# Supplemental Report of the Oversupply Technical Oversight Committee
# November 15, 2012

## Background

The OTOC completed a set of Recommendations on April 26, 2012, and discussed them with the Steering Committee on May 14, 2012. At the May 14 meeting the Steering Committee asked the OTOC to continue to explore the most promising alternative of shifting load into light load hours. The Steering Committee also encouraged further exploration of the other alternatives to identify those that could have significant impact on Oversupply conditions at low cost in the near term. The Steering Committee requested examination of additional specific alternatives (annual outages at CGS and use of more flexibility on TDG limits). Also, the Steering Committee asked for clarity on the plan and schedule to move forward on implementation of Oversupply alternatives.

The OTOC and its workgroups have completed work on these requests and this Supplemental Report presents their findings and recommendations.

**<u>2012 Experience with Oversupply</u>:** The April 2012 OTOC report noted that technical solutions to address Oversupply abound, but since BPA expected the average cost of displacing wind in 2012 to be approximately $12 million, solutions must be very low cost per kW to be cost effective – far lower than the costs of solutions such as new storage. Since the April OTOC report and May Steering Committee meeting the region passed through the second spring runoff period in which BPA implemented an Oversupply policy[1], providing one more data point on actual amounts of Oversupply and costs. Like the spring of 2011, 2012 was another year of high runoff – 129.4 MAF January to July runoff vs. 142.7MAF in 2011. Despite the high runoff, wind displacement under BPA's Oversupply Management Protocol totaled around 49,600 MWh vs 97,500 MWh in 2011. The cost to wind project owners of the 49,600 MWh of displacement, as reported by those owners, was approximately $3 million.

The estimate of the annual "expected value" of Oversupply costs used in the April OTOC report was $12 million per year, with 300,000 MWh of wind displacement. The OTOC took note of the fact that actual Oversupply costs in 2012 were only 25% of the predicted expected value despite the fact that hydro conditions were well above average. This raised a question about whether the $12 million estimate might be high, further reinforcing the need to find very low-cost solutions to Oversupply. The answer to this question is not yet clear. Oversupply costs for 2012 were well below the expected value and actual 2011 results, because of factors such as a late but smooth PNW runoff, reduced hydro conditions and generating plant outages in California. BPA also took a number of actions to minimize use of its Oversupply Management Protocol. These included rescheduling non-essential maintenance and construction on transmission lines

[1] In March 2012, BPA adopted an Oversupply Management Protocol to address how oversupply conditions would be addressed for the term March 31, 2012 through March 30, 2013.

and federal generators, storing 2.8 million acre-feet of water under the Non Treaty Storage Agreement with Canada, use of 66,260 MWh under the Mid-Columbia Spill Exchange agreement, maximizing the amount of pump load, spilling on Willamette projects when possible within TDG limits, reducing CGS nuclear plant generation to 85% when it was helpful to minimize spill, reducing reserves when feasible, and selling recallable energy. On the other hand, since 2011 another 1000 MW of wind had been added in the Northwest and the CGS nuclear plant was operating.

At a minimum, the 2012 experience did nothing to dispel the earlier OTOC conclusion that to be cost effective, the cost of Oversupply solutions must either be quite low, or those solutions must serve other purposes which create additional benefits.

## Executive Summary

At the time of the May report to the Steering Committee, there was some hope of a "silver bullet" solution to Oversupply – one that would have a major impact in the near term at low cost. The OTOC has not found such a silver bullet solution. However in its further examination of the ranges of alternatives, the OTOC concludes that there are a number of initiatives which taken together, and if diligently pursued, will reduce, but not eliminate, the level and frequency of Oversupply conditions. Many of these initiatives are already underway as parts of other ongoing regional efforts. Brief summaries of OTOC findings on these initiatives follow:

### Initiatives Likely to Mitigate Oversupply Conditions

**Load Shifting:** The April 2012 OTOC report reflected the hope that altering retail tariffs to reduce demand charges in light load hours[2] might induce significant amounts of load to shift into those hours, thereby greatly reducing Oversupply conditions, which have primarily occurred in those hours. The potential scale of this alternative was thought to be as high as a couple thousand megawatts, with possible cost savings in the tens of millions of dollars.

To further investigate the potential of this alternative, Council staff surveyed utility tariffs and confirmed that many tariffs do expose large retail customers to demand charges during light load hours. Next, the OTOC formed a Load Shifting Workgroup that conducted a survey of utilities serving the bulk of regional load to determine the amount of load on such tariffs, and to assess the potential for load shifting. The OTOC's conclusion is that while there is load shifting potential in the region, it is in the hundreds of MW, not thousands, and will take a number of years to realize. This is still an important opportunity, but not a complete solution to the Oversupply challenge.

The OTOC recognizes that retail tariffs are driven by a large number of factors, but encourages utilities, as part of their periodic reviews of retail tariffs, to consider

[2] In this paper, the term "light load hours" is synonymous with off-peak hours, and the term "heavy load hours" is synonymous with peak hours.

examining the savings they might realize by shifting loads to light load hours, and to consider whether modification of tariffs might be appropriate to reflect the lower cost of service in light load hours.  Likewise, the OTOC encourages utilities to consider identifying and pursuing opportunities for mutually beneficial load shifting with specific customers.

**Improved Power System Coordination:** The OTOC recommends a modest amount of funding for further exploration of two areas that may yield Oversupply mitigation benefits.  These are the use of preemptive spill at nonfederal hydro projects, and the use of reservoir surcharge at nonfederal projects during Oversupply conditions, and within current operating rules and limitations for those projects.  The OTOC also recommends three actions be taken under the auspices of the NWPP Market Committee or the Joint Initiative.  These are establishing a working group of cash market traders and generation schedulers to assess the feasibility of, barriers to and potential for increased use of "other than firm" heavy load hour transactions, establishing a forum to discuss and share operational experiences and practices among industry parties relative to Oversupply conditions, and engaging Columbia Grid and NTTG in performing grid constraint analysis to increase regional understanding of possible displacement option limitations.

**Resistive Load Banks:** As described in the April 2012 OTOC report, resistive load banks may be a cost-effective alternative with theoretically unlimited potential to mitigate Oversupply conditions   However, there are many questions surrounding Resistive Load Banks that BPA is examining for Oversupply mitigation purposes.  At this point in time, BPA does not have new findings to report on this alternative.

**Keys Pump-Generating Plant Improvements:** The pump generators at Keys represent a 600 MW load, and therefore make a significant impact on Oversupply when they are available.  Since the May Steering Committee meeting BPA has conditionally approved the base level reliability investments at Keys to allow the plant to essentially maintain current operational flexibility.  This level of investment is anticipated to make the pumps more reliable, which can aid in managing Oversupply under some conditions. However, an agreement with Reclamation has not yet been signed as Columbia Basin Irrigation Districts' concurrence has not yet been obtained.

BPA will continue to work with Reclamation to evaluate the potential benefits and associated costs of further investments to the Keys facility, which could potentially improve flexibility for storing energy during Oversupply conditions.

**Demand Response**: Using demand response programs to mitigate Oversupply is an alternative not listed in the April 2012 OTOC report, but one which the OTOC explored in a limited way after the May Steering Committee meeting.  The OTOC found that the demand response technology needed to mitigate Oversupply largely exists today, and that the technological requirements to mitigate Oversupply are substantially lower than those needed for other demand response objectives such as peak shaving and within-hour power system balancing.  However, the economic value of Oversupply mitigation is not high enough by itself to justify demand response investments.  The OTOC recommends that the incremental value of Oversupply mitigation be factored into economic feasibility assessments of potential demand response programs, and that where appropriate those programs be designed to address Oversupply as well as other program objectives.

**Electric Vehicle Charging Coordination:** Electric vehicle charging is an example of the broader category of demand response. The technological requirements for tapping electric vehicle charging to boost light load hour load are not high. But the potential for such charging to make a significant difference to Oversupply over the next five years is low, because of the low numbers of vehicles likely to be present. The OTOC recommends communication take place with parties most involved in consideration of use of electric vehicles in demand management, to ensure that Oversupply mitigation potential is recognized.

**Aquifer Recharge:** BPA is wrapping up an aquifer recharge pilot project with United Electric Co-op and results and lessons learned should be available later this year. BPA is also continuing to investigate other aquifer recharge potential as well.

**Efficient Generation Displacement, Transmission System Trading Enhancements, Mini Energy Imbalance Market (EIM) Pilot, Cross Balancing Area Exchanges, Transmission System Enhancements:** These alternatives were included in the April OTOC report but were not the focus of the OTOC in its subsequent work, except to the extent they overlap with its work on Power System Coordination. However, the OTOC notes that an enormous amount of effort is underway in these areas. These improvements will help mitigate Oversupply by making it easier to identify and make transactions to absorb excess energy during Oversupply events, and also by reducing the need to hold reserves, and by expanding transmission capacity to reach markets for excess energy. This work is underway in the NWPP Market Assessment and Coordination Committee, at BPA and other utilities, at Columbia Grid and NTTP and in other venues. This work is likely to have significant spillover benefits for Oversupply. The OTOC has not identified a need for new initiatives in this area beyond those already underway and those described under Improved Power System Coordination. However, the OTOC recommends ongoing monitoring of these efforts to help ensure that opportunities to capture Oversupply mitigation benefits are actually captured. Some OTOC members are actively involved in these efforts, which will facilitate this monitoring.

**Other Alternatives Reviewed:**
With Steering Committee encouragement, three other alternatives were reviewed further by the OTOC:

> Annual Spring Outages at CGS: At the request of Steering Committee members, BPA examined annual CGS outages as a means of mitigating spring Oversupply conditions. BPA concluded that the costs and risks to reliability and worker safety would substantially outweigh Oversupply mitigation benefits and for this reason is not planning to pursue this option.

Reducing total dissolved gas (TDG) levels: The Corps of Engineers reviewed the list of potential measures to reduce TDG it had previously provided to the OTOC and concluded that some of those measures were already in progress, and the others were unlikely to be feasible.

Greater Use of Existing Flexibility in TDG Limits: At the request of the Steering Committee, the OTOC discussed the potential for mitigating Oversupply by spilling more water under certain conditions. Some OTOC members argued that additional spill is allowable under the current state and tribal TDG standards under some high flow conditions, even when it would cause TDG levels to rise above normal limits. BPA's view, supported by other OTOC members, is that its efforts to limit spill and TDG are not driven solely by the state and tribal standards, and that it has other commitments to make efforts to limit spill to protect fish under high flow conditions. More detail on both points of view is in the TDG Flexibility Appendix to this report. While OTOC members are not in full agreement on this issue, there is agreement that the OTOC is not the best forum for further advancement of this issue.

## Recommendation on Future of the OTOC

The OTOC believes that its task of identifying, examining, and recommending changes to the power system to address Oversupply has been largely completed. The OTOC does not see a current need to continue at its past level of effort. Because most of the initiatives to mitigate Oversupply are taking place as part of other larger regional efforts, the Steering Committee may wish to have the OTOC continue in a scaled back role of monitoring these efforts, to help ensure that Oversupply mitigation benefits are actually captured. This could be accomplished via semiannual reports from the OTOC to the Steering Committee on progress of these various efforts.

# Oversupply Mitigation Actions: Status and Timeline

| ACTION | Responsible Entity | STATUS | Potential Contribution | Potential Completion Date |
|---|---|---|---|---|
| Shifting Load to LLH | TBD | OTOC Supplemental Report encourages utilities to consider action. | 200-500 MW?<br>(Very rough estimate) | 2013 - 2018 |
| Efficient Generation Displacement, Transmission System Trading Enhancements, Mini Energy Imbalance Market (EIM) Pilot, Cross Balancing Area Exchanges: Transmission Expansions | NWPP MA<br>Col Grid<br>NTTG<br>Others | These are ongoing efforts with significant benefits for Oversupply. | Significant, but not quantified | 2018 |
| Resistive Load Banks | BPA | Under Study | Theoretically Unlimited | 2014 |
| Aquifer Recharge | BPA | Pilot recently completed | 200-300 MW | 2014 |
| Keys Pumped Generating Station | BPA/USBR | BPA Approve Phase 1<br>Additional phases under study | 200-300 MW for all phases | Phased in through 2021 |
| Preemptive spill at non-federal projects | OTOC | OTOC Recommendation to fund contract work | No Estimate Yet<br>Likely Under 300 MW | 2015 |
| Reservoir Surcharge at non-federal projects | OTOC | OTOC Recommendation to fund contract work | No Estimate Yet<br>Likely Under 300 MW | 2015 |

| | | | | |
|---|---|---|---|---|
| Demand Response, including electric vehicle charging | Various | Utilities moving to next-stage. OS could be added to business cases. | 400 MW | 2015? |
| Establish a working group of cash market traders and generation schedulers to assess the feasibility of, barriers to and potential for increased use of "other than firm" HLH transactions | NWPP MA | OTOC Members who also participate on NWPP MA committee will advance this | No Estimate Yet | 2013 |
| Establish a forum to discuss and share operational experiences and practices among industry parties | NWPP MA | OTOC Members who also participate on NWPP MA committee will advance this | No Estimate Yet | 2013 |
| Engage regional transmission planning groups such as NTTG and Columbia Grid to perform grid constraint analysis to increase regional understanding of possible displacement option limitations | NWPP MA | OTOC Members who also participate on NWPP MA committee will advance this | No Estimate Yet | 2013 |

# Detailed Report

Details on alternatives on which more work was done by the OTOC than contained in the Executive Summary is presented below.

## Load Shifting

The April 2012 OTOC report suggested that there may be many customers of Northwest utilities that are discouraged from shifting load into light load hours, where it would reduce Oversupply, by the possibility that they risk incurring a higher peak demand charge by doing so. Other things being equal, this situation would tend to keep loads concentrated in heavy load hours and increase total power system costs, not only during Oversupply episodes but for the rest of the year as well. While ratemaking is not a theoretically pure process, the general rationale for peak demand charges is to reflect cost components of the power system that increase with peak load, as contrasted with cost components that increase with total electricity production. Examples of the former are the fixed investments of peaking generators and the marginal costs of the transmission and distribution systems. The best example of the latter is the cost of fuel for generators. As a general rule, individual utilities' peak loads are well-correlated with their systems' peak loads, and with very few exceptions they occur during heavy load hours.[1]

The OTOC understood that the practice of assessing demand charges during off-peak periods is not universal -- a number of utilities offer tariffs that avoid this possibility by limiting peak demand charges to load during heavy load hours. However, it was not clear how many customers and how much load is exposed to such tariffs, nor how much difference it would make to Oversupply conditions if tariffs were changed. The April OTOC report suggested that potentially thousands of megawatts of load could be shifted into light load hours at little cost to utilities, or even with a cost savings. Thus, further investigation of this potential became the first priority for the OTOC. The OTOC first did a survey of utility tariffs to verify whether demand charges were assessed for light load hours. Then it surveyed regional utilities to assess how much load was subject to such tariffs, and to make a first-cut assessment of the feasibility of load shifting. A Load Shifting Workgroup then assessed and discussed the results of this survey to reach conclusions on the size of the potential.

### Tariff Review

The staff of the Northwest Power and Conservation Council reviewed the tariffs of a number of utilities in the Pacific Northwest to evaluate the effect of these tariffs on retail customers' incentives to avoid consumption of electricity during heavy load hours (generally, 6 AM to 10 PM) and increase consumption of electricity during light load hours (11 PM to 5 AM).

[1] It is possible that some components of a utility's distribution system could face peak loads during light load hours. An example is an individual substation, sized based on the peak demand on a local feeder, which could occur during light load hours. If and when this occurs it would provide a rationale for setting some part of a peak demand charge during light load hours.

The tariff review collected tariff information on peak demand charges from 25 utilities, including six investor-owned utilities (IOUs) and 19 consumer-owned utilities (COUs). The tariffs were examined to see if peak demand charges on commercial, industrial, and irrigation customers were limited to loads during heavy load hours, or based on peak loads whenever they occurred. Most utilities had more than one tariff option that involved peak demand charges and nearly all utilities had at least one tariff that levied the peak demand charge regardless of whether the peak demand occurred during heavy load hours or light load hours. In total, 10 utilities (three IOUs and seven COUs) offered at least one tariff that limited peak demand charges to loads during heavy load hours. The remaining 15 utilities (three IOUs and 12 COUs) levy peak demand charges regardless of whether peak load occurs during heavy load hours or not. This tariff review did not attempt to determine the fraction of total sales subject to peak demand charges that falls into each category. Detailed results of this tariff review are available from the Council.

Utility Survey

Sixteen utilities serving approximately 80% of the region's load responded to a load shifting survey containing the following questions:

1. How much of your non-residential load falls under tariffs where demand charges are levied irrespective of heavy or light load hours?
2. If available, what is the volume breakdown of these loads between types (i.e. commercial, industrial, institutional, irrigation), rate schedules, and sizes of loads?
3. Do you have any specific large customers that might be logical candidates for a pilot application of the load shifting concept? That is, customers who might shift load to from heavy to light load hours if they had a demand charge reduction for light load hour peaks?
4. What's your utility's initial view of the feasibility of the load shifting approach in your service territory? We are looking for any thoughts on the relative ease or difficulty and likely impact.
5. Though we don't expect it in this timeframe, any estimates of the amount of load shifting that could be accomplished would be most useful.

Detailed survey results appear in the Utility Survey appendix.

Survey responses were often inconsistent and difficult to compare and derive totals from. On the other hand, the survey responses represent the knowledge and experience of utility staff that in many cases have deep knowledge and experience with their large customers and with prior efforts to influence load shapes. The OTOC considered follow-up interviews to clarify responses and derive more reliable data. This was not done because some clear conclusions, presented below, emerged from the survey responses and subsequent discussion. The OTOC does not believe these basic conclusions would change significantly based on a refined survey. Survey respondents:

- Confirmed the observation in the April 2012 OTOC report that a large amount of regional load is subject to demand charges that apply to light load hours. Though precise numbers are difficult to derive from the survey, it is clear that over 2000 average MW of commercial, industrial, irrigation, and municipal loads in the region are subject to such rates.

- Listed less than 100 MW of specific customers they thought would be potential candidates for load shifting, but noted a number of other possible candidates without quantifying the potential.
- Were generally not able to quantify the total potential for load shifting in their service territories, but offered a number of observations that are reflected in the conclusions below.

<u>Conclusions and Recommendations on Load Shifting</u>

The Load Shifting Workgroup and the OTOC discussed the results of the utility survey and developed the following conclusions.

1. While there appears to be an opportunity for customers to shift load to off peak periods, the amount of potential load shifting appears to be relatively modest in the short term. The limited short term load shifting opportunities are due in part to many large industrial customers already having optimized their operations by running at very high capacity factors. Shifting load to off peak periods therefore would entail such customers either de-optimizing their operations, or adding more off-peak production capacity at a cost exceeding the current value of load shifting. Another reason that the potential is longer-term is that modification of tariffs can be a complex and time-consuming task. Further, existing metering infrastructure for many utilities does not support time-differentiated rates.
2. Longer term load shifting might prove more promising when combined with advancing technology such as sophisticated metering and the reduction of off-peak demand charges to better reflect the value of generating capacity during times of lower demand.
3. It is difficult to quantify the amount of long term load shifting potential absent sending price signals to customers. Price signals could be in the form of near-real-time posted prices, or longer term tariff revisions.
4. The OTOC noted that BPA's current rate structure provides a strong incentive to shift peak loads to light load hours, as it charges a relatively high marginal demand rate which applies only to peak loads in heavy load hours. While there are some complexities that can limit the value for some customers, most BPA non-Slice preference customers have opportunities for demand charge savings by shifting peak loads. The extent to which BPA's non-Slice customers transmit BPA's wholesale price signals to their end use customers is limited and further work is suggested in this area to determine if and whether there would be value in exploring this topic for the larger customers of the consumer owned customers of BPA. BPA's Slice/Block customers do not face the same price signals from BPA, though they experience wholesale market price signals which may be higher or lower than BPA's.
5. While off-peak demand is generally less expensive for utilities to meet than on-peak demand, this does not justify zeroing-out of off-peak demand charges, since utilities use demand charges to recover fixed costs that are not avoided when loads are shifted off-peak.

6. The OTOC recommends individual utilities strongly consider investing time in identifying and pursuing load shifting opportunities with specific customers, in both the short term and long term. An initial step for many utilities would be to identify the cost savings they can realize by such load shifts, as the basis for providing a price signal to their customers.
7. The OTOC also recommends that utilities without time-differentiated demand charges consider implementing them in future rate proceedings. The OTOC recognizes that many factors go into rate-setting and such a change may not make sense for some utilities. The recommendation is simply that utilities give due consideration to this change.

**<u>Improved Power System Coordination</u>**

OTOC subcommittee on Improved Power System Coordination was populated by staff from operating entities with a strong focus on identifying, examining and specifying alternatives that would be practical, pragmatic and commercially desirable so as to achieve rapid acceptance and or adoption in the marketplace. Ensuring that these efforts were conducted with the expectation that a clear business need should be met by the recommendations and that meaningful input from the operator / marketers that will be using them is considered was a paramount concern.

The subcommittee culled its area of focus to four categories that it believed were most promising for immediate discussion and examination. These four categories were "products, services & transaction platforms", "educational awareness & outreach", "unconventional hydro operational practices" and "improved forecasting techniques". Within each of these categories, a number of potential options were raised for consideration. Moreover, the subcommittee also realized that certain items may be classified into multiple categories.

The following items were ultimately identified as worthy of further investigation: use of "preemptive spill" at non-federal hydropower projects, increased use of flashboards and reservoir surcharging at non-federal hydropower projects, increased utilization of other than "firm" heavy load hour sales, improved hydropower production and stream flow forecasting, examination of the regional grid to better understand grid security requirements that may limit plant displacement opportunities (especially large thermal project displacements), increased outreach regarding operational practice sharing and increased use of WebExchange (a.k.a. "ITAP") as a posting mechanism for non-standard products bid or offered.

The main driver for these items rising on the list is that they either have the potential to create increased operational flexibility needed to mitigate Oversupply impacts and/or increase awareness of what may be able to be done or what may be available to deal with Oversupply events. In each case, at least the potential for some degree of "win-win" outcomes was determined to exist. That being said, the magnitude of mitigation that may be derived from any or all of these alternatives is unknown.

The use of “preemptive spill” at non-federal hydropower projects to provide additional operating flexibility has seen some level of use in the region already and it has demonstrated cost effective operational benefit. Similarly, the increased use of flashboards and or reservoir surcharging may be possible within the current operational limits of some nonfederal hydro projects and provide for temporary buffering to ride through and mitigate Oversupply events. These actions may be combined with better stream flow forecasting or enhanced stream flow forecast sharing relative to today’s level so as to provide increased optionality with respect to Oversupply mitigation. Similarly, an increased use of heavy load hour sales designated as interruptible or with other applicable product codes such that a reduced spinning portion of contingency reserve would be required during heavy load hours may be able to enhance light load hour optionality through increased pond evacuation potential. This may be able to be accomplished through increased use of idle quick starting units in the region that are fully capable of providing the resulting increased requirement for non-spinning portion of contingency reserve. While this increased pond evacuation resulting from these actions may not be large, it may be significant at the margin when Oversupply events tend to occur.

In addition to these actions, the subcommittee also believes that an increased effort on best practice sharing and outreach among affected industry parties may be very worthwhile. Ensuring that the best “tricks of the trade” are shared and discussed so that all regional parties can think about the applicability of them in their own systems well ahead of need is important. This type of effort should provide outcomes where valid and effective alternatives are not either overlooked or rendered unusable due to lack of preparation when needed.

Finally, the subcommittee decided that obtaining a better regional understanding of grid security requirements that may affect or constrain the ability of certain power projects to respond in Oversupply events is warranted. This is suggested in response to persistent questions that exist in the region as to what may be limits on the displacement of a resource that has been observed running during past Oversupply events – e.g. “is project XYZ needed for local voltage stability?” The result of this work would reduce uncertainty about what may be feasible regarding Oversupply mitigation when planning ahead. The starting point for this work could be use of the EPA’s CEMs data to identify potential grid constraints for further consideration.

**Recommendations:**

- Request that non-federal hydropower operators in the Pacific Northwest and Northern California assess their potential for use of preemptive spill. Only aggregate results would be made public, not results for individual owners. – *this recommendation should be pursued under the auspices of Wind Integration Forum Oversupply Technical Oversight Committee with funding for a dedicated staff resource to complete the work.*

- Request that non-federal hydropower operators in the PNW and NCAL assess their potential for additional use of flashboards and or reservoir surcharging, within current operational limits.  Only aggregate results would be made public, not results for individual owners – *this recommendation should be pursued under the auspices of Wind Integration Forum Oversupply Technical Oversight Committee with funding for a dedicated staff resource to complete the work.*

- Establish a working group of cash market traders and generation schedulers to assess the feasibility of, barriers to and potential for increased use of "other than firm" HLH transactions – *this recommendation should be pursued under the auspices of another forum such as either the NWPP MC or the Joint Initiative because it is closely associated with the scope of work being undertaken there*.

- Establish a forum to discuss and share operational experiences and practices among industry parties – *this recommendation should be pursued under the auspices of another forum such as either the NWPP MC or the Joint Initiative because it is closely associated with the scope of work being undertaken there*.

- Engage regional transmission planning groups such as NTTG and Columbia Grid to perform grid constraint analysis to increase regional understanding of possible displacement option limitations –*this recommendation should be pursued under the auspices of another forum such as either the NWPP MC or the Joint Initiative because it is closely associated with the scope of work being undertaken there*.

## Demand Response

While the Load Shifting alternative addressed above could be described as a form of demand response, the OTOC was interested in whether other forms of demand response programs could mitigate Oversupply.  BPA staff presented information to the OTOC that suggested that there is substantial Regional demand response potential, some of which overlaps the potential from Load Shifting, but much of which would not.

The following table summarizes the types of Regional demand response programs that could contribute to Oversupply mitigation, with rough estimates of costs and MW contribution.

| Load type | Peak DEC potential in MWs | 2013 | | 2014 | | 2015 | |
|---|---|---|---|---|---|---|---|
| | | % | MWs | % | MWs | % | MWs |
| Aquifer recharge | 50 | 2.5% | 1.3 | 5.0% | 2.5 | 7.5% | 3.8 |
| Cold storage* | 60 | 2.5% | 0.8 | 5.0% | 1.5 | 7.5% | 2.3 |
| Space heating* | 500 | 1.0% | 2.5 | 2.0% | 5.0 | 3.0% | 7.5 |
| C&I aggregation | 400 | 2.5% | 10.0 | 5.0% | 20.0 | 7.5% | 30.0 |
| Electric water heaters* | 5950 | 2.5% | 74.4 | 5.0% | 148.8 | 7.5% | 223.1 |
| Irrigation load shifting | 500 | 2.5% | 12.5 | 5.0% | 25.0 | 7.5% | 37.5 |
| Industrial process adjustment | 500 | 2.5% | 12.5 | 5.0% | 25.0 | 7.5% | 37.5 |
| IOU loads | 1000 | 1.0% | 10.0 | 2.0% | 20.0 | 3.0% | 30.0 |
| Municipal pumping | 75 | 2.5% | 1.9 | 5.0% | 3.8 | 7.5% | 5.6 |
| Total MWs | | 125.8 | | 251.5 | | 377.3 | |

| Annual Capacity Cost Estimates | | 2013 | 2014 | 2015 |
|---|---|---|---|---|
| Cost - low ($ per kw/month) | $2.50 | $3,772,500 | $7,545,000 | $11,317,500 |
| Cost - average ($ per kw/month) | $4.25 | $6,413,250 | $12,826,500 | $19,239,750 |
| Cost - high ($ per kw/month) | $6.00 | $9,054,000 | $18,108,000 | $27,162,000 |

BPA staff noted that demand response programs, though probably too expensive to conduct on a standalone basis to address Oversupply, are being explored because of their potential for providing a number of other system benefits. These include peak load reduction, provision of balancing and other reserves, deferral of the need for distribution and transmission system investments, and energy cost savings.

OTOC conclusions and recommendations on Demand Response are:

- Demand response programs appear to have substantial MW potential at moderate cost.
- Even though costs may be moderate, they are still higher than can be justified by the economic value of Oversupply mitigation
- However the incremental value of Oversupply mitigation, in combination with other values of demand response programs, may make them cost effective.
- The incremental value of Oversupply mitigation should be factored into economic feasibility assessments of potential demand response programs, and where appropriate those programs should be designed to address Oversupply as well as other program objectives.

**<u>Annual CGS Outage</u>**

In response to requests from Steering Committee members, BPA examined both an annual refueling outage scenario for CGS and another scenario involving a non-refueling outage every other year. BPA estimated that an annual refueling outage would increase O&M costs by $75 million per year, reduce fuel costs by $4 million per year, and reduce surplus revenues by $5 to 20 million per year, for a net cost increase of $75 to $90 million per year. These costs are well in excess of the $12 million annual expected value of Oversupply costs. BPA also noted that more refueling outages also mean more worker radiation exposure, which Energy Northwest is seeking to reduce, more exposure to nuclear safety risks, and increased reliability risk.

BPA did not conduct a separate economic analysis of shutting CGS down in the spring every other year without refueling. However BPA noted that even without refueling an annual spring shutdown would mean incremental radiation exposure and incremental nuclear safety risks and reliability risks. BPA also noted that roughly the same losses in net surplus sales revenues would occur, and that there would likely be incremental O&M costs though these were not quantified.

Based on this assessment, BPA concluded that it will not pursue annual outages at CGS.

# Utility Survey Appendix

| Question 1 | How much non-residential load falls under tariffs where demand charges are levied irrespective of heavy or light load hours? |
|---|---|
| Utility 1 | Approximately one third. |
| Utility 2 | Annual Avg. Energy – 285 aMW; Peak load - 436 MW |
| Utility 3 | Utility 3 currently does not levy demand charges on all members, particularly residential and small general service members. Having a time-dependent demand charge requires special metering if time of day metering has not been implemented. Typical residential mechanical or early digital two way metering typically collects a demand reading that is the highest value during the billing period, regardless of time of day, unless the meter is programmed for TOU periods. A significant portion of Utility 3's Total Retail Load is residential 105.9 aMW (with losses at POD) or 65.5% of annual energy (2011 Form 7)<br>Of the remaining non-residential loads at Utility 3, Mid-sized rate classes (Medium General Service – 50 to 100 kW and Large General Service – 100 to 400 kW), generally have demand charges, but these demand charges are not time of day dependent. Mid-sized rate classes typically make up 24.6 aMW / 15.2% of loads. These classes have some capability for the application of Time-based rates due to existing demand metering capability, but TOU rates have not yet been implemented.<br>For large commercial and industrial customers (Extra-Large General Service – 400 to 1,000 kW and Industrial – greater than 1 MW), Utility 3 has implemented mandatory Time of Use rates, see http://www.__.com/rates/rates.html. These make up 30.3 aMW / 18.8% of loads. TOU rates have been in effect for several months and we have seen some minor changes in operations at our largest industrial customer, such as moving maintenance periods to heavy load hours, but have not yet have a full year of data to measure the load shifting savings. It is important to note, that the development of the appropriate rate that takes into account the load shaping charges and the demand charge is needed to develop appropriate TOU rates. The hourly power cost model for each BPA customer will be different, depending upon their system shaped load, resources, and how they serve above High Water Mark load. However, once an hourly cost model is developed, it can be used as the basis for a time-based rate schedule to pass through the incentives inherent in the TRM rate design for shifting load.<br>Remaining rate classes include small irrigation and municipal street lights which account for less than 1% of total loads. |
| Utility 4 | 2 to 3 aMw |
| Utility 5 | For all non-residential load, demand charges are levied irrespective of load hours. Demand rates are not differentiated between heavy and light load hours. |

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| Utility 6 | Utility 6 has 1 non-residential tariff, Medium General Service, which has a demand charge irrespective of the time of the peak kW. As of 6/12, this tariff contains approximately 3,300 meters, 2.6 million kWh, about 25% of Utility 6 sales by kWh |
| Utility 7 | The data is based on bill determinants for the month of July 2012 only. For this month Utility 7 had 12,289,000 kWh of non-residential load with no demand charge out of a total of 168,555,000 kWh. So, 92.5% of our non-residential load has demand charges.<br>Utility 7 does have off-peak rates imbedded within our commercial and industrial tariffs (see Off-Peak Demand language below). All our large industrial customers on Schedule 85 have an off-peak demand price and commercial Schedule 34 tier two. There are very few customers and close to zero kWh's that load shift today.<br>Off - Peak Demand<br>By special contract with the Utility, off-peak demand is available for customers with demands in excess of 30 kW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 60¢/kW of demand for each kW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.<br>Data below for July 2012:<br>Schedule 34 (less than 1,500 KW)<br>· Time-Of-Use or off-peak demand customers' loads total 2,233,480 kWh and if we include wells that serve the CPU water department the total load is 2,676,250 kWh.<br>Schedule 85 – (1,500 KW or more) all include off-peak demand<br>· 185 93,310 kWh (secondary delivery)<br>· 285 16,338,910 kWh (primary delivery)<br>· 385 49,594,580 kWh (transmission delivery) |
| Utility 8 | At this time, all of Utility 8's customers' loads have demand charges levied irrespective of heavy or light load hours. |
| Utility 9 | 633,543 MWh/Year |
| Utility 10 | Utility 10 has 3 rate schedules that contain demand charges that are applied to the peak hour, irrespective of the time of day: Schedules 5, 8, and 9. The 2010 consumption data for these three rate schedules are: 22.7 aMW, 18.3 aMW, and 22.7 aMW, respectively, for a combined total of 63.7 aMW. |
| Utility 11 | All significant size non-residential load falls into this category at Utility 11. |
| Utility 12 | Utility 12 has 2,300,000 MWh of annual non-residential load with associated demand charges. |

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| Utility 13 | Approximately 861 MW of average monthly peak non-residential system load is subject to tariffs that levy seasonal demand charges. Approximately 36 MW is on interruptible tariffs. |
| Utility 14 | Approximately half of our load is under tariffs with demand charges. None of our schedules differentiate based on hlh/llh usage. |
| Utility 15 | Utility 15 has two non-residential rate classes for which demand charges are levied irrespective of heavy or light load hours, our Large General Secondary service (secondary voltage less than 1 MW and greater than 2,000 kWh per month) and Irrigation service. Based on 2011 actual data (not weather normalized) the load served under these two rate classes combined constituted approximately 35% of total energy sales. |
| Utility 16 | Industrial: Oregon 600 MW; Washington 100 MW<br>Commercial: Oregon 1,250 MW; Washington 400 MW |

| **Question 2** | **If available, what is the volume breakdown of these loads between types (i.e. commercial, industrial, institutional, irrigation), rate schedules, and sizes of loads?** |
|---|---|
| Utility 1 | The loads subject to a demand charge are under Utility 1's GS-2 and GS-3 rate schedules. While most of the load under this schedule is Industrial in nature, there are some larger facilities, such as hospitals, that fall under this category as well. |
| Utility 2 | 30% Industrial, 70% Commercial; 16% High Voltage General Rate, 71% General Service Rate, 13% CP Rate |
| Utility 3 | See answer to question 1. |
| Utility 4 | (Left blank.) |
| Utility 5 | 2011 calendar year load data (MWh):<br>Commercial 504,112<br>Industrial 65,817<br>Irrigation 382,515<br>Municipal 9,528<br>19% of load was in off peak hours; most of the off peak load was for irrigation and industrial customers. |
| Utility 6 | Not readily available |

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| Utility 7 | Commercial Rate Sch. 34 Loads with less than 1,500 KW demands: 102,528,200 kWh for July 2012 and 1,190,219,507 kWh for 2011<br>Industrial Rate Schedule 85 Loads with KW demands of 1,500 or more: 66,026,800 kWh for July 2012 and 761,628,452 kWh for 2011<br>Institutional: included in commercial<br>Irrigation: included in commercial (small number of customers…small load). |
| Utility 8 | Small 150,000 MWh, Medium 500,000 MWh, Large 200,000 MWh, Contract 500,000 MWh |
| Utility 9 | Non-Residential Loads w/ Demand Charges<br>Schedule 2 Commercial w/ Demand Charges 320,000 MWh<br>Sch. 3/30 Industrial (w/o Load Shift) 109,500 MWh<br>Sch. 3/30 Industrial (w/ Load Shift) 174,500 MWh<br>Sch. 5 Irrigation Subject to Demand 29,543 MWh<br>Total 633,543 MWh/Year |
| Utility 10 | We don't have a precise breakdown at this time. None of the load is irrigation. Nearly all of Schedule 5 would be commercial with some light industrial, i.e. less than 1,000 kW demand. Schedule 8 contains nearly all industrial with a hospital and water treatment plant. Schedule 9 is all industrial.<br>So roughly I would guess 40-50 MW is industrial and 13-23 MW is commercial. |
| Utility 11 | See attached graph |
| Utility 12 | Schedule 20 (commercial customers with load greater than 100kW but less than 5000 kW) ~1,800,000 MWh<br>Schedule 36 (commercial and industrial customers with load greater than 5000 kW) ~500,000 MWh |
| Utility 13 | See attached spreadsheet for a breakdown of load types. |
| Utility 14 | Please see the attached spreadsheet. Schedules 011, 021, 025 and 025P contain demand charges, though Schedule 011 for the most part has few customers that exceed the base demand level and who are assessed a separate demand charge (i.e., most loads are below 20 kW, where demand charges begin to be assessed under this schedule). To be a large customer service (025 or 025P) you must have a minimum demand of 3 MVA. |
| Utility 15 | Utility 15's Large General Secondary service is considered part of the commercial sector and was an estimated 23% of the total energy sales for 2011. Utility 15's Irrigation service was an estimated 12% of the total energy sales for 2011. |
| Utility 16 | See above. |

| Question 3 | Do you have any specific large customers that might be logical candidates for a pilot application of the load shifting concept? That is, customers who might shift load to from heavy to light load hours if they had a demand charge reduction for light load hour peaks? |
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| Utility 1 | Utility 1 has been evaluating demand response for some time. It is unclear why this question is directed specifically to utilities. Utility 1 has observed 3rd party aggregators entering this market and the Federal Energy Regulatory Commission's order 745 has set the tone where national policy seems to be trending towards removing financial incentives for utilities to promote demand response since FERC appears to want to transfer all economic benefit to the end user. With larger loads potentially working with third parties to do load shifting behind the meter (and outside utility control) it is conceivable that loads will have multiple agreements that may result in conflicting results (e.g. one agreement with a utility to reduce peak may be triggered while an agreement to increase load for wind integration with a third party may triggered at the same time). Utility 1 expects larger loads to enter into as many agreements as practicable to take advantage of uncoordinated market variables and maximize revenues. Until the issue is further resolved to provide certainty to utilities, it is unclear to Utility 1 why utilities would be aggressively pursuing demand response at this time. But, to answer the questions directly – yes there might be candidates for load shifting (even though it may be detrimental to utilities) and, yes, there are customers that might shift load particularly if all economic value was given to end users rather than utilities. However, Utility 1 has approached large users in the past and the economic impacts associated with modifying worker shifts and larger industrial processes are complex and not as straightforward as one might initially conclude. Also, larger users that are not industrial in nature, such as hospitals, may not have lighting or other loads that are subject to shifting due to practical concerns. There may be backup generation at some locations that could be triggered, but again, the net result of that generation may not be beneficial to utilities. Utility 1 continues to find it interesting that vendors and end users are surprised about stances similar to Utility 1's given the market environment that promotes uncertainty around utility benefits associated with demand response. Utility 1 also finds it interesting that other entities that desire market transformation and the promotion of demand response by utilities do not appear to understand the lack of regulatory incentives and significant uncertainty utilities are facing. |
| Utility 2 | There are potentially 3 customers who might have load they can shift from heavy to light load hours. |
| Utility 3 | Utility 3 currently does have one industrial customer that has been pro-active in adjusting operations for application of our implementation of the load shifting concept. They also have been good about participating in many of BPA's Energy Efficiency initiatives. Depending upon the "pilot" approach, Utility 3 may be able to assist with the regional "load shifting" effort, but this would depend upon the parameters (i.e. demand incentives for particular hours within a month). (Utility 3's TOU rate includes the following TOU periods SEASONAL DEFINITION: Winter months are defined as October L through May 31. Summer months are defined as June 1 through September 30; ON-PEAK PERIOD: Winter: Monday through Friday 7:00 a.m, to 11:00 a.m. and 6:00 p.m. to 10:00 p.m. Summer: |

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| | Monday through Friday 1:00 p.m. to 10:00 p.m. MID-PEAK PERIOD: Winter: Monday through Friday 11:00 a.m. to 6:00 p.m. Summer: None; OFF-PEAK PERIOD: All non On-Peak or Mid-Peak Period plus the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. In the event the holiday falls on a Sunday, the following Monday is an Off-Peak Period). |
| Utility 4 | We do not have any load that could shift as a block. |
| Utility 5 | No. |
| Utility 6 | When Utility 6 adopted the demand charge in the 1980s, Jorgensen Forge shifted most of its production to the off-peak periods. For Utility 6's Large and High Demand classes, there is a peak/off-peak difference in the demand and energy charges so Utility 6 does provide a price incentive to the approximately 150 largest customers that consume nearly 30% of Utility 6's total sales by kWh. |
| Utility 7 | We have one large industrial customer that has used the off-peak demand rate. They ran nearly 100% of the operation off-peak. They did this to cut operating costs. Currently they are not running off-peak. We also are looking at our large municipal and our own water departments as candidates.<br>Electric vehicle charging stations, should the infrastructure and numbers increase, would be another logical candidate. Additionally we will be contacting our industrial and key account customers to check for opportunity, interest and to identify potential candidates. |
| Utility 8 | Potential customer A 0.50 MW, B 0.50 MW, C 0.4 to 4.0 MW, D 0.3 MW |
| Utility 9 | Nearly all of our industrial fruit warehouses could do some form of load shifting, primarily during winter months by turning off industrial refrigeration compressors during peak hours. |
| Utility 10 | We do not. Much of the load is operating 24/7 now. Power cost impacts most of these customers' budgets in the 5-15% range, so they don't tend to get excited about shifting production. |
| Utility 11 | We have several large customers that are logical for a pilot and have begun a "pilot-like" effort already. |
| Utility 12 | Based on information we've learned of recently, Garth Williams, Senior Mgr of our Business Services, is checking with several of our large commercial customers who operate rock quarries in our service territory to assess potential interest and viability in the load shifting concept. |
| Utility 13 | 10 MW in 2012 ramping to 50 MW by 2015 |

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| Utility 14 | We have a few customers that might be interested if the price is right. That said, we have attempted this before and have not been greatly successful based on cost-of-service principles. |
| Utility 15 | At this time, Utility 15 has not identified any specific large customers that might be logical candidates for a pilot application of the load-shifting concept. The two rate classes mentioned above (Large General service and Irrigation service) currently have the opportunity to participate in the Company's demand response programs. The Company's Large General Primary and Transmission service and Large Power service (Industrial) customers currently have mandatory time-of-use energy rates and time-differentiated demand charges in their tariffs. |
| Utility 16 | See below. |

| **Question 4** | **What's your utility's initial view of the feasibility of the load shifting approach in your service territory? We are looking for any thoughts on the relative ease or difficulty and likely impact.** |
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| Utility 1 | Very low at this time. FERC's stance (discussed above) has substantially reduced incentives for utilities to consider demand response plans, FERC reporting and FERC compliance for pilot programs is costly, some third party entrants to the Home Area Network technology have stepped away from demand response because it was not economically practical. If Google can't make demand response work at this time (Google entered the HAN market and then removed itself), it certainly is an indicator that the demand response market has significant regulatory and technological uncertainty as well as implementation issues. |
| Utility 2 | Judging feasibility for our utility is difficult. We do not have the correct meters in place for 90% of the customers described above. Also, given our current cost structure, we are not sure we could provide much of an incentive to push customers onto this type of rate structure. |
| Utility 3 | Passing through time-based rate incentive is feasible and appropriate under the existing BPA TRM rate design, but the costs vary between customer classes, depending upon existing metering technology and configuration. Generally, for larger more sophisticated customers there appears to be some opportunity. However, there are limits to business process change and work schedules. It likely will only be a part of the solution. It is important that the incentives are not taken away in the rate making process and utilities that have taken efforts to improve their load shape are not punished in future rate case by updated data and lack of action by others. This is partially preserved by the grandfathered Contract Demand Quantities that have been finalized in contract. Thus the preservation of these grandfathered amounts is essential to the fairness of future incentives. |
| Utility 4 | We are about 80 percent residential and the industrial loads we do have could not really shift so it is not very feasible for us. |

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| Utility 5 | We have not surveyed our commercial or industrial customers. The majority of off peak load was irrigation load during May-September. We have talked to our irrigation customers, however, there is very little interest because of the risk of harming crops. Most irrigators pump and apply water 24x7 in peak times, which is usually when the load shifting is needed. Large irrigators have to pump at specific times of the day (normally the hottest time of the day). Industrial customer characteristics don't lend to load shifting. |
| Utility 6 | If Utility 6 were to upgrade to smart meters, that would increase the feasibility of a load shifting program for the Medium General Service tariff. Depending on the magnitude of price incentive required to encourge customer load shifting, such a program could conflict with Utility 6's cost recovery and cost of service policies. |
| Utility 7 | Not easy. Utility 7 staff thinks there will be many challenges to implementing a load shifting approach. Business customers face higher labor prices during off-peak hours, process challenges and in some cases would require a cultural shift. We have almost no irrigation load. Load shifting potential during super peaks to other times is probably a bit easier if the tools are available to accurately predict these times and the associated coincidental loads. |
| Utility 8 | Utility 8 believes time of use rates could be economically feasible within the next 2-5 years. |
| Utility 9 | The degree of load shifting would depend on the price signal offered. During the power crisis of December of 2000, Utility 9 offered up to $1.00 per kWh to get our industrial fruit warehouses to reduce their peak loads during a four hour period. This resulted in a peak load reduction of approximately 6 aMW during a four hour period. During the winter peak hours of 6:00 AM through 10:00 AM, these industrial fruit warehouses have a total peak of 19.8 MW. With sufficient price signals, it is likely that these same customers could temporarily turn off their compressors during this period to again save approximately 6 MW. |
| Utility 10 | We don't see much impact from load shifting in our service territory. |
| Utility 11 | Utiliity 11 believes we have a high degree of feasibility to achieve some load shifting. Initial indications on feasibility are favorable and we have an outreach and exploratory effort going now. We have briefed our Board and are working on a pilot agreement to test the structure, logistics and other factors with a single customer to inform our efforts on a broader approach. |
| Utility 12 | (Left blank.) |
| Utility 13 | We anticipated developing a Commercial/Industrial Load Control program as described above. The value of capacity in the market has made the program not cost-effective for the moment. However, we believe we will implement a program in the future. We are currently examining the feasibility of utilizing demand response to provide ancillary services, which has been advocated by FERC. |
| Utility 14 | Given our past experience, we have some concerns with regard to customer acceptance. That said, the concept of removing or relaxing the demand "penalty" for shifting loads to the llh has merit. It has been discussed internally but we have not proceeded. For us, given our technology, it would not be overly difficult to implement such a program on our medium to large customers as they have the necessary metering in place. |

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| Utility 15 | The majority of Utility 15's customer loads are either under time differentiated demand charge tariff structures or have demand response programs available to them. Utility 15's current approach is being or has been integrated into our planning and operations, and any change to the current path may be difficult at this time. |
| Utility 16 | Utility 16 does not anticipate any significant opportunities for load shifting for large customers in Oregon and Washington. Current rate design for large nonresidential customers (Schedule 48 - over 1 MW) in Oregon and Washington already contain an incentive to shift usage to off-peak hours by setting monthly demand charges based on on-peak demand. Additionally, in Oregon, energy charges are also differentiated by peak and off-peak rates. A study PacifiCorp conducted in 2006 on time of day pricing in Oregon for these large nonresidential customers included the following findings:<br>• Load research data showed no change in energy usage patterns for Sch 48 customers after implementation of time of day pricing.<br>• Survey results indicated that many Sch 48 customers do not seem responsive to time of day pricing due to the nature of their operations. (88% of respondents claimed they could not shift usage to off-peak periods.)<br>• Survey results also indicated that the financial incentive was not sufficient for those that might be able to shift usage. |

| Question 5 | Though we don't expect it in this timeframe, any estimates of the amount of load shifting that could be accomplished would be most useful. |
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| Utility 1 | Not much at this time (for load shifting "on demand" – within a relatively short period e.g. 24 hour notice or less). Utility 1 is evaluating rate changes that promote longer term shifts in usage (such as off-peak and on-peak pricing), but that is to provide incentives for end users to modify processes over the long term, rather than ramp load up and down with short term market signals. |
| Utility 2 | No, we don't have any estimates. |
| Utility 3 | Utility 3 currently does not have very much data, but we have noticed some changes to operations. Very little flexibility exists in consumer's production schedules, and can vary greatly. One opportunity for most consumers is scheduling any maintenance intervals during On-Peak periods, which may or may not be an actual load shift. Of the 30 aMW of load currently under mandatory TOU, it is conceivable that a 5% demand reduction or load shift may be realized, but this would go up or down depending upon the wholesale price differential and how a "load shift" is measured. (see FERC estimated the potential to be 5.8% in their 2008 Demand Response Report at pg 33 of http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf also lots of information on this area in http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf ) Determining what actually causes a change in load shape, takes a case by case hourly analysis. However, creating good incentives can encourage good results. There are regions of the country that have gotten further along in these areas such as |

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| | http://www.srpnet.com/prices/pdfx/July2012/ProposedSRPElectricPricePlansJuly2012.pdf and http://www.ontario-hydro.com/index.php?page=current_rates However, a good measurement and verification reference is http://www.aeic.org/load_research/AEIC-MV-Whitepaper-030409.pdf |
| Utility 4 | (Left blank.) |
| Utility 5 | Initial analysis suggests that less than 2 aMW may be available for load shifting. We have not surveyed our commercial or industrial customers so the number is probably high. |
| Utility 6 | As part of the 2008 and 2010 Integrated Resource Plans, Utility 6 studied demand response. Utility 6 estimated potential of 40 MW of home space and water heating and 0-10% of commercial load. Market prices for capacity and energy compared to the costs to allow for load shifting are not favorable to the load shifting program as of 2012. |
| Utility 7 | Utility 7 is just beginning to look at this opportunity and have discussed a potential pilot with our water utility. We have it in our IRP to study load shifting and/ or demand response over the next year or two. Though we do not have any hard data our power supply team feels a goal of somewhere in the neighborhood of a 10% shift of our demand customers load could be accomplished. |
| Utility 8 | Based on current information, the potential amount of load-shifting is about 2 MW in the next 2-5 years. |
| Utility 9 | It would take approximately four business days to create and implement the price signal mechanism to achieve a temporary load reduction program. It would take approximately three months to create a formal load reduction tariff. |
| Utility 10 | (Left blank.) |
| Utility 11 | Expect we may have between 20 – 50 MW of potential in next several years but this is a very preliminary estimate. |
| Utility 12 | (Left blank.) |
| Utility 13 | Our 2011 Integrated Resource Plan estimated achievable technical potential for demand response of 83 MW winter and 87 MW summer by 2031 (see attached). We believe these targets are readily achievable, but curtailment events would only be called under seasonal system peaking conditions. |
| Utility 14 | We have no estimates at this time. Well less than 100 MW. |
| Utility 15 | Utility 15 does not have any estimates at this time as to the amount of load shifting that could be accomplished under a load-shifting pilot. |

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| Utility 16 | As part of our IRP process, a conservation potential study is updated every few years which includes an assessment of the peak load reduction potential from capacity reduction programs, both firm (i.e., through direct or scheduled interruptions or cycling of equipment/appliances) and non-firm (i.e., through voluntary programs based on a financial incentive or time-specific price signal). The 2011 study estimated achievable potential peak demand reduction from these types of programs to be 67 MW in 2030 from commercial and industrial customers in the Utility 16 states. |

# TDG Flexibility Appendix

In response to the Steering Committee's request to examine the potential for greater use of TDG flexibility, the OTOC's representative from Renewable Northwest Project provided the following assessment of the current state and tribal TDG standards:

> **Existing Flexibility in TDG Requirements—for discussion purposes:**
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> BPA is not prosecuted for exceeding TDG standards when exceedences occur under what are known as "involuntary spill conditions." The management of TDG levels on the Mid-Columbia, Lower Columbia, and Lower Snake rivers is governed by the Total Maximum Daily Load for Total Dissolved Gas ("TMDL"), as prepared by the Washington State Department of Ecology, the Oregon Department of Environmental Quality, and the Spokane Tribe of Indians.[3] The three TMDLs explain "involuntary spill" as follows:
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>> As its name suggests, there is no choice involved in "involuntary" spill. At times of very high river flows, the quantity of water exceeds the capacity of a dam to either temporarily store the water upstream of the dam or pass the water through its turbines. … Often dissolved gas levels from involuntary spill exceed those experienced during periods of spill for fish. *However, high river flows under these circumstances are often in excess of the 7Q10 high flow, in which case the TDG standard would not apply. …Involuntary spill as a result of lack of power market is a variant of the above. In this scenario, the power marketing authority [BPA] cannot sell any more power, and even though turbines are available, water is released over the spillway because there is nowhere for electricity generated to go.*[4]
>
> When flows exceed the 7Q10 criteria (the average peak annual flow for seven consecutive days that has a recurrence interval of ten years), the Colville Tribe, Oregon and Washington's TDG criteria do not apply. In 2011, river flows exceeded the 7Q10 flow criteria as measured at the Corps' dams on the lower Columbia River and at Chief Joseph Dam from May 17.[5]
> Similarly, the 2011 Dissolved Gas and Water Temperature Report defines involuntary spill as spill that occurs when there are:
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> 1. "Hydrologic conditions and river flows that exceed the hydraulic capacity of hydro-power generation facilities; or

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[3] All available at: http://www.ecy.wa.gov/programs/wq/tmdl/ColumbiaRvr/ColumbiaTDG.html
[4] See p. 14 (Mid-Columbia), p. 14 (Lower Columbia), and p. 10 (Lower Snake). All available at: http://www.ecy.wa.gov/programs/wq/tmdl/ColumbiaRvr/ColumbiaTDG.html
[5] 2011 TDG report. P. 17

2. Market for the electricity generate from the hydro power system is less than produced by the current river flow."[6]

**BPA provided the following response:**

In its analysis entitled "Existing Flexibility in TDG Requirements" the RNP observes that "BPA is not prosecuted for exceeding TDG standards when exceedences occur under what are known as 'involuntary spill conditions.'" It also observes that "When flows exceed the 7Q10 criteria (the average peak annual flow for seven consecutive days that has a recurrence interval of ten years), the Colville Tribe, Oregon and Washington's TDG criteria do not apply." In making both observations, RNP implies that Federal agencies should disregard high flows and resulting levels that exceed TDG standards when they occur due to involuntary spill, particularly when flows exceed 7Q10 flows. BPA disagrees.

In BPA's 2011 Environmental Redispatch ROD BPA explained that TDG is managed at levels beyond the applicable state and tribal water quality standards, at pp. 6-7: "In considering the ecological objectives of the ESA and CWA, operations are planned to comply with the ESA Biological Opinions ("BiOps") and applicable state and tribal water quality standards, to the extent practicable. For Spring 2011, these spill and water quality constraints have also been adopted by court order. On March 24, 2011, Judge James A. Redden issued a Court Order in the on-going BiOp litigation mandating that 2011 spring fish operations be conducted as set forth in the 2011 Spring Fish Operation Plan ("FOP")." The 2011 Spring FOP states that during the spring freshet "the Corps will attempt to minimize TDG on a system-wide basis," using the "125, 130, and 135% saturation as a means of minimizing saturation thoughout the system." On August 2, 2011, Judge James A. Redden issued a Court Order that continues to require that "spring and summer spill operations (be conducted) consistent with this Court's annual spill orders." See p. 24, para (6) of Judge Redden's August 2, 2011 Order. The 2012 FOP contained a similar requirement.

Excess spill also can adversely affect other aquatic life and increase adult fallback. In its July 19, 2011 Answer at FERC, p.33, note 60, BPA explained that in a Washington-Oregon joint report Washington concluded that "the weight of all evidence clearly points to detrimental effects on aquatic life near the surface when TDG approaches 120%." In the same Answer, pp. 32, 122, BPA explained that RPA 29 in the FCRPS Biological Opinion places limits on the amount of spill provided to improve juvenile fish passage to avoid "high TDG supersaturation levels or adult fallback problems." NOAA has also raised a concern that high levels of spill delay adult passage "exposing them to sea lion predation." See,

[6] 2011 Dissolved Gas and Water Temperature Report. US Army Corps of Engineers, Northwestern Division, Columbia Basin Water Management Division Reservoir Control Center Water Quality Team. December, 2011. p. v

TMT Official Minutes for May 2, 2012. http://www.nwd-wc.usace.army.mil/tmt/agendas/2012/0502_Minutes_Rev3

System spill is managed using the Spill Priority List during high flow conditions involving involuntary spill. During these conditions flows at some dams may exceed state and tribal water quality standard levels and may even exceed 7Q10 levels. During these conditions there may also not be sufficient load to pass flows through available turbines, e.g. lack of load. In an April 10, 2012, letter to BPA Regional NOAA Administrator Will Stelle noted that fin gas bubble trauma symptoms increase from 3 to 6.5% as TDG levels rise from 120 to 130%. He ratified the continued use of the spill priority list at all TDG levels to minimize the impacts of high levels of TDG:

> "Accordingly, in order to protect migrating salmon and steelhead we recommended that dams should not be voluntarily operated to exceed tailrace TDG levels of 120% - consistent with the state waivers. In cases of overgenerational spill (beyond the TDG levels allowed in the state waivers) we continue to support the U.S. Army Corps of Engineers' use of the spill priority list in consultation with the Technical Management Team to minimize the impacts of these events on migrating juvenile and adult salmon and steelhead."
> http://www.salmonrecovery.gov/Hydro/Operations/TDG.aspx

In its July 19, 2011 Answer at FERC, p.35, BPA explained why it adopted the Environmental Redispatch policy:

> "During times of high flows, spill and consequent TDG levels can be reduced by additional generation, which sends water through the turbines instead of through the spillways. Because generation and load must always be balanced, however, Bonneville cannot increase generation unless it has sufficient load to absorb all the power. If BPA has insufficient load, it must curtail other sources of generation, including wind generation. Under the Environmental Redispatch policy, BPA can maximize FCRPS generation during high-water events, thus reducing excess spill and minimizing TDG levels to the lowest practical levels."

BPA adopted a similar policy (Oversupply Management Protocol) in 2012. As with the use of the spill priority list, this policy applies at TDG levels beyond the applicable state and tribal water quality standards to minimize the impacts of these events on aquatic life, including migrating juvenile and adult salmon and steelhead.