the project feasibility evaluation.

SUGGESTED MOTION:
I move to direct staff to move forward with an environmental review of the Imperatrice Property and to develop a project strategy document to help guide future project evaluation.

ATTACHMENTS:
BEF – Letter of February 10, 2017
OS Engineering Analysis – January 31, 2017
Council Meeting November 15, 2017 – Staff Report and Minutes

Mark Holden
Ashland Municipal Electric Utility
90 N. Mountain Ave
Ashland, OR 97520

February 10, 2017

Dear Mark,

The following includes our recommendations to the City of Ashland with respect to the goals of Ordinance No. 3134, and enabling the production of 10% of Ashland's electricity consumption to be produced from new, local and clean resources by the year 2020. The Bonneville Environmental Foundation is committed to partnering and supporting this effort per our dually executed Memorandum of Understanding, 800036-12, dated 12/28/16.

At the Bonneville Environmental Foundation (BEF), we believe that addressing the most pressing energy and environmental challenges requires, innovation, creative problem solving and discovering new ways of doing business. As an entrepreneurial non-profit we thrive in working toward innovative solutions and value partnerships as essential to success. BEF has a long history of supporting publicly owned utilities in the development of cost-effective renewable resources including the first pubic power wind project in the region, the first community solar project with Ashland, and subsequently 22 community solar partnerships with utilities across the Pacific NW.. BEF's partnership with the Bonneville Power Administration (BPA) allows us to aid BPA's Wholesale Public utility customers like Ashland as they endeavor to integrate more renewable energy projects into the PNW's utility generation mix.

BEF is uniquely positioned to assist Ashland in meeting its "10x20" goals. Our team dedicated to the project includes Dick Wanderscheid, Vice President of the Renewable Energy Group, and Evan Ramsey, Senior Project Manager for the Renewable Energy Group. Collectively we bring over 40 years of experience with publically owned electric utilities, energy efficiency, sustainability, and renewable energy. Dick brings the intimate knowledge of Ashland's situation, having served in the city's energy conservation and renewable energy programs for 20 years and also as the City's Electric Utility's Director for nearly a decade. Evan brings a wealth of experience in solar energy systems having deep commercial management experience with SolarCity, and has served as the primary BEF consultant to all our utility partners developing solar projects.

BEF fully supports Ashland's commitment to renewable energy, and has committed all of the resources at our disposal to help the City develop the most cost effective, resilient, and beneficial solution for the electric Utility and it's citizens. While the actual cost and scope of solar PV construction is relatively simple, the development, siting, and financing provides the bulk of

the risk and complexity. It is with this in mind that BEF recommends a measured approach with as much due diligence as possible on the front end to maximize the project economics and benefits to the City of Ashland. Solidifying as many of the pre-development unknowns as possible lessens the unknowns and risk to developers and will provide the best ultimate price to the City. This approach has been validated through our research and outreach with other industry experts such as Rocky Mountain Institute (RMI) and the Smart Electric Power Alliance (SEPA), who both specialize in utility solar procurement. We have also discussed solar integration and contract issues with the BPA's Solar Task force staff.

The entire process of developing a solar project includes system siting, environmental reviews, interconnection studies, financing, procurement, contractual negotiations, engineering, permitting, land use approvals, distribution system upgrades, construction, commissioning, and finally standard operations and maintenance. This overall process can take years and it is advisable to have a destination before undertaking a journey.

To release an RFP simply for pricing of the solar does not return all the necessary data points needed to evaluate the full impact of a utility scale project to the City of Ashland. Furthermore, there is industry data available that will provide PV system cost estimates, without having to run a premature RFP. SEPA has published a "Utility Scale Pricing Report" which provides a matrix of capital costs with associated levelized costs of energy (LCOE). The total capital cost of a 12 MW system alone is likely to be between $15,000,000 and $20,000,000. We can expect with confidence the LCOE of a horizontal single access tracker for this sized system, with a 20% capacity factor, to provide an LCOE of $90 per Megawatt hour, plus or minus 10%. This is nearly a three-fold increase compared to existing wholesale power pricing of around $30/MWh. This pricing is not inclusive of any development activities, distribution system upgrades, resource support services, contractual and take or pay implications.

Given all the outlined complexities, BEF remains committed to supporting the City of Ashland, as it pursues the goal of 10% of Ashland's energy consumption from new, clean, and local energy sources. After substantial research and evaluation we would like to present the following recommendations:

1. **Rare Species Survey**: Complete the biological survey, Spring of 2017.
    - This study will be necessary for the entire parcel regardless of where the solar array is located. If rare species are found during the Spring bloom, this will allow for project siting changes and may ultimately dictate a necessary location for the array.
2. **Utility Interconnection**: Submit a request to PacifiCorp, Spring of 2017.
    - Regardless of whether a new solar generation project connects to a substation in Ashland or a Pacificorp line, a feasibility and system impact study will be required by Pacificorp. This is their responsibility as the Balancing Authority for the area, and this process can take 6-18 months. It will provide valuable information regarding interconnection capacity, location, and cost. In parallel, the City may evaluate costs and benefits for the various utility interconnection options.
3. **Conditional Use Permit (CUP)**: Submit for a CUP with Jackson County for siting on the Imperatrice Property. Once siting and size are known. Fall of 2017.
4. **Substation Capacity**: Determine capacity of an interconnect to the BPA owned Mountain Substation and minimum load at this wholesale point of delivery. If direct connection to this Substation is feasible, secure cost estimates for the necessary distribution work.

5. **BPA Contract:** Evaluate implications to the existing Bonneville Power Administration power sales contract, including "take or pay" provisions, resources support services cost, transmission implications, purchase of the substation, and effect on the General Transfer Agreement between Pacificorp and BPA.
6. **Rooftop Solar Potential**: Determine the rooftop solar capacity for City owned facilities, privately and publically owned buildings, SOU facilities and determine the total distributed generation potential if possible. Any project less than 200kW nameplate that serves customer load does not have a negative effect on the BPA power sales contract with Ashland. Evaluate energy and economic impacts of implementing additional solar rebates or feed-in-tariffs for customer owned capacity.
7. **1MW Solar Siting**: Determine if there is a suitable site for a ground mounted 1MW array with a direct connection to Ashland's distribution system. A system sized less that 1MW is easily integrated into the distribution system and also does not have a negative effect on the BPA power sales contract.
8. **Energy Efficiency**: Determine the potential conservation measures that could be accelerated by 2020, as energy efficiency is the least cost, local, and cleanest resource.
9. **Low Income Support**: Determine what support may be available for low-to-moderate income utility customers, to insulate them from projected rate increases. This could include dedicated low-income community solar, voluntary energy assistance programs, or a broader partnership with ACCESS to increase low-income weatherization and renewable energy benefits.
10. **Request for Proposals**: Release an RFP for up to 13MW of solar on the Imperatrice property after these critical questions have clarity, 2018.

Upon receiving all this information the City can then evaluate all of the options for complying with Ordinance No. 3134 and begin the hard job of implementing a cohesive and well researched package of measures.

Best Regards,

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City of Ashland PV Generation Interconnect Analysis

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DATE:	January 31, 2017

1.0 EXECUTIVE SUMMARY

1.1 General

This engineering document describes a preliminary review of options and interconnect feasibility for adding a large scale Photovoltaic (PV) generation facility and connecting it into the City's existing electrical distribution system. It is our understanding that the project objective is to install a solar generation system with the capacity to meet approximately 10% of the City's annual energy consumption, which is equivalent to a system with a nameplate capacity of approximately 10 MW. It is also our understanding that the City prefers to interconnect the PV system directly to the City's existing distribution system rather than a transmission interconnection.

This engineering investigation evaluated integrating photovoltaic systems with generation output ranging between 2.5 MW and 10 MW. This range was based on the ability of the City's existing facility capabilities at practical interconnection locations.

The PV site is located approximately 1 mile from nearby City electric distribution facilities and, although the solar array would be constructed on City owned property, the interconnection would be constructed outside the City's existing service territory. Therefore, interconnect construction will require permitting, easements and rights-of-way access.

Presently the City has an exclusive power purchase agreement with the Bonneville Power Administration (BPA) and BPA has a General Transfer Agreement with PacifiCorp. Our review of the interconnect options assumes generation export is not desired and that all energy production from the new system will be utilized by the City. Because of the City's intent to maximize the amount of solar generation and the desire to not export power, the engineering investigation evaluated the estimated PV generation profile with seasonal adjustment against typical seasonal load profiles as a base criteria for establishing maximum interconnect generation capacity.

1.2 PV System Interconnect

Distribution system connected generation can have significant impacts on protection and power quality of an electric distribution system. Therefore, carefully defined protection and control requirements are necessary. This includes output protection and control at the inverter by the PV developer and protection, control and metering at the utility point of common coupling (PCC) by the City.

Multiple interconnection points are available within the City's distribution system. Several of these connection points were evaluated to identify maximum feasible PV capacity. This included remote interconnections at radial taps and connection with main backbone circuits. To maximize PV generation, interconnection with a distribution backbone feeder circuit is necessary. However, due to minimum peak substation loading at certain times of the year, the maximum PV output that can be interconnected to any one substation is limited to 5 MW based on a review of historic load data and estimated generations profiles. To interconnect PV output generation to the extent desired by the City (~10 MW), it will likely be necessary to interconnect with two backbone feeder circuits from two separate substations.

We have assumed the PCC interconnection between the PV system and utility system will be located within the southwest region of the Imperatrice Property, not within the Short-Term Lease area. Leaving the Short-Term Lease property available for other future uses.

We recommend that the City substantiate, through the PV development RFP, that the solar construction project conforms to all applicable industry standards regarding equipment, construction and operation to assure protection of the electric systems normal operation and quality of service to existing customers.

1.3 Comments and Recommendations

Our preliminary analysis and review indicates that the City can achieve the PV generation interconnect desired without excessive deleterious effect to the existing distribution system or violation of existing purchase agreements. However, interconnection to the existing City distribution facilities should be coordinated as stated above and described in greater detail in this memorandum. Where are analysis has concluded a maximum interconnect generation size, it can be assumed that a smaller system can be accommodated thus allowing the City to install PV generation in increments staged, for example, in 1 MW or 2.5 MW output capacities.

To achieve strong interconnection(s) between the PCC and the existing electric distribution system it is recommended that a tie location occur near the vicinity or N Mountain Avenue and E Nevada Street. This location offers connection to a feeder from Ashland Substation, Mountain Avenue Substation, or both to accommodate the full PV build-out capacity of 10 MW. This location should be considered even if the PV facility is built in stages. Other interconnection locations are available and are described elsewhere in this memorandum but to achieve the City's ultimate capacity goal this tie point is the optimal location for the existing system.

To accomplish interconnection between the PV system and the City's existing distribution system we recommend consideration for underground construction to meet the least public resistance. This can be accomplished with both open trench and directional bore construction. If the City intends to have the PV

site developed in incremental stages, it is suggested that all underground infrastructure be installed initially, with major equipment installed as needed to meet generation capacity.

If the City is considering having the utility interconnection construction performed by the PV developer it is suggested that construction technical specifications and material standards be assembled and provide to ensure quality construction.

Budgetary pricing has been assembled to expand the City's electric system to interconnect at the PCC with the PV site as described herein. The cost to construct circuit interconnections for a PV facility with capacity ranging between 2.5 MW and 10 MW is estimated to be between $0.9 and $1.5M.

2.0 INTRODUCTION

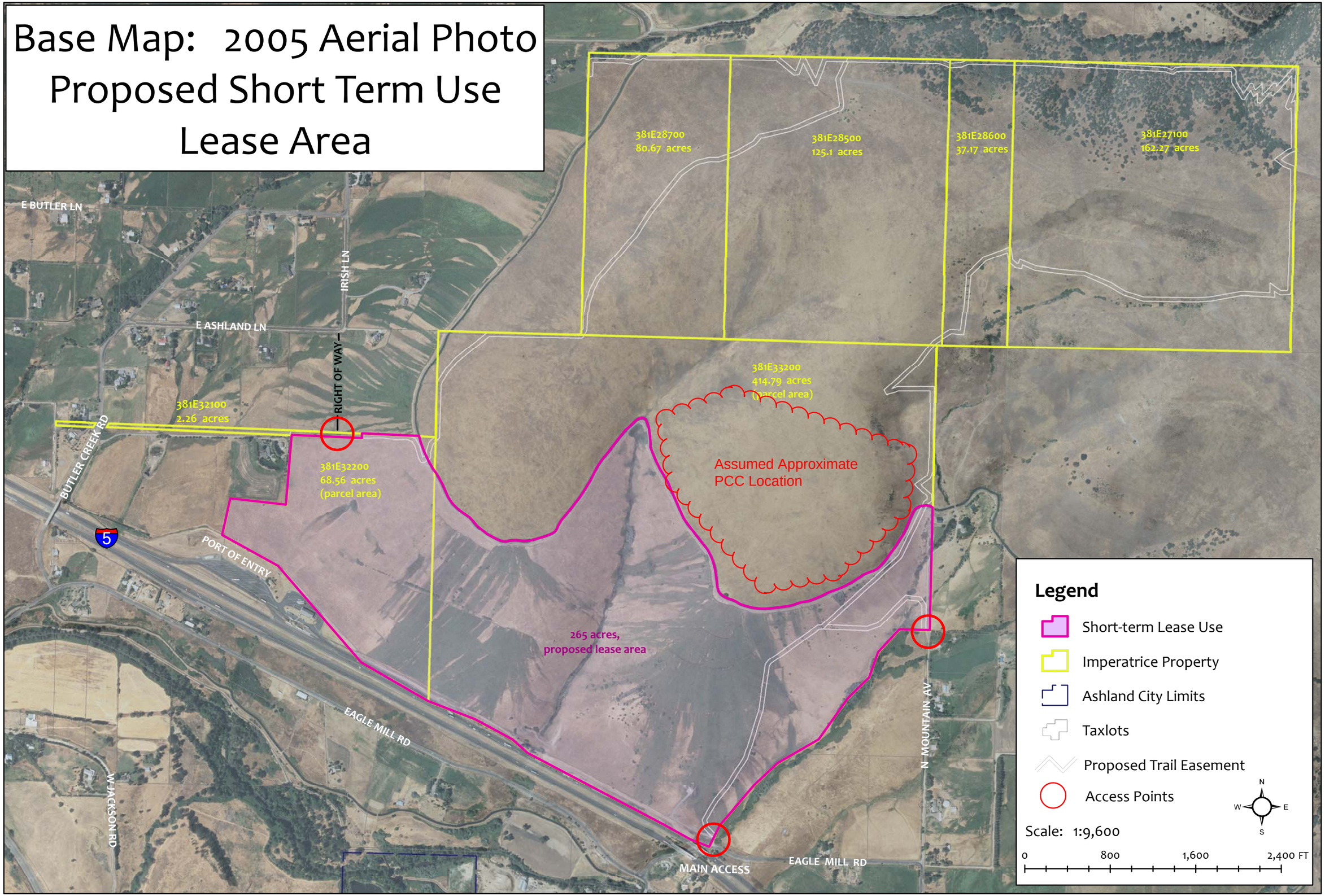
2.1 Overview of the project

The City of Ashland intends to install a PV generation system that can support approximately 10% of its annual energy usage, 17.4M kWh, which the City has determined to be equivalent to approximately 10 MW. The City has explained its preference to interconnect the PV system directly to the City's existing 12.47 kV distribution system, and requested OS Engineering, engineering service contractor for the City, to evaluate the feasibility and impacts of various interconnect options to meet the City's intent. In this study, OS Engineering has developed and assessed three different interconnecting options of the integration of a power generation PV system into existing City of Ashland distribution facilities. Our review includes estimated generation output, system load profiles, power quality considerations, protection, and approximate cost estimates.

