From:	Richard Lauckhart
To:	UTC DL Records Center
Cc:	david.danner@utc.wa.gov; Rendahl, Ann (UTC); Balasbas, Jay (UTC); Nightingale, David (UTC); Johnson, Steven (UTC)
Subject:	Further comments/documents for the record in Docket No. UE-160918
Date:	Wednesday, February 21, 2018 3:06:19 AM
Attachments:	Richard Lauckhart Comments made at WUTC Public Meeting February 21 red letters for speaking.docx NERC TPL-001-4.pdf Supporting Attachment 2.pdf UE-160918 Rebuttal to PSE Criticisms of the Lauckhart-Schiffman Load Flow Study.pdf

Dear Records-

Please file this email and its three attachments as comments under PSE IRP Docket No. UE-160918.

Attachment 1 contains the comments I will be making at today's Public Hearing on PSE's Integrated Resource Plan.

Attachment 2 is the NERC/FERC Reliability Criteria TPL-001-4. I am filing this document to rebut PSE's recent contention that Energize Eastside (EE) is needed to meet reliability requirements. This is the document that PSE refers to in saying that EE is needed to meet federal reliability requirements. Look at the attached 22 page document (NERC TPL-001-4) and see if you see anything in there that says a load flow study needs to have 1,500 MW flowing to Canada. You won't find it. There is a requirement that load flow studies need to attempt to meet "Firm Commitments", but there is no evidence that a "Firm Commitment" to deliver 1,500 MW to Canada exists.

We have challenged PSE to point us to any place in TPL-001-4 where it says a load flow study needs to have 1,500 MW flowing to Canada.
We have also challenged PSE to provide evidence of a "Firm Commitment" to deliver 1,500 MW to Canada.
Not surprisingly, they have produced no response to these challenges.

Further, at Attachment 1 to this TPL-001-4 Reliability requirement it states that there is a need to perform reliability studies in an open and transparent fashion with stakeholder input is described. PSE has refused not only to do this, but they also refuse to show the work they did. PSE is not complying with TPL-001-4.

Further comment on PSE criticisms of the WUTC staff comment in this Docket No. UE-160918 are:

1. PSE once again provides its very old criticisms of the Lauckhart-Schiffman report, but fails to acknowledge the rebuttal that was made to those criticms on March 28, 2016, shortly after PSEs criticisms were made. I attach that rebuttal again for your

convenience. **<u>See Attachment 3.</u>**

2. PSE states that it has responded to questions placed to it on its justification for EE. However, there are 7 key questions/challenges placed to PSE in Attachment No. 3. These key questions/challenges were given to PSE nearly two years ago. PSE has never responded to these key questions/challenges.
3. PSE's rebuttal to the WUTC staff comments in UE-160918 are full of inaccurate statements. <u>It might be best for the WUTC to require PSE to answer questions about their document under oath in a fact finding hearing that the WUTC could Order to occur.</u>

Rich Lauckhart
Energy Consultant
Davis, California
On behalf of a large number of citizens that are concerned about transmission matters in the greater Bellevue area.

Richard Lauckhart Comments made at WUTC Public Meeting February 21, 2018 re PSE IRP

My name is Richard Lauckhart. I am an energy consultant and past VP at Puget.

I will be handing out hard copies of the written comments I filed in UE-160918 on January 8, 2018. They refer to 17 documents I provided for the record in this Docket UE-160918. This binder includes those 17 documents. There is a considerable amount of information in these 17 documents.

In my comments today, I will focus on a few key matters referred to in my January 8, 2018 written comments.

