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December 18, 2018

VIA ELECTRONIC FILING

Oregon Public Utility Commission
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: PCN-2 – Tillamook People’s Utility District’s Errata Supplemental Testimony

Filing Center,

Attached for filing in Docket PCN-2 is Tillamook People’s Utility District’s errata filing of TPUD/400, the testimony of KC Fagen filed yesterday. This version corrects an error in the header of the testimony and should replace the original.

Please let us know if you have any questions.

Sincerely,

A handwritten signature in blue ink, appearing to read 'TAB', with a long horizontal flourish extending to the right.

Tommy A. Brooks

TAB:lms

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PCN-2

In the Matter of)
)
TILLAMOOK PEOPLE’S UTILITY)
DISTRICT,)
)
Petition for Certification of Public)
Convenience and Necessity.)
_____)

**SUPPLEMENTAL TESTIMONY OF KC FAGEN
ON BEHALF OF
TILLAMOOK PEOPLE’S UTILITY DISTRICT**

December 17, 2018

1 **Q. PLEASE STATE YOUR NAME AND OCCUPATION.**

2 A. My name is KC Fagen and I am the Engineering Manager for the Tillamook People's
3 Utility District ("TPUD" or "District").

4 **Q. HAVE YOU ALREADY PROVIDED TESTIMONY IN THIS PROCEEDING?**

5 A. Yes. I testified through submittal of the pre-filed testimony identified as TPUD/200 and
6 TPUD/300, along with the exhibits accompanying that testimony. I also appeared in person
7 during the evidentiary hearing in this matter and provided sworn testimony.

8 **Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR**
9 **TESTIMONY?**

10 A. Yes. Included with this testimony are exhibits TPUD/401 through TPUD/419.

11 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

12 A. Following the evidentiary hearing in this docket, the Public Utility Commission of Oregon
13 ("Commission") issued a request for supplemental testimony, posing several specific
14 questions to TPUD. The purpose of my testimony is to respond to those questions and to
15 provide the supporting detail the Commission requested. In this testimony I will also
16 provide a more detailed update to the Commission regarding the land use proceedings in
17 Tillamook County ("County") relating to the County's approval of the Transmission Line.

18 **Q. THE COMMISSION'S FIRST SET OF QUESTIONS TO THE DISTRICT ASKED**
19 **IF TPUD'S CAPACITY CONCERN IS SYSTEM-WIDE OR LIMITED TO THE**
20 **WILSON SUBSTATION. THE COMMISSION ALSO ASKED IF YOU WOULD**
21 **EXPLAIN ANY CAPACITY CONCERN AT OTHER SUBSTATIONS, AND HOW**
22 **THE DEMAND AT OCEANSIDE/NETARTS FIGURES INTO TPUD'S**
23 **CAPACITY REQUIREMENTS. HOW DO YOU RESPOND TO THOSE**
24 **QUESTIONS?**

25 A. TPUD's capacity concerns are not system-wide and are limited to three areas within the
26 District's service territory. Capacity concerns exist: (1) in the central Tillamook valley
27 where electric power originates from the Wilson, Trask, and Garibaldi substations; (2) in

1 the Oceanside/Netarts area where electric power originates from the Wilson substation;
2 and (3) in the Neskowin area located in south Tillamook County, where the electric
3 power originates from the Nestucca substation.

4 The capacity concerns in the central Tillamook valley and in the
5 Oceanside/Netarts areas are related. The electric demand in Oceanside/Netarts
6 contributes to the capacity concerns in the central Tillamook valley and, specifically, the
7 Wilson substation. The electric circuit that provides electricity to Oceanside/Netarts is
8 Feeder W51 and the current electric demand is nearing the capacity of the electric wire.

9 The way TPUD's system was constructed, there is no direct electric connection
10 between the central Tillamook valley or the Oceanside/Netarts areas and the Neskowin
11 area or other areas of the District's service territory. Exhibit No. TPUD/102, Simmons/1
12 shows a map of TPUD's transmission lines and substations. Two other sources of
13 electric power, the Beaver and Hebo substations, serve the areas between the Neskowin
14 area and the central Tillamook valley area. The capacity concerns at Oceanside/Netarts
15 therefore do not figure into the capacity issues in the Neskowin area.

16 The capacity concerns in the Neskowin area, which, again, are unrelated to the
17 concerns in the Oceanside/Netarts area, are the ability to serve the Neskowin customers
18 under N-1 conditions, i.e. the loss of the Nestucca substation. The electric demand in
19 Neskowin is approaching 10 MW and is approximately 7 miles from the Neskowin
20 substation and another 6.7 miles from the Hebo substation, which is the backup supply of
21 electricity.

22 **Q. THE COMMISSION'S SECOND QUESTION FIRST ASKS YOU TO "PROVIDE A**
23 **REEVALUATION OF TPUD'S CAPACITY NEED FOR OPTION 4, GIVEN THE 12**
24 **MVA OF CAPACITY ASSOCIATED WITH OPTION 3 HAS BEEN INSTALLED." AS**
25 **PART OF THAT INQUIRY, THE COMMISSION ASKS YOU TO SHOW ALL**
26 **FORMULAE AND THE VARIABLES USED IN THE CALCULATIONS AND**

1 **EXPLAIN THEIR USE. IT FURTHER ASKS YOU TO EXPLAIN WHETHER THE**
2 **RESULTS ARE BASED ON ONE SUBSTATION OR SYSTEM-WIDE AND THE**
3 **CORRESPONDING PEAK DEMAND GROWTH RATES. CAN YOU RESPOND?**

4 A. I have performed the re-evaluation the Commission has requested. By way of
5 background, the evaluation I originally performed looked at the pros and cons of various
6 options for adding capacity to the portion of the District's system serving the
7 Netarts/Oceanside area. Option 4 is the Transmission Line. Option 3 had two
8 components: (1) upgrade a transformer (T1) in the Wilson substation, and (2) construct a
9 second distribution circuit between the Trask substation and the Netarts/Oceanside area
10 to operate in tandem with the existing distribution feeder (W51). After we filed the
11 Petition in this proceeding, the original Wilson T1 transformer had ancillary equipment
12 fail during the 2017-18 winter and the District determined that replacing the transformer
13 was more beneficial than refurbishing the 46-year-old transformer and replacing the
14 ancillary equipment. TPUD has now completed the upgrade of the Wilson T1
15 transformer.

16 When I re-evaluate the capacity need for Option 4 based on the additional
17 capacity from increasing the Wilson T1 transformer size, I conclude that the District's
18 system in this area can accommodate between only eight and seventeen years of
19 additional load growth before it will no longer be able to serve customer loads under N-1
20 conditions, with the lower end of that range being the more likely result. This is different
21 than my original analysis, before the upgrade of Wilson T1, when the system in this area
22 was already operating at capacity and could not serve any future loads under N-1
23 conditions. That difference, however, does not change the need for the Transmission
24 Line.

1 Electric loads and peak demands are increasing in Tillamook County and, more
2 specifically, in the central Tillamook valley and Oceanside/Netarts areas. While the
3 additional capacity from the replacement of Wilson T1 is beneficial to TPUD and its
4 customers, the additional capacity from that upgrade does not last long, and it does not
5 address the reliability issues facing the approximately 1,700 customers in the Whiskey Creek,
6 Netarts, and Oceanside communities.

7 **Q. HOW DID YOU DETERMINE THAT THE UPGRADE OF WILSON T1**
8 **PROVIDES EIGHT TO SEVENTEEN YEARS OF CAPACITY?**

9 A. As a starting point, the capacity was re-evaluated based on the upgrade to the Wilson T1
10 transformer providing an additional 11.5MVA of capacity. This was also the basis of the
11 original capacity analysis, but I had rounded the additional capacity to 12MVA. To
12 determine the longevity of the additional capacity from upgrading the Wilson T1 transformer,
13 I considered different assumptions regarding load growth on this part of our system. If I
14 assume there has been no load growth in the peak demand since 2009, which is clearly not
15 the case, and that future load growth will be at 0.9259 percent per year, the additional
16 increase in capacity of 11.5MVA would provide approximately 17 years of additional
17 capacity.¹ Based on a more complete analysis, however, the load growth trend for peak
18 demand and average use has actually been 0.8848 percent per year and 0.9259 percent per
19 year, respectively, over the 9 year period from October 2006 to March 2016. Based on that
20 analysis, the remaining capacity we have after the upgrade of the Wilson T1 transformer is
21 approximately eight years.²

22 **Q. WOULD YOU PLEASE DESCRIBE IN DETAIL HOW YOU ARRIVED AT THE**
23 **SEVENTEEN-YEAR AND EIGHT-YEAR FIGURES?**
24

¹ See Exh. TPUD/401 (WT1 WT2 tab at line 27).