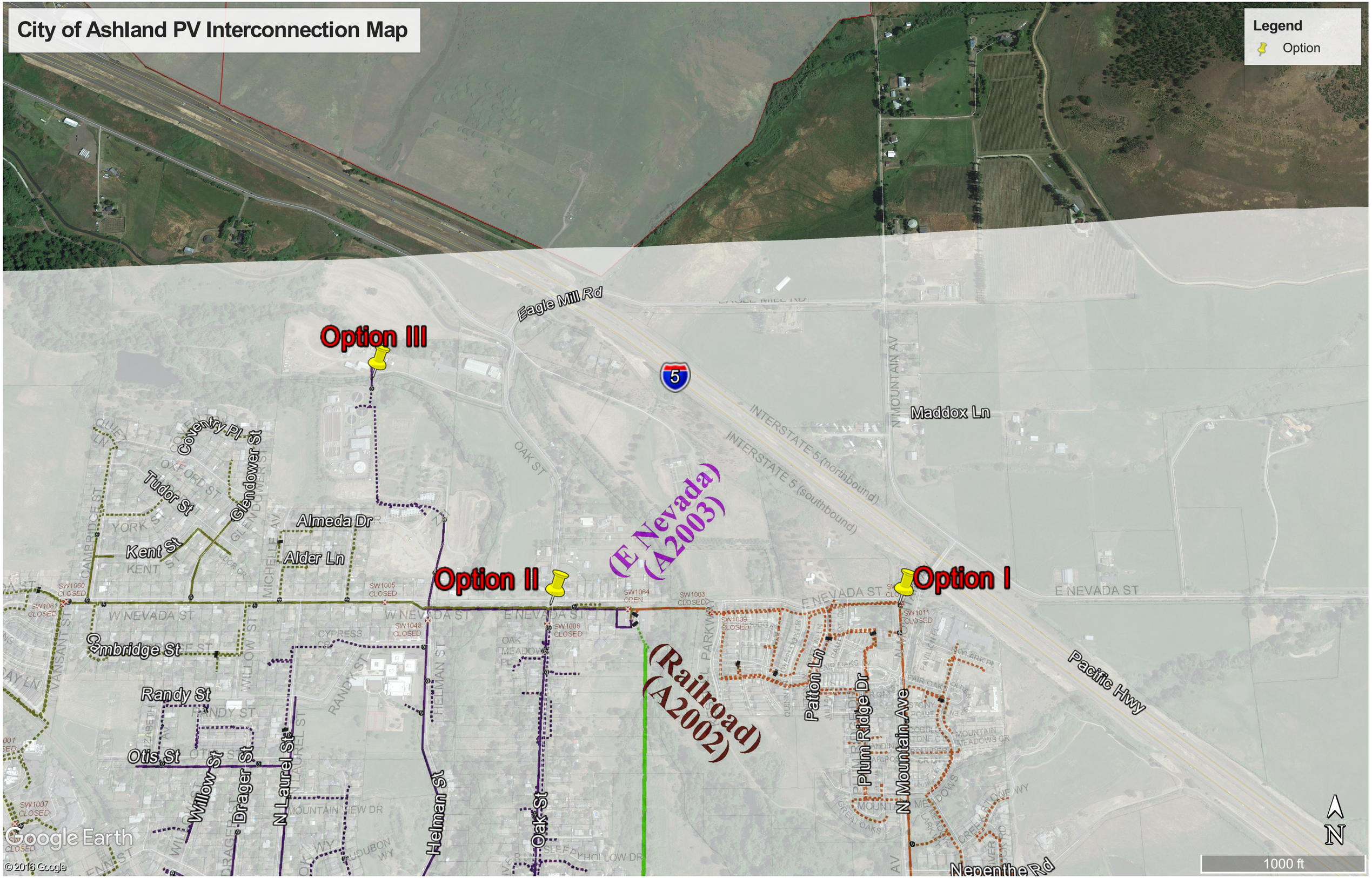
2.2 Map of the project and potential interconnect points

The following two maps show the City of Ashland Imperatrice Property Map 2005, and potential PV Interconnection Points Map, respectively.

Base Map: 2005 Aerial Photo Proposed Short Term Use Lease Area



City of Ashland PV Interconnection Map



3.0 PV TECHNOLOGY OVERVIEW

Photovoltaics (PV) systems have been well recognized as a promising renewable energy technology and have been growing exponentially worldwide for more than two decades, during which PV technologies evolved in many different aspects, such as flat-plate vs. concentrating, improved materials, higher efficiency, lower costs, etc. During this time, many improvements have been realized in inverter technology, tracking systems, controls, and protection that facilitate PV generation in large scale power production interconnected to transmission and distribution systems. As a preliminary study regarding the City of Ashland PV project, we did not investigate the option of concentrator and different type of PV modules and inverters, but utilized a generic flat-plate PV and inverter combination in order to provide representative PV generation profiles for different mounting configurations based on actual seasonal weather data in the City of Ashland area.

3.1 PV Generation Profile

The City of Ashland 2014 hourly weather data, including solar irradiance (Solar irradiance is the power per unit area received from the Sun in the form of electromagnetic radiation), is available from the NREL National Solar Radiation Database (NSRDB). The database contains satellite-derived data from the Physical Solar Model (PSM) for both typical year data and historical single year data for 1998 through 2014 for locations in the United States. The weather in the Northwest area has a fairly repeatable pattern every year, therefore the 2014 weather data is used to as a typical profile for the City of Ashland.

One of the parameters available in the 2014 weather data is the Global Horizontal Irradiance (GHI). The GHI is the total amount of shortwave radiation received from above by a surface horizontal to the ground. This value is of particular interest to photovoltaic installations and includes both Direct Normal Irradiance (DNI) and Diffuse Horizontal Irradiance (DHI). DNI is solar radiation that comes in a straight line from the direction of the sun at its current position in the sky. DHI is solar radiation that does not arrive on a direct path from the sun, but has been scattered by molecules and particles in the atmosphere and comes equally from all directions. Figure 1 shows the three profiles for City of Ashland, 2014.

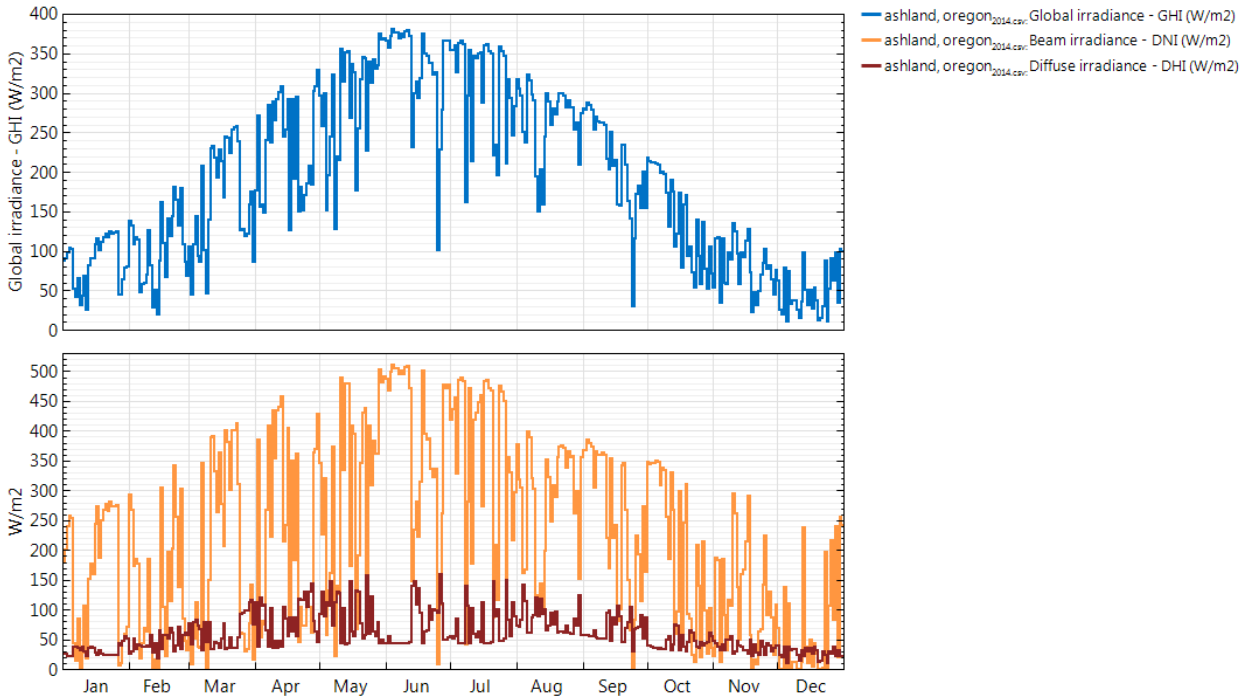


Figure 1: Global Horizontal Irradiance (GHI), Direct Normal Irradiance (DNI), and Diffuse Horizontal Irradiance (DHI) in watts/m^2 in City of Ashland, 2014

Figure 2 shows the daily temperature map throughout the entire year of 2014 in degrees Celsius. The data provides the typical temperature distribution pattern in Pacific Northwest area. Figure 3 illustrates the same data as provided in Figure 1 and 2 but in monthly averages. The left axis and blue line of Figure 3 represents the level of irradiance and the right axis and orange line represent temperature.

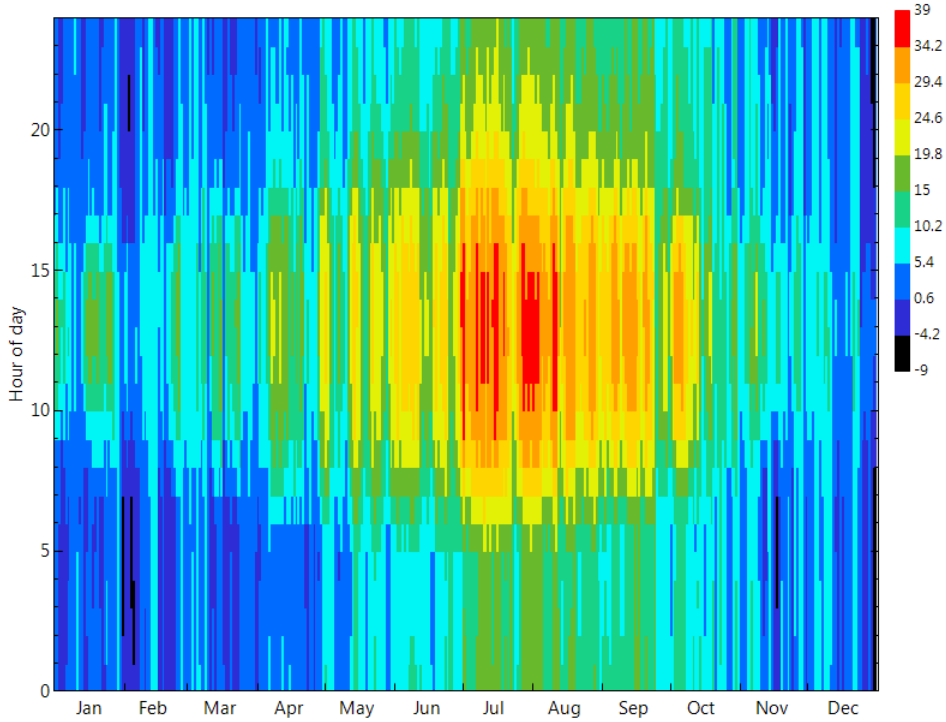


Figure 2: Daily temperature map for City of Ashland, 2014

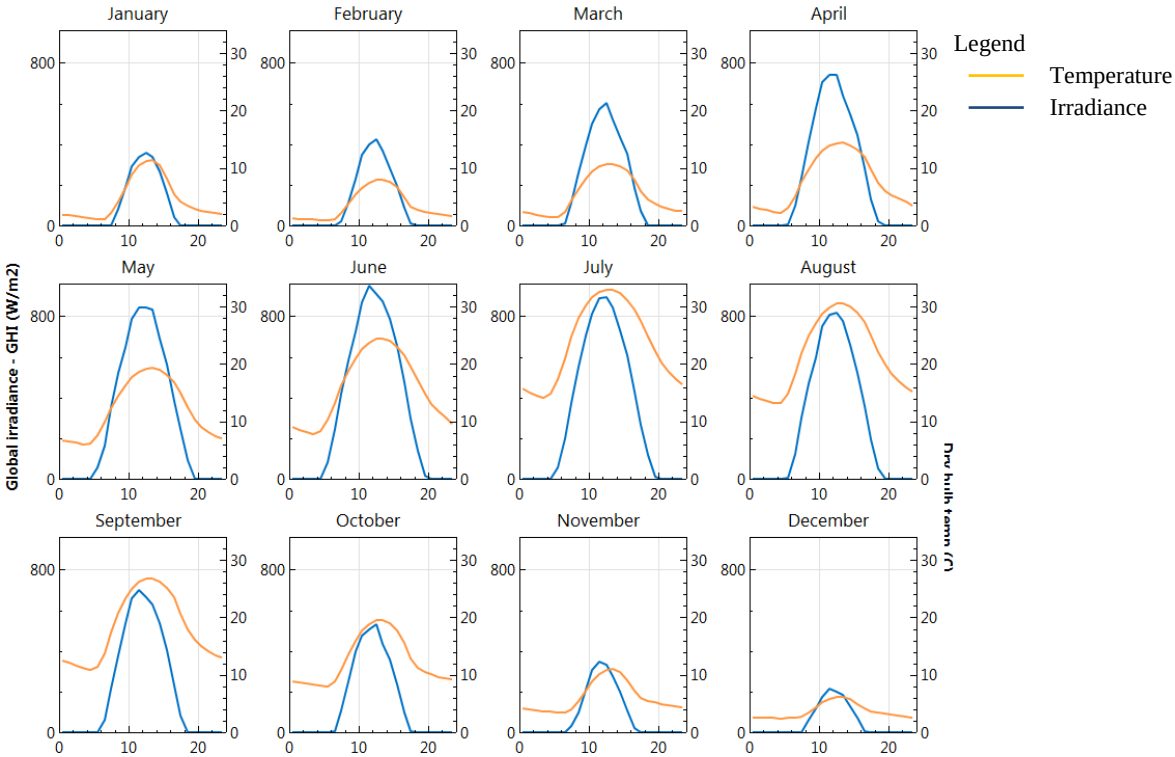


Figure 3: Monthly irradiance and temperature profile for City of Ashland, 2014

With the actual weather data, PV array power outputs can be estimated or simulated using System Advisor Model (SAM) developed by National Renewable Energy Laboratory (NREL) SAM is a tool that is able to facilitate renewable energy integration in both system performance and financial aspects. In this study, a compatible generic combination of flat-plate PV module and inverter is utilized to form a 1 MW grid-connected PV array as an example. Larger size PV arrays can be achieved by increasing the number of modules and inverters, and their power output is essentially scaled up linearly.

PV generation, for the same solar profile, can be maximized/optimized by using technologies such as tracking systems. Tracking systems orient PV panels toward the Sun, which increases the power generating capability significantly. Tracking technologies add complexity and may require extra cost and maintenance and generally is not feasible for most home systems but can provide great benefit to utility scale grid-connected PV arrays. The additional energy production may offset the added cost of the tracking system and the increased generation typically is equivalent to a smaller array for the same overall level of energy production. Figure 4 shows the monthly average power profile using a fix-mount array that is oriented south (180° Azimuth degree) for a 1 MW PV array, while Figure 5 shows a similar monthly power profile using an array with a 2-axis tracking system. As can be seen from these two figures, there is a considerable difference in PV array power output with and without tracking capability. Specifically, with a tracking system, power output of the same PV array can reach the high power region much quicker and maintains at that level longer than PV arrays using fixed-mounting. (Note: Simulation is based on hourly weather data, and no loss and shade is considered for this early phase study.)

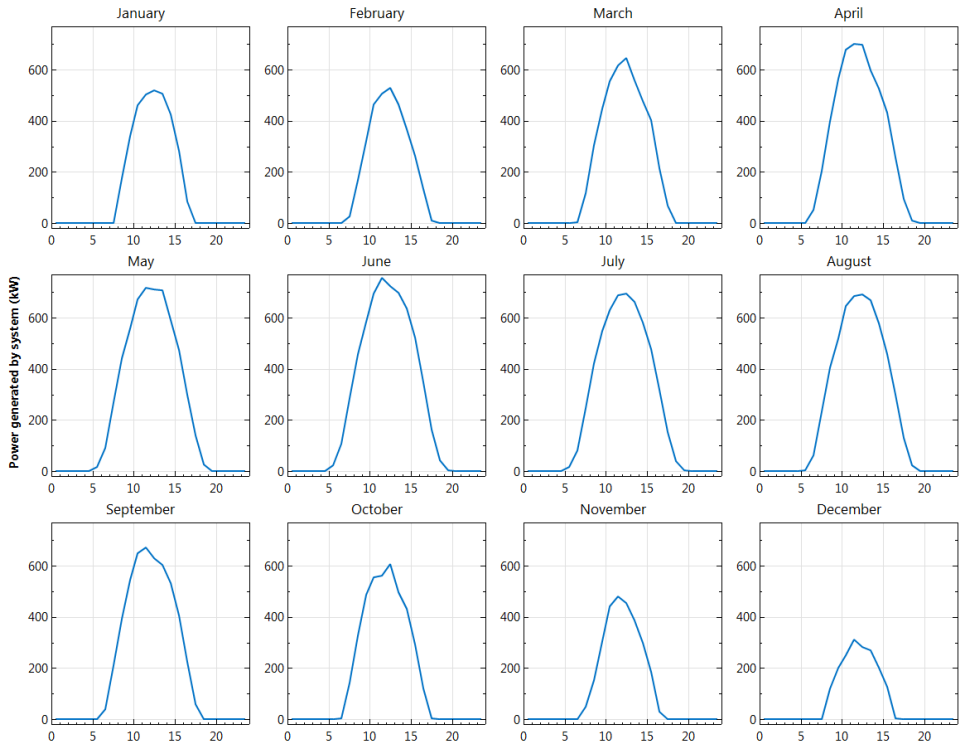


*Figure 4: Monthly average power profile using **fixed-mount** for a 1 MW PV array in City of Ashland, 2014*

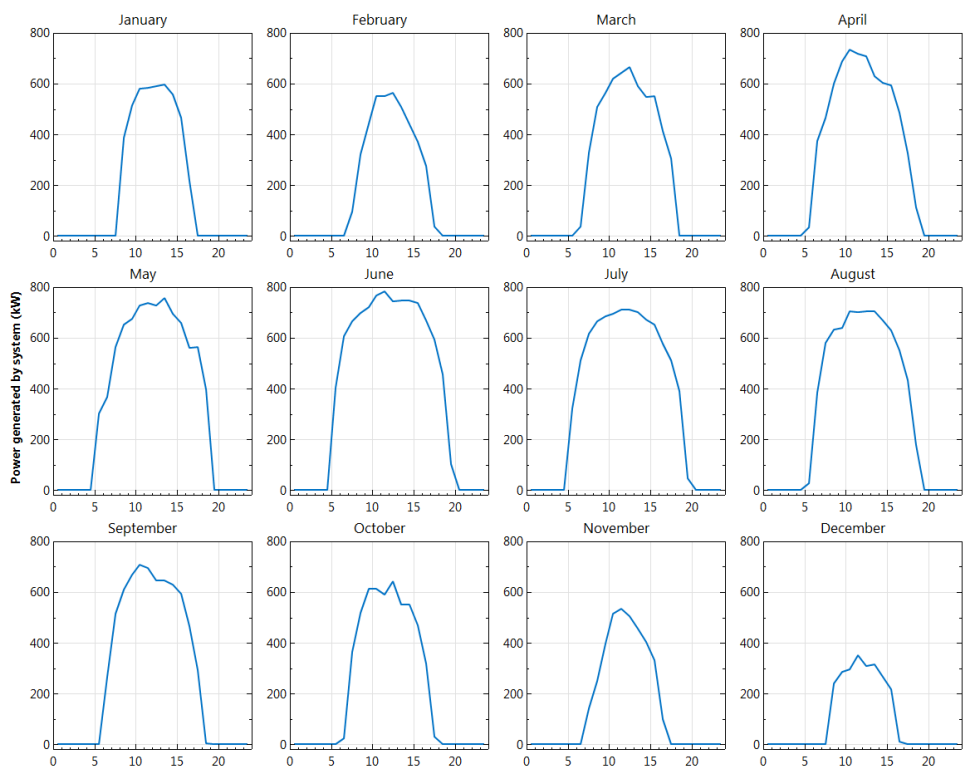


*Figure 5: Monthly average power profile using **2-Axis tracking** for a 1 MW PV array in City of Ashland, 2014*

3.2 System load evaluation

The City of Ashland 2016 metering data from BPA was evaluated and the results shown in below table. The coincident peak demand in 2016 is about 40 MW and occurred during the month of August. The minimum coincident demand is about 10 MW and occurred during the month of June. At peak demand, each substation has about 13 MW of load and, in general, the City's load is typically divided uniformly across the three substations.