1) Part way down in page one I state "*It has been long WUTC policy that a prudent decision is one which a reasonable board of directors and company management would make given the facts they know, or reasonably should know, **at the time they make the decision**, without the benefit of hindsight.*" I first became aware of this WUTC policy in the early 1980's when Puget was trying to get recovery for their $128 Million share of the $400 Million that had been spent on the Skagit Nuclear plant before it was cancelled. At that time there was not yet an IRP rule. **Parties were arguing about what Puget knew (or should have known) and when** (regarding the need for the Skagit Nuclear plant). In the end, the WUTC ruled that Puget should have stopped work on Skagit much earlier than it did. Puget was given a $46 Million disallowance on the $128 Million we had spent. Puget had to take a $46 Million write-off.
2) Out of that contentious hearing, the WUTC and Puget and others felt it would be better for all stakeholders if the matters of "what is needed and when" were brought up well before Puget asked for recovery of the money it spends. **That lead to the development of the WAC IRP Rule**. The idea was to give Puget advance notice that future expenditures could likely be considered imprudent. I was the Puget person who was involved in working on that rule. The team working on that rule obviously included WUTC staff. In the end the parties were able to agree on what would be written in that rule without the need for a contentious hearing. Originally it was called a "Least Cost Plan", then changed to Integrated Resource Plan (IRP).
3) At (6) of the IRP rules it states "The *commission will consider the information reported in the integrated resource plan when it evaluates the performance of the utility in rate and other proceedings*."
4) As required by the IRP Rule, PSE has a chapter (Chapter 8) that discusses "Delivery Infrastructure Planning" including PSE's analysis of the need for Energize Eastside. Chapter 8 is completely inadequate to demonstrate that a decision to build Energize Eastside would be a prudent decision.
5) the Power Flow (aka Load Flow) modeling performed by PSE/Quanta to demonstrate a need for the Energize Eastside project is flawed. The primary problems with their Load Flow modeling is that:

   (a) They erroneously assumed that the proposed Energize Eastside project must increase the ability of BPA to move large amounts of power to and from Canada during extremely cold temperatures in the Puget Sound region, and
   (b) They erroneously assumed that essentially all of their owned/controlled power plants located in the Puget Sound region would not be operating during this extremely cold event.

(c) With their scenario PSE ignores the Puget Sound Area **voltage collapse** problem that I first talked about in the Puget 1992 IRP (aka Least Cost Plan). See page 36 of the transcript from the May 26, 1992 public hearing on that plan Docket No. UE-910151.

6) **The Lauckhart-Schiffman Load Flow study is on the record in this proceeding. The only Load Flow study on the record in Docket No. UE-160918 that uses the load forecast PSE gave to the Western Electricity Coordinating Council, correct inter-regional flows, appropriate generation dispatch,** and avoids the voltage collapse problem. **That study concludes that Energize Eastside is not needed now or any time soon.** [*See Supporting Document 1*]

7) Clearly now is the time that PSE needs to demonstrate the need for the Energize Eastside Project. There is plenty of information in documents on record for this PSE IRP Proceeding (Docket No. UE-160918) that makes it clear that Energize Eastside is not needed. I believe that the Record before you, the WUTC Commissioners, provides ample evidence for you to find in your Order on this PSE IRP that evidence as of the date PSE is making a decision to build Energize Eastside shows that such a decision to build the Energize Eastside project would not be a prudent decision.

8) **Regarding the Lake Hills-Phantom Lake 115 KV transmission line**: Not properly studied…not needed. There has been no substantive review of this transmission project in this or in any previous IRP. As such, PSE has not complied with the IRP rule on this project. Further, PSE has failed in its duty to properly analyze the need for this transmission line. The City of Bellevue and PSE were advised by the City's consultant, Exponent, in 2012 that "looped 12.5 KV distribution" could be an alternative to the Lake Hills transmission line. But PSE failed to analyze this alternative. A prudent utility would analyze this alternative before making a decision to build this transmission line.

9) PSE has not adequately studied the need for the Lake Hills-Phantom Lake Transmission line either in its IRP or elsewhere by not looking at the Distribution solution. That being the case the WUTC should state in your Order on this PSE IRP that this Commission would deem it imprudent for purposes of rate recovery if PSE builds the line and asks for it to be included in ratebase in the future.

10) **What would motivate PSE to want to build these two transmission projects (Energize Eastside and Lake Hills-Phantom Lake) that are not needed?** The answer lies in the Macquarie investment objectives it had when it decided to buy all of the common stock of Puget nearly 10 years ago. Adding transmission ratebase increases their profits without requiring competitive bidding by third party suppliers that must be done when adding new generation. *See Supporting Documents 5 and 6*.

In Conclusion:

Your Order on this IRP should accomplish what was intended when the IRP process was set up in the 1980's. It should give PSE advance notice that any decision they make to build (a) Energize Eastside or the (b) Lake Hills-Phantom Lake transmission projects would be imprudent based on the information that is available now when they are making these decisions.

I leave you with a copy of these comments. Thank you for your attention.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in	

		Requirement 1 from Medium to High.	

March 28, 2016

Bellevue City Council
450 110th Ave. NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mayor Stokes and Councilmembers,

On March 23, PSE sent you a letter criticizing the Lauckhart-Schiffman Load Flow Study and making other inaccurate statements regarding needs and requirements for the company's Energize Eastside project. As the author of the Lauckhart-Schiffman report and a 22-year veteran of Puget Power, the citizen group CENSE asked me to respond.