² See Exh. TPUD/401 (WT1 WT2 tab at line 18).

1 A. As I described above, the seventeen-year figure and the eight-year figure both rely on an
2 understanding of what our electrical peak demand in this area has been and will continue
3 to be.

4 To determine peak demand, I used electric demand data from the highest coincident
5 system peak that occurred on December 10, 2009 of 133MVA (130.846MW),³ when
6 temperatures dropped down to around 10 degrees Fahrenheit. The highest coincident peak
7 load for the central Tillamook valley was recorded at 91MVA (89MW)⁴ on the same date and
8 time as the system coincident peak of December 10, 2009, which includes loads from
9 Wilson, Trask and Garibaldi substations. I also reviewed the historic coincident peak load
10 for Wilson T1 and Wilson T2 which was 63MVA⁵ on December 10, 2009 at 8am, where
11 Wilson T1 and Wilson T2 were recorded at 42MVA and 21MVA, respectively. The
12 conclusion is that the local electric load, i.e. the Wilson substation, peaked at the same time
13 as the region area and the system, hence the coincident and non-coincident electric peak
14 demand are the same. When I reviewed data at the individual transformer level for the
15 Wilson substation, this was not the case due to shifting of electric load between the two
16 Wilson transformers.

17 To determine the load growth used in this calculation, I reviewed several factors,
18 including the number of new meters, major changes in industrial loads, trending of energy
19 (average loading), and trending of annual peak loads.

20 The District does not retain individual feeder data for more than a few years and
21 therefore does not have load data at the feeder level that can be used to look at how electric
22 loads have changed. Because of the lack of historic data at the feeder level, I used the best

³ Exh. No. TPUD/402 (Summaries tab, cell N16).

⁴ Exh. No. TPUD/403 (Load Sum Paste Values tab, cell L2172).

⁵ Exh. No. TPUD/404 (WT2 BPA Meter Data tab, Cell I32401).

1 available data (the number of electric services) to determine the change in electric usage in
2 the Oceanside/Netarts area, which is serviced by Feeder W51. The total number of electric
3 services on Feeder W51 in 2018 was 1,895, and that number increased by 95 services from
4 2009 through September 2018 as shown in Exhibit No. TPUD/405.⁶ This equates to an
5 average of 9.5 (95 meters divided by 10 years) new electric services per year and a growth
6 rate of 0.53 percent per year in the Oceanside/Netarts area over the past 10 years.⁷

7 **Q. DOES THE DISTRICT HAVE ANY OTHER INDICATION THAT THE ELECTRIC**
8 **LOADS WILL CONTINUE TO INCREASE?**

9 A. Yes. TPUD has recently received applications for electric services for the development of
10 111 new residential lots⁸ and a new commercial business⁹ in the Oceanside/Netarts area.
11 Currently, there are 13 residential lots and a commercial lot under construction. In addition,
12 earth work has started on a 66 residential lot development that is included in the above
13 referenced 111 new residential lots. Developers estimate the residential lot development will
14 be completed within the next 3 to 5 years. Even if the District experiences growth at half that
15 rate ($112/2/5 = 11.2$ new meters per year), the rate of new services would exceed the current
16 10-year average. This demonstrates that the Oceanside/Netarts area has been and is
17 continuing to grow.

18 To verify the reasonableness of this method to estimate load growth, I also reviewed
19 the number of electric meters at the system level. Based on that analysis, the number of new

⁶ See Charts tab in the spreadsheet.

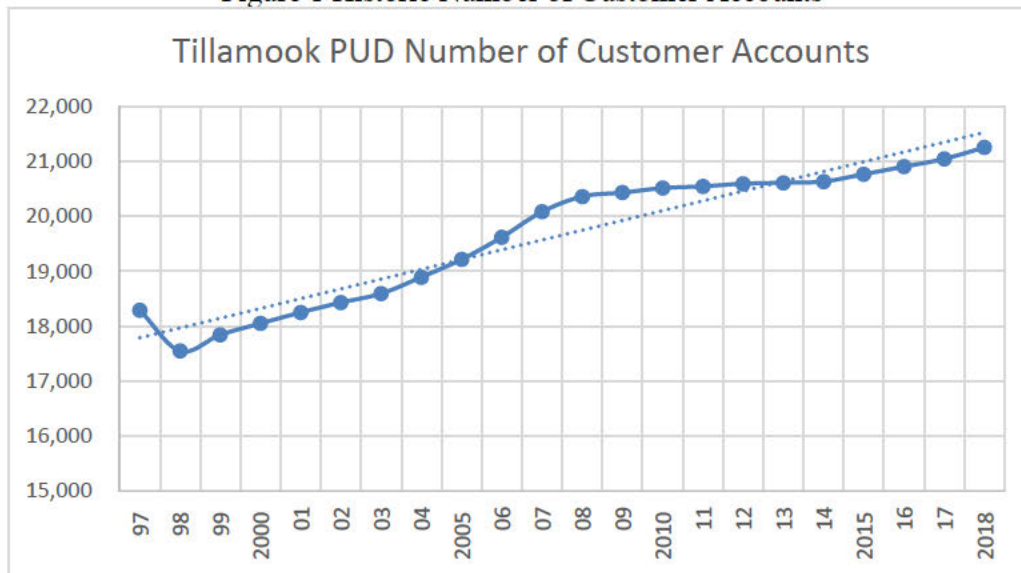
⁷ 95 (new services) divided by original services (1,898-95) divided by 10 years.

⁸ Exhibit No. TPUD/406 (see page 20 of the 2017 report and page 22 of the April 2018 report). Further, I am aware of an existing development with 37 remaining lots, where 5 lots have recently applied for temporary electric service (not included in the six new services in 2018).

⁹ Exhibit No. TPUD/406 (see page 17 of the March 2018 report).

1 meters has been steadily increasing as showing in Figure 1 from the dashed trend line. The
 2 rate of increase is calculated to be 0.87 percent per year.¹⁰

3
 4 Figure 1 Historic Number of Customer Accounts



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 6 I also reviewed major customer accounts and found two major changes in loads that
 7 have occurred in the past decade. One industrial customer added electricity as an energy
 8 source to compliment other energy sources. This equates to an average increase in electric
 9 use of about 2 to 3MW but does not contribute to TPUD’s system peak because the customer
 10 switches from electricity to other fuel sources during our system peak hours. The second
 11 major change in industrial load has been the reduction of one of our customer’s work
 12 schedules. The customer reduced its work schedules from three, eight-hour shifts to two,
 13 eight-hour shifts. This did not reduce TPUD’s peak load as the plant is in operation during
 14 TPUD’s peak hours, but it did reduce TPUD’s overall energy requirements. The impact to
 15 the District from these operational changes is considered to be negligible as they basically
 16

¹⁰ Exh. No. TPUD/407 (SalesSum – Graph).

1 cancel each other out and are relatively small in magnitude when compared to the overall
2 system (net of less than 1MW in relation to 130MW).

3 I also looked at our annual system peak demand. The trend in that demand, shown in
4 Figure 2 as the blue dashed line, is equal to 1.06%. This is calculated using the 1997 peak
5 trend value at 98,000kW (98MW) and 120,000kW (120MW) in 2018 and yields a growth
6 rate of 1.06% per year.¹¹ Also shown in Figure 2 as the black dashed line is the growth trend
7 based on peak demand, which adjusts the trend line as calculated from the MS Excel build-in
8 function to the 2009 peak value. This indicates that the 2018 peak demand would be around
9 141MW if temperatures were to drop down to the lower teens and single digits as it did
10 during the December 10, 2009 system peak. Figure 2 shows that TPUD experiences high
11 system peak demand about every 12-15 years and therefore it is prudent and necessary for
12 TPUD to plan for these re-occurring high peak demands.