Table 1: BPA metering data summary for City of Ashland 2016

Substation	Ashland	Oak Knoll #1	Oak Knoll #2	Oak Knoll East	Mtn Avenue	**Total**
Meter ID	575	1014	1304	1705	1820	
Demand						
Average Demand	6,333	2,384	2,541	1,905	6,431	**19,594**
Peak Demand	13,200	4,690	5,320	4,040	12,850	**40,100**
Date/Hour	8/19/16 5:00 PM	7/29/16 5:00 PM	12/7/16 7:00 PM	8/19/16 4:00 PM	8/19/16 5:00 PM	
Min Demand	3,510	1,390	0	940	2,900	**8,740**
Date/Hour	4/18/16 4:00 AM	4/11/16 4:00 AM	1/1/16 2:00 AM	1/3/16 12:00 AM	6/12/16 4:00 AM	
Load Factor	0.48	0.51	0.48	0.47	0.50	**0.49**

Coincident Peak Demand	
Maximum	**39,940**
Date	**8/19/16 5:00 PM**
Minimum	**10,295**
Date	**6/12/16 5:00 AM**

To better evaluate how PV power generation affects the metering profile at the point of delivery, four daily profiles in 2016 are selected to represent the Spring light load, Summer peak load, Fall light load, and Winter peak load cases. Those four days are picked according to daily power consumption in each of the four meteorological seasons. The typical PV power profiles in those associated months (monthly average curve as shown in Figure 5) were compared with the selected four daily profiles in the below plots.

PV generation along with other renewable generation are often treated as negative load. The BPA meter data summary in Table 1 shows that the peak load at Ashland substation is approximately 13 MW. However, it does not indicate that this substation can support the integration of as much as 13 MW PV generation because load curves and PV generation curve do not match each other the majority of the time. The four groups of plots in Table 2 demonstrate how daily power consumption patterns in different seasons at Ashland Substation change with the addition of 1 MW or 5 MW. The PV generation is the monthly average data and does not represent actual power output for any given date since the actual daily profile will typically have a significant amount of variation due to weather and operational factors. However, the plot represents a typical trend of power generation for a day in those months, and it provides a sufficient approximation of a typical output profile.

The overlaid plots in Table 2 provide an indication of how much PV generation that can be added to Ashland Substation. It can be seen that Ashland substation can readily integrate a 1 MW PV system connected to any of its feeders without causing power export. It is also found that Ashland substation is safe to have 5 MW PV system integrated to any of its feeders as long as the feeder has sufficient ampacity

for the peak generation. Power factor exceeds the 0.97 limit during the summer peak of 2016 due to a large amount of reactive power consumption, presumably by HVAC loads. This is likely to get worse with more active power generation by PV integrated into the system. A further discussion of power factor issues is discussed in Section 4.2. A similar conclusion can be made at the Mountain Avenue Substation as having capacity to integrate as much as 5 MW of PV generation to any of its feeders provided the feeder has sufficient ampacity.

Table 4 shows a group of similar plots indicating the integration of a 10 MW PV system at Ashland Substation. The combined daily curves reach a net negative region at the substation resulting in power export. Similar trends show the same result at Mountain Avenue Substation. To prevent power export, we estimate significant periods of generation curtailment would be necessary with a 10 MW system integrated into one substation. Therefore, we do not recommend the full integration of 10 MW of PV generation to either individual substation.

*Table 2: **Ashland Substation** Daily Power Profile with and without PV Generation, 1 MW or 5 MW*

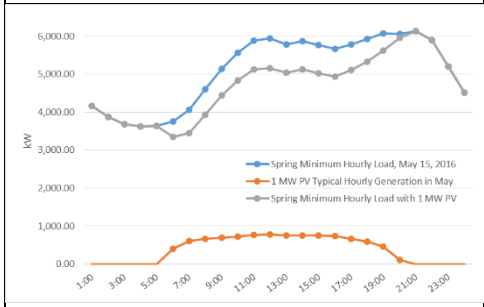
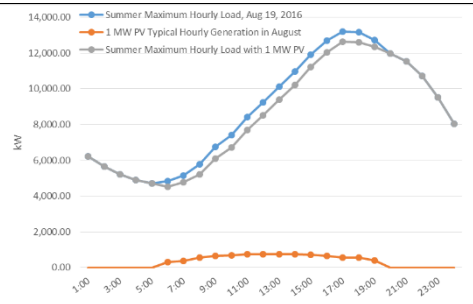
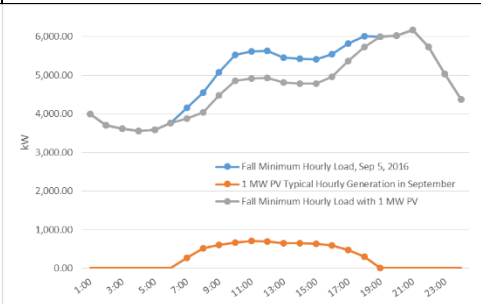
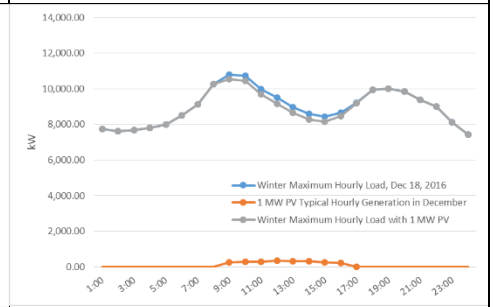
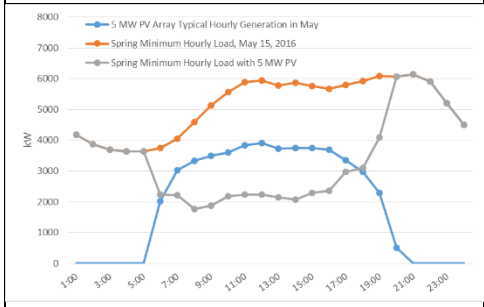
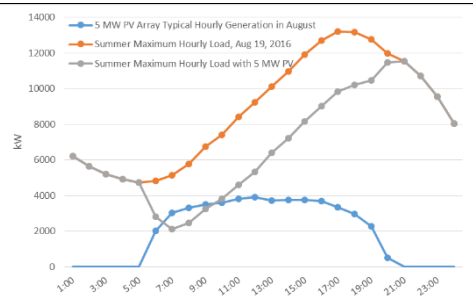
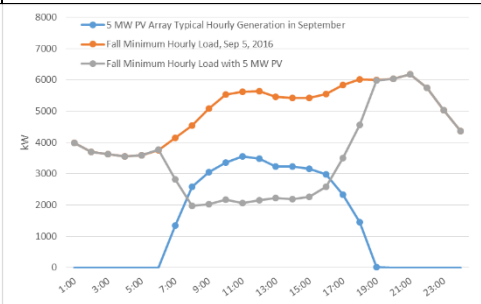
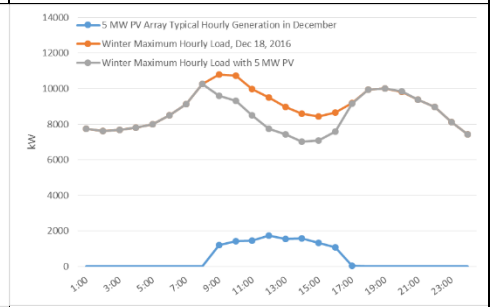
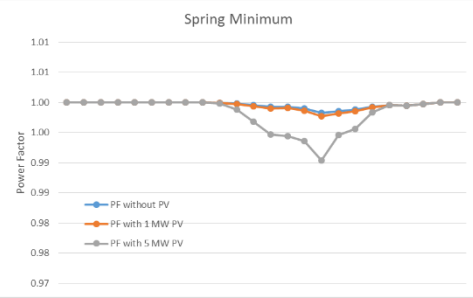
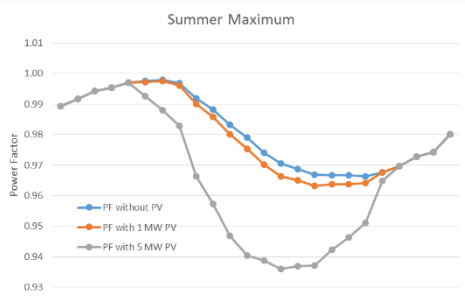
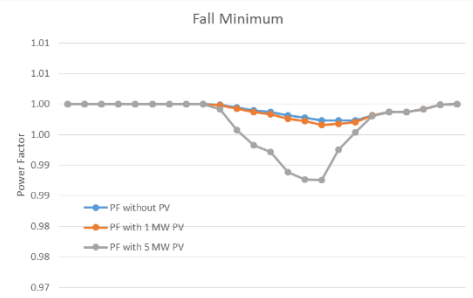
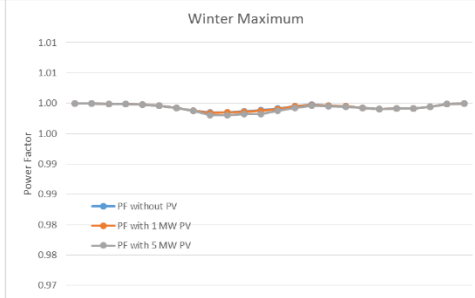
Daily Power Profile **Spring Minimum, May 15 2016** **Ashland Subsation**	**Daily Power Profile** **Summar Maximum, Aug 19 2016** **Ashland Subsation**	**Daily Power Profile** **Fall Minimum, Sep 5 2016** **Ashland Subsation**	**Daily Power Profile** **Winter Maximum, Dec 18 2016** **Ashland Subsation**
			
With 1 MW PV	With 1 MW PV	With 1 MW PV	With 1 MW PV
			
With 5 MW PV	With 5 MW PV	With 5 MW PV	With 5 MW PV
			
PF with 1 MW and 5 MW PV	PF with 1 MW and 5 MW PV	PF with 1 MW and 5 MW PV	PF with 1 MW and 5 MW PV

*Table 3: **Mountain Avenue Substation** Daily Power Profile with and without PV Generation, 1 MW or 5 MW*

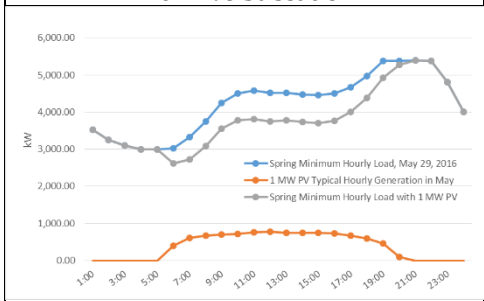
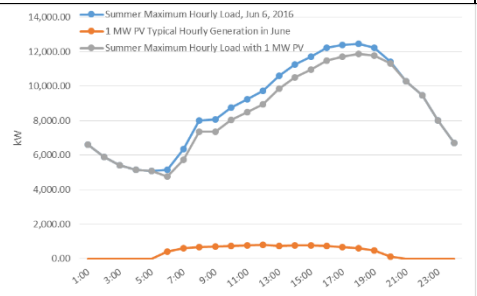
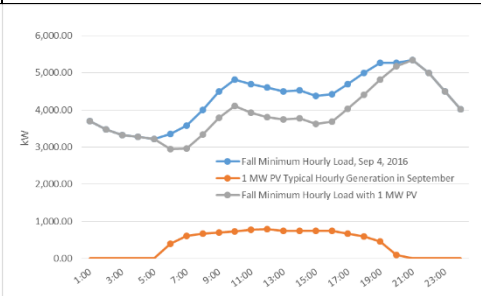
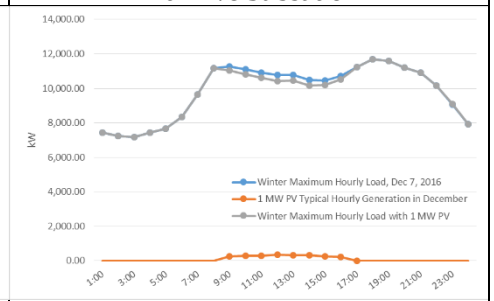
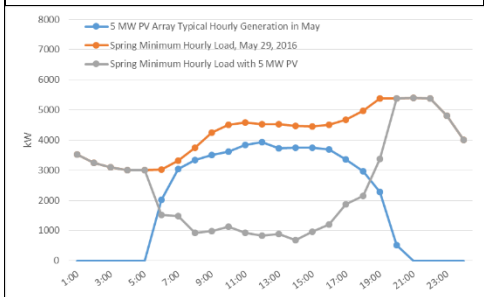
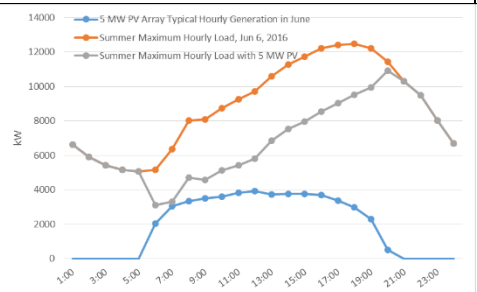
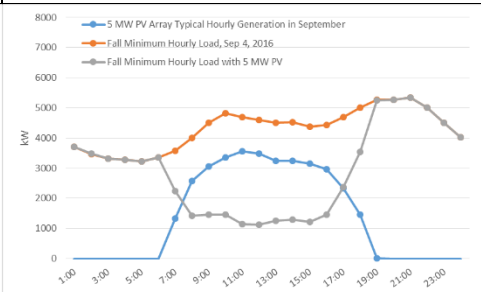
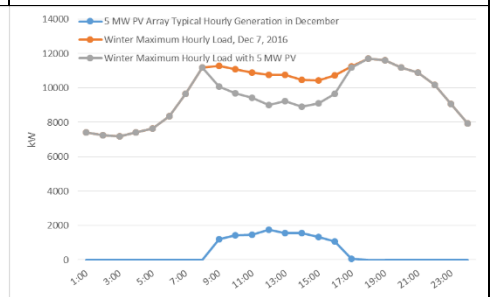
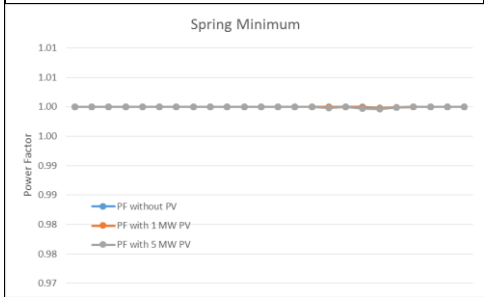
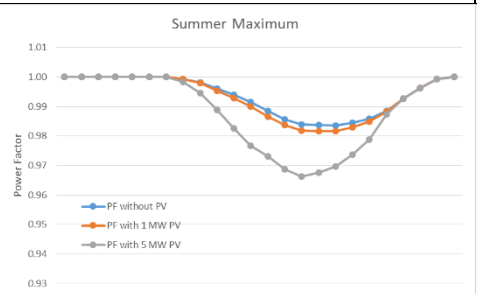
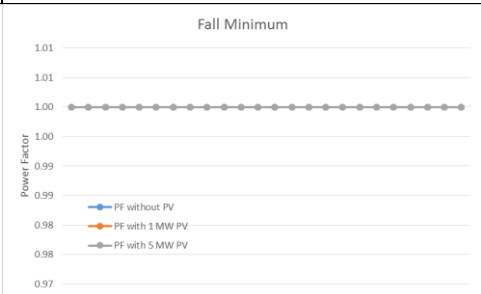
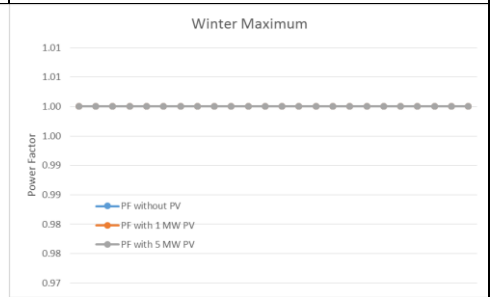
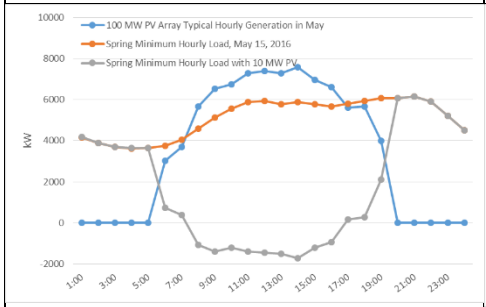
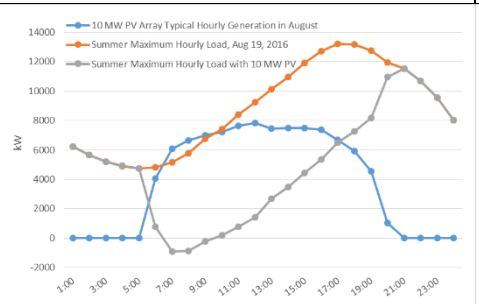
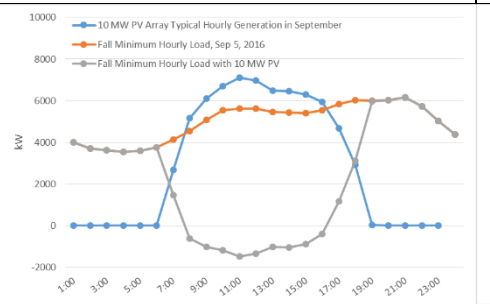
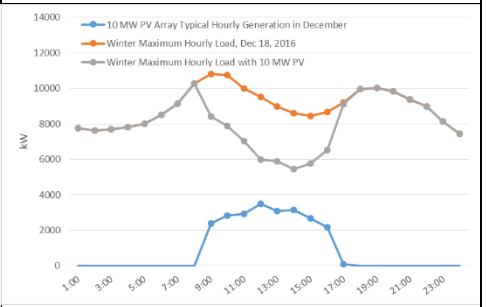
Daily Power Profile **Spring Minimum, May 29 2016** **Mtn Ave Subsation**	**Daily Power Profile** **Summar Maximum, Jun 6 2016** **Mtn Ave Subsation**	**Daily Power Profile** **Fall Minimum, Sep 4 2016** **Mtn Ave Subsation**	**Daily Power Profile** **Winter Maximum, Dec 7 2016** **Mtn Ave Subsation**
			