There are three main areas of disagreement:

1. We disagree that PSE is required to support the export of 1,500 MW to Canada.
2. We disagree with the characterization of the project as upgrading the "backbone of the Eastside."
3. We disagree that other studies have sufficiently addressed the need for the project.

I will cover these points and some of the other lesser disagreements below. I have highlighted and numbered specific questions for PSE that we ask PSE to answer.

Where does the requirement to export 1,500 MW to Canada originate?

PSE's letter states, "Flows to and from Canada for planning purposes are set by the regional planning authority (ColumbiaGrid) in conjunction with other regional utilities."

This statement is incorrect for the following reasons:

- ColumbiaGrid does not have the authority to require exports of this magnitude at all times of year and under all operating conditions. While ColumbiaGrid has written that NERC Reliability Standards require 1,500 MW to flow to Canada, there is no evidence that such a requirement exists in the NERC Reliability Criteria. There is also no requirement in ColumbiaGrid's Planning and Expansion Functional Agreement.

  1. **We challenge PSE or ColumbiaGrid to cite a specific requirement to transmit 1,500 MW to Canada in the NERC Reliability Criteria or PEFA.**

- CENSE asked FERC to require ColumbiaGrid to run PSE's load flow studies in a transparent fashion with stakeholder input. FERC rejected this request, because PSE did not submit the project as a part of a Regional Transmission Plan, therefore FERC does not have jurisdiction over it. If FERC does not have jurisdiction, neither does ColumbiaGrid. Neither of these organizations can require PSE ratepayers to pay for a line that supports delivery of 1,500 MW to Canada, when smaller and less expensive solutions are possible without this export requirement.

- Any "Firm Commitment" to move 1,500 MW of power to Canada requires a written contract. PSE has refused to show any contract demonstrating such a requirement exists, but instead referred us to BPA. BPA is the only utility in Washington State that has power lines that can transmit power to Canada. In response to a Freedom of Information Act request, BPA has stated it has no such contract.

2. We challenge PSE, ColumbiaGrid, or BPA to produce a contract showing a Firm Commitment to deliver 1,500 MW to Canada.

- The Western Electricity Coordinating Council (WECC) provides Base Cases for utilities and stakeholders to use for load flow studies. The WECC Base Case for heavy winter consumption in 2018 specifies only 500 MW flowing to Canada. PSE does not dispute this fact. PSE has stated that it uses WECC Base Cases as the basis for its studies. If PSE ran a load flow study for the winter of 2018 that had 1,500 MW flowing to Canada, then engineers running the simulation must have increased the flow to Canada by 1,000 MW.

3. We challenge PSE to prove that they did not increase flow to Canada relative to the WECC Base Case.

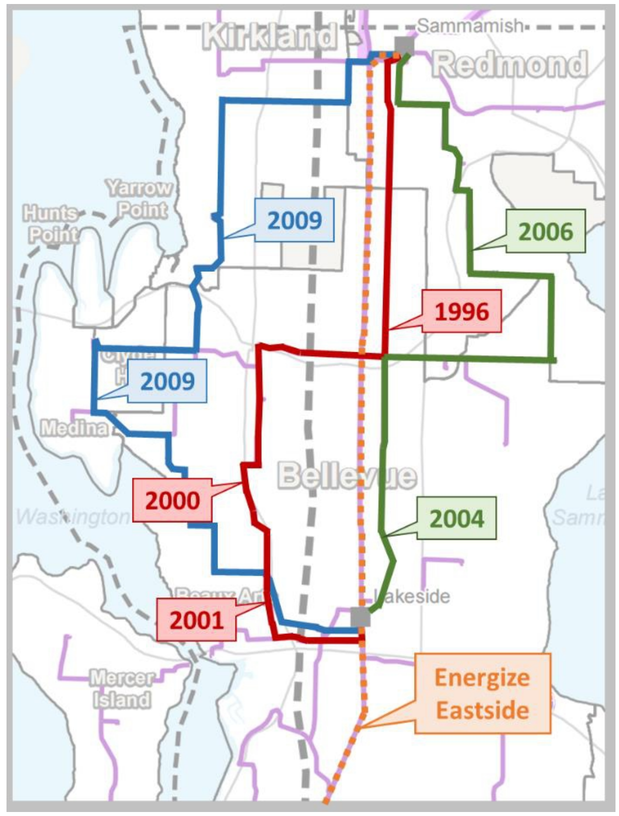
- Lauckhart and Schiffman tried to duplicate PSE's work by starting with the WECC Base Case for heavy winter consumption in 2018. We modified the Base Case by increasing flow to Canada from 500 MW to 1,500 MW. The simulation identified a problem with lines that carry electricity across the Cascade mountain range from central Washington to the Puget Sound region. Unless PSE has a specific solution to this problem, it invalidates the assumptions that underlie the Energize Eastside project.