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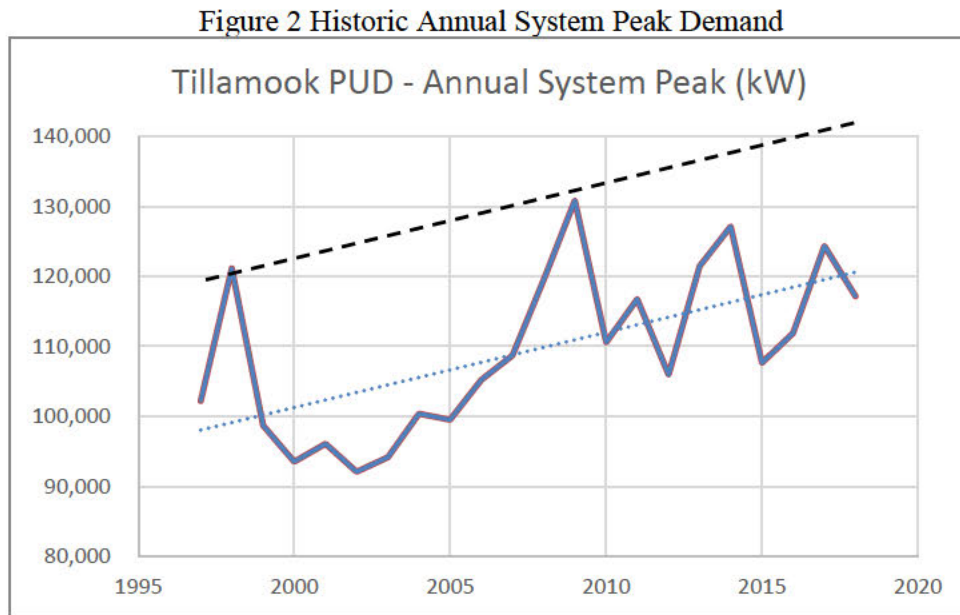
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¹¹ Exh. TPUD/402 (Summaries – Graphs), using the calculation $(120-98)/98/(2018-1997)*100 = 1.06\%$.

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The trending of the annual system energy (average electric usage) as shown on the

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Figure 3 indicates the 1997 trend peak value at 405,000MW/hr and 495,000MW/hr in 2018.¹²

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This equates to a growth rate of 1.05% per year.¹³

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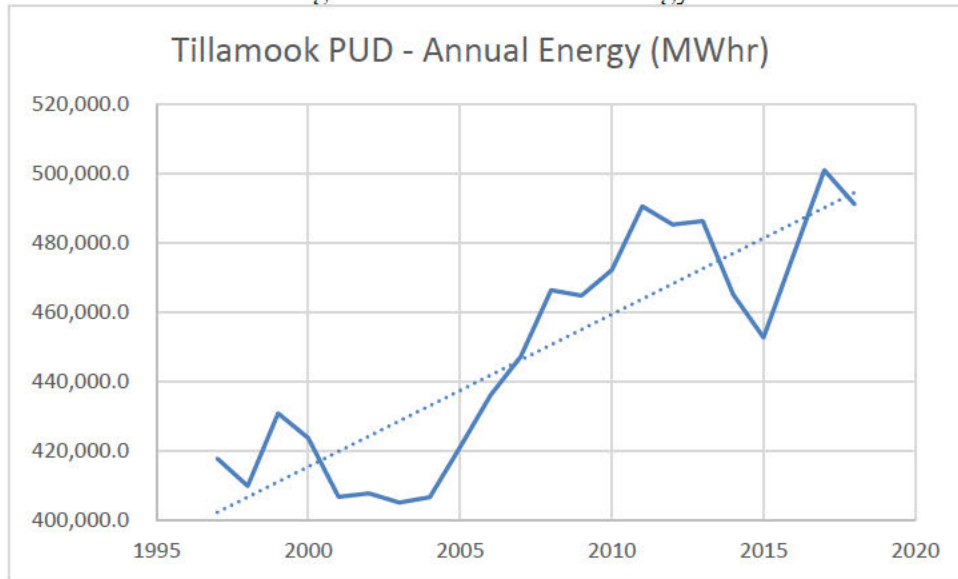
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¹² Exh. TPUD/402 (Summaries – Graphs).

¹³ Using the calculation $(495,000-405,000)/405,000/(2018-1997)*100 = 1.05\%$.

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Figure 3 Historic Annual Energy



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The trending of coincident hourly loads (average electric usage) from Wilson T1 and

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T2 is shown in Figure 4 and indicates that the Wilson substation loads are growing at

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0.9259% per year.¹⁴ Wilson substation was constructed in 2005 and energized in 2006 and

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there is no data prior to 2006 for the older substations that Wilson replaced.

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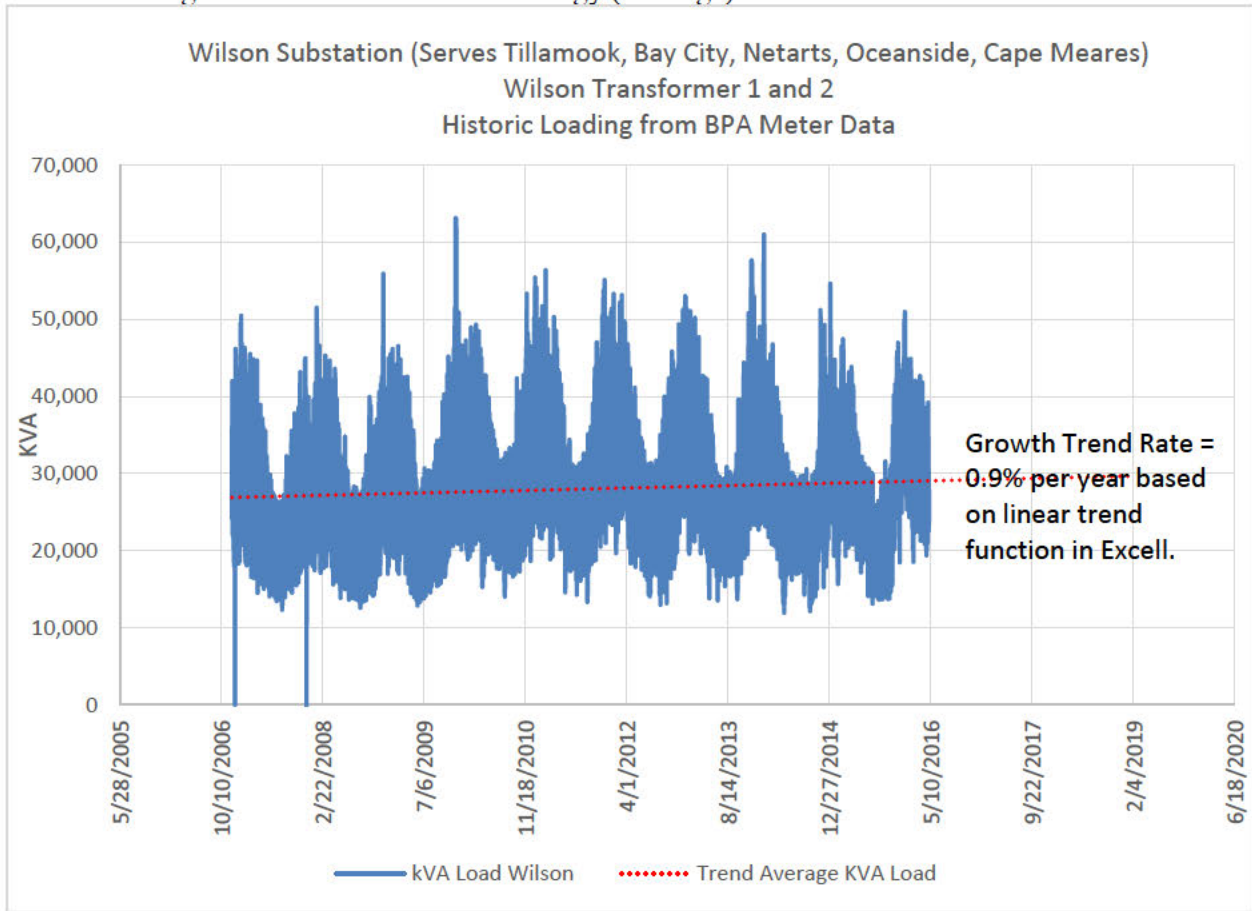
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¹⁴ Exh. TPUD/414 (Growth Trend and Chart Total tabs). The 0.9529% per year figure is based on the following calculation using the trend line in Figure 4: $(29,500-27,000)/27,000/(2016-2006)*100=0.9259\%$ per year.