With 1 MW PV	With 1 MW PV	With 1 MW PV	With 1 MW PV
			
With 5 MW PV	With 5 MW PV	With 5 MW PV	With 5 MW PV
			
PF with 1 MW and 5 MW PV	PF with 1 MW and 5 MW PV	PF with 1 MW and 5 MW PV	PF with 1 MW and 5 MW PV

*Table 4: **Ashland Substation** Daily Power Profile with and without PV Generation, **10 MW***

Daily Power Profile **Spring Minimum, May 29 2016** **Mtn Ave Subsation**	**Daily Power Profile** **Summar Maximum, Jun 6 2016** **Mtn Ave Subsation**	**Daily Power Profile** **Fall Minimum, Sep 4 2016** **Mtn Ave Subsation**	**Daily Power Profile** **Winter Maximum, Dec 7 2016** **Mtn Ave Subsation**
			
With 10 MW PV	With 10 MW PV	With 10 MW PV	With 10 MW PV

3.3 Overview of options for interconnect

Based on the evaluation in Section 4 and Section 5 and geographic proximities, several locations have been identified for interconnection to the City's electric distribution system including:

- Ashland Substation
  - Business Feeder to WWTP radial tap circuit, support for ~2.5 MW.
  - N Main Feeder at Oak St/Nevada St backbone circuit, support for ~5 MW.
  - Business Feeder at Oak St/Nevada St, backbone circuit support for ~5 MW.
  - E Nevada Feeder at N Mountain Rd, backbone circuit, support for ~5 MW.
- Mountain Avenue
  - N Mountain Feeder at N Mountain Rd, backbone circuit support for ~5 MW.

Any of these interconnection points are estimated to be able to support up to approximately 2.5 MW to 5 MW as indicated. To accommodate greater generation, up to approximately 10 MW, would require generation to be split between feeders from different substations. The interconnect locations and construction requirements are summarized below and described greater detail in Section 5.0.

Option I

Strong and recommended distribution interconnection points are near the E Nevada Street and N Mountain Avenue intersection vicinity southwest of the PV point of common coupling (PCC). This location, approximately 1.1 miles from the southwest corner of the PV Imperatrice Property site, allows interconnection to two feeders and different substations. The route from the solar site could be south and west along N Mountain Avenue, then via the I-5 N Mountain Avenue overpass to the electric system interconnections.

At this location good circuit interconnections can tie into one or two existing City of Ashland electric distribution backbone circuits at the PV system primary delivery voltage (12.47 kV). The existing interconnection points available are 1) the N Mountain Feeder served from the Mountain Avenue Substation; and 2) the E Nevada Feeder served from the Ashland Substation with minor switching changes. A generated capacity of up to 5 MW could be delivered to one circuit or up to 10 MW delivered and split between both circuits. The associated PV array interconnection configuration one-line diagrams are shown in Figure 6 for 10 MW capacity and Figure 7 for 5 MW capacity.

In Figures 6, 7, and 8, the PV system is modeled as a cluster of 500 kW PV arrays and 500 kW inverters, with individual step-up transformers having built-in fusing and disconnects for isolation. This is one potential arrangement and is not intended to indicate a technical requirement or preference for the PV system arrangement. However, the arrangement does show our recommendation for the City operated interface at the PCC. As shown, we recommend two switchgear sections with a combination breaker and disconnect switch plus metering as the utility interface to the PV system.

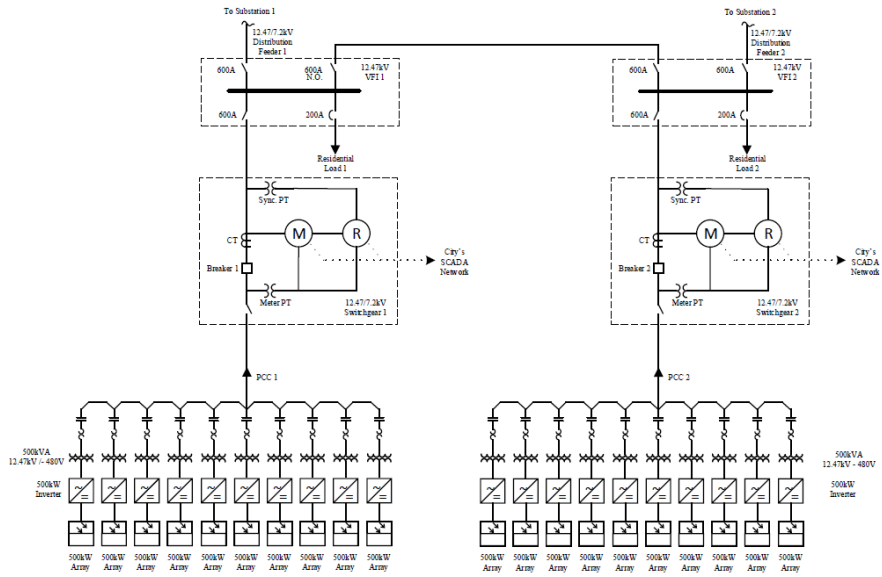


Figure 6: 10 MW PV configuration

Option II

A second interconnection location is a tie between the PV system PCC primary delivery voltage (12.47) and the existing Business Feeder or N Main Feeder served from the Ashland Substation near the intersection of Oak Street and Nevada Street. This tie location is approximately 1.5 miles from the southwest corner of the PV Imperatrice Property site and could be connected by overhead or underground construction. The route from the solar site could be south along N. Mountain Avenue, west along Eagle Mill Road and via the I-5 Eagle Mill overpass south along Oak Street to the Nevada Street interconnect. This interconnection location could accommodate one feeder interconnection up to ~5 MW, whose potential interconnection configuration is shown in Figure 7.

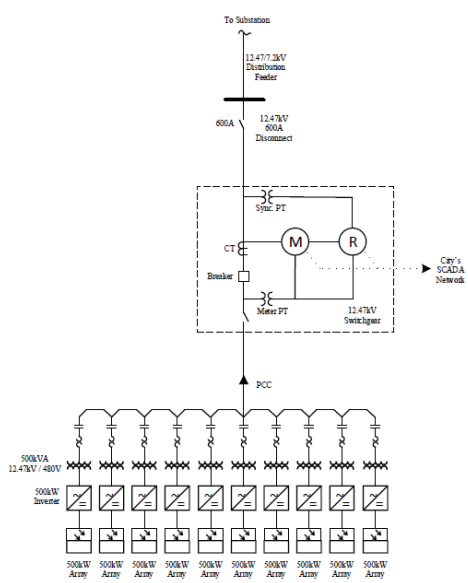


Figure 7: 5 MW PV configuration

Option III

An option to the Case II interconnection description above would be to intercept the circuit feeding the WWTP by extending the line along the Bear Creek Greenway access road from Oak Street. This option would be limited to ~2.5 MW of PV generation. Although the total distance is similar, approximately 1.4 miles, the advantage is a more accessible easement for construction along the Bear Creek Greenway access road which could include open trench and underground bore construction beneath I-5 from the generation site to the circuit interconnect. Figure 8 illustrates a possible interconnecting configuration for a 2.5 MW PV farm.

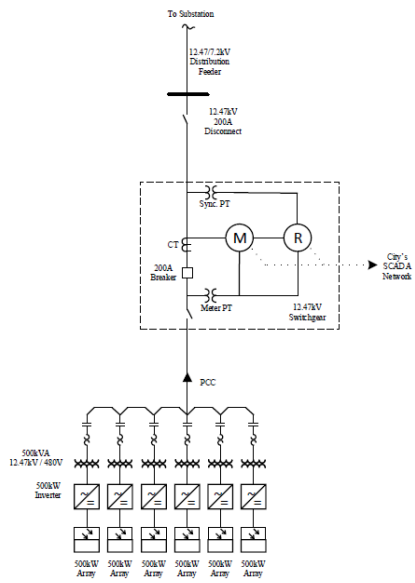


Figure 8: 2.5 MW PV configuration

4.0 ANALYSIS AND SYSTEM REQUIREMENTS

The following assumptions are consistent for all study scenarios unless otherwise noted.

- This study assumed that no major system expansion projects were implemented by the area utility since the *Electrical System 10-Year Planning Study for City of Ashland (by CVO Electrical Systems)*, in 2014.
- This study mainly focused on integrating PV generation into City of Ashland electrical distribution system as proposed by the City, and did not analyze in detail any PPL distribution or transmission interconnections options with BPA, even though they are physically closer to the potential PV sites.

For inverter-based energy resource including PV generation, the following standards and guidelines are recommended as required for the construction of this project:

IEEE Standard 929-2000, "IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems."

IEEE Standard 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems."

UL Standard 1741, "Inverters, Converters and Charge Controllers for Use in Independent Power Systems."

4.1 Power flow analysis.

This study included steady state analysis and system response analysis only. Transient and stability analysis was not conducted. A description of the procedures used to complete the analyses is presented below:

a. Development and Description of System Model

The City of Ashland distribution system model was developed in *EasyPower* analysis software according to the 2014 System Planning Study based on the information provided by the City, State, County, BPA and PacifiCorp. Two base cases used in this analysis are shown below:

- Base Case 1A – normal system configuration under peak load conditions, 2013.
- Base Case 1B – normal system configuration under light load conditions, 2013.

(Note: the 2013 model is readily available from the 2014 System Planning Study. Its peak consumption is about 43 MW, which is higher than the 2016 peak demand – 40 MW, however, the light loads for both years are almost the same. It should not make significant differences in this study.)

b. PV Generation Modeling

IEEE Standard 929-2000 requires that PV system should operate at a power factor >0.85 lagging or leading when output is >10% of rating. Modern inverter technologies typically have high efficiency and provide a nearly unit power factor (pf > 0.99) at rated power. Some inverters are able to provide reactive power compensation to the grid by advanced inverter control, to enable PV arrays to participate in grid voltage control and power factor correction. This is briefly discussed in Section 4.1. PV arrays in this study are modeled as PQG type generators and we have assumed that inverters operate at unit power factor (pf = 1) with no reactive power (var) generation. The generator was modeled at the voltage level of the point of the interconnection, and no step-up transformer (GSU) was modeled.

c. Steady State Power Flow Analysis

Power flow analysis was implemented for each of the interconnecting options that have been discussed in this study. More details about the interconnecting options can be found in Section 3.3 and Section 5.

I. Two available interconnecting points near the E Nevada Street and N Mountain Avenue intersection for up to 10 MW:
   - 5 MW, N Mountain feeder served from Mountain Avenue Substation
   - 5 MW, E Nevada feeder served from Ashland Substation

II. Two available interconnecting points near the Nevada Street and Oak Street intersection for up to 5 MW:

- 5 MW, N Main feeder served from Ashland Substation, or
- 5 MW, Business feeder served from Ashland Substation, or
- Split to the above two feeders and not exceed a total of 5 MW

III. Interconnecting with the circuit serving Waste Water Treatment Plant (WWTP) for up to 2.5 MW.

Peak load and light load base cases were evaluated regarding equipment overload and bus voltage violation under both normal and contingency conditions prior to and after the addition of the proposed PV generation. Equipment is evaluated as overloaded if load exceeds its rated capacity, and voltage violation is assessed in accordance with standards established by the American National Standard Institute (ANSI C84.1, Range A), the voltage ranges in Table 5, shown as acceptable voltage or allowable voltage drop, should be maintained throughout the City's electric system. The voltages shown are presented on a 120 volt base, however the percentages indicated apply to any voltage base, for example 12.47/7.2 kV, 480/277 V, etc., as applicable to the specific location.

Table 5: Acceptable voltage levels, City of Ashland

Facility	Acceptable Voltage or Allowable Voltage Drop (Volts)	Acceptable Percentage
Bus voltage range at substation.	122 - 126	102% - 105%
Maximum voltage drop along a distribution feeder.	8	
Voltage range at primary terminals of distribution transformers.	118 - 126	98% - 105%
Maximum voltage drop across distribution transformer and service conductors.	4	
Voltage range at customer meter.	114 - 126	95% - 105%
Voltage range at customers utilization equip.	110 - 126	92% - 105%

Power flow analysis results

Power flow study analysis results are summarized in Table 6 and Table 7. It is shown in Table 6 that no transmission facilities were overloaded and bus voltage did not exceed the acceptable limits in Table 5 in the territory of City of Ashland electrical system at normal system conditions, peak and light load cases, and prior to and after the addition of the PV generation proposed in the three interconnection options.

In the 2014 System Planning Study, system's switching flexibility during outages and abnormal conditions were evaluated. While in this study, two major contingency scenarios significant to this PV integration project are assessed. Specifically, the loss of either the Ashland Substation or Mountain Avenue Substation. Loss of Oak Knoll Substation was not considered in the assessment because the proposed interconnection options do not involve any major feeder served from Oak Knoll Substation.

The scenario involving the loss of Ashland Substation during peak load results in the transformer at Mountain Avenue Substation being heavily overloaded. There are also conditions of overloaded cables and a number of bus voltage violations. More information about this case can be found in the 2014 System Planning Study Section D. From Table 7, it can be concluded that PV generation proposed in three options can actually eliminate or reduce the overload within the system, which is reasonable since renewable energy generation are normally treated as negative load due to its varying characteristic.

Similarly during loss of Mountain Avenue Substation, the transformer at Ashland Substation is significantly overloaded prior to integrating PV generation. However, with proposed PV integration options, the transformer overload is eliminated. From this analysis we conclude that with or without full PV generation integrated to the City's distribution system, no overload or voltage violation was observed for the scenarios reviewed.