4. We challenge PSE to explain how they solved issues that arise from their scenario with the electrical limits of the "West of Cascades-North" transmission lines.

- We have asked for PSE's study data so we can determine whether PSE solved this problem or simply ignored it. PSE has refused to share the data. **Until PSE provides these files, PSE's load flow studies should not be considered adequately vetted for purposes of approving or permitting the Energize Eastside project.**

Is the project needed to upgrade the "backbone of the Eastside?"

PSE describes the Energize Eastside transmission lines as the "backbone of the Eastside" that hasn't been upgraded for 60 years. This is a marketing ploy that distorts the truth. These transmission lines might have been a backbone some decades ago when they were the only north-south transmission lines through Bellevue. However, it is my understanding that in the last 20 years, PSE has constructed numerous transmission line segments, completing three additional north-south transmission lines through Bellevue. These are shown with dates of completion in the map shown here that was included in the Draft EIS.



The red transmission line between the Lakeside and Sammamish substations was completed in 2001. The green line was completed in 2006, and the blue line was completed in 2009. This represents a 250% increase in north-south capacity during the last 15 years. PSE has not been sitting on its hands, as its public statements imply.

These new lines provide enough capacity and redundancy that PSE says the two Energize Eastside lines could be removed for 9 months of the year with no impact on system reliability. In fact, I believe they could be removed entirely if they weren't needed to transmit regional electricity during periods of high local demand.

The transmission of regional electricity is primarily an economic transaction, not a reliability requirement. These transactions benefit BPA, which receives income from such transfers. To the extent that this project benefits regional transmission capacity, BPA should be contributing funds to the project. The burden should not be placed solely on PSE's ratepayers.

Did Lauckhart-Schiffman study stresses correctly?

PSE faults Lauckhart-Schiffman for reviewing "only limited N-0 and N-1-1 contingencies" rather than "variations of N-0, N-1, N-1-1, and N-2." This statement is incorrect. Our analysis evaluated N-0, N-1 and N-1-1 contingencies. For this type of study an N-2 contingency is the same as an N-1-1 contingency. Further, these contingencies are irrelevant until we address the fundamental questions of whether 1,500 MW must be exported to Canada and whether the regional grid can handle that.

Did Lauckhart-Schiffman use correct growth projections?

PSE is vague about how they calculate a 2.4% annual rate of demand growth based on significantly lower rates of population and economic growth for the Eastside. PSE frequently makes the case they repeat in their letter, "Projections … show a 2.4% growth rate for the Eastside – growth you can see when you look out your window or walk down the streets of Bellevue." PSE is using a qualitative argument, when we want quantitative confirmation. No independent consultant has independently verified the accuracy of PSE's projections.

Lauckhart and Schiffman calculated the rate of growth from data PSE provided to WECC. By comparing the numbers PSE provided for loads on Eastside substations in the 2014, 2018, and 2020 WECC Base Cases, we calculated a growth rate of 0.5%.

5. **We challenge PSE to explain their methodology leading to a 2.4% growth rate. We further challenge PSE to dispute the methodology used by Lauckhart-Schiffman to estimate future growth. Both methods should be reviewed by qualified experts.**

Did Lauckhart-Schiffman study local generation plants correctly?

PSE's letter says, "It doesn't matter which generators are turned on or off when analyzing problems with the Eastside transmission delivery system." We disagree. These generators might not directly serve Eastside load, but turning them off forces more power to flow through the transformers that PSE says are overloading in its scenario. If the generators don't matter, PSE shouldn't object that we turned them on in the Lauckhart-Schiffman study (just like was done in the WECC Base Case).

One fact is beyond dispute. Turning off 1,400 MW of generation in the Puget Sound area would require that amount of electricity to be imported from central Washington (since PSE insists that it can't come from Canada). We believe that the transmission lines carrying electricity from central Washington do not have sufficient capacity to deliver that additional power along with 1,500 MW to Canada. Once again, this is an unrealistic scenario.

6. **We challenge PSE to cite standards that require them to turn off 6 local generation plants at the same time they are serving peak demand with an N-1-1 contingency.**

What criteria should be used in planning?

PSE says, "Lauckhart and Schiffman are making an observation regarding how an electric system operator may potentially operate the system in an emergency situation, which is irrelevant to planning." This misstates our objection. We say that the system cannot be operated in the scenario PSE is proposing without causing blackouts in the Puget Sound Region. It is reasonable and prudent to consider how grid operators would respond in that scenario. PSE argues that it is acceptable to justify their plan for the Eastside using a scenario that would cause blackouts elsewhere in the region.

Do other studies prove the need for Energize Eastside?

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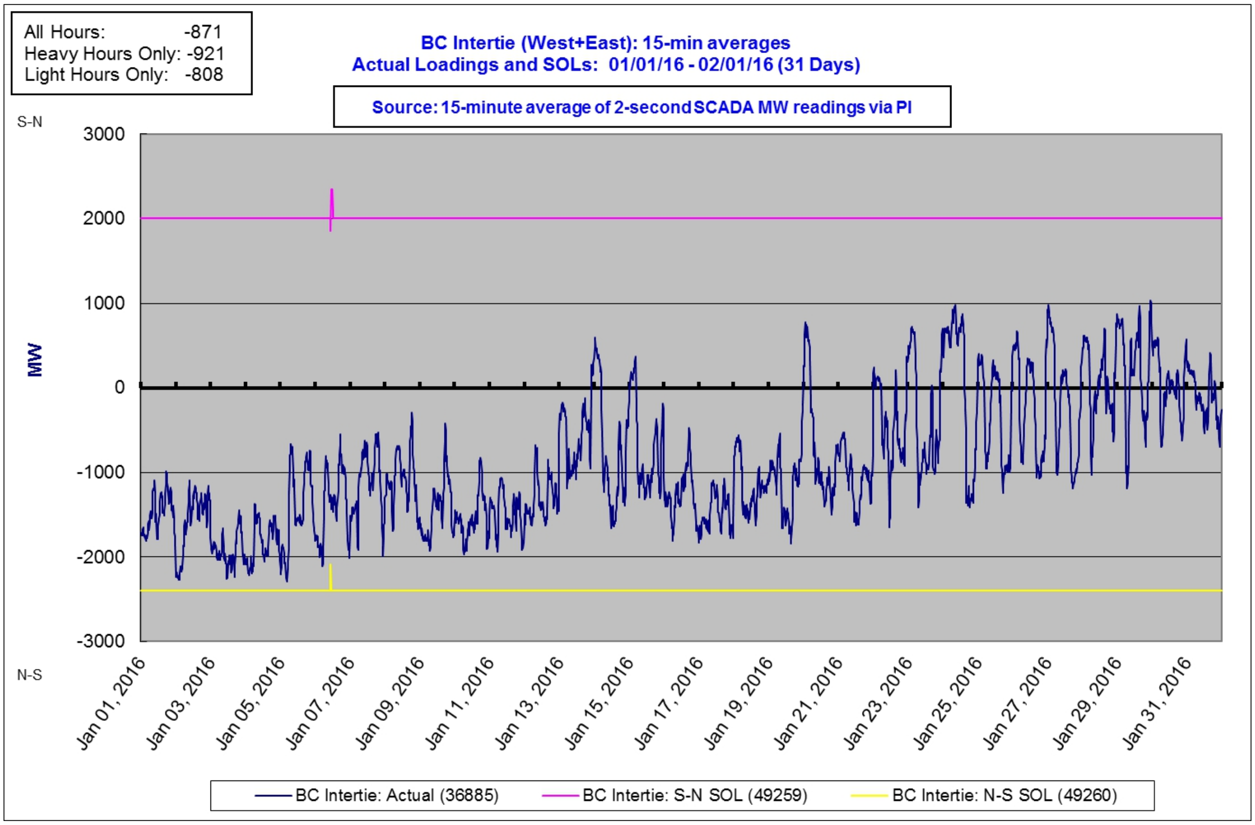

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This graph is significant, because energy flowing from Canada reduces stress on the transformers that PSE says are vulnerable to overloads during heavy winter peak demand. There is no evidence during the past decade that large amounts of electricity flow northward during very cold winter weather. If PSE says there is a contractual obligation to transmit large amounts of electricity to Canada at all times and under all conditions, why wasn't this done in January 2016?

7. We challenge PSE or BPA to provide examples of when 1,500 MW was transferred to Canada when temperatures in the Puget Sound region were lower than 23° F, as stipulated in PSE's *Energize Eastside Needs Assessment*.

Summary

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Sincerely,

Richard Lauckhart

Richard Lauckhart
CENSE consultant

Cc: Booga Gilbertson, PSE
Brad Miyake
Kate Berens

Supporting Attachment No. 2

To Comments made by Richard Lauckhart dated December 11, 2017

Rebuttal to PSE criticisms of Lauckhart-Schiffman

(including Q's and challenges to PSE)

March 28, 2016

Bellevue City Council
450 110th Ave. NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mayor Stokes and Councilmembers,

On March 23, PSE sent you a letter criticizing the Lauckhart-Schiffman Load Flow Study and making other inaccurate statements regarding needs and requirements for the company's Energize Eastside project. As the author of the Lauckhart-Schiffman report and a 22-year veteran of Puget Power, the citizen group CENSE asked me to respond.

There are three main areas of disagreement:

1. We disagree that PSE is required to support the export of 1,500 MW to Canada.
2. We disagree with the characterization of the project as upgrading the "backbone of the Eastside."
3. We disagree that other studies have sufficiently addressed the need for the project.

I will cover these points and some of the other lesser disagreements below. I have highlighted and numbered specific questions for PSE that we ask PSE to answer.

Where does the requirement to export 1,500 MW to Canada originate?

PSE's letter states, "Flows to and from Canada for planning purposes are set by the regional planning authority (ColumbiaGrid) in conjunction with other regional utilities."

This statement is incorrect for the following reasons:

- ColumbiaGrid does not have the authority to require exports of this magnitude at all times of year and under all operating conditions. While ColumbiaGrid has written that NERC Reliability Standards require 1,500 MW to flow to Canada, there is no evidence that such a requirement exists in the NERC Reliability Criteria. There is also no requirement in ColumbiaGrid's Planning and Expansion Functional Agreement.

1. We challenge PSE or ColumbiaGrid to cite a specific requirement to transmit 1,500 MW to Canada in the NERC Reliability Criteria or PEFA.

- CENSE asked FERC to require ColumbiaGrid to run PSE's load flow studies in a transparent fashion with stakeholder input. FERC rejected this request, because PSE did not submit the project as a part of a Regional Transmission Plan, therefore FERC does not have jurisdiction over it. If FERC does not have jurisdiction, neither does ColumbiaGrid. Neither of these organizations can require PSE ratepayers to pay for a line that supports delivery of 1,500 MW to Canada, when smaller and less expensive solutions are possible without this export requirement.

- Any "Firm Commitment" to move 1,500 MW of power to Canada requires a written contract. PSE has refused to show any contract demonstrating such a requirement exists, but instead referred us to BPA. BPA is the only utility in Washington State that has power lines that can transmit power to Canada. In response to a Freedom of Information Act request, BPA has stated it has no such contract.

> **2. We challenge PSE, ColumbiaGrid, or BPA to produce a contract showing a Firm Commitment to deliver 1,500 MW to Canada.**

- The Western Electricity Coordinating Council (WECC) provides Base Cases for utilities and stakeholders to use for load flow studies. The WECC Base Case for heavy winter consumption in 2018 specifies only 500 MW flowing to Canada. PSE does not dispute this fact. PSE has stated that it uses WECC Base Cases as the basis for its studies. If PSE ran a load flow study for the winter of 2018 that had 1,500 MW flowing to Canada, then engineers running the simulation must have increased the flow to Canada by 1,000 MW.

> **3. We challenge PSE to prove that they did not increase flow to Canada relative to the WECC Base Case.**

- Lauckhart and Schiffman tried to duplicate PSE's work by starting with the WECC Base Case for heavy winter consumption in 2018. We modified the Base Case by increasing flow to Canada from 500 MW to 1,500 MW. The simulation identified a problem with lines that carry electricity across the Cascade mountain range from central Washington to the Puget Sound region. Unless PSE has a specific solution to this problem, it invalidates the assumptions that underlie the Energize Eastside project.

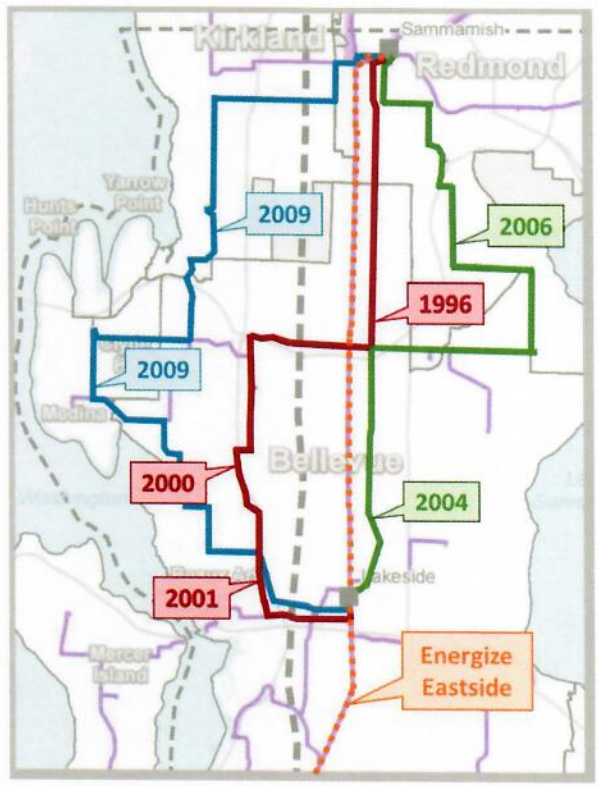
> **4. We challenge PSE to explain how they solved issues that arise from their scenario with the electrical limits of the "West of Cascades-North" transmission lines.**

- We have asked for PSE's study data so we can determine whether PSE solved this problem or simply ignored it. PSE has refused to share the data. **Until PSE provides these files, PSE's load flow studies should not be considered adequately vetted for purposes of approving or permitting the Energize Eastside project.**

Is the project needed to upgrade the "backbone of the Eastside?"

PSE describes the Energize Eastside transmission lines as the "backbone of the Eastside" that hasn't been upgraded for 60 years. This is a marketing ploy that distorts the truth. These transmission lines might have been a backbone some decades ago when they were the only north-south transmission lines through Bellevue. However, it is my understanding that in the last 20 years, PSE has constructed numerous transmission line segments, completing three additional north-south transmission lines through Bellevue. These are shown with dates of completion in the map shown here that was included in the Draft EIS.

The red transmission line between the Lakeside and Sammamish substations was completed in 2001. The green line was completed in 2006, and the blue line was completed in 2009. This represents a 250% increase in north-south capacity during the last 15 years. PSE has not been sitting on its hands, as its public statements imply.



These new lines provide enough capacity and redundancy that PSE says the two Energize Eastside lines could be removed for 9 months of the year with no impact on system reliability. In fact, I believe they could be removed entirely if they weren't needed to transmit regional electricity during periods of high local demand.

The transmission of regional electricity is primarily an economic transaction, not a reliability requirement. These transactions benefit BPA, which receives income from such transfers. To the extent that this project benefits regional transmission capacity, BPA should be contributing funds to the project. The burden should not be placed solely on PSE's ratepayers.

Did Lauckhart-Schiffman study stresses correctly?

PSE faults Lauckhart-Schiffman for reviewing "only limited N-0 and N-1-1 contingencies" rather than "variations of N-0, N-1, N-1-1, and N-2." This statement is incorrect. Our analysis evaluated N-0, N-1 and N-1-1 contingencies. For this type of study an N-2 contingency is the same as an N-1-1 contingency. Further, these contingencies are irrelevant until we address the fundamental questions of whether 1,500 MW must be exported to Canada and whether the regional grid can handle that.

Did Lauckhart-Schiffman use correct growth projections?

PSE is vague about how they calculate a 2.4% annual rate of demand growth based on significantly lower rates of population and economic growth for the Eastside. PSE frequently makes the case they repeat in their letter, "Projections ... show a 2.4% growth rate for the Eastside – growth you can see when you look out your window or walk down the streets of Bellevue." PSE is using a qualitative argument, when we want quantitative confirmation. No independent consultant has independently verified the accuracy of PSE's projections.

Lauckhart and Schiffman calculated the rate of growth from data PSE provided to WECC. By comparing the numbers PSE provided for loads on Eastside substations in the 2014, 2018, and 2020 WECC Base Cases, we calculated a growth rate of 0.5%.

5. **We challenge PSE to explain their methodology leading to a 2.4% growth rate. We further challenge PSE to dispute the methodology used by Lauckhart-Schiffman to estimate future growth. Both methods should be reviewed by qualified experts.**

Did Lauckhart-Schiffman study local generation plants correctly?

PSE's letter says, "It doesn't matter which generators are turned on or off when analyzing problems with the Eastside transmission delivery system." We disagree. These generators might not directly serve Eastside load, but turning them off forces more power to flow through the transformers that PSE says are overloading in its scenario. If the generators don't matter, PSE shouldn't object that we turned them on in the Lauckhart-Schiffman study (just like was done in the WECC Base Case).

One fact is beyond dispute. Turning off 1,400 MW of generation in the Puget Sound area would require that amount of electricity to be imported from central Washington (since PSE insists that it can't come from Canada). We believe that the transmission lines carrying electricity from central Washington do not have sufficient capacity to deliver that additional power along with 1,500 MW to Canada. Once again, this is an unrealistic scenario.

6. **We challenge PSE to cite standards that require them to turn off 6 local generation plants at the same time they are serving peak demand with an N-1-1 contingency.**

What criteria should be used in planning?

PSE says, "Lauckhart and Schiffman are making an observation regarding how an electric system operator may potentially operate the system in an emergency situation, which is irrelevant to planning." This misstates our objection. We say that the system cannot be operated in the scenario PSE is proposing without causing blackouts in the Puget Sound Region. It is reasonable and prudent to consider how grid operators would respond in that scenario. PSE argues that it is acceptable to justify their plan for the Eastside using a scenario that would cause blackouts elsewhere in the region.

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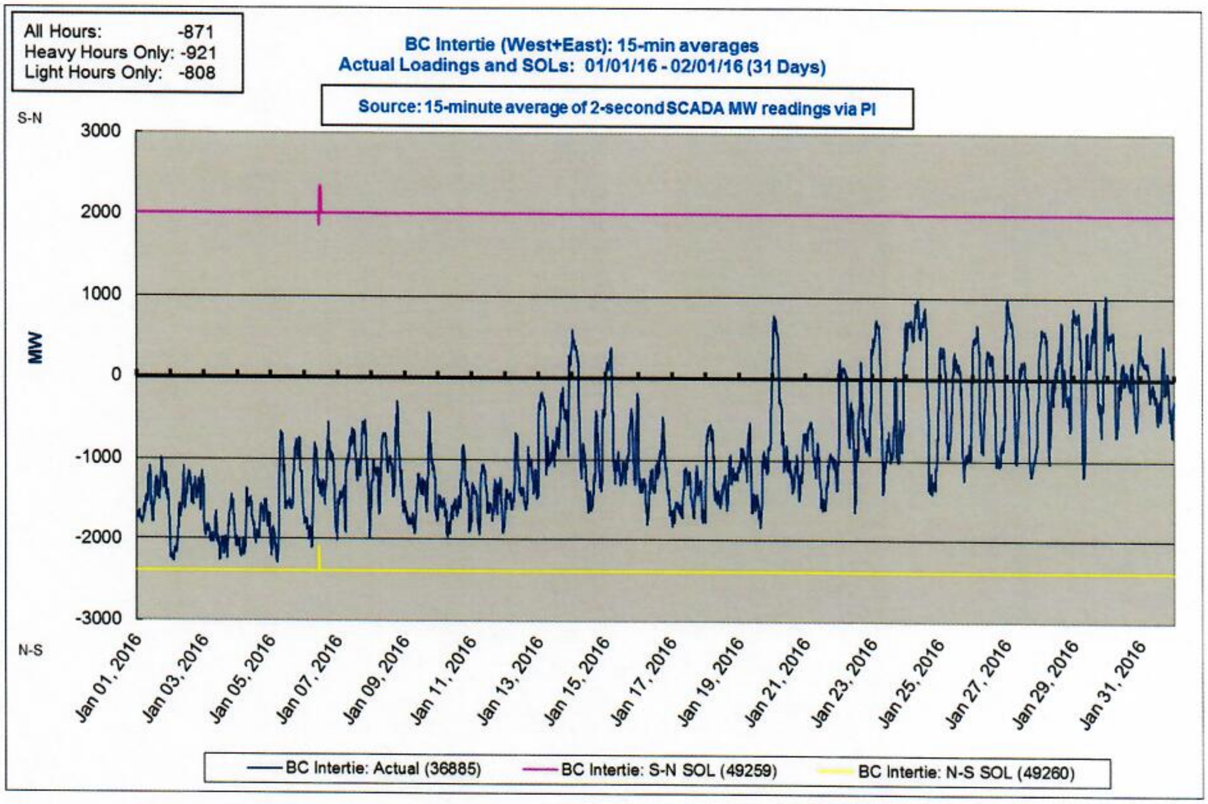

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