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Figure 4 Historic Coincident Energy (Average) for Wilson T1 and Wilson T2



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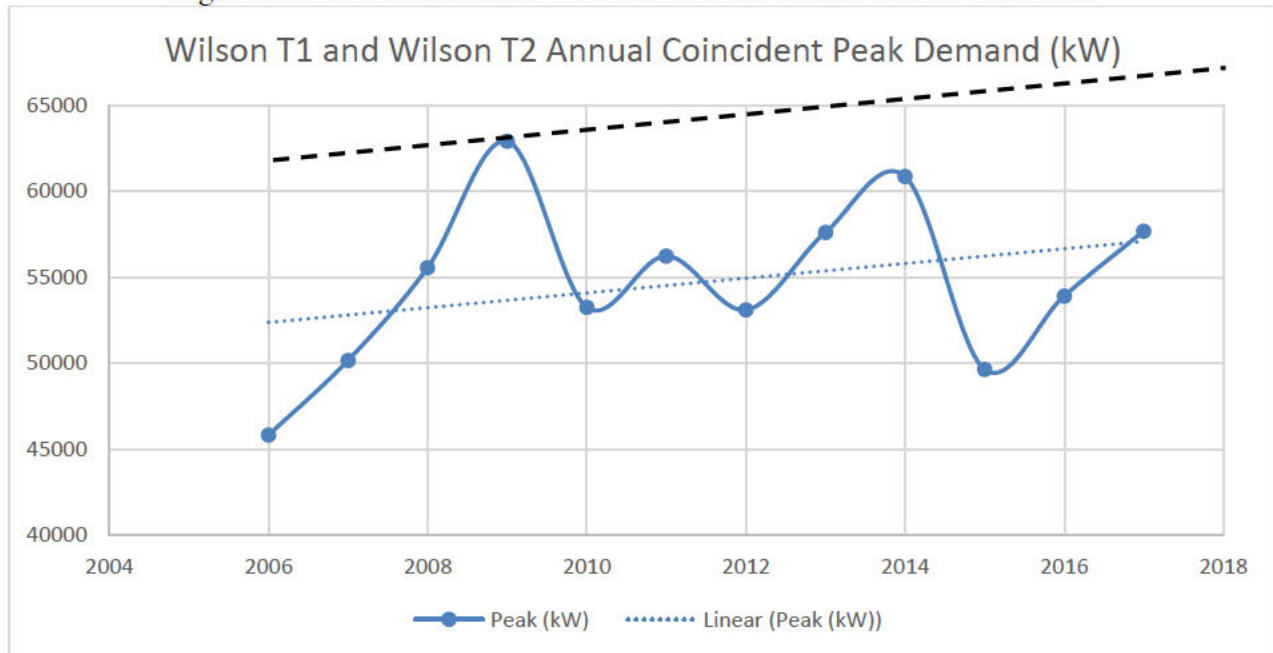
I also analyzed annual coincident peak demand for Wilson T1 and Wilson T2.¹⁵ The growth trend, as shown in Figure 5, is 0.8848 percent per year. The dashed linear trend line in Figure 5 has a value of 52,400 in 2006 and 57,500 in 2017. Based on these figures, the annual growth trend rate is 0.8849% per year.¹⁶ The growth trend line shown in Figure R5 as the black dashed line was adjusted to the 2009 peak and indicated that the 2018 adjusted peak demand would be around 67kW.

¹⁵ Exh. No. TPUD/408 (T1 and T2 Coincident Peak tab). This information was provided to Staff as part of TPUD's response to Staff DR DR19 a b c e.xls.

¹⁶ Using the calculation $(57500-52400)/52400/(2017-2006)*100=0.8848$ percent per year.

1

Figure 5 - Historic Coincident Peak Demand for Wilson T1 and Wilson T2



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4 Based on all the data I reviewed, I decided to use the growth trend rate from the
5 coincident loads of the Wilson substation of 0.9259% per year for the central Tillamook
6 valley (Wilson T1 and Wilson T2) to determine the impact or longevity of different Options.
7 This methodology was used over the peak demand growth trend because the peak demands
8 have been low given the warmer than normal temperatures over the past few years. Because
9 TPUD is a winter peaking utility, the warmer temperatures would have a greater impact on
10 peak demands than on energy and it is my opinion that the average energy growth trend
11 better reflects TPUD's current status.

12 The historic coincident peak load for Wilson T1 and Wilson T2 was 63.1MVA¹⁷ on
13 December 10, 2009 at 8 a.m. When escalated annually by the growth trend rate of 0.009259
14 (0.9259%), the resulting peak load for the following year would be 63.7MVA.¹⁸ This
15 calculation was repeated for 46 years and is shown in Table 1 below. This calculation was

¹⁷ Exh. TPUD/404 (WT2 BPA Meter Data tab, cell I32401).

¹⁸ See TPUD/401(WT1 WT2 tab).

1 updated based on an actual growth trend rate of 0.9259% per year, as compared to the
2 calculations from 2017 in the original analysis, which used round numbers of 12MVA and
3 0.9% growth trend rate per year.

4 **Q. WHAT IS YOUR TAKE-AWAY FROM THIS ANALYSIS**

5 A. As described above, given the addition of 11.5MVA of capacity and if I assume no electric
6 load growth from the 2009 peak to today, TPUD would have approximately seventeen years
7 of additional capacity. In my view, however, the more accurate conclusion is that electric
8 loads have grown over the nine-year period from 2009 to 2018. This is shown on Table 1
9 where the system peak would be 6.1 MVA higher than in 2009. Based on the growth of the
10 electric loads, the remaining capacity of the 11.5MVA addition would be 5.5MVA. From
11 Table 1, this would indicate that the additional 11.5MVA capacity addition leaves only eight
12 years of additional capacity.

13 While the addition of the 11.5MVA of capacity at the Wilson substation helped
14 relieve the immediate capacity concern in the central Tillamook valley, by itself it does
15 not provide any relief to the capacity concerns for the Oceanside/Netarts communities.
16 The loads in Oceanside/Netarts are approaching 11MVA where the majority of the
17 electric load is located more than nine miles from the power source at the Wilson
18 substation. Even with the addition of a second 24.9kV feeder as contemplated in Option
19 3, transmitting 5.5MVA of power more than nine miles will still have reliability issues
20 when one of the two 24.9kV distribution lines is out of service, i.e. under N-1 conditions.
21 This will require the addition of voltage-boosting equipment, one set for each of the
22 24.9kV feeders, in order to provide adequate voltage under N-1 conditions.

23 As structured now, the total 33.5MVA from Option 4 would provide
24 approximately 12-15MVA of capacity for the Oceanside/Netarts area that will be

1 sufficient for existing loads and future load growth. It would also provide approximately
2 7 to 10MVA of capacity that can be used to service electric customers within the City of
3 Tillamook without having to add any voltage-boosting equipment and using feeder W51
4 after it is rebuilt.

5 From a longevity and economic standpoint, performing major system upgrades
6 that will have less than 10 years of life is not prudent utility practice. Likewise, if major
7 system upgrades have a life span of more than the expected equipment life of 50 years,
8 the improvements should be evaluated to determine if they can be postponed until they
9 are really needed. In this instance, Option 3, inclusive of the second 24.9kV distribution
10 line, is on the short end of the timeline, whereas, Option 4 is closer to the expected
11 longevity target.

12 **Q. THE COMMISSION DIRECTED YOU TO SHOW A SYSTEM-WIDE N-1**
13 **CAPACITY CASE, AND ANY LOCALIZED N-1 CAPACITY CASE,**
14 **INCLUDING ALL FORMULAE AND VARIABLES YOU RELY ON. HAVE**
15 **YOU DONE THAT?**

16 A. Yes, I have updated my original N-1 analysis as directed. However, the power flow
17 analysis I used was based on the N-1 scenario for the central Tillamook valley region
18 rather than on a system-wide basis. As I mentioned earlier, TPUD's entire system is not
19 electrically connected. TPUD's system stretches 70 miles north to south and the electric
20 systems at the extremities do not connect to electric systems in the central areas. Because
21 of this, the N-1 scenarios are regional events only, limited to the largest system
22 components within each region. For this reason, the N-1 analysis cannot be a "system-
23 wide" analysis the Commission asked for, and it focuses just on the central Tillamook
24 valley served primarily by the Wilson T1 and Wilson T2 transformers, backed up by the
25 Garibaldi and Trask substation transformers.

1 I updated the previous N-1 analysis to reflect the larger transformer that now exists at
2 Wilson T1. Given that loads can be switched between Wilson T1 and Wilson T2 within the
3 Wilson substation, removing one of the Wilson transformers is essentially the same as
4 removing the other transformer. Therefore, the largest system component that may be
5 removed from service is the Wilson T2 transformer.

6 I used our SynerGEE® electric system electric power flow model to run simulations
7 for existing conditions and N-1 conditions. For the existing configuration, the model
8 reflected the conditions of the electric system as they were in 2016. A more recent model
9 was not used, as there would not be as good of an alignment between the configuration of the
10 electric grid and the peak customer loads from the most recent peak on February 6, 2014. I
11 updated the 2016 model to reflect the few system improvements that have been performed
12 from the 2016 extraction and today, including the upgrade of the Wilson T1 transformer. I
13 then adjusted the 2014 electric demand to match the electric demands that occurred on
14 December 10, 2009. I removed Wilson T2 from service and reconfigured the electric
15 system to shift the electric load serviced by Wilson T2 to Wilson T1, and Garibaldi and
16 Trask substations. Those results are in Table 2, which shows what happens if we assume
17 Wilson T2 goes out of service. Under that scenario, the central Tillamook valley is at 85
18 percent of the manufacturer's name plate capacity, leaving a reserve capacity of 15.2MW. I
19 calculated that reserve capacity by subtracting the 2009 Peak Load (90.6 MVA) from the
20 total capacity (106.7 MVA).

21

Table 2 – Substation Capacity for N-1 Analysis in Central Tillamook Valley 2009 Peak Demand (TPUD/205 Fagen/50 revised for the larger Wilson T1)¹⁹

Substations	2009 Peak Loads MVA ³	Capacity ₁	% Capacity (2009 Peak Demand Loads)
Garibaldi (1994)	23.3	25	93%
Wilson T1 (2018)	36.4	44.8	83%
Wilson T2 ² (2002)	0	0	0%
Trask (1996)	30.9	36.9	81%
Total	90.6	106.7	85%

1. Manufacturer's Name Plate Capacity in MVA. See Exh. TPUD/410 (provided in response to Staff DR 32)
2. Wilson T2 loads were transferred to Trask, Wilson T1, and Garibaldi substations.
3. Exh. TPUD/409 (cells B33-39). This exhibit used peak loads from December 2009 reflected onto the 2016 electric system.

I then performed the same analysis but based on 2018 loads. I estimated the electrical peak demand for 2018 based on a 0.9 percent growth rate per year over the 9-year period since the all-time coincident system peak that occurred in 2009. The SynerGEE software performed the load growth calculations using the same methodology that I used for the longevity calculations discussed earlier in my testimony, but it only accepts inputs down to the tenths digit.

As I did for the 2009 loads, I calculated the percent of available capacity in 2018 by dividing the substation transformer load by the capacity of the transformer and multiplying by 100. Table 3 shows the same analysis I used for Table 2, but with the 2009 electric loads grown to 2018 electric loads at the growth trend rate. As you can see in that table, using 2018 loads reveals that the central Tillamook valley is at 93 percent of capacity in the N-1 scenario.

¹⁹ Exh. TPUD/409 (cells B33:B39).

Table 3 – Substation Capacity for N-1 Analysis in Central Tillamook Valley at 2018 Peak Demand²⁰

Substations	2018 Peak Loads MVA ³	Capacity ₁	% Capacity (2018 Peak Demand Loads)
Garibaldi (1994)	21.6	25	86%
Wilson T1 (2018)	44.5	44.8	99%
Wilson T2 ² (2002)	0	0	0%
Trask (1996)	33.8	36.9	92%
Total	99.9	106.7	93%

1. Manufacturer's Name Plate Capacity in MVA
2. Wilson T2 loads were transferred to Trask, Wilson T1, and Garibaldi substations.
3. Adjust 2009 peak loads to 2018 peak loads using a 0.9% per year growth trend rate.

At 93 percent of the regional capacity under N-1 conditions for 2018 peak loads, TPUD needs to start implementing capacity additions, especially given the length of time that it takes to construct major projects. As a check on the load growth, I used the longevity calculations on the 90.6MVA from the SynerGEE model with 2009 loads, which calculated to 8.7MVA²¹ of additional load for 2018. When I check these numbers in the 2018 SynerGEE model, there is approximately a 0.6MVA difference. This small difference is the result of increased line losses which is a squaring function of the electric current in the power lines.

Q. CAN YOU PROVIDE MORE DETAIL ON HOW YOU CONDUCTED THE N-1 ANALYSIS AND WHAT THE N-1 ANALYSIS REVEALS?

A. When I perform an N-1 analysis, I use SynerGEE power flow software, which is an electric system power flow model. The electric model was extracted from our GIS mapping system as configured during the early 2016 winter time frame. The base SynerGEE

²⁰ Exh TPUD/411 (cells B46-B56).

²¹ Exh. TPUD/401 (WT1 WT2 G T tab).

1 model created from the 2016 electric system configuration was uploaded with customer
 2 metering data from the recent peak on February 6, 2014, at 8am of 128MVA
 3 (127.146MW).²² The more recent peak in 2014 was used as the customer load information
 4 more closely aligned with the 2016 electric system configuration than what a more current
 5 GIS extraction would have. This is because the connection between the electric system
 6 model and the customer metering data is the meter number, and as meters have been changed
 7 out the link was broken and the data cannot be uploaded.

8 The common data points that exist for the 2009 and 2014 time periods are the electric
 9 loads of the substation power transformers. Using that common data, the 2016 electric
 10 system model with 2014 loads were adjusted to match the coincident system peak of the
 11 substation transformer that occurred on December 10, 2009. Any resulting changes in
 12 electric loads at the substation level were propagated to the end use (customer metering data)
 13 electric loads. For example, the Wilson T1 peaked at 20MW at the system peak in 2014 and
 14 peaked at 21MW at the system peak in 2009, which is a difference of 5.8% $((21.3 -$
 15 $20.13)/20.13 * 100 = 5.81$ percent). Therefore, the 2014 electric loads on the feeders
 16 connected to Wilson T1 were increased by 5.8% to reflect the peak load that occurred in
 17 2009. The same exercise was performed on the other substation transformers and their
 18 associated electric feeders.

19 Power flow simulations were run in the SynerGEE model for normal system
 20 configurations and the resulting loads were verified to match the recorded loads at the
 21 substation transformer level for the 2009 system peak. To verify the loading of feeder
 22 W51 used in the model for in the Oceanside/Netarts area, recent electric demand for W51
 23 was collected from December 22, 2016 through February 12, 2018. The peak hourly

²² Exh. TPUD/401 (cell S6).

1 demand of 9.211MVA was recorded on January 5, 2017 at 8am. The resulting 2009
2 electric load in the SynerGEE model had 10.5MVA for feeder W51, which is in line with
3 what would be expected for the system wide higher 2009 peak loads. Wilson T2 was
4 removed from service and those loads were then switched to surrounding feeders and
5 substations. The results of the peak demand at the substation level are shown in Table
6 R2-1 above.

7 Exhibit TPUD/412 includes several screen shots from the SynerGee model under
8 these N-1 conditions. The first figure shows that under 2018 peak load conditions the
9 main tie circuit between Trask substation and Wilson substation is at capacity. The
10 second figure shows that under 2028 peak load conditions (10 years in the future) the
11 main tie circuit between Trask substation and Wilson substation is over capacity, is
12 causing low voltage issues within the City of Tillamook, and will need to be upgraded.
13 In that scenario I show a second feeder to Oceanside/Netarts (shown in magenta), but that
14 does not resolve the issue of the overloaded main tie circuit. But when the Transmission
15 Line and Oceanside substation are added to the analysis with Wilson T2 out of service
16 (the third figure), there are no system performance issues, i.e. no overloaded conductors
17 or low voltage problem. The reason for this is that about 15MVA has been transferred
18 from the Trask and Wilson substation to the Oceanside substation, including 11MVA
19 from the Oceanside/Netarts customers and another 4MVA using the rebuilt W51 feeder
20 tie to pick up customers in the area southwest of the City of Tillamook and on the
21 western fringes of the City of Tillamook. This resolves the low voltage conditions and
22 overloaded conductors without the use of voltage-booster stations, and the entire load can
23 be served.

1 **Q. THE COMMISSION’S THIRD REQUEST CONTAINS SEVERAL**
2 **QUESTIONS RELATING TO RELIABILITY. FIRST, THE COMMISSION ASKS**
3 **YOU TO RE-EVALUATE YOUR RELIABILITY NEEDS FOR OPTION 4 “GIVEN**
4 **THAT THE DISTRICT APPARENTLY PLANS TO USE THE EXISTING LINE**
5 **TO OCEANSIDE/NETARTS TO COMPLETE A LOOP FROM TILLMOOK TO**
6 **OCEANSIDE.” HOW DO YOU RESPOND?**

7 A. It remains my conclusion that the need for a second independent and highly reliable
8 source of electricity to Oceanside/Netarts is the only way to significantly improve
9 reliability to the Oceanside/Netarts area. Option 3 relies on two very long feeders
10 (including the existing feeder W51 which is already nearing its end of life) that traverse a
11 combined 19.2 miles of overhead distribution along roads and through heavily forested
12 areas to provide two sources of electricity. Option 4 establishes two new local
13 underground feeders that are less than 3 miles in length from the proposed new
14 Oceanside substation to the end use customers. The Transmission Line, which will be the
15 source of electricity to the two new feeders, was specifically routed where it avoids major
16 roads to reduce outages from vehicular accidents. As a transmission line, it also utilizes
17 larger rights-of-ways which are cleared of potential tree hazards, improving reliability
18 compared to Option 3. Accidents involving both vehicles and trees are the major causes
19 of outages on the existing feeder W51.

20 The “loop” the Commission is referring to would consist of the two new feeders
21 originating from the new Oceanside substation and the existing feeder W51. In this
22 scenario, W51 actually serves as a third source of electricity in the event there is an
23 outage on the Transmission Line or when performing maintenance on the Transmission
24 Line and associated Oceanside substation. Accordingly, the goal of the “loop” is to help
25 increase the District’s reliability and flexibility of its system, but it is contingent on the
26 Transmission Line being built.

1 **Q. THE NEXT PART OF THE COMMISSION'S QUESTION ASKS YOU TO**
2 **QUANTIFY THE REDUCED CUSTOMER OUTAGE HOURS OF OPTION 4**
3 **RELATIVE TO OPTION 3, TAKING INTO ACCOUNT PLANS TO USE THE**
4 **EXISTING LINE IN CONJUNCTION WITH OPTION 4. CAN YOU DO THAT?**

5 A. Reliability is determined by analyzing the frequency of outages and the number of hours
6 customers are out of service. The best way to quantify the difference in reliability
7 between Option 3 and Option 4 is to compare the distances of the feeders, the number of
8 feeders, the number of customers on each feeder, and the risk of an outage.

9 As I noted above, Option 3 would have two feeders, a new 24.9kV feeder out of
10 the Trask substation called T51, and the existing W51 feeder out of the Wilson
11 substation. Both feeders would be express feeders for the first 14 and 8.5 miles,
12 respectively, meaning that they would serve only a few hundred customers along the
13 way. The majority of the customers served by those feeders are located after those initial
14 14 and 8.5-mile distances. Different routes and power sources would be used for each of
15 the 24.9kV feeders. Thus, the likelihood of both feeders being off-line at the same time
16 would be small but nevertheless remains a possibility as both routes traverse through
17 heavily forested areas and along road ways. For example, outages caused by windstorms
18 are more likely to impact multiple locations in the same area.

19 The routes for both feeders pass through forested areas for several miles each and
20 along roads for most of their entire length. The original route for T51 used the old
21 Netarts transmission line route along Matejeck Road where portions of the route were
22 located along roads that have low traffic levels. Similarly, feeder W51 traverses along
23 the State Highway Route 131 roadway, which has high traffic levels. However, during
24 the permitting process with Tillamook County, the County planning staff, and ultimately
25 the Board of Commissioners, recognized that the old Netarts route passed through areas

1 that the County had designated as sensitive environmental areas and along estuaries,
2 which raised doubt that the line could be permitted. Attached as Exhibit 413 is the
3 County's final decision and findings permitting the Transmission Line.²³

4 An alternative route that was evaluated early in 2016 would use Tillamook River
5 Road rather than Matejeck Road, which is a more heavily traveled road, and Eckloff
6 Road which passes through forested areas. But as I noted earlier, falling trees and
7 vehicular accidents are the two major causes of outages for W51.²⁴

8 Each feeder for Option 3 would service about 1,100 customers with the additional
9 customers coming from the Trask feeder that would become the new T51 feeder (west of
10 State Route 101). I estimated the risk of outages by looking at the exposure of the feeder
11 to accidents and the number of customers that could be impacted by an outage. W51
12 would have 8.5 miles and 1,100 customers and T51 would have 14 miles (10.7 miles of
13 overhead and 3.3 miles of underground) and 1,100 customers.

14 Option 4 includes a new substation proposed to be located about a half mile and
15 two miles from the Oceanside and Netarts communities, respectively. Two new feeders
16 are planned to serve these communities. The Oceanside feeder was installed
17 underground when the Oceanside waste treatment plant was constructed about 5 years
18 ago and will need 0.25 miles of new underground facilities to extend the feeder to the
19 Oceanside substation. The Netarts feeder would be installed underground and connect
20 into the existing power lines in Netarts. The third feeder is the existing W51, which
21 would serve about 250 customers from the Wilson substation to the Whiskey Creek area.

²³ See finding #81 of County decision.

²⁴ Exh. TPUD/212, Fagen/5.

1 The new Oceanside and Netarts feeders would provide electricity to about 775 customers
2 each. The resulting risk of outages would be 250 customers and 8.4 miles for W51. The
3 resulting risk of outages for the Oceanside and Netarts new feeders would be 0.5 mile and
4 2 miles of underground, respectively, with 775 customers each.

5 The risk of outages on the 8.7 miles of Transmission Line is considered extremely
6 low when compared to the Option 3 distribution feeders. The proposed route of the
7 Transmission Line is away from traffic with the exception of only 0.4 miles along Wilson
8 River Loop where the transmission line is planned to be 25 feet off the shoulder of the
9 road, along gravel county roads with little traffic, and over farm lands. There are no trees
10 to speak of along this 4.2 mile stretch of the Transmission Line. Additional changes were
11 made at the request of property owners that increase reliability, such as relocating the
12 poles from the middle of farm lands to the edge of the farm fields. This reduces the
13 likelihood of farm equipment damaging poles as well as providing other benefits such as
14 providing the farms with unobstructed fields. The remaining 4.5 miles of the
15 Transmission Line are located in commercial forest land with 50 feet of cleared space on
16 either side of the power line. In addition, transmission lines are inherently more reliable
17 because they are designed and constructed to more stringent standards as required by
18 state codes.

19 The probability of an outage occurring on a feeder in Option 3 is greater than
20 Option 4. For Option 3, there are 19.2 total miles of exposure of overhead lines and 3.3
21 miles of underground line, as compared to 2.5 miles of underground lines for the
22 Oceanside and Netarts feeders, 8.4 miles of overhead exposure for feeder W51, and 8.7
23 miles of exposure from the Transmission Line.

1 While distribution lines can be built to the same standards as the Transmission
2 Line, this would also drive the cost per mile of the distribution line to be the same as the
3 Transmission Line, making the cost of Option 3 more expensive than Option 4 because
4 Option 3 has 19.2 miles of overhead distribution lines compared to 8.7 miles of overhead
5 lines for the Transmission Line.

6 **Q. THE THIRD PART OF THE COMMISSION'S THIRD QUESTIONS ASKS HOW**
7 **TPUD WILL MANAGE THE SYSTEM TO DEAL WITH THE SAME OUTAGES**
8 **IF YOU PROCEED WITH OPTION 4. HOW DO YOU RESPOND?**

9 A. For a given outage, the District would have more switching options with Option 4, which
10 will have a total of three feeders, when compared to Option 3 and its two feeders.
11 Having more switching options and shorter feeder distances to inspect after an outage
12 would also help to shorten the duration of each outage for the customers by allowing
13 TPUD to transfer customers outside of the outage area to adjacent feeders. The reduction
14 in time for determining the location of an outage comes from the fact that there is
15 significantly less area or length of line that would need to be inspected to find the cause
16 of the outage. Once the outage is located, the way the District would address the outages,
17 including switching customers outside of the outage zone, would otherwise be similar for
18 both options.

19 **Q. THE COMMISSION ALSO INQUIRED TO WHAT EXTENT THE ADDITION OF**
20 **THE REDUNDANT LINE IN OPTION 3 WOULD MITIGATE THE**
21 **RELIABILITY RISK ASSOCIATED WITH THE EXISTING LINE, AND**
22 **WHETHER TPUD ANTICIPATES THAT BOTH LINES UNDER OPTION 3**
23 **WOULD BE OUT OF SERVICE AT THE SAME TIME. HOW DO YOU**
24 **RESPOND?**

25 A. As I noted earlier, while the likelihood that both lines under Option 3 would be out of
26 service at the same time is relatively lower than a single outage, it remains a possibility.
27 The redundant line in Option 3 does mitigate the reliability risk on the existing line but

1 shares some of the same reliability issues. For example, both lines consist of long lengths
2 of overhead distribution in forested and high vehicle traffic areas. While a vehicular
3 accident would not take out both lines at the same time, a wind storm like what is typical
4 in the central Tillamook valley has the possibility to do so.

5 **Q. THE COMMISSION ALSO ASKED, GIVEN THAT TPUD RATES THE**
6 **RELIABILITY RISK OF OPTION 3 AS "GOOD", FOR YOU TO COMPARE**
7 **THAT ESTIMATE OF ITS RELIABILITY WITH INDUSTRY STANDARDS.**

8 **A.** There is no question that a Transmission Line is more reliable than the distribution feeders
9 contemplated in Option 3 because of the way it is built and the location of the
10 Transmission Line compared to the facilities in Option 3. Having said that, it is true that
11 having two sources of electricity to an area will in general improve the reliability and
12 customer hours out, by 50 percent. Customer hours out is defined by the number of
13 customers impacted by an outage, multiplied by the duration of the outage. In general,
14 only half of the customers would experience an outage if there were two independent
15 sources of electricity. And for significant outages, such as a car-hit pole, the customers
16 that are outside of the immediate outage area can be switched to the alternative feeders,
17 reducing the duration of the outage to the impacted customers from approximately 6 to 8
18 hours for a car-hit pole to 1 or 2 hours.

19 In order to assess Option 3 reliability with industry standards, I compared the
20 reliability of Option 3 to existing reliability of feeder W51 and to the average reliability
21 of TPUD's system. Compared to W51's existing reliability, the reliability of Option 3
22 would be rated as "good" in my opinion. However, given that the existing reliability of
23 feeder W51 is 8.8²⁵ times worse than the average reliability of the feeders in TPUD's

²⁵ Exhibit TPUD/414 (Outage by Feeder Pivot Table, cell J48). This exhibit was provided to Staff in response to a data request and is the same exhibit as TPUD/212, Fagen 1 but with annotations added.

1 service territory, I am not convinced that Option 3 would improve the reliability to the
2 Oceanside/Netart customers such that the reliability would be better than the TPUD
3 system average.

4 **Q. AS THE FINAL PART OF ITS THIRD QUESTION, THE COMMISSION ASKED**
5 **YOU TO EXPLAIN WHAT OTHER OPTIONS TPUD HAS CONSIDERED TO**
6 **MITIGATE THE RELIABILITY RISK AT OCEANSIDE/NETARTS USING**
7 **OPTION 3, SUCH AS BACKUP GENERATION OR STORAGE AND PROVIDE**
8 **YOUR ESTIMATES OF THE COSTS OF THESE OPTIONS. HOW DO YOU**
9 **RESPOND?**

10 **A.** Other options the District considered were rebuilding the existing overhead line along
11 Bayocean Road, expansion of the Trask Substation to add more capacity, alternative
12 (non-wires) sources, and conservation.

13 The existing feeder along Bayocean Road was reviewed early in 2016 for the
14 potential to provide a second feeder or as a third feeder to the Oceanside/Netarts area.
15 However, this route is plagued with land slide issues and is directly exposed to the natural
16 elements given its location next to Tillamook Bay. In addition, the road between Cape
17 Meres and Oceanside has been closed for several years due to a major land slide on the
18 mountain. This section of the route is needed to connect Oceanside north to Cape Meres
19 and the Bayocean Road Feeder.

20 The District commissioned a study to expand the Trask substation and place a
21 sister 33MVA transformer and a second line-up of 24.9kV feeder bays to match the
22 existing transformer at the Trask substation. A second 24.9kV distribution feeder would
23 be needed to provide redundancy to Oceanside/Netarts, just as it would be for Option 3.
24 In addition, the T68 feeder would need to be rebuilt, which is an underbuild circuit on
25 BPA's 115kV transmission line, and another feeder would be needed between the Trask
26 substation and the Wilson substation in order to transfer the additional capacity from

1 Trask to Wilson if one of the Wilson transformers were to be removed from service.
2 While this option provided the same capacity as Option 4 and improved reliability to
3 Oceanside/Netarts, the preliminary cost estimates showed the Trask Substation
4 Expansion was more expensive than the Tillamook to Oceanside transmission line
5 (Option 4) with lower reliability to Oceanside/Netarts.

6 While wind and solar are becoming more prevalent, these non-wire technologies
7 are intermittent power sources and the level of local generation in the Oceanside/Netarts
8 areas required for a firm source of electricity would be cost-prohibitive. Back-up battery
9 banks for storage or diesel generation can be used to reduce the intermittency of solar and
10 wind. However, these technologies are very expensive and require significantly higher
11 levels of operations and maintenance than a transmission line or substation. Battery
12 storage options cost in the range of \$1 million per MWhr²⁶ where the Oceanside/Netarts
13 would need 11 MW multiplied by the expected duration of the outage. Average outage
14 times are around 3-4 hours²⁷ with longer outages taking 6-8 hours, meaning the cost of
15 battery storage would be approximately \$44 million (\$1M*11MW*4hours).

16 The District has and still offers conservation, for example replacing electric heat
17 with heat pumps, the addition of insulation, and double pane windows. The effectiveness
18 of conservation has been decreasing.²⁸ While these efforts have slowed electric load
19 growth, the District's current growth assumptions account for these impacts based on our
20 12 and 20-year load growth trends.²⁹

²⁶ Exh. TPUD/414, Fagen/19.

²⁷ Calculated from Exhibit TPUD/212, Fagen/2 (850 hours) divided by Exh. TPUD/212, Fagen/3 (250 outages) = 3.4 hours.

²⁸ Exh. TPUD/416 (provided in response to Staff DR19d).

²⁹ See the District's response to the Commission's second question above.

1 **Q. THE COMMISSION’S FOURTH QUESTION ASKS YOU TO PROVIDE UPDATE**
2 **COSTS OF OPTION 3 AND OPTION 4. CAN YOU PROVIDE THAT**
3 **INFORMATION?**

4 A. Yes. Exhibit 417 included with this testimony is an update of TPUD/209, Fagen/1. That
5 exhibit shows the updated costs with the inclusion of the underground distribution feeders
6 associated with Option 4. The estimate for the substation and Transmission Line was
7 developed by TriAxis Engineering in 2017 and reflects the final transmission line route, as
8 well as the 25MVA of capacity at the Oceanside substation estimated at \$800,000.
9 Adjustments were made to the substation cost estimate based on the now proposed 22MVA
10 transformer size and the recent TPUD purchase costs for a 22MVA transformer of \$410,000.
11 TriAxis included a 10 percent contingency for the Transmission Line given the that the
12 design for the Transmission Line is almost complete, and a 20 percent contingency for the
13 substation given the design level is only at 15 percent.

14 Exhibit 417 included with this testimony shows the updated cost as of February 2018
15 for Option 3. A 20 percent contingency was added to the planning level construction cost
16 estimates given the design level is only 15 percent complete.

17
18 **Q. IN THE NEXT PART OF THE COMMISSION’S FOURTH QUESTION, IT ASKS**
19 **YOU, FOR EACH PROJECT SHOWN IN THE 2018 CONSTRUCTION WORK PLAN**
20 **FOR THE WILSON RIVER SUBSTATION, TABLE 2-1-1, TO STATE WHETHER**
21 **THAT PROJECT IS PART OF OPTION 3 AND/OR OPTION 4, AND THE**
22 **SCHEDULE FOR COMPLETION OF EACH PROJECT. THE COMMISSION ALSO**
23 **ASKS YOU TO RECONCILE THE FIGURES SHOWN IN THE WORK PLAN WITH**
24 **THE FIGURES SHOWN IN YOUR EXHIBIT 209 WHERE APPLICABLE. HOW DO**
25 **YOU RESPOND?**

26 A. The projects listed in the 2018-2021 Construction Work Plan (“CWP”), Table 2-1-1, that
27 are included in Option 4 are projects 201B, 402B, and 810B. These projects are

1 highlighted in blue in Exhibit 418 included with my testimony. There are no projects
2 listed in the CWP Table 2-1-1 that are required for Option 3.

3 The CWP included three line items that make up the Option 4 costs. The costs in
4 the CWP for the 810B Transmission Line, 201B the underground feeder get-a-ways, and
5 402B the Oceanside substation, assumed costs from the previous 2014-2017 CWP
6 because the updated costs were not yet finalized. Exhibit TPUD/209 provides the most
7 current cost estimates for the transmission line and substation, which match the final
8 estimates developed by TriAxis for the final Transmission Line alignment and provided
9 as Exhibits TPUD/209, Fagen1-10. The most accurate estimates of the Option 4 costs,
10 the Transmission Line option, are shown in Exhibit TPUD/417 and includes the
11 underground feeder get-a-ways.

12 The cost in the CWP for the substation was estimated at \$3.8 million and the
13 revised estimate from TriAxis is \$2.9 million based on the most current configuration and
14 equipment pricing. This estimate was then further revised to reflect the change from the
15 larger transformer to a 22MVA transformer.

16 The cost in the 2018-2021 CWP for the Transmission Line was estimated at \$10.5
17 million and the revised estimate from TriAxis is \$9.1 million based on the most current
18 configuration, routing, and equipment pricing.

19 The cost in the 2018-2021 CWP for the underground feeders from the Oceanside
20 substation to Netarts was \$2.1 million and assumed parallel runs of 500MCM cable.
21 With the revised capacity of the Oceanside substation, a single run of 750MCM cable
22 will be able to provide the level of service needed. The revised cost for the 2.25 miles of
23 underground cable get-a-ways is \$1.4 million.

1 **Q. THE COMMISSION’S FOURTH QUESTION ALSO ASKS YOU TO PROVIDE A**
2 **BREAK-DOWN OF ESTIMATED EMINENT DOMAIN COSTS BY PROPERTY FOR**
3 **OPTION 4, INCLUDING COSTS FOR RIGHTS-OF-WAY AND SEVERANCE**
4 **DAMAGES, LEGAL FEES, AND EXPERT WITNESS FEES.**

5 A. Actual and precise costs for eminent domain are unknown at the point in time. TPUD
6 cannot begin the condemnation process until it receives the Certificate of Public
7 Convenience and Necessity from the Commission. Although TPUD anticipates eminent
8 domain will be required for more than one property, it is also not yet known how many
9 easements the District may be able to obtain through a negotiated transaction. Further, it
10 is my understanding that the cost of eminent domain on each individual property can vary
11 widely, depending in part on how aggressively the property owner objects. For example,
12 I am aware of a project where two similarly-situated property owners refused to negotiate
13 a transaction, but where one never appeared in the condemnation proceeding while the
14 other participated heavily in the proceeding, filing multiple motions and other pleadings.
15 The outcome for each property owner was essentially the same but at a much different
16 cost to the utility for each.

17 The only way to estimate the cost of condemnation at this point is to determine a
18 worst-case-scenario whereby the District is forced to pay the full fee interest value of
19 each easement area. This is an extremely conservative approach, as the just
20 compensation for an easement area is typically a discounted amount of the fee interest
21 value of that area. Exhibit TPUD/419 contains a table listing each property and the fair
22 market value of the portion of the property that is subject to the easement. This value is
23 the most accurate predictor of what the fee interest of the easement area is.

24 With respect to “severance damages,” I believe the Commission is referring to
25 what the statutes call “damage to remaining land.” In some instances, a taking of a

1 portion of a property can have an impact to the portion of the property that remains with
2 the underlying owner. This is typically not the case, however, where the interest being
3 taken is only an easement interest and the underlying property owner continues to be able
4 to use the property. In the situation we have, where we are largely crossing large lots
5 with farm and forest uses, the physical and legal characteristics of the larger parcel and its
6 functionality will be essentially unchanged in the before and after situations. There will
7 be no change in access. The highest and best use of the remainder of the parcel is
8 unaffected by the project acquisitions. We therefore do not anticipate any supportable
9 basis for which a property owner will be able to assert damages to the remaining land.

10 The primary expert fees incurred in condemnation proceedings are to obtain an
11 appraisal. TPUD anticipates that it will be able to obtain appraisals at a cost of \$3,000 to
12 \$4,000 for each property. It is possible that additional expert witness fees would be
13 incurred if the proceeding goes all the way to trial, but as discussed below, that it not a
14 frequent occurrence.

15 With respect to attorney fees, I am also informed that these are very hard to
16 predict. If a case were to go all the way to trial, the fees could be large. However, it is
17 my understanding that, for linear projects involving easement interest on multiple parcels,
18 the condemnation proceedings rarely go to trial. There are many procedural steps
19 involved in condemnation intended to have the parties work together. This begins with a
20 “40-day Offer” letter where the governmental entity (i.e. TPUD) will make an official
21 offer to the property owner based on the actual appraisal it obtains. Later in the
22 proceeding, the governmental entity has the ability to make an “Offer of Compromise”
23 which serves as a highest and best offer that the government believes can be proven at

1 trial and, as long as that number is achieved, the property owner's entitlement to attorney
2 fees is cut off. It is also my understanding that most parties in condemnation conduct
3 traditional settlement talks.

4 Because we anticipate most condemnation proceedings will not make it to trial
5 and that we will be able to find a settlement amount acceptable to property owners, we
6 would expect that our attorneys' fees for condemnation would be no more than \$10,000
7 per property. There may, of course, be outliers, but it is too speculative at this point in
8 time to try and quantify what those outliers may look like.

9 **Q. IN THE FINAL SECTION OF THE COMMISSION'S FOURTH QUESTION, IT ASKS**
10 **THE FOLLOWING: "GIVEN THE REPