

**DISTRIBUTED ENERGY RESOURCE AGREEMENT**  
**executed by**  
**CITY OF RICHLAND WASHINGTON**  
**and**  
**ENERGY NORTHWEST**

**Table of Contents**

---

<b>Sections</b>	<b>Page</b>
1. Term .....	2
2. Definitions .....	2
3. Project Specifications .....	4
4. Adding DERs .....	4
5. Capacity Incentive .....	5
6. Energy Incentive .....	5
7. Scheduling .....	5
8. Event Requests .....	5
9. Measurement and Verification .....	6
10. Unsuccessful Events & Outages .....	8
11. Termination .....	10
12. Billing & Payment .....	10
13. Information Security .....	10
14. Project Management .....	11
15. Confidentiality .....	11
16. Assignment .....	11
17. Amendments .....	11
18. Uncontrollable Forces .....	11
19. Governing Law .....	12
20. No Third Party Beneficiaries .....	12
21. Notices and Contact Information .....	12
22. Signatures .....	13
 <b>Appendices</b>	
A. DER Inventory .....	14
B. DER Schematics .....	15

This DISTRIBUTED ENERGY RESOURCE AGREEMENT (Agreement) is executed by ENERGY NORTHWEST (EN) a municipal corporation and joint operating agency formed under the laws of the State of Washington and CITY OF RICHLAND WASHINGTON (Utility). EN and Utility are sometimes referred to individually as "Party" and collectively as "Parties."

### RECITALS

EN has entered into a Distributed Energy Resource (DER) Agreement with Bonneville Power Administration (BPA) dated April 20, 2017, to supply and manage net load reduction resources for use by BPA for the Summer 17 Demonstration Project (Summer 17 Agreement). In furtherance of the Summer 17 Agreement, EN desires to enter into a series of agreements with select utilities to supply a portion of the net load reduction.

Utility desires to enter into an agreement with EN to test the Parties' ability to provide suitably responsive electrical loads, effectively aggregate with others, and operate those assets to respond to BPA-originated grid management events (Events) through the use of contractual obligations, software, and communications infrastructure. Under this Agreement, Utility agrees to respond to Events, called by BPA through EN, by accomplishing net load reductions, an "INC", within its service territory. The Parties, as well as BPA, intend to use the experience gained and data collected from this Summer 17 Demonstration Project, of which this Agreement is a part, to help determine the broader applicability of utilizing load flexibility and distributed generation to manage a variety of transmission system and utility-scale conditions via aggregated net load reductions.

### AGREEMENT:

The Parties agree as follows:

#### 1. TERM

This Agreement shall become effective upon the date executed by the Parties (Effective Date) and shall expire on September 30, 2017, unless terminated earlier in accordance with the termination provisions specified in Section 11.

#### 2. DEFINITIONS

Capitalized terms below shall have the meaning stated. Capitalized terms that are not listed below are defined within the section in which the term is used. Specific amounts for many of these defined terms are stated in Exhibit A.

- (a) "Actual Load Reduction" means the difference between the Adjusted Baseline Usage applicable to such DER which results in a reduction in net load on the Federal Columbia River Power System and the energy usage of a DER during a given Event. The Actual Load Reduction shall be calculated using 1-minute measurement intervals and averaged over each hour of the Event. If the difference is less than zero the value shall be deemed zero
- (b) "Availability" means the days of the week and hours in the day that a DER is available to respond to an Event. Availability for each DER is identified in Exhibit A.
- (c) "Business Day" means Monday through Friday except for Federal holidays. If not specified as a Business Day, then calendar days are intended.

- (d) "Capacity" is the amount of electric power a DER or group of DERs are able to reduce from its load, as measured and confirmed in accordance with Exhibit B. Measured in whole kilowatts (kW).
- (e) "Capacity Incentive" means the per kilowatt-month price EN shall pay Utility for its Committed Capacity. The rate at which Capacity Incentive is paid is listed in Section 5.
- (f) "Committed Capacity" means the amount of DER load reduction or increase in generation, measured in kilowatts ("kW"), that the Utility is required to make available for Events requested by EN. Committed Capacity, by DER, is set forth in Appendix A.
- (g) "Demand Response Aggregated Control System" (DRACS) is an integrated software and hardware solution that communicates between BPA, EN, Utility, and DERs. It serves also to provide the operational and business logic of the aggregated load response contemplated in the Pilot Agreement and this Agreement as well as related data storage, processing, and reporting needs. The DRACS serves to support the monthly settlement process on which payments are made.
- (h) "Dispatch Group" means a DER or group of DERs, including those contributed by other utilities that can respond to a common set of characteristics.
- (i) "Distributed Energy Resource" or "DER" means a grouping of one or more electric energy consuming loads or DERs that are capable of changing electrical consumption or generation in response to outside control signals. Utility provides Assets listed in Exhibit A. Exhibit B provides meter schematic diagrams and other technical specifications of each Asset.
- (j) "Energy Incentive" means the price EN shall pay Utility, determined in accordance with application provisions of Section ##, for successful participation in an Event.
- (k) "Event" means a period during which a Dispatch Group, and thus DERs, are called on and are obliged to respond under the terms of this Agreement. Events, for purposes of performance, begin upon BPA sending to EN; then EN sending to DERs an Event Request, and ends with EN sending an Event Termination. For purposes of measurement, payment, and reporting, data collected from DERs prior to Event Request and after Event Termination may, depending on DER type, be utilized to determine successful performance of each DER.
- (l) "Event Request" means EN's request sent to Utility DER(s) to initiate an Event.
- (m) "Event Termination" means EN's request sent to Utility DER(s) to terminate an Event.
- (n) "Monthly Capacity Payment" means the Capacity Payment owed by EN to Utility for a month adjusted according to performance and incentive provisions in Sections 3, 5, and 6 of this Agreement. Utility may elect payment be made directly to DERs.
- (o) "Ramp Time" means the period of time after EN sends the Event Request to Utility within which a DER must fully accomplish its response to meet its Committed Capacity.
- (p) "Unsuccessful Event" means an Event, or an DER's performance during an Event, that does not meet the requirements of this Agreement as outlined in Section 10 of this Agreement.
- (q) "Unsuccessful Event Payment Reduction" means the reduction in Capacity Payment which occurs each time Utility incurs an Unsuccessful Event.
- (r) "Load" means an end use device that uses electricity or consumer that receives power from the electric system.
- (s) "Preference Customers" means a cooperative or public bodies, such as municipalities and public utility districts, that by law have priority access to Federally generated power.
- (t) Summer 17 Agreement shall mean the contract between the Bonneville Power Administration and Energy Northwest, Contract No. \_\_\_\_\_ and dated April X, 2017.

(u) "Unsuccessful Event" is described in Section 10 of this Agreement

**3. PRODUCT SPECIFICATIONS**

<b>Product</b>	Utility shall provide hourly blocks of Demand Response in the form of temporary decreased energy consumption and/or increased energy production from DERs.
<b>Eligibility Requirements</b>	<p>Eligible DERs are: a) short term load reduction, b) deployment of batteries or other energy storage device, c) dispatchable voltage reduction, and d) distributed generation (excluding diesel-fueled generators). Energy efficiency measures shall not be considered a DER.</p> <p>A DER must be either a BPA public Preference Customer, or served by one of Bonneville's public preference customers including those customers served by transfer service. Loads served by Investor Owned Utilities (IOU) are excluded from eligibility.</p> <p>For all participating DERs Utility will provide EN prior to May 19, 2017, a schematic of the DER showing meter locations and associated loads.</p>
<b>Committed Load Reduction</b>	See Appendix A.
<b>Delivery Period</b>	"Delivery Period" means the period that DERs will be available to respond to Events: June 1, 2017 through September 30, 2017, Monday through Friday, from 1300 to 2000 hours Pacific Prevailing Time, excluding NERC holidays.
<b>Deployment Limits</b>	<p>Events shall be requested and provided in hourly blocks that begin at the start of the hour.</p> <p>Minimum:</p> <ul style="list-style-type: none"> <li>i. one (1) hour per Event.</li> <li>ii. thirty six (36) hours of Events total for all months.</li> </ul> <p>Maximum:</p> <ul style="list-style-type: none"> <li>i. four (4) consecutive hours per Event,</li> <li>ii. one (1) Event each day,</li> <li>iii. three (3) consecutive Event days,</li> <li>iv. forty (40) hours of Events total for all months.</li> </ul>
<b>Ramp Time</b>	DERs shall provide the Committed Load Reduction at the top of the upcoming hour upon receipt of EN's Event Request. To assure Events begin at the top of the hour, Event Requests shall be provided to the Utility no less than 0:27:00 prior to the top of the hour. Modification to the Ramp Times may be designated for specific DERs only by mutual agreement by both Parties.

**4. ADDING DERs**

Utility may request EN to add DERs in any increment. If deemed eligible, EN will timely seek approvals to add DERs with BPA in accordance with requirements of the Summer17 Agreement.

**5. CAPACITY INCENTIVE**

The monthly Capacity Incentive rate paid by EN to Utility is \$3.76 per kilowatt-month (kW-month) subject to adjustment under provisions of Section 10.

**6. ENERGY INCENTIVE**

The Energy Incentive rate paid by EN to Utility is \$0.04 per kilowatt-hour (kWh). Utility is not compensated for DER load response or generation in excess of Committed Capacity.

**7. SCHEDULING**

- a. For any DER that resides within the service territory of a BPA Preference Customer who purchases a Slice/Block Product, EN will coordinate with Utility's scheduling staff, its serving utility, or designated scheduling agent (Scheduling Agent). For each Event, EN will inform the Scheduling Agent of the event and Scheduling Agent will submit to BPA a real-time adjustment to its e-tag reflecting the change in its net load caused by the event.
- b. Under the Summer 17 Agreement, BPA allows the Scheduling Agent to make e-tag adjustments outside the normal scheduling window, but no later than 22 minutes prior to the top of the hour, when those adjustments are made solely to bring Utility's schedule into alignment with Utility's change in load due to the Event Request.
- c. Under the Summer 17 Agreement, any DER residing within the service territory of a BPA Load Following Customer shall not require any scheduling actions.

**8. EVENT REQUESTS**

- (a) EN shall communicate all Event Requests to Utility via a mutually agreed upon technology solution.
- (b) After EN has sent Utility an Event Request, Utility shall provide the Committed Capacity for the Dispatch Group within the Ramp Time specified in Section 3. Utility's inability to meet this requirement will be considered non-performance for that hour. Each hour of a properly-notified Event shall be evaluated separately for purposes of meeting this requirement.
- (c) An Event ends when the Maximum Deployment Limit, specified in Section 3, is reached or a subsequent hourly Event notification is not received. At the end of an event, Demand Response Aggregated Control System (DRACS), or a technology solution agreed to under Section 9(a) above, shall immediately send a signal to all Assets to begin returning to normal operations. There is no prescribed timeframe or specific requirements for an Asset's return to normal operations.

**9. MEASUREMENT AND VERIFICATION**

- (a) Direct Load Control – Metered (DLCM)

This section describes the measurement and verification methods to be used for DERs with one or more specified metering data points which, in the aggregate, definitively describe and quantify the DER's load at specific timed intervals.

- i. DERs using this metering protocol shall be metered directly and average real power measured in kilowatts (kW) shall be recorded at one minute intervals on an on-going basis during the duration of the Agreement. Each power meter shall have an internal watt transducer with at least a 2% accuracy class for real energy (kWh). The location of meter(s) must ensure that the subject DER's load and any interdependent loads are captured by the metering. It is recommended that the DR asset capacity amount be at least 20% of the average load being metered in order to reduce error in the Event capacity calculation. In some cases it may be reasonable to meter at the facility service entrance.
- ii. Baseline Usage for a load measured and verified under this section shall be determined (subject to the Day-of Load Adjustment as defined below) as the average of the DER's measured demand, in kW, on a minute by minute basis, during the same time period as the Event in each of the DER's five (5) highest energy usage days (as defined below) of the immediate past ten (10)

Delivery Period days; provided, however, that the past ten (10) Delivery Period days shall exclude any Delivery Period day on which an Event was dispatched under this Agreement or an Uncontrollable Force outage, defined in Section 19. Notwithstanding the foregoing, in the event ten (10) Delivery Period days' worth of meter data is not available, Utility shall utilize meter data from the maximum number of available Delivery Period days, but in no event shall Utility utilize fewer than five (5) Delivery Period days' worth of meter data for a DER in order to establish an initial valid DER Baseline Usage

The five (5) highest energy usage days for a given DER are those days having the highest average kilowatt (kW) usage (highest energy usage in kWh) for such DER during Delivery Period hours.

- iii. A "Day-of Load Adjustment" will be applied to each initial DER Baseline Usage on a minute by minute basis during an Event. The Utility shall not intentionally alter or manipulate any data in any manner that results in a DER Baseline Usage or Actual Load Reduction value that is not accurate to the native operation of the facility and the DER.
- iv. EN and Utility agree to review the DER Adjusted Baseline Usage calculation methodology from time to time throughout the Term and shall review if the BPA makes a change in the calculation methodology in the Summer 17 Agreement. If the Parties agree that a more accurate calculation is available and feasible to implement, it will be incorporated into this Agreement, provided that the calculation is incorporated into the Summer 17 Agreement.
- v. To the extent BPA, EN, or Utility identifies potential instances of manipulation or excessive variation of a DER Baseline Usage calculation, the Parties will share related data and upon review, mutually determine appropriate remedial measures to address such variability.
- vi. The Actual Load Reduction delivered on a minute by minute basis shall be the difference between the DER's Adjusted Baseline Usage and each minute average power (kW) DER load measured during the Event.
- vii. If Events are executed up to 4 consecutive hours, the Adjusted Baseline Usage shall reflect that specific hour of the Event but the Day of Load Adjustment for any Event within the same calendar day shall remain the same.

(b) Energy Storage Device (ESD)

This section describes the measurement and verification methods to be used for Energy Storage Devices with one or more specified metering data points which, in the aggregate, definitively describe and quantify the DER's energy production at specific timed intervals.

- i. DERs using this metering protocol shall be metered directly and average real power measured in kilowatts (kW) shall be recorded at one minute intervals on an on-going basis during the duration of the Agreement. Each power meter shall have an internal watt transducer with at least a 2% accuracy class for real energy (kWh). The location of meter(s) must ensure the energy released by the subject ESD is captured by the metering.
- ii. Baseline energy measured and verified under this section shall be the metered power (kW) one minute prior to the date/time stamp of the Event notification. This Baseline Usage power (kW) amount shall be considered constant during the Event.
- iii. The Actual Load Reduction delivered on a minute by minute basis shall be the difference between the DER's Baseline Usage and each minute average power (kW) DER load measured during the Event
- iv. If Events are executed up to 4 consecutive hours, the Baseline Usage shall be the same for any Event within the same calendar day.

(c) Demand Voltage Reduction (DVR)

This section describes the measurement and verification methods to be used for loads or load groupings that deliver capacity via a change in the distribution system voltage.

- i. For loads measured and verified under this section Utility shall:
  - A. Measure and record three-phase average voltage at one minute intervals for each voltage control zone, feeder regulator and/or transformer load tap changer (LTC); and
  - B. Record voltage set point at one minute intervals for each voltage control zone, feeder regulator and/or transformer load tap changer (LTC); and
  - C. Measure and record average power (kW) delivered to each voltage control zone at one minute intervals.
- ii. Baselines shall not be determined for loads measured and verified under this section.
- iii. For each voltage control zone, the Actual Load Reduction delivered on a minute by minute basis shall be the product of measured load (kW), the percent (%) change in voltage set point upon execution of the load curtailment action within 30 minutes of receiving the Event Request (expressed as a decimal factor), and a deemed demand voltage reduction (DVR) load response factor of 0.75 (%kW / % voltage change). The parties may revise the agreed-to deemed DVR factor by mutual written Agreement. Utility will document and report the voltage set points at one minute intervals during each Event and the 35 minutes prior to each Event. The percent (%) change in voltage set point shall be calculated by taking the difference between the voltage set point 1 minute prior to the minute in which the voltage set point was changed, after receiving an Event Request, this will be labeled V1 and the voltage set point 1 minute after the minute the voltage set point was changed in pursuit of load reduction following an Event Request, this will be labeled V3 then dividing that difference by the voltage set point 1 minute prior to the minute in which the voltage set point was changed, after receiving an Event Request, V1. The example below shows the voltage set point chronology and labeling. If there is a subsequent change in voltage set point after the initial reduction pursuant a load reduction action, the same application of calculating percent voltage set point shall apply and that decimal change will be added or subtracted from the original decimal change. Added to it if the voltage set point is further reduced, and subtracted from it if the voltage set point is increased but not as far as to the level at the pre Event baseline.

Example calculation of percent voltage change:

V1 (example 122 V), V2 (example 119 V), V3 (example 119 V). These are consecutive minutes of voltage set point recording. V2 is the minute when the change in voltage set point was made. V1 is the minute prior, and V3 is the minute after.

$$\% \text{ V change (decimal)} = (V1 - V3) / V1 = (122 - 119) / 122 = 0.0246$$

- iv. If Events are executed up to 4 consecutive hours, the percent (%) change in voltage set point will be the same for any Event within the same calendar day
- (d) Distributed Generation (DG)

This section describes the measurement and verification methods to be used for Distributed Generation with one or more specified metering data points which, in the aggregate, definitively describe and quantify the Demand Recourse's energy production at specific timed intervals.

- i. DERs using this metering protocol shall be metered directly and average real power measured in kilowatts (kW) shall be recorded at one minute intervals on an on-going basis during the duration of the Agreement. Each power meter shall have an internal watt transducer with at least a 2% accuracy class for real energy (kWh). The location of meter(s) must ensure the energy generated by the subject DG is captured by the metering.

- ii. Baseline energy measured and verified under this section shall be the metered power (kW) one minute prior to the date/time stamp of the Event notification. This Baseline Usage power (kW) amount shall be considered constant during the Event.
- iii. The Actual Capacity delivered on a minute by minute basis shall be the absolute value difference between the DER's Baseline Usage and each minute average power (kW) DER power output measured during the Event.
- iv. If Events are executed up to 4 consecutive hours, the Baseline Usage will be the same for any Event within the same calendar day

**10. UNSUCCESSFUL EVENT & OUTAGES**

**(a) Unsuccessful Events**

EN will evaluate the performance of all DERs in each sixty-minute interval using the average of the DER's Actual Load Reduction for each 1-minute interval of the Event. The methodology for calculating DER's 1-minute interval Actual Load Reduction is provided in Section 10.

The **Hourly Actual Load Reduction** shall be the average of the DER's Actual Load Reduction in each 1-minute interval during each sixty (60) minute period.

The **Committed Capacity** is the sum of all the Utility DERs' Committed Capacity.

An Event shall be considered an Unsuccessful Event if the Hourly Actual Load Reductions during the Event does not equal or exceed the Committed Load Reduction during any sixty (60) minute period of the Event.

BPA, under the Summer 17 Agreement is solely responsible for determining if Events are successful or unsuccessful; however, BPA agrees such determination shall not be unreasonably made. Utility shall meter, baseline, and initially verify the performance of each Event and report these findings to EN. Upon request, EN shall provide BPA with all metering, baseline, and verification data that BPA requests in order that BPA may audit EN and Utility's compliance with the requirements of the Summer 17 Agreement.

The first Unsuccessful Event shall give EN the right, but not the obligation to reduce the Utility's monthly capacity payment for that month by the capacity value of one day which shall be calculated as follows:

**((1 / Potential Delivery Days in the Month (from Table 1))\* (Monthly Capacity Incentive).**

<b>Table 1.</b>			
<b>Potential Delivery Days in the Month:</b>			
<b>Jun 2017</b>	<b>Jul 2017</b>	<b>Aug 2017</b>	<b>Sep 2017</b>
<b>22</b>	<b>20</b>	<b>23</b>	<b>20</b>

The second Unsuccessful Event shall give EN the right, but not the obligation to reduce the Utility's capacity payment by one half for the month.

The third Non Performance Event shall give EN the right but not the obligation to forgo the Utility's monthly capacity payment and/or terminate this Agreement effective immediately.

If an Event Request is provided Utility under circumstances not in accordance with the Product Specification in Section 3 and Utility does not respond or elects to respond in good faith but does not fully achieve performance requirements, then an Unsuccessful Event shall not be deemed to have occurred.

If: (1) Utility DER(s) fail to perform for an Event and thus cause an Unsuccessful Event; (2) DERs from other utilities over supply their respective Committed Capacity; and (3), as a result of that over supply contribution, the overall Dispatch Group does not incur an Unsuccessful Event, EN shall distribute as an incentive, on a pro rata basis, the amount of Utility's Unsuccessful Event Payment Reduction to the utility or utilities whose DERs over supplied.



If the Dispatch Group, as a whole, incurs an Unsuccessful Event by virtue of one or more of its DERs failing to perform then all DERs assigned to that Dispatch Group shall be charged an Unsuccessful Event Payment as well.

(b) Outage

- i. Any period of time during which a DER is not fully available to perform according to the requirements of this Agreement shall be considered an "outage." Utility shall provide EN with a minimum of forty-eight (48) hours' notice before any planned outage. Utility shall send notification via e-mail to <<td>> with a copy sent to <<td>>. Utility's e-mailed notifications shall include the reason for the outage and the expected time the DER will be unavailable.
- ii. For each day of a properly notified outage EN will reduce the Utility's Monthly Capacity Payment for that month by the capacity value of one day which shall be calculated as follows:  
  

$$((1 / \text{Potential Delivery Days in the Month (from Table 1)}) * (\text{Monthly Capacity Payment}))$$
- iii. For each day of a properly notified outage, the Monthly Capacity Payment shall be reduced per Section 10(b)(ii) until the DER is back in service and all Committed Load Reduction is available.
- iv. Utility is expected to perform maintenance on Utility's information systems outside of the Delivery Period hours.

**11. TERMINATION**

- (a) In the event of termination due to the number of Unsuccessful Events as provided in Section 10, the notice of termination shall be effective immediately upon receipt by Utility.
- (b) In the event of termination of the Summer 17 Agreement by BPA due to the information security deficiencies, EN will provide a notice of termination effective three (3) days after receipt by Utility
- (c) Upon termination of the Agreement, any liabilities of a Party under this Agreement incurred under the terms of this Agreement prior to the date of termination and which have not been satisfied as of the date of termination shall be preserved until satisfied. For the sake of clarity and avoidance of doubt, under no circumstances shall either Party be liable to the other Party for incidental, consequential or punitive damages, including but not limited to claims for loss of power or claims for economic loss.

**12. BILLING AND PAYMENT**

EN shall provide Utility with preliminary DER-level Event metering and baseline information and a preliminary statement on or before the 10<sup>th</sup> Day of the following each month after capacity was provided.

- (a) The Monthly Capacity Payment shall be calculated as follows:

EN shall multiply the Capacity Price, as defined in Section 5, by the Total Committed Load Reduction for the month, including any adjustments to the Total Committed Load Reduction made under Section 4.

From the resulting product:

Subtract the appropriate amounts for any Outages or Unsuccessful Events in the month, as described in Section 11.

- (b) The Monthly Energy Payment shall be calculated as follows:

The Monthly Energy Payment shall be calculated as follows: For each Program Event in the month, multiply (i) the lesser of the Committed Load Reduction or Actual Load Reduction for all 1 minute intervals of a Program Event measured in megawatts, by the (ii) Program Event Duration in minutes, divided by (iii)

sixty (60) minutes, multiplied by (iv) the Energy Price as defined in Section 6, (v) add the result of this calculation together for all Program Events in the month.

- (c) EN shall pay Utility any Monthly Capacity Payment and Monthly Energy Payment owed via electronic funds transfer. At no time shall the Monthly Capacity Payment to Utility total less than zero.
- (d) Finalized DER performance information and statement shall be provided and payment shall be made to Utility on or before the 7<sup>th</sup> day following receipt of payment from BPA to EN. If the 7<sup>th</sup> day falls on a non-Business Day, then the payment shall be due on the next Business Day. The BPA payment, under the Summer 17 Agreement is expected before the 26<sup>th</sup> day of the month after capacity is provided.
- (e) Utility acknowledges BPA shall not make, nor shall EN be responsible for, any adjustments to Utility power or transmission bills resulting from responding to an Event under this Agreement.

**13. INFORMATION SECURITY**

The Parties agree the data EN is collecting from Utility and providing to BPA has a Federal Information Processing Standards Publication (FIPS) 199 Standards for Security Categorization of Federal Information and Information Systems potential impact rating of "Low". As a condition of its Summer 17 Agreement, EN shall protect the data using the most current final version of National Institute of Standards and Technology (NIST) 800-53 Security and Privacy Controls for Federal Information Systems and Organizations or International Standards Organization ISO-27001:2005/2013 for a low rated system.

**14. PROJECT MANAGEMENT**

EN shall host via conference call weekly, or other mutual agreeable period, status meetings for all participant utilities starting by mid-May 2017 and extending through the term of this Agreement. The call will be to report on team performance, emergent issues, and other topics of interest to the group.

**15. CONFIDENTIALITY**

- a) If any information or documents furnished by one Party to the other Party are confidential or proprietary and are conspicuously marked as such, the receiving Party shall take reasonable steps to protect against the unauthorized use or disclosure of such information or documents; provided that this section shall not apply to information or documents in the public domain.
- b) EN shall notify Utility as soon as practicable of any request received under the Freedom of Information Act (FOIA), or under any other federal law or court or administrative order. EN may release information provided by Utility to comply with FOIA or if required by any other federal law or court order. For information that Utility designates in writing as proprietary, EN will limit the use and dissemination of that information internally to employees who need the information for purposes of this Agreement.
- c) Utility understands that this Agreement and related information may become a public record in accordance with Washington law and may not be exempt from disclosure under the Washington State Public Records Act (Act). In the event that any request to EN for disclosure to the public is made for this Agreement or related information or data related to this Agreement, EN shall give Utility notice of the request and provide reasonable opportunity for Utility to prepare response should it choose to do so. EN shall disclose such information responsive to such request in accordance with the Act unless Utility obtains, at its sole cost and expense, a court order precluding the disclosure of the information. If a court or regulatory authority should order the disclosure of information or documents received by EN from Utility, EN shall be bound by such order. Neither Party shall be liable for any inadvertent public disclosure of information despite the exercise of reasonable care.

**16. ASSIGNMENT**

This Agreement is binding on any successors and assigns of the Parties. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld.

**17. AMENDMENTS**

Except where this Agreement explicitly allows for one Party to unilaterally amend a provision or exhibit, no amendment of this Agreement shall be of any force or effect unless set forth in writing and signed by authorized representatives of each Party.

**18. UNCONTROLLABLE FORCES**

The Parties shall not be in breach of their respective obligations to the extent the failure to fulfill any obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its contractual obligations under this Agreement and which, by exercise of that Party's reasonable care, diligence and foresight, such Party was unable to avoid. Uncontrollable Forces include, but are not limited to:

- (a) Any unplanned curtailment or interruption of firm transmission or distribution service interconnected to the DER;
- (b) Any planned curtailment or interruption of firm transmission or distribution service interconnected to the DER if such curtailment or interruption occurs on BPA's or a third Party's transmission or distribution system;
- (c) Any failure of Utility's distribution or transmission facilities that prevents the DER from interconnecting to BPA's system;
- (d) Strikes or work stoppage;
- (e) Floods, earthquakes, or other natural disasters; terrorist acts; and
- (f) final orders or injunctions issued by a court or regulatory body having competent subject matter jurisdiction which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

If an Uncontrollable Force prevents a Party from performing any of its obligations under this Agreement, such Party shall: (1) immediately notify the other Party of such Uncontrollable Force by any means practicable and confirm such notice in writing as soon as reasonably practicable; (2) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable; (3) keep the other Party apprised of such efforts on an ongoing basis; and (4) provide written notice of the resumption of performance. Written notices sent under this section must comply with Section 22, Notices and Contact Information.

**19. GOVERNING LAW**

This Agreement shall be interpreted consistent with and governed by Washington law.

**20. NO THIRD PARTY BENEFICIARIES**

Except for the resource identified in Appendix A, this Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

**21. NOTICES AND CONTACT INFORMATION**

Any notice required under this Agreement that requires such notice to be provided under the terms of this section shall be provided in writing to the other Party in one of the following ways:

- (a) delivered in person;
- (b) by a nationally recognized delivery service with proof of receipt;
- (c) by United States Certified Mail with return receipt requested;
- (d) electronically, if both Parties have means to verify the electronic notice's origin, date, time of transmittal and receipt; or
- (e) by another method agreed to by the Parties.

Notices are effective when received. Either Party may change the name or address for delivery of notice by providing notice of such change or other mutually agreed method. The Parties shall deliver notices to the following person and address:

If to Energy Northwest:

Energy Northwest  
 3000 George Washington Way  
 P.O. Box 968  
 Richland, WA, 99352  
 Attn: John A. Steigers  
       ATI Lead  
 Phone: 509-377-4547  
 FAX: 509-372-5078  
 E-Mail: jasteigers@energy-northwest.com

If to Utility:

City of Richland WA  
 555 Swift Blvd  
 P.O. Box 190, MS #21  
 Richland, WA 99352  
 Attn: Robert Hammond  
       Energy Services Director  
 Phone: 509-942-7402  
 FAX: 509-942-5680  
 E-Mail: rhammond@ci.richland.wa.us

**22. ENTIRE AGREEMENT**

This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

**23. SIGNATURES**

ENERGY NORTHWEST

By 

Name Todd Johnson  
(Print/Type)

Title PRINCIPAL CONTRACT OFFICER

Date 5/25/17

CITY OF RICHLAND

By 

Name Robert Hammond  
(Print/Type)

Title Energy Services Director

Date 5/10/2017

**APPENDIX A – DER INVENTORY**

<b>ID</b>	<b>NAME</b>	<b>CAPACITY[kW]</b>	<b>RAMP</b>	<b>BASELINE TYPE</b>	<b>POD</b>
COR-01	DVR	1,000	2 minutes	DVR	See Appendix B

**APPENDIX B - DVR SCHEMATIC**

**1. City of Richland Demand Voltage Reduction**

**COR-01 - Asset Detail**

Data Point	Substation	Transformer	Feeder	Meter	Data Point	Substation	Transformer	Feeder	Meter
COR-01-011			X11	lon 8600/8650	COR-01-091			X91	lon 8600/8650
COR-01-012		Thayer	X12	lon 8600/8650	COR-01-092	Snyder	Snyder	X92	lon 8600/8650
COR-01-013		Bank 1	X13	lon 8600/8650	COR-01-093		Bank 1	X93	lon 8600/8650
COR-01-014			X14	lon 8600/8650	COR-01-094			X94	lon 8600/8650
COR-01-021			X21	lon 8600/8650	COR-01-071			X71	lon 8600/8650
COR-01-022		Thayer	X22	lon 8600/8650	COR-01-072		Tapteal	X72	lon 8600/8650
COR-01-023	Thayer	Bank 2	X23	lon 8600/8650	COR-01-073		Bank 1	X73	lon 8600/8650
COR-01-024			X24	lon 8600/8650	COR-01-074			X74	lon 8600/8650
COR-01-025			X25	lon 8600/8650	COR-01-075	Tapteal		X75	lon 8600/8650
COR-01-061			X61	lon 8600/8650	COR-01-076		Tapteal	X76	lon 8600/8650
COR-01-062		Thayer	X62	lon 8600/8650	COR-01-077		Bank 2	X77	lon 8600/8650
COR-01-063		Bank 3	X63	lon 8600/8650	COR-01-078			X78	lon 8600/8650
COR-01-064			X64	lon 8600/8650	COR-01-111			X111	lon 8600/8650
COR-01-031			X31	lon 8600/8650	COR-01-112			X112	lon 8600/8650
COR-01-032		Stevens	X32	lon 8600/8650	COR-01-113		Sandhill	X113	lon 8600/8650
COR-01-033		Drive Bank 1	X33	lon 8600/8650	COR-01-114		Bank 1	X114	lon 8600/8650
COR-01-034			X34	lon 8600/8650	COR-01-115			X115	lon 8600/8650
COR-01-041			X41	lon 8600/8650	COR-01-121	Sandhill		X121	lon 8600/8650
COR-01-042	Stevens	Stevens	X42	lon 8600/8650	COR-01-122		Sandhill	X122	lon 8600/8650
COR-01-043	Drive	Drive Bank 2	X43	lon 8600/8650	COR-01-123		Bank 2	X123	lon 8600/8650
COR-01-044			X44	lon 8600/8650	COR-01-124			X124	lon 8600/8650
COR-01-051			X51	lon 8600/8650	COR-01-125			X125	lon 8600/8650
COR-01-052		Stevens	X52	lon 8600/8650	COR-01-081			X81	lon 8600/8650
COR-01-053		Drive Bank 3	X53	lon 8600/8650	COR-01-082	Richland	Richland	X82	lon 8600/8650
COR-01-054			X54	lon 8600/8650	COR-01-083	Switch	Switch	X83	lon 8600/8650
COR-01-001			X1	lon 8600/8650	COR-01-084		Bank 1	X84	lon 8600/8650
COR-01-002		First Street	X2	lon 8600/8650	COR-01-085			X85	lon 8600/8650
COR-01-003		Bank 1	X3	lon 8600/8650	COR-01-131			X131	lon 8600/8650
COR-01-004			X4	lon 8600/8650	COR-01-132			X132	lon 8600/8650
COR-01-005	First Street		X5	lon 8600/8650	COR-01-133	City View	City View	X133	lon 8600/8650
COR-01-006			X6	lon 8600/8650	COR-01-134		Bank 1	X134	lon 8600/8650
COR-01-007		First Street	X7	lon 8600/8650	COR-01-135			X135	lon 8600/8650
COR-01-008		Bank 3	X8	lon 8600/8650					
COR-01-009			X9	lon 8600/8650					
COR-01-010			X10	lon 8600/8650					

Note: all City of Richland substations control distribution voltage with transformer LTC. All metering will be performed by ION 8600/8650 revenue grade meters in the substation.

Example: Sandhill Substation