*Table 6: Power flow analysis results at **NORMAL** condition for both peak and light base cases*

Condition	Option	Interconnection Points	Peak Load (Base Case 1A)	Light Load (Base Case 1B)
Normal	Pre-Project	No PV generation integrated	No overload and voltage violation	No overload and voltage violation
	I (Up to 10 MW)	5 MW, N Mountain feeder from Mountain Avenue substation	No overload and voltage violation	No overload and voltage violation
		5 MW, E Nevada feeder served from Ashland Substation	No overload and voltage violation	No overload and voltage violation
	II (Up to 5 MW)	5 MW, N Main feeder served from Ashland Substation	No overload and voltage violation	No overload and voltage violation
		OR	---	---
		5 MW, Business feeder served from Ashland Substation	No overload and voltage violation	No overload and voltage violation
	III (Up to 2.5 MW)	2.5 MW Interconnecting with circuit serving (WWTP)	No overload and voltage violation	No overload and voltage violation

*Table 7: Power flow analysis results at **CONTINGENCY** condition (e.g., loss of substation) for both peak and light base cases*

Condition	Option	Interconnection Points	Peak Load (Base Case 1A)	Light Load (Base Case 1B)
Loss of Ashland Substation	Pre-Project	No PV generation integrated	**Significant overload** observed at Mountain Ave Substation transformer and several cables	No overload and voltage violation
	I (Up to 10 MW)	5 MW, N Mountain feeder from Mountain Avenue Substation	**No overload** at Mountain Ave Substation transformer, and **much less** overloaded cables observed.	No overload and voltage violation
		5 MW, E Nevada feeder served from Ashland Substation		
	II (Up to 5 MW)	5 MW, N Main feeder served from Ashland Substation	**Less overloaded** at Mountain Ave Substation transformer, and **less** overloaded cables observed.	No overload and voltage violation
		OR	---	---
		5 MW, Business feeder served from Ashland Substation	**Less overloaded** at Mountain Ave Substation transformer, and **less** overloaded cables observed.	No overload and voltage violation
	III (Up to 2.5 MW)	2.5 MW Interconnecting with circuit serving (WWTP)	**Less overloaded** at Mountain Ave Substation transformer, and **less** overloaded cables observed.	No overload and voltage violation

Condition	Option	Interconnection Points	Peak Load (Base Case 1A)	Light Load (Base Case 1B)
Loss of Mountain Avenue Substation	Pre-Project	No PV generation integrated	**Significant overload** observed at Ashland Substation transformer, and **no other overload and voltage violation** observed. .	No overload and voltage violation
	I (Up to 10 MW)	5 MW, N Mountain feeder from Mountain Avenue Substation	**No overload** at Ashland Substation transformer, and **no other overload and voltage violation** observed.	No overload and voltage violation
		5 MW, E Nevada feeder served from Ashland Substation		
	II (Up to 5 MW)	5 MW, N Main feeder served from Ashland Substation	**Less overloaded** at Ashland Substation transformer, and **no other overload and voltage violation** observed.	No overload and voltage violation
		OR	---	---
		5 MW, Business feeder served from Ashland Substation	**Less overloaded** at Ashland Substation transformer, and **no other overload and voltage violation** observed.	No overload and voltage violation
	III (Up to 2.5 MW)	2.5 MW Interconnecting with circuit serving (WWTP)	**Less overloaded** at Ashland Substation transformer, and **no other overload and voltage violation** observed.	No overload and voltage violation

In summary, the analysis showed that the addition of the proposed PV generation to the system would not have an adverse impact on the City of Ashland electrical distribution system in steady state power flow analysis. Instead, it could relieve the transformer overload and the potential voltage violations during peak load when there is a loss of either Ashland Substation or Mount Avenue Substation, depending on the level PV generation. In addition, there is no overload and voltage violation observed during light load conditions with or without PV generation integration.

4.2 Power factor

In October 1999 BPA began requiring compliance by its customers to adhere to a 97 percent power factor, an increase from the previous power factor requirement of 95 percent. This compliance is based on a bandwidth established at 25% reactive deadband of monthly real power demand compared to the previous 33% reactive deadband. Consumers must not only conform to a smaller power factor bandwidth but will encounter more rigid penalties for failure to comply. Poor power factors will also be penalized through a ratcheted demand penalty. This penalty will be enforced for a 12-month period, the violation month and the following 11-months after each violation. During this 12-month period BPA metering will continue to monitor for out of range power factors, and if a power factor is incurred that results in a greater penalty a new penalty will be assessed for the next 12 months. This process continues and will repeat until the power factor is in compliance with the penalty criteria at all times.

Figure 9 shows the power factor profile in a day without and with 1 MW or 5 MW PV generation for Ashland Substation, August 19, 2016. Power factor exceeds the 0.97 (97 percent) limit in summer peak

2016 due to large amounts of reactive power consumption, presumably by HVAC load, even without PV generation. This likely results in the City of Ashland having to pay an approximate $1,000 penalty change. However, with more active power generation by PV arrays integrated to the system the overall peak demand during the month is likely to be reduced. With the reactive power demand remaining the same in the system the probability of the peak reactive power exceeding the deadband value (25% of monthly demand peak) and the duration and extent of the reactive power exceeding the deadband are likely to increase.

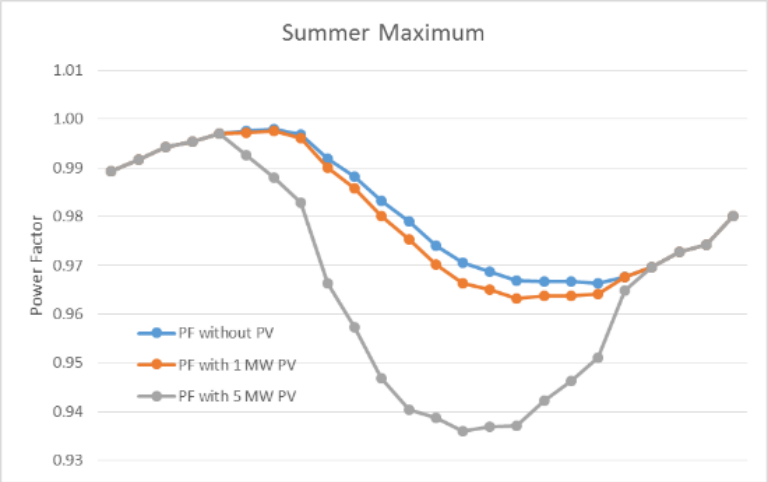


Figure 9: Power factor profile without and with 1 MW or 5 MW PV generation (Operating PF =1) for Ashland Substation, August 19, 2016

Additional considerations for power factor improving/correcting measurements might be required to avoid increased penalties. As mentioned briefly in the introduction, advanced inverter control technology could be utilized to either generate or absorb certain reactive power by adjusting the current phase angle allowing the PV system to participate grid stability control and power quality improvement. A quick example is shown in Figure 10, where the operating power factor of the inverter is set at 0.95 lagging (note, a lagging power factor on a generator is equivalent to a leading power factor on a load). This would produce approximately 30% of total kVA demand as reactive power. The supplied vars would compensate lagging loads in the system reducing the total reactive power requirement from the substation. As can be seen, with inverter power factor at 0.95, the power factor profile at the substation is improved overall. However, the morning var consumption is over compensated and results in leading overall system power factor for 5 MW PV array. Therefore, a dynamic inverter operating power factor could be developed according to an active or simulated Ashland load profile to more closely match compensation with changing load, although this advanced control could impact the system cost. There are additional methods that can help improve power factor as alternatives to the above. These methods are not described here but can be provided by OS Engineering if of interest to the City.

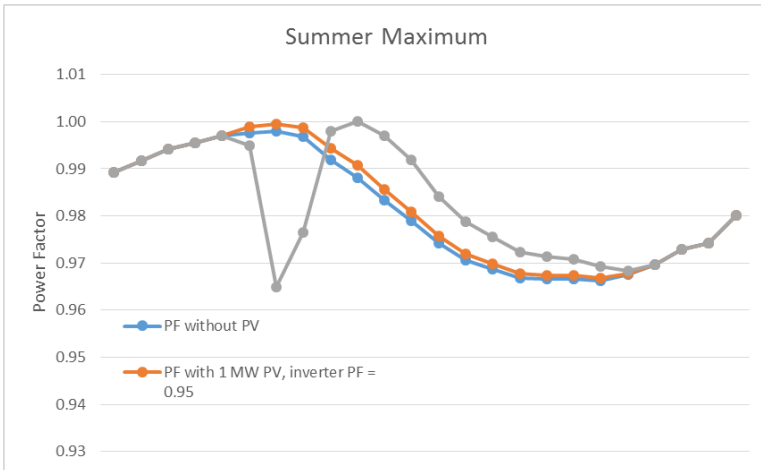


Figure 10: Power factor profile without and with 1 MW or 5 MW PV generation (Operating PF = 0.95) for Ashland Substation, August 19, 2016

4.3 Short circuit capabilities at PCC

A short circuit analysis is required to evaluate the maximum fault current level at the PCC with the addition of the proposed PV generation. This is necessary to determine the adequacy of equipment interrupting capability.

For a grid-tie PV farm, the maximum fault current at PCC consists of three parts:

- Potential fault current contribution from step-up transformers (GSU)
- Fault current contribution form inverter-based PV array
- Fault current from the system.

In this study, the PV array was modeled as a lump generator at the PCC and the GSU was not modeled. In any case, the GSU would not contribute fault current at the PCC for three-phase faults. However, if a Delta-Grounded Wye connected transformer is used as is common for generation interconnects with the PV array connected on the Delta side, the transformer will contribute zero-sequence fault current at the PCC for unbalanced faults (i.e., single-line to ground fault, line to line fault, and double-line to ground fault) due to the circulating current within Delta connection. Taking a Delta-Grounded Wye transformer with z% impedance as an example, the fault current contribution from a single-line to ground fault is $I_f = 3 * V_{LN} / (Z_a + Z_b + Z_0 + 3Z_g)$, where Z_a, Z_b, Z_0, and Zg are the positive sequence, negative sequence, zero sequence, and ground impedances. Assuming a solid ground fault with typical impedance values as an example, a single-line to ground fault is estimated to contribute approximately 1 kA from a 5 MVA transformer.

The second contribution factor from inverter-based PV array is more difficult to quantify mathematically. Unlike synchronous generators or induction motors, inverters do not have a rotating mass component; therefore, they do not develop inertia to carry fault current based on an electro-magnetic characteristics. Power electronic inverters have a much faster decaying envelope for fault currents because the devices lack predominately inductive characteristics that are associated with rotating machines. Research has been done to quantify the fault current from inverter based renewable energy generation, and the general conclusion is that inverter-based distributed energy resource provides insignificant or minimal fault

current contribution. The current industry's practice regarding fault current level assessment for setting protective relays has been to apply a "rule of thumb" of 2 times rated continuous current for distributed energy resource. Therefore, assuming the inverter ac voltage is 480V, the maximum fault current contribution at the 12.47kV PCC for a 5 MW PV array is estimated as:

$$5000 / 480 / 1.732 * 2 * (480 / 12470) = 463 \text{ A}$$

The third part is the fault current contributed by the existing distribution system, which can be readily obtained from a short circuit study using computer-based tool. The fault current levels for those proposed interconnection points, from the simulation, are in a range of 3.5 kA to 5 kA for both single-line to ground and three-phase fault.

At PCC, the equipment installed shall have a minimum interrupting rating higher than the summation of the above three parts for both three-phase fault and single-line to ground fault, which should be less than 10 kA due to the insignificance of the first two parts. Detailed calculation can be done when the actual PV technology and size are selected but the result is not expected to exceed the capabilities of existing distribution system equipment.

4.4 Harmonic requirements

Harmonics are omnipresent in electrical distribution systems and can cause a variety of problems. In both IEEE Standard 929 and IEEE Standard 1547, they refer to IEEE Standard 519-1992, which establishes limits for harmonic currents and voltages. The objective of these limits is to limit the maximum individual frequency voltage harmonic to 3% and the total harmonic distortion (THD) to 5%. It also requires that each individual harmonic to be limited to the percentages listed in Table 8. These limits apply to the Point of Common Coupling (PCC) with the utility.

Table 8: Distortion limits as recommended in IEEE Std 519-1992 for six-pulse converters

Odd harmonics	Distortion limit
3rd–9th	< 4.0%
11th – 15th	< 2.0%
17th– 21st	< 1.5%
23rd–33rd	< 0.6%
Above the 33rd	< 0.3%

Note: These requirements are for six-pulse converters and general distortion situations. IEEE Std 519-1992 gives a conversion formula for converters with pulse numbers greater than six.

4.5 Voltage requirements including flicker

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The IEEE curve in Figure 11 showing fluctuations per time period versus borderline of visibility and borderline of irritation is shown below.

The suggested operating criteria is that the magnitude of voltage flicker must be limited to less than 3% and that the frequency of flicker fluctuations be less than the border line of irritation boundary.

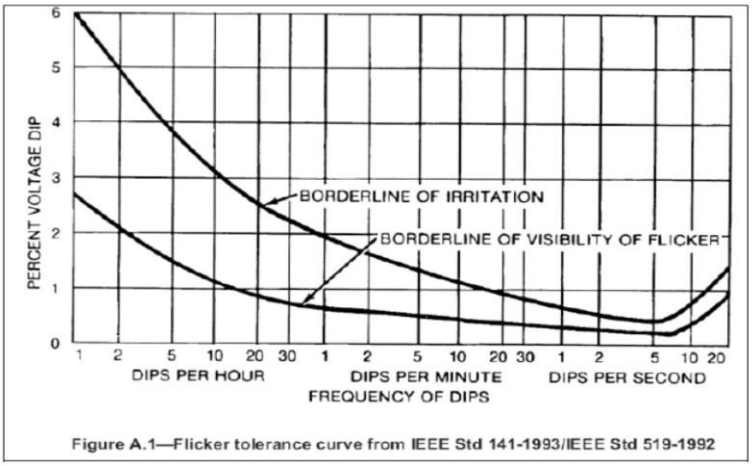


Figure 11: Flicker curve in IEEE Standard 141-193/IEEE Standard 519-1992

Clouds shading adversely impact the output of a PV system. As a cloud shadow passes over a PV system the power output will decrease due to the reduction in sunlight. The change in PV system power output on a distribution circuit may cause a fluctuation of voltage that might be seen by City of Ashland electric customers. This fluctuation would be classified as a voltage flicker.

Additionally, a rapid change in load cannot be compensated by the voltage regulation equipment installed on a distribution system. Most utilities use a typical time delay setting of 60 seconds for substation LTCs and 90 seconds for line voltage regulators. This time delay means that an LTC or voltage regulator will not respond to voltage changes until the voltage has been outside of the bandwidth for as long as 60 to 90 seconds. This helps to control “hunting” of the multiple devices trying to control the voltage.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known, the assumption is that it goes to zero and returns to full output once sunlight returns. A semi-transient simulation was implemented by switching on and off of the PV system in both peak load and light load conditions, and no significant voltage drop or flicker was noted in the system analysis.

4.6 Metering requirements

Per FERC *Standardization of Small Generator Interconnection Agreements and Procedures* and BPA *Standard Small Generator Interconnection Procedures* (Attachment N of BPA Open Access Transmission Tariff), any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with the Transmission Provider's specifications. It also would require that the Interconnection Customer's metering equipment conform to applicable industry rules and operating requirements.

For this project, metering is recommended to be installed at the 12.47kV interconnection/tie point, and shall be connected with the City’s existing SCADA network. Typically, each PV array will have an independent monitoring system, which can be tied with the existing SCADA network if desired.

4.7 Protection requirements, including disconnecting means, relaying, grounding, and prevention of islanding

Proper and safe operation of the installed PV system shall be ensured for both normal and abnormal/emergency conditions. IEEE Standard 929 lists a few import safety and protective function requirements of PV inverters.

a. Response to abnormal utility condition

- Voltage disturbance

VOLTAGE (AT PCC)		MAXIMUM TRIP TIME*
V< 60	(V<50%)	6 CYCLES
60≤V<106	(50%≤V<88%)	120 CYCLES
106≤V≤132	(88%≤V≤110%)	NORMAL OPERATION
132<V<165	(110%<V<137%)	120 CYCLES
165≤V	(137%≤V)	2 CYCLES

Note: Trip time refers to the time between the abnormal condition being applied and the inverter ceasing to energize the utility line.

- Frequency disturbance

FREQUENCY (AT PCC)	MAXIMUM TRIP TIME*
<59.3 HZ	6 CYCLES
59.3 - 60.5 HZ (NORMAL)	--
>60.5 HZ	6 CYCLES

- Islanding protection
  Most inverters are nonislanding type inverters to ensure that the inverter ceases to energize the utility line when the inverter is subjected to islanding conditions. However, it is possible that circumstances may exist on a line section that has been isolated from the utility and contains a balance of load and PV generation that would allow continued operation of the PV systems. This is not supported mostly due to its inability to supply demand distortion or non-unity power factor associated with nonlinear loads as well as the inability to resync the system. As such, transfer trips are typically utilized to ensure the generation facility is tripped off-line any time the interconnecting feeder or substation is off-line
- Reconnect after a utility disturbance
  A minimum 5 mins after continuous normal voltage and frequency have been maintained is required before reconnect PV system to the grid.

b. Direct Current Injection

The PV system should not inject dc current > 0.5% of rated inverter output current into the ac interface under either normal or abnormal operating conditions.

c. Grounding

IEEE Standard 929 does not discuss grounding issue in detail, but requires that PV system and interface equipment should be grounded in accordance with applicable codes, including NEC.

d. Manual Disconnect

Manual disconnect switch is required to provide a visible load break from the PV system when the utility determines that the PV site needed to be isolated from the utility during maintenance on utility lines. This switch would only be operated when the utility were operating in the immediate vicinity of the maintenance work. This manual disconnect is shown in all one-line sketches in Figures 6 to 8.

4.8 Control/Communication requirements (curtailment, SCADA data, etc.)

A wide array of options are available for integrating the PV system into the City's existing SCADA system. However, it is common that large scale PV system have integration packages that provide HTML based monitoring via Internet connections. The City will need to consider functional requirements for information desired to be integrated into the utilities system but, as a minimum, the following should be required:

- Transfer trip control from the associated interconnecting substation. This could be network based but dedicated hard wire, fiber, or radio is preferred to ensure reliability
- Curtailment control from the substation to force PV output reduction when substation net load becomes negative
- Active power factor control from the substation. This would allow active compensation of power factor at the substation by controlling PV phase angle similar to compensation with a synchronous generator.

5.0 SYSTEM RECOMMENDATIONS

Due to the potential adverse impact of the solar facility on power quality, as discussed in detail in Section 4, the amount of PV power generation should be limited to approximately 2.5 MW to 5 MW if interconnecting at one location to the City's electric distribution system at medium voltage (12.47 kV). If greater generated capacity is desired we recommend two interconnection locations and different substations.

Should the City determine it feasible to export all solar generated power, the PCC circuit could interconnect with PacifiCorp at the distribution or transmission voltage, but transmission interconnection would require the PV inverter voltage be stepped-up to 115 kV. This type of interconnection complicates matters since the City presently does not own any transmission facilities, does not have bi-directional metering in place to export power, all construction would be out of the Ashland service territory, and will require permitting, acquisition of easements and rights-of-way. In addition the City has an exclusive power purchase agreement with the Bonneville Power Administration (BPA), and BPA has a General Transfer Agreement with PacifiCorp for use of their transmission facilities. These agreements would require re-negotiation to modify.

Based on the evaluation, practical options for interconnection to the City's electric distribution system that are within reasonable distance from the PV property include:

- Ashland Substation
    - Business Feeder to WWTP radial tap circuit, support ~2.5 MW.

    - N Main Feeder at Oak St/Nevada St backbone circuit, support ~5 MW.
    - Business Feeder at Oak St/Nevada St, backbone circuit support ~5 MW.
    - E Nevada Feeder at N Mountain Rd, backbone circuit, support ~5 MW.
- Mountain Avenue
    - N Mountain Feeder at N Mountain Rd, backbone circuit support ~5 MW.

Any of these interconnection options can support up to approximately 2.5 MW or 5 MW as indicated, but to accommodate greater generation up to approximately 10 MW will require connection to feeders from different substations. These interconnect option routes and possible construction are described greater detail below:

5.1 Option I

Strong and recommended distribution interconnection points are near the E Nevada Street and N Mountain Avenue intersection vicinity southwest of the PV point of common coupling (PCC). This location, approximately 1.1 miles from the southwest corner of the PV Imperatrice Property site, allows interconnection to two feeders and different substations. The route from the solar site could be south and west along N Mountain Avenue, then via the I-5 N Mountain Avenue overpass to the electric system interconnections.

At this location good circuit interconnections can tie into one or two existing City of Ashland electric distribution backbone circuits at the PV system primary delivery voltage (12.47 kV). The existing interconnection points available are 1) the N Mountain Feeder served from the Mountain Avenue Substation; and 2) with minor switching changes the E Nevada Feeder served from the Ashland Substation. A generated capacity of up to 5 MW could be delivered to one circuit or up to 10 MW delivered and split between both circuits.

The PV circuit extension from the PCC could either be overhead or underground construction, but is out of the existing City of Ashland service territory. Therefore, permitting, easements and rights-of-way will need to be established as will the I-5 crossing even if bored underground.

It is suggested to accommodate a total PV system capacity of approximately 10 MW and allow for either substation to be out of service with continuous PV generation that two paralleled circuits extend from the PCCs to interconnection ties with the existing electric system. Since an existing single-phase PPL circuit presently exists along N Mountain, construction of a double circuit overhead line on the opposite side of the roadway would likely be considered unsightly and with difficulty to obtain access permits, but undergrounding the circuits, either open trench and/or bore construction, will allow paralleled circuits with little landscape disturbance through the use of vaults as needed to accommodate construction.

With these two points for PV generation delivery the electric distribution system configuration can accommodate a total of approximately 10 MW generation without concern of power export. More details can be found in Section 4.1 - power flow analysis. Should either substation be out of service for any reason, that substation's feeder circuits and load will be transferred to the substation feeders remaining in service, and will actually make it easier to disperse the total amount of PV generated energy (10 MW).

However, this option requires a major modification where the existing VFI near the E Nevada Street and N Mountain Avenue intersection resides, and it must be replaced by two VFIs to better incorporate a total generation of 10 MW. This increase the total construction cost as indicated in Section 6.

5.2 Option II

A second interconnection location is a tie between the PV system PCC primary delivery voltage (12.47) and the existing Business Feeder or N Main Feeder served from the Ashland Substation near the intersection of Oak Street and Nevada Street. This tie location is approximately 1.5 miles from the southwest corner of the PV Imperatrice Property site and could be connected by overhead or underground construction. The route from the solar site could be south along N Mountain Avenue, west along Eagle Mill Road and via the I-5 Eagle Mill overpass south along Oak Street to the Nevada Street interconnect. However, this construction is out of the existing City of Ashland service territory. Therefore, permitting, easements and rights-of-way will need to be established as will the I-5 crossing even if bored underground. In addition, both PPL transmission and distribution facilities exist along Eagle Mill Road and Oak Street so negotiations will be necessary if joint-use facility construction is a viable option. This interconnection location could accommodate one feeder interconnection up to ~5 MW.

5.3 Option III

An option to the Case II interconnection description above, but only to accommodate one ~2.5 MW interconnection, could be to intercept the circuit serving the WWTP, which would require line extension along the Bear Creek Greenway access road from Oak Street. Although the total distance is similar, approximately 1.4 miles, the advantage is more accessible easement for construction along the Bear Creek Greenway access road which could include open trench and underground bore construction beneath I-5 from the generation site to the circuit interconnect. Again some construction is out of the Ashland service territory, permitting, easements and rights-of-way will need to be established as will the I-5 crossing even if bored underground.

6.0 SYSTEM COST ESTIMATES

Cost estimates have been determined regarding the electrical interconnection. The cost estimates are in US dollars and are based upon typical construction costs in the area for previously performed similar construction. Budgetary pricing for three different capacity PV system interconnection options are summarized in Table 9. The cost estimates for utility construction to interconnect the existing City's electric system to the PV sites point of common coupling (PCC) range between $0.9M to $1.5M. They are budgetary pricing estimates and not detailed take-off construction estimates. Each estimate includes some pricing related to the City's electric staff and administration requirements considered necessary for the PV projects interconnection. The City may want to evaluate these items for accuracy and comment or edit as necessary.

In addition, the estimates show pricing for miscellaneous contractor services which include: permitting, easement and rights-of-way acquisition, survey, erosion sedimentation control (ESC) requirements applicable for the region and any necessary traffic control planning (TCP).

Table 9: Construction Cost Estimate, City of Ashland

	Option I	Option II	Option III
Cost	$1,481,877	$963,707	$876,420

The estimated total cost for the required upgrades using Option I is $1.5M, which is the highest among the three options. This is because Option I as described previously is to integrate a total of 10 MW. It requires two switchgear (one for each 5 MW array) and involves replacing an existing VFI by two VFIs near the E Nevada Street and N Mountain Avenue intersection, while Option II and Option III only need one switchgear and one VFI.

Detailed cost breakdown (i.e., sectionalizing equipment, vaults, conductors, fiber, conduit, connectors, modification, contingency, etc.) can be found in the following three sheets:

- CASE I: PV PCC – ELECTRICAL SYSTEM INTERCONNECT, PV SYSTEM TOTAL GNERATION – 10 MW
- CASE II: PV PCC – ELECTRICAL SYSTEM INTERCONNECT, PV SYSTEM TOTAL GNERATION – 5 MW
- CASE III: PV PCC – ELECTRICAL SYSTEM INTERCONNECT, PV SYSTEM TOTAL GNERATION – 2.5 MW

ASHLAND ELECTRIC CONSTRUCTION COST ESTIMATE

CASE I - PV PCC - ELECTRIC SYSTEM INTERCONNECT
PV SYSTEM TOTAL GENERATION - 10 MW

January 2017 - Work Order #534.100

Description	Quantity	Installed Cost/Unit	WO 534.100 Developer Cost	WO 534.100 CoA Cost
Sectionalizing Equipment:				
PV-PCC-SWGR (3Ø-rly-mtr-SCADA)[1]	2	$125,000	$250,000	$0
VFI (3Ø, 4-way)[1]	2	$32,000	$64,000	$0
VR PadMounted (3Ø, 250-kVA)[1]	2	$36,000	$72,000	$0
Vaults:				
UV-5106-LA[1] (splice vaults)	2	$8,000	$16,000	$0
UV-810-LA[1] (swgr + VRs)	4	$8,000	$32,000	$0
UV-444-LA[1] (comm)	4	$3,200	$12,800	$0
Conductors:				
750-kcmil AL, EPR, 15-kV[1]	0	$11.50 /Ft	$0	$0
500-kcmil AL, EPR, 15-kV[1]	0	$9.25 /Ft	$0	$0
350-kcmil AL, EPR, 15-kV[1]	33480	$7.00 /Ft	$234,360	$0
#4/0 AWG, AL, EPR, 15-kV[1]	0	$5.00 /Ft	$0	$0
Fiber System				
Fiber cable/equipment[1]	1	Lot	$15,000	$0
Conduit Installed				
6" PVC Sch. 40[1] (qty 2)	5020	60 /Ft	$301,200	$0
4" PVC Sch. 40[1]	0	0 /Ft	$0	$0
3" PVC Sch. 40[1]	0	0 /Ft	$0	$0
2" PVC Sch. 40[1] (qty 1)	5020	20 /Ft	$100,400	$0
2.5" Flex Conduit[1]	0	0 /Ft	$0	$0
Bore I-5 Xing (2-6"+1-2")[1]	380	140 /Ft	$53,200	$0
Cable Connectors				
3-Way Junction Module[1]	0	$750	$0	$0
4-Way Junction Module[1]	0	$1,000	$0	$0
Separable Splice (600-Amp)[1]	12	$1,000	$12,000	$0
Elbows (600-Amp)[1]	42	$350	$14,700	$0
Elbows (200-Amp)[1]	6	$175	$1,050	$0
Deadbreak Protective Cap[1]	0	$50	$0	$0
Fault-Current Indicator[1]	12	$150	$1,800	$0
Fused Elbow (200-Amp)[1]	0	$375	$0	$0
Metering and CT's[1]	0	Lot	$0	$0
Miscellaneous Connectors[1]	1	Lot	$2,500	$0
Miscellaneous Contingency[1] (5%)			$59,151	$0
Contractor Mob/Demob/Insur/Survey/ESC/TCP[2]	1	Services	$50,000	$0
Permitting-Easements-Rights-of-Way[2]	1	Services	$50,000	$0
Energization[5]	1	Services	$5,000	$0
Administrative[5] (10%)	1	Lot	$134,716	$0
		TOTAL COST ESTIMATE:	**$1,481,877**	**$0**

Notes:

[1] This item furnished and installed by the developer, unless Contract Documents state otherwise.
[2] These services provided by developer.
[3] This item furnished by City and installed by the developer, cost includes material and wire make-up.
[4] This item furnished and installed by City, full cost is included in this estimate.
[5] This effort includes City crew inspection, voltage check and energization coordination with developer.
[5] This item includes City administration, engineering, design and inspection.

[√ - typ rural pri const ~$120/ft multiple conduit, open trench excavation/backfill/compaction/restoration; assume 3 conduits/cables @$135/ft x 5600' = $0.8M + maj equip @$400k + admin/misc @15% = $1.4M]

ASHLAND ELECTRIC CONSTRUCTION COST ESTIMATE

CASE II - PV PCC - ELECTRIC SYSTEM INTERCONNECT
PV SYSTEM TOTAL GENERATION - 5 MW

January 2017 - Work Order #534.100

Description	Quantity	Installed Cost/Unit	WO 534.100 Developer Cost	WO 534.100 CoA Cost
Sectionalizing Equipment:				
PV-PCC-SWGR (3Ø-rly-mtr-SCADA)[1]	1	$125,000	$125,000	$0
VFI (3Ø, 4-way)[1]	1	$32,000	$32,000	$0
VR PadMounted (3Ø, 250-kVA)[1]	1	$36,000	$36,000	$0
Vaults:				
UV-5106-LA[1] (splice vaults)	2	$8,000	$16,000	$0
UV-810-LA[1] (swgr + VRs)	2	$8,000	$16,000	$0
UV-444-LA[1] (comm)	4	$3,200	$12,800	$0
Conductors:				
750-kcmil AL, EPR, 15-kV[1]	0	$11.50 /Ft	$0	$0
500-kcmil AL, EPR, 15-kV[1]	0	$9.25 /Ft	$0	$0
350-kcmil AL, EPR, 15-kV[1]	16740	$7.00 /Ft	$117,180	$0
#4/0 AWG, AL, EPR, 15-kV[1]	0	$5.00 /Ft	$0	$0
Fiber System				
Fiber cable/equipment[1]	1	Lot	$15,000	$0
Conduit Installed				
6" PVC Sch. 40[1] (qty 1)	5020	40 /Ft	$200,800	$0
4" PVC Sch. 40[1]	0	0 /Ft	$0	$0
3" PVC Sch. 40[1]	0	0 /Ft	$0	$0
2" PVC Sch. 40[1] (qty 1)	5020	20 /Ft	$100,400	$0
2.5" Flex Conduit[1]	0	0 /Ft	$0	$0
Bore I-5 Xing (1-6"+1-2")[1]	380	130 /Ft	$49,400	$0
Cable Connectors				
3-Way Junction Module[1]	0	$750	$0	$0
4-Way Junction Module[1]	0	$1,000	$0	$0
Separable Splice (600-Amp)[1]	6	$1,000	$6,000	$0
Elbows (600-Amp)[1]	18	$350	$6,300	$0
Elbows (200-Amp)[1]	0	$175	$0	$0
Deadbreak Protective Cap[1]	0	$50	$0	$0
Fault-Current Indicator[1]	6	$150	$900	$0
Fused Elbow (200-Amp)[1]	0	$375	$0	$0
Metering and CT's[1]	0	Lot	$0	$0
Miscellaneous Connectors[1]	1	Lot	$2,500	$0
Miscellaneous Contingency[1] (5%)			$36,814	$0
Contractor Mob/Demob/Insur/Survey/ESC/TCP[2]	1	Services	$50,000	$0
Permitting-Easements-Rights-of-Way[2]	1	Services	$50,000	$0
Energization[5]	1	Services	$3,000	$0
Administrative[5] (10%)	1	Lot	$87,609	$0
		TOTAL COST ESTIMATE:	**$963,703**	**$0**

Notes:

[1] This item furnished and installed by the developer, unless Contract Documents state otherwise.
[2] These services provided by developer.
[3] This item furnished by City and installed by the developer, cost includes material and wire make-up.
[4] This item furnished and installed by City, full cost is included in this estimate.
[5] This effort includes City crew inspection, voltage check and energization coordination with developer.
[5] This item includes City administration, engineering, design and inspection.

ASHLAND ELECTRIC CONSTRUCTION COST ESTIMATE

CASE III - PV PCC - ELECTRIC SYSTEM INTERCONNECT
PV SYSTEM TOTAL GENERATION - 2.5 MW

January 2017 - Work Order #534.100

Description	Quantity	Installed Cost/Unit	WO 534.100 Developer Cost	WO 534.100 CoA Cost
Sectionalizing Equipment:				
PV-PCC-SWGR (3Ø-rly-mtr-SCADA)[1]	1	$110,000	$110,000	$0
VFI (3Ø, 4-way)[1]	1	$32,000	$32,000	$0
VR PadMounted (3Ø, 114-kVA)[1]	1	$30,000	$30,000	$0
Vaults:				
UV-5106-LA[1] (splice vaults)	2	$8,000	$16,000	$0
UV-810-LA[1] (swgr + VRs)	2	$8,000	$16,000	$0
UV-444-LA[1] (comm)	4	$3,200	$12,800	$0
Conductors:				
750-kcmil AL, EPR, 15-kV[1]	0	$11.50 /Ft	$0	$0
500-kcmil AL, EPR, 15-kV[1]	0	$9.25 /Ft	$0	$0
350-kcmil AL, EPR, 15-kV[1]	0	$7.00 /Ft	$0	$0
#1/0 AWG, AL, EPR, 15-kV[1]	16740	$4.00 /Ft	$66,960	$0
Fiber System				
Fiber cable/equipment[1]	1	Lot	$15,000	$0
Conduit Installed				
6" PVC Sch. 40[1] (qty 1)	0	40 /Ft	$0	$0
4" PVC Sch. 40[1]	5020	40 /Ft	$200,800	$0
3" PVC Sch. 40[1]	0	0 /Ft	$0	$0
2" PVC Sch. 40[1] (qty 1)	5020	20 /Ft	$100,400	$0
2.5" Flex Conduit[1]	0	0 /Ft	$0	$0
Bore I-5 Xing (1-4"+1-2")[1]	380	130 /Ft	$49,400	$0
Cable Connectors				
3-Way Junction Module[1]	0	$750	$0	$0
4-Way Junction Module[1]	0	$1,000	$0	$0
Separable Splice (200-Amp)[1]	6	$800	$4,800	$0
Elbows (600-Amp)[1]	0	$350	$0	$0
Elbows (200-Amp)[1]	18	$175	$3,150	$0
Deadbreak Protective Cap[1]	0	$50	$0	$0
Fault-Current Indicator[1]	6	$150	$900	$0
Fused Elbow (200-Amp)[1]	0	$375	$0	$0
Metering and CT's[1]	0	Lot	$0	$0
Miscellaneous Connectors[1]	1	Lot	$2,500	$0
Miscellaneous Contingency[1] (5%)			$33,036	$0
Contractor Mob/Demob/Insur/Survey/ESC/TCP[2]	1	Services	$50,000	$0
Permitting-Easements-Rights-of-Way[2]	1	Services	$50,000	$0
Energization[5]	1	Services	$3,000	$0
Administrative[5] (10%)	1	Lot	$79,675	$0
		TOTAL COST ESTIMATE:	**$876,420**	**$0**

Notes:

[1] This item furnished and installed by the developer, unless Contract Documents state otherwise.
[2] These services provided by developer.
[3] This item furnished by City and installed by the developer, cost includes material and wire make-up.
[4] This item furnished and installed by City, full cost is included in this estimate.
[5] This effort includes City crew inspection, voltage check and energization coordination with developer.
[5] This item includes City administration, engineering, design and inspection.

In closing we appreciate the opportunity to provide engineering services to the City of Ashland. If there are any concerns or questions with the information presented herein please contact us at your convenience. In addition, we would gladly be available to meet and discuss our findings.

CITY OF ASHLAND

Council Communication
November 15, 2016, Business Meeting

Discussion of policy questions to be addressed regarding the 10x20 Ordinance

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FROM:
Dave Kanner, city administrator, dave.kanner@ashland.or.us
Mark Holden, director, Ashland Electric Utility, mark.holden@ashland.or.us
Adam Hanks, management analyst (manager of Conservation Division and staff to the ad hoc Climate and Energy Action Plan Committee), adam.hanks@ashland.or.us

SUMMARY
This is a discussion of potential answers to a list of policy questions that need to be addressed in order to conduct feasibility and cost analyses for implementation of the 10x20 ordinance. These questions were initially developed by City staff and supplemented by the ad hoc Climate and Energy Action Plan Committee.

BACKGROUND AND POLICY IMPLICATIONS:
On April 26, 2016, a group of local citizens filed an initiative petition to refer to the ballot an ordinance titled "An Ordinance Requiring the City of Ashland to Produce 10 Percent of the Electricity Used in the City from New, Local and Clean Resource by the Year 2020." On August 10, the City Recorder verified that the petitioners had gathered enough signatures to refer the ordinance to the ballot. At its August 16 business meeting, the Council agreed to accept the ordinance rather than referring it, and adopted the ordinance on first and second reading at its September 6 meeting.

Before the ordinance can be implemented and the fiscal implications of various implementation scenarios can be determined, many clarifying questions must be answered. This includes not just definitional and ordinance content questions, but basic policy questions that relate to the goals of the ordinance, the juxtaposition of the ordinance with state-mandated renewable portfolio standards and the relationship of the ordinance to the still-in-progress Climate and Energy Action Plan.

Given the above, staff assembled a list of questions -- both policy questions and clarifying questions -- that it feels must be answered to determine how and at what cost the ordinance will be implemented. This list was shared with the Climate and Energy Action Plan ad hoc committee for the purpose of having the committee add other questions that staff may not have considered. When these questions were reviewed with the Council at its November 1 business meeting, the Council requested that a discussion of the policy questions be scheduled for this meeting.

The policy questions developed by staff and the ad hoc committee are as follows:
1. What are the primary objectives of the ordinance and in what order of priority?
    a. Independence from the regional electricity grid?
    b. Emergency access to electricity due to regional grid failure?
    c. Carbon mitigation locally?

d. Carbon mitigation regionally?

2. Should the ordinance be developed to utilize the State of Oregon Renewable Portfolio Standards (RPS) structure as defined in Oregon Revised Statutes as the template and model to implement the 10 by 20 ordinance?
3. Should the ordinance be developed with its own set of definitions, standards and eligible resources separate from the State RPS structure?
4. If separate from the State RPS, should the local supplemental RPS include or exclude the state RPS mandates, i.e. cumulative or additive?
5. Should the clarified goals and intent of the ordinance be incorporated into the Climate and Energy Action Plan (CEAP) or remain as a stand-along ordinance?
6. How does the ordinance fit in with the other goals of the CEAP? Should it take precedence both financially and in priority or should it be reviewed and evaluated equally with the other strategies and actions within the plan?
7. What would the impacts of this ordinance be on low income residents/customers in our community?
8. How does the ordinance impact the existing BPA contract?
9. What is the total renewable energy potential in the City?
10. How would implementation of this ordinance impact future GHG emissions as defined and calculated in the City's GHG Inventory?

Attached to this Council communication is background information and staff's perspective on the answers to some of these questions to aid in the Council discussion.

In addition to addressing these policy questions, staff will develop alternative answers to the ordinance content questions and with those answers, assemble a variety of scenarios for achieving the goal of the ordinance. Staff will then return to the Council to have it review, amend or add to these scenarios, after which staff will hire an objective third-party consultant to evaluate the feasibility and cost of each of the scenarios. With this information in hand, the Council can then either amend the ordinance or adopt an implementing resolution and the City can begin the work of actual implementation.

COUNCIL GOALS SUPPORTED:

21. Be proactive in using best practices in infrastructure management and modernization.

FISCAL IMPLICATIONS:

None

STAFF RECOMMENDATION AND REQUESTED ACTION:

N/A. This item is for discussion only

SUGGESTED MOTION:

N/A. This item is for discussion only

ATTACHMENTS:

10x20 ordinance policy questions for Council
Renewable Portfolio Standards fact sheet
Ordinance No. 3134

CITY OF ASHLAND

10% by 2020 Ordinance Questions for Council

Policy Questions

1. **Q - What are the primary objectives of the ordinance and in what order of priority?**

The answer to this question impacts how we define "local." If the goal is to reduce the carbon emissions of the regional grid, then new generation capacity – if that is how the 10% is to be achieved – can be built anywhere that is served by the regional grid. However, if the objective is energy independence or access to emergency power, then new generation capacity must be built in a location that allows direct connection to the City's distribution system. Objectives for Council to consider include the following:

1) **Reduction of carbon emissions**
   Local GHG Calculation - Greenhouse gas (GHG) inventory protocol utilizes the regional energy mix to calculate a community's carbon emissions in the energy sector. Any action that reduces total net electric consumption locally reduces the carbon emissions equivalent to the regional grid. Generation of 10 percent of local annual consumption is roughly equivalent to mitigation of just over 5,000 metric tons of CO2.

   Regional GHG Calculation – GHG Inventory protocol utilizes the regional energy mix rather than the City's purchased power contract to calculate net carbon emissions. While the 10% local generation reduces the City's contractual (predominantly hydro) resource commitment (although not what we are required to purchase from the BPA), the benefit accrues to the regional grid, as this action would "free up" hydro resources to be used elsewhere and incrementally avoid future potential high carbon generation.

   GHG Calculation caveat – If 10 percent local generation utilizes Renewable Energy Credits (RECs) as part of the financing mechanism (common practice), the carbon mitigation described above would apply to the City's GHG inventory only if the City were to retain/obtain ownership of the RECs. If the City were to contract with a third party to build new renewable energy generation facilities and the contractor kept the RECs (again, common practice), the City would receive no credit for carbon reduction.

2) **Independence from the regional electricity grid** –Local generation of 10 percent of electricity provides no functional independence from the larger regional grid. Any intermittent sources of electricity require battery storage. Additionally, grid independence requires the ability to generate, store and distribute peak load levels of electricity, which can be over twice the average daily capacity resulting in total infrastructure costs far exceeding the community's financial abilities.

   However, incremental levels of local generation do provide benefits such as:

Diversification of local energy sources – The City currently has one predominant supplier of electricity. While BPA has been and is expected to continue to be a reliable source of cost effective, low carbon electricity, local generation provides some level of insulation from potential unforeseen financial, regulatory or environmental risks of that sole source provider.

Reduction in transmission costs and associated energy losses – The delivery of electricity requires transmission from its source to its destination, resulting in costs for the use of the transmission lines of various other utilities owning and maintaining transmission grid infrastructure between source and destination. Additionally, the movement of energy along the transmission lines results in electricity being consumed in the delivery process, called line loss. This loss is typically between 4-7% of total electricity delivered. Local generation eliminates the transmission and line loss costs associated with delivery into the local grid.

3) **Emergency access to electricity due to regional grid failure** - While regional grid failures are exceedingly rare, significant natural disasters could impact the regional grid and cause power outages locally. If deemed a priority, solutions to regionally caused power outages would be considerably different than standard grid supported local electricity generation. Generation facilities would need to be matched to local community emergency shelter locations. Generation facilities would also need to be supported with battery storage infrastructure and be designed to connect to the facility's electrical distribution system to provide power to the building(s). While potentially feasible, a completely different cost/benefit analysis and project design would be required to meet this particular objective.

2. **Q - Should the ordinance be developed with its own set of definitions, standards and eligible resources separate from the State Renewable Portfolio Standards (RPS) structure?**

   A – The RPS structure is state law and the City is required to comply with that law irrespective of the 10x20 ordinance. Certain elements of the RPS, if adopted in whole as part of the 10x20 ordinance, would effectively negate the ordinance. However, the definitions contained in the RPS provide guidance for definitions that might become part of the ordinance. To the extent practical, staff recommends that the ordinance be as consistent as possible with the Oregon RPS definitions and structure, with exceptions being clearly justified and defined.

3. **Q - If separate from the State RPS, should the local supplemental RPS include or exclude the state RPS mandates, i.e. cumulative or additive?**

   A – This is likely to be reviewed as part of the third party consultant scenario analysis. The ultimate ordinance language and actions taken to meet the new requirements may or may not have any bearing on the State RPS standards that the City is required to meet.

4. **Q - Should the clarified goals and intent of the ordinance be incorporated into the Climate and Energy Action Plan (CEAP) or remain as a stand-along ordinance?**

   A – The CEAP Committee voted to include a reference to the 10x20 ordinance in the draft CEAP. Due to the timing and yet-to-be-clarified policy issues of the ordinance, the committee did not vote to incorporate the ordinance directly into any particular action item, but recognized its place within several focus area strategies with the plan.

5. **Q - How does the ordinance fit in with the other goals of the CEAP? Should it take precedence both financially and in priority or should it be reviewed and evaluated equally with the other strategies and actions within the plan?**

   A – Again, the timing and unknown policy issues of the ordinance prevented the committee from being able to directly compare the 10x20 action with other actions being developed in the CEAP, both in terms of potential carbon mitigation and cost per unit of carbon mitigated versus other potential actions in the plan. The committee did recognize and note that the 10x20 initiative does generally fit as a potential implementing action within several strategy statements in the Buildings and Energy focus area of the plan document.

6. **Q - What would the impacts of this ordinance be on low income residents/customers in our community?**

   A - It is difficult to anticipate the impacts on low income residents/customers until the details of ordinance implementation and effects on utility energy costs are determined. As discussed in the recent study session on the cost of service study, low income does not mean low use. In fact, low income customers are often higher usage customers because they are less able to afford weatherization projects and energy efficient appliances. An increase to the consumption component of electric rates would clearly more severely impact high usage customers than low usage customers. The Council could, as a matter of policy, expand or enhance the Low Income Energy Assistance Program. However, doing so would require additional money from some source, which would presumably be all other ratepayers who do not qualify for that program.

7. **Q - How does the ordinance impact the existing BPA contract?**

   The ordinance, if implemented through a generation resource, will displace Tier 1 BPA power and will trigger the "take or pay" provision of the BPA contract. As a result, the City will still be responsible for the BPA charges (energy and transmission) that are displaced by the ordinance. Total BPA charges will remain relatively unchanged.

8. **Q - What is the total renewable energy potential in the City?**

A – While there are no complete data sets that would provide this answer, the City GIS staff has worked with the Energy Conservation Division to develop an online solar site assessment tool to provide individual homeowners with a snapshot of the solar potential for their home or business. Staff is working on calculating an aggregate number to provide an estimate of the total solar (not total renewable) resource based on the existing roof systems in Ashland. This will not include the potential ground mount solar system opportunities, nor micro-hydro, wind or other renewable energy potential.

The City did participate with Rogue Valley Council of Governments in 2010-11 in the development of a Renewable Energy Assessment (REA) for Jackson and Josephine County. The project inventoried the renewable energy potential in the two-county boundary and was completed by The Good Company (same consultant that did the City's Greenhouse Gas Inventory). Those results indicated that, by a significant degree, energy efficiency had the highest renewable energy potential in the region and also at the lowest cost. This report is available on the City's website at www.ashland.or.uw/rea

9. Q - How would implementation of this ordinance impact future GHG emissions as defined and calculated in the City's GHG Inventory

A **–** See question #1 – local generation of 10% of the total electric consumption within the City of Ashland would result in the mitigation of just over 5,000 metric tons of CO2 equivalent.

Summary of Oregon's Renewable Portfolio Standard

The Renewable Portfolio Standard (RPS) requires that all utilities and electricity service suppliers (ESSs)[1] serving Oregon load must sell a percentage of their electricity from qualifying renewable energy sources. The percentage of qualifying electricity that must be included varies over time, with all utilities and ESSs obligated to include some renewable resources in their power portfolio by 2025.

For current information on Oregon eligible facilities, please visit www.oregon-rps.org.

Table 1 summarizes the percentage targets for the RPS.

Table 1: Summary of RPS Targets and Timelines

RPS obligations on all utilities and electricity service suppliers						
	Percent of Oregon's Total Retail Electric Sales	**Utilities[2] and ESSs**	**Applicable Targets in Year:**			
			2011	**2015**	**2020**	**2025**
Large Utilities	Three percent or more	Portland General Electric, PacifiCorp, Eugene Water & Electric Board	**5%**	**15%**	**20%**	**25%**
Small Utilities	At least one and a half percent but less than three percent	Central Lincoln PUD, Idaho Power, McMinnville W&L, Clatskanie PUD, Springfield Utility Board, Umatilla Electric Cooperative	**No Interim Targets**			**10%**
	Below one and a half percent	All other utilities (31 consumer-owned utilities)				**5%**
Electricity Service Suppliers (ESSs)	Any sales in Oregon	Any Electricity Service Supplier (ESS)	If an ESS sells electricity in the service area of more than one utility its targets may calculated as an aggregate of electricity sold in its territory.			

Conditional Targets

There are two conditions when a small utility would be required to meet the large utility standard regardless of their size if purchase coal power (ORS 469A.055 (4) or if they annex utility territory (ORS 469A.0555 (5)). In the case that a small utility's load increases to exceed three percent of the state load for a period of three consecutive years they would also be subject to the standard as a large utility (ORS 469A.052 (2).

[1] Oregon's deregulation law allows non-utility power sellers (called ESSs) to sell power to non-residential customers. Currently, this applies only to Portland General Electric and PacifiCorp service territory.
[2] Based on 2010 Oregon Public Utility Commission (OPUC) utility data. See the Statistics Book: http://www.puc.state.or.us/puc/Pages/Oregon_Utility_Statistics_Book.aspx.

Exemptions to RPS Targets
Utilities are not required to comply with an RPS target to the extent that compliance will:

- Lead to a utility expending more than four percent of its electricity-related annual revenue requirement in order to comply with the RPS.
- Displace firm Federal Base System (FBS) preference power rights from the Bonneville Power Administration (BPA) for a consumer-owned utility.
- Result in acquisition of power resources in excess of their load requirements in a given compliance year.
- Result in the displacement of a non-fossil-fueled power resource.
- Unavoidably displace hydropower contracts with Mid-Columbia River dams until such a time when those contracts cannot be renewed or replaced.

Eligible Resources and Facility Eligibility Date

Qualifying electricity for Oregon's RPS must be derived from the sources and types of facilities listed in Table 2. Qualifying facilities must also be located within the Western Electricity Coordinating Council's territory. Note that where multiple fuels are used to power a generating facility only the proportion of output that uses qualifying resources can count toward the RPS.

Table 2: Eligible Resource Types Based on Facility Operational Date

From Generating Facilities in Operation Before January 1, 1995	From Generating Facilities That Became Operational On or After January 1, 1995
Up to 90 average megawatts (aMW) per utility per compliance year of low-impact certified hydropower, capped at 50 aMW owned by an Oregon utility and 40 aMW not owned by a utility but located in Oregon.	Hydropower, if located outside of certain state, federal, or NW Power & Conservation Council protected water areas.
	Wind
	Solar Photovoltaic and Electricity from Solar Thermal
	Wave, Tidal, and Ocean Thermal
	Geothermal
The increment of improvement from efficiency upgrades made to hydropower facilities, although if the improvement is to a federally-owned BPA facility only Oregon's share of the generation can qualify.	Biomass and biomass byproducts; including but not limited to organic waste, spent pulping liquor, woody debris or hardwoods as defined by harvesting criteria, agricultural wastes, dedicated energy crops and biogas from digesters, organic matter, wastewater, and landfill gas. Under certain conditions, municipal solid waste may qualify. The burning of biomass treated with chemical preservatives disqualifies any biomass resource.
The increment of improvement from capacity or efficiency upgrades made to facilities other than hydropower facilities.	Other resources as determined to qualify through ODOE rulemaking. However, nuclear fission and fossil fuel sources are prohibited in all cases as qualifying resources.
	Electricity from hydrogen derived from any of the above resources.

Renewable Energy Certificates

Compliance with the RPS requires proof of generation of the qualifying electricity. Like many states, Oregon requires proof in the form of a Renewable Energy Certificate (REC). Oregon Administrative Rule states that a REC is a unique representation of the environmental, economic and social benefit associated with the generation of electricity from renewable energy sources that produce Qualifying Electricity. Each REC represents one megawatt-hour (MWh) of generation of qualifying electricity. By rule, all RECs must be issued by the Western Renewable Energy Generation Information System (WREGIS).

Oregon recognizes two types of Renewable Energy Certificates (RECs) in the RPS. Initially, all RECs are "bundled" together with their associated electricity that is produced at the renewable electricity generation facility. When both a REC and the electricity associated with that REC are acquired together, one has acquired a "bundled" REC.

A generator or REC owner may decide to "unbundle" the REC from the electricity associated with that REC by using or selling the two components separately. In doing so the purchaser of the power loses the ability to claim that the power is renewable energy. The "unbundled" REC may be used by its new owner to comply with the RPS.

To meet an RPS target obligated utilities or ESSs must permanently retire the number of RECs equivalent to the target load percentages. For example, if a utility is subject to a 10% target and sold 100,000 MWh to Oregon customers, then it must retire 10,000 RECs to meet its compliance target.

For large utilities, no more than 20 percent of their compliance target in a given year may be met through the use of unbundled RECs, although large consumer-owned utilities such as EWEB have a limit of 50 percent until 2020. RECs from PURPA facilities in Oregon are exempt from this limit.[3]

RECs may be banked indefinitely and used in future years. Older RECs must be used before newer RECs, called the "first in first out" principle.

<u>Implementation Plans and Compliance</u>

The Oregon Renewable Portfolio Standard compliance schedule for the state's three largest utilities began in 2011. In 2012, Eugene Water and Electric Board, PacifiCorp, and Portland General Electric will demonstrate REC retirement in an amount equivalent to five percent of its 2011 retail sales, unless otherwise exempted (see Exemptions to RPS Targets, above).

Every two years, large utilities submit implementation plans detailing how they expect to comply with the standard.[4] The plans include annual targets for acquisition and use of qualifying

[3] PURPA is a federal law that requires utilities to purchase the output of smaller energy projects.
[4] EWEB reports its plan to comply with the RPS in its Integrated Energy Resource Plan.

electricity and the estimated cost of meeting the annual targets. Prudently incurred costs associated with RPS compliance are recoverable in rates.

Investor-owned utilities and ESSs must submit their annual compliance reports to the OPUC. Consumer-owned utilities report compliance to their customers, boards, or members.

Consumer Protection and Cost Controls

There are two mechanisms that serve as cost protections for Oregon consumers: an alternative compliance payment mechanism and an overarching "cost cap" on utility RPS expenditures.

Alternative Compliance Payment: In lieu of acquiring a REC to comply with a portion of the RPS, a utility or ESS may instead pay a set amount of money per megawatt-hour (MWh) into a special fund that can be used only for acquiring renewable energy resources in the future, or for energy efficiency and conservation programs. This mechanism sets an effective cap on the cost of complying with the RPS on a per MWh basis.

Cost Cap: Utilities are not required to comply with the RPS to the extent that the sum of the incremental costs of compliance with the RPS (as compared with fossil-fuel power), the costs of unbundled RECs, and alternative compliance payments exceed four (4) percent of a utility's annual revenue requirement in a compliance year. Consumer-owned utilities may also include R&D costs associated with renewable energy projects in this calculation. As of 2012, the incremental cost of compliance for all Oregon utilities has been well below the four percent cap.

ORDINANCE NO. 3134

AN ORDINANCE REQUIRING THE CITY OF ASHLAND TO PRODUCE 10 PERCENT OF THE ELECTRICITY USED IN THE CITY FROM NEW, LOCAL AND CLEAN RESOURCE BY THE YEAR 2020 AND AN EMERGENCY IS DECLARED TO TAKE EFFECT ON ITS PASSAGE

RECITALS:

WHEREAS climate change is caused in large part by human action.

WHEREAS Ashland citizens have a responsibility to contribute to slowing of climate change.

WHEREAS Ashland owns its own electric utility.

SECTION 1. The City of Ashland shall cause at least 10 percent of the electricity used in the City to be produced from new, local and clean resources from and after the year 2020.

SECTION 2. The City of Ashland shall enact such ordinances and resolutions, and appropriate such funds and take necessary actions as are necessary to implement the requirements of Section 1 above.

SECTION 3. This Ordinance being necessary to meet the requirements set by Oregon State Elections Law, an emergency is declared to exist, and this Ordinance takes effect on its passage.

The foregoing ordinance was first read by title only in accordance with Article X, Section 2(C) of the City Charter on the 6 day of September, 2016, and duly PASSED and ADOPTED this 6 day of September, 2016.

Barbara M Christensen

Barbara M. Christensen, City Recorder

SIGNED and APPROVED this 6 day of September, 2016.

John Stromberg

John Stromberg, Mayor

Reviewed as to form:

David H. Lohman

David H. Lohman, City Attorney

City Council - Minutes

View Agenda

Tuesday, November 15, 2016

MINUTES FOR THE REGULAR MEETING
ASHLAND CITY COUNCIL
November 15, 2016
Council Chambers
1175 E. Main Street

CALL TO ORDER
Mayor Stromberg called the meeting to order at 6:00 p.m. in the Civic Center Council Chambers.

ROLL CALL
Councilor Voisin, Morris, Lemhouse, and Rosenthal were present. Councilor Seffinger arrived at 6:04 p.m. Councilor Marsh was absent.

CONTINUATION OF DISCUSSION FROM NOVEMBER 1, 2016
1. Discussion of policy questions to be addressed regarding the 10x20 ordinance
Mayor Stromberg explained there were three kinds of clean power, solar, wind, and hydro. Management Analyst Adam Hanks would provide the best case for each during the discussion. Complex resolutions or topics that could not be resolved during the meeting would go on a list for further review and action at the next Council meeting.

Wind
Mr. Hanks explained part of using wind power was getting inventories where there were enough flows. A renewal energy assessment from 2011 indicated one location of scale on the backside of Shale City due to its close proximity to connect to larger lines. There was talk regarding Mt. Ashland but wind volume and how it would connect were unknown at this time. Wind was most likely not viable. Mayor Stromberg moved it to the list.

Hydro
Hydro required the right flow, head, and diameter pipe. There were a few locations in the City's system that had potential but the scale of production would not meet the 10x20 ordinance requirements. The item moved to the list.

Mayor Stromberg explained the City defined the 10% clean energy as 10% of the annual electric power usage of the City of Ashland. Mr. Hanks clarified 10% of the 170,000,000 kilowatt hours used per year would mean 17,000,000-kilowatt hours coming from a clean energy source. It equated to .017 gigawatts. A solar industrial plant would have be a 12 to 15 megawatt facility to produce that annually.

Solar
There were three options for solar power. Option 1 would put a solar farm on the Imperatrice property. The second option would add solar panels to City owned facilities like rooftops, parking lots, and covering the reservoir. Staff was currently conducting a site inventory. Option 3 would place community solar on

commercial and residential buildings. It would require new incentive packages to form various utility City partnerships.

Mayor Stromberg added the following concerns regarding solar to the list for future discussion:

- Potential issues with tree shading to cool the affluent may affect the use of the Imperatrice property
- Environmental concerns on using 150 acres for a 12-15 megawatt facility
- Ordinance requiring local energy – the City defined local as wherever the facility was located it connected directly into an Ashland electric utilities distribution grid

There were two ways to fund a solar power system. One way was determine the cost to build a facility and recoup the expense through user rates. Another way was entering into a power purchase agreement (PPA) with an entity or organization that would build the facility, operate it, and sell the electricity to the City with the city assuming ownership after a 20-year period.

Mr. Hanks explained the carbon mitigation component was indirect regarding a solar power system in that the less hydro purchased left more available in the grid and offset the need for other generation opportunities regionally. However, the way the greenhouse gas inventory was calculated worked to the City's advantage from a climate action planning perspective because it calculated it on the regional grid. Alternately, if it was just a carbon concern then a PPA from a facility within the grid itself either locally or regionally was more feasible.

The City was committed to purchasing a certain amount of electricity from the Bonneville Power Administration (BPA). If the City was generating some of their own through the 10x20 ordinance it could drop total usage with BPA and cause the City to pay for both. Mayor Stromberg acknowledged this as a potential issue and set it aside for future review.

Mr. Hanks addressed having a solar farm system on the Imperatrice property. The City could send out a request for proposal (RFP) for a 12-megawatt solar installation on the Imperatrice property. The RFP could include a request for a PPA estimate but was not necessary. It would take staff 30-45 days to develop the RFP. It/Electric Director Mark Holden added the RFP would include connection to the distribution site at the Mountain Avenue station. It would need a substantial transformer and lead to purchasing the Mountain Avenue station from BPA prior to updating the equipment.

Council majority directed staff to create an RFP with a review by Council prior to sending it out for bid.

Council went on to discuss postponing agenda item **#2 Discussion of removing public art review and approval requirements from Chapter 18 of the Ashland Municipal Code** under **New and Miscellaneous Business** to the January 17, 2017 Council meeting.

Councilor Lemhouse/Rosenthal m/s to postpone this item until January 17, 2017, or a date that accommodates both the Historic and the Public Arts Commission. Voice Vote: All AYES. Motion passed.

MAYOR'S ANNOUNCEMENTS
Mayor Stromberg announced vacancies on the Housing & Human Services, Public Arts, and Tree Commissions.

APPROVAL OF MINUTES
The minutes of the Study Session of October 31, 2016, the Executive Session of October 31, 2016, and the Business Meeting of November 1, 2016 were approved as presented.

SPECIAL PRESENTATIONS & AWARDS
1. Annual presentation by the Housing and Human Services Commission
Housing and Human Services Commission (HHSC) vice Chair Rich Rohde and Commissioner Tom Buechele provided the annual update for the HHSC. Vice Chair Rohde commented on the housing emergency crisis in Ashland. Medford and Ashland had become the fastest growing unaffordable housing cities in the country.

This year the HHSC worked on the Housing Trust Fund, developing a funding strategy chart, student fair housing, and recommendations for Community Development Block Grant (CDBG) funding. HHSC created nine goals that included donation boxes, affordable housing, inclusionary zoning, diversity, more Porta-Potties, developing resources for middle-income work force housing, increase shelter nights, ongoing rental research, and housing solutions that included the aging community.

PUBLIC FORUM
Michael Molitch-Hou/1151 Tolman Creek Road/Recently spoke with Unite Oregon in Medford who reported there were 70 counts of hate speeches and acts following the election directed towards Latino and Muslim Americans. He wanted to know if any similar acts had occurred in Ashland, if the City had a process in place to deal with racial harassment, and if there was a specific group a person could contact. He suggested Ashland become a Sanctuary City.

City Attorney Dave Lohman explained Ashland was already a sanctuary city and Oregon was a sanctuary state. City Administrator Dave Kanner encouraged anyone experiencing any form of hate speech to call the police. Police Chief Tighe O'Meara was not aware of any hate speech since the election and reiterated anyone experiencing that behavior should call the police.

Huelz Gutcheon/2253 Hwy 99/Spoke on solar energy.

Shane Elder/830 Carol Rae, Medford OR/Asked Council to amend the ordinance that prohibited address number painting on curbs. Ashland allowed this form of painting until two years ago. He went on to note the benefits of having addresses painted on curbs.

City Attorney Dave Lohman confirmed the issue came up two years prior where it was determined prohibitive. Council could change the ordinance. Mr. Lohman would follow up with Mr. Elder.

CONSENT AGENDA
1. Minutes of boards, commissions, and committees
2. Approval of a resolution titled, "A resolution adopting guidelines for the

creation and installation of murals"

3. Medford Water Commission water delivery contract

Councilor Voisin pulled Consent Agenda item #3 for further discussion. Public Works Director Mike Faught explained the only change to the agreement removed using Talent Ashland Phoenix (TAP) water for emergency purposes under Article 3. The new agreement would last five years with three five-year extensions. Talent, Ashland, and Phoenix could sell excess water to each other if a city exceeded their allotment. Each city had their own meter.

Councilor Seffinger/Rosenthal m/s to approve the Consent Agenda items. Voice Vote: all AYES. Motion passed.

Engineering Services Manager Scott Fleury provided an update on the Grandview Drive shared road project. Public Works and Electric department staff determined a strategy to install the storm drain, the electrical conduit, the new transformer, paving, and cleanup regarding the retaining wall. The location of the new transformer required extending the guardrail 20-feet and partial relocation of the old guardrail to accommodate the radius. Mr. Fleury confirmed the City did not require an encroachment permit since it was a City contract and staff did the work. They would install the electrical conduit that week followed by paving and cleanup work. Once that was completed, they would set up speed limit and share the roadway signs. They targeted the second week of December for completion of the first phase. Council expressed concern they were not notified of the guardrail extension prior to it happening. Public Works Director Mike Faught took responsibility for the oversight. Staff followed policy regarding notifying neighbors within the project site. After the project finished, staff would itemize the expenditures, determine overall costs, and forward that information to Council.

PUBLIC HEARINGS - None

UNFINISHED BUSINESS - None

NEW AND MISCELLANEOUS BUSINESS

1. Council review of questions for downtown behavior study

Management Analyst Ann Seltzer explained the City contracted with Southern Oregon University Research Center (SOURCE) to conduct a survey of downtown businesses to determine the effectiveness of the ordinances that went into effect over the summer. Director of SOURCE, Dr. Eva Skuratowicz explained the process in measuring downtown activities involved people who were in that area consistently over time. She decided to focus on the 194 businesses in the downtown, primarily street level businesses. It was also important to be clear on activities that took place in the front, side and back of the business. SOURCE would mail out the survey twice with research assistants calling businesses to get an accurate sense of how these behaviors have shifted, changed, reduced, or increased. Dr. Skuratowicz would follow up with any business in person who failed to respond to all of SOURCE's attempts to gather information. She may talk to the Oregon Shakespeare Festival (OSF) separately.

Council discussed the question regarding the occurrence of ATM users solicited for money. Dr. Skuratowicz would remove the question, call the banks instead, and replace it with another question relating to smoking in the alley or sidewalk areas.

2. Discussion of removing public art review and approval requirements from Chapter 18 of the Ashland Municipal Code
Item delayed to the January 17, 2017 meeting.

ORDINANCES, RESOLUTIONS AND CONTRACTS

1. First reading by title only of an ordinance titled, "An ordinance amending AMC 14.04.060 Water Connections Outside City The Limits" and move to second reading.
City Attorney Dave Lohman noted the ordinance currently stated no premises located outside the City of Ashland may be connected to the City water system with some provisions for Council to make specific approvals. The wording, "may be" could be misunderstood. He proposed changing the language to read, **"no premises located outside the City of Ashland may be connected to the city water system or make use of water obtained through a direct or indirect connection to the city water system."** Exceptions were narrowly defined but lacked clarity. For **14.04.060(C)(3)(i-v)**, the punctuation did not make it clear that all five criteria needed to be met. Mr. Lohman proposed changing **14.04.060(C)(3)** to read, **"Connections authorized under subsection (B)(3) above shall be made only after all the criteria in subsection (B)(3) and the following have been met."**

Under **14.04.060(E)**, Mr. Lohman suggested removing the current language and adding, **"Any person who violates any provision of this Chapter shall be punished as set forth in Section 1.08.020 of the Ashland Municipal Code, in addition to other legal and equitable remedies to the City of Ashland, including restriction or termination of service."** Termination of service was already in **14.05.070** where the City could disconnect service connection from the water supply line if the equipment using the water did not comply with all city, state, and federal laws or standards. He reiterated this was not a change in policy or direction, just clarification.

John Benson/1120 South Mountain/Questioned whether premises had to have a structure on the property. Oregon state law said he could water a half acre from a city connection into a county lot. Last Thursday, Mike Faught and Steve Wilson came to his mother's house who had recently come home from the hospital, and informed her she needed to cut the line extending to county property. He claimed the City had given them approval to use city water in 1970, 1990 and in 2009. His neighbor below him had the same zoning and the City had not talked to them. The Oregon state law he referred to was on the Oregon Medical Marijuana Program (OMMP) website. He could get a pump from Talent Irrigation District (TID), or drill a well but that actually violated OMMP rules. He went on to talk about the complaint process, traffic to neighbor's homes and false statements that he had armed guards and vicious dogs. He confirmed he had two lots, one county, and the other had the city limits boundary running through the lot.

Council confirmed the proposed changes clarified the ordinance and that Mr. Benson had brought up points he wanted Council to consider. Mr. Lohman added Council could make changes to the ordinance and Mr. Benson could appeal his water issues through the appeals process.

The term premise did not mean a structure or building. Councilor Morris noted a situation on his property that meant he too was violating the ordinance. His lot

was half in the City and half in the county.

Mr. Lohman clarified they had researched the claims the Benson's received permission to use city water three times in the past and did not find anything indicating there was an agreement to that effect. Nor had the City received any documentation from the Benson's confirming permission. The ordinance did not provide for an exception. Mr. Benson's family could have received a verbal ok but that still did not comply with the ordinance.

Councilor Lemhouse/Rosenthal m/s to approve the first reading of an Ordinance titled, "An Ordinance Amending AMC 14.04.060 Water Connections Outside the City Limits."
DISCUSSION: Councilor Lemhouse did not think Council could make a value judgment on what occurred on someone's property to determine whether to enforce or clarify the code. He did not want the trees to die but the code was there for a reason. Making an exception set a precedence of value judgments. The code did not provide water outside the city unless the request matched the exceptions criteria. Councilor Rosenthal expressed concern about wading into a neighborhood relations issue and that Council was potentially revising an ordinance that may have unintended consequences. He did not know if clarifying the language clarified the implementation of the ordinance.

Councilor Morris recused himself from the matter.

Councilor Voisin did not think it was a water supply issue because the City supplied water to the Welcome Center and would supply water to the 550 residential units in the Normal Neighborhood Plan. The issue was accommodating residents living on the edge of town who may bring their properties into city limits in the future. She suggested extending the ordinance to include the urban growth boundary. Councilor Seffinger was not comfortable with the possible unintended consequences of changing the ordinance at this point. She wanted a different way to address the neighborhood concerns regarding the use of the property. It was unknown how the clarifications would affect other properties. Mayor Stromberg noted the ordinance was not changing and questioned how it would affect anyone differently.
Roll Call Vote: Councilor Rosenthal and Lemhouse, YES; Councilor Seffinger and Voisin, NO. Mayor Stromberg broke the tie with a YES vote. Motion passed 3-2.

OTHER BUSINESS FROM COUNCIL MEMBERS/REPORTS FROM COUNCIL LIAISONS
Councilor Seffinger announced the Red Cross had a program that provided smoke detectors for citizens that may need financial assistance or help with installation.

ADJOURNMENT OF BUSINESS MEETING
Meeting adjourned at 8:20 p.m.

Dana Smith, Assistant to the City Recorder John Stromberg, Mayor

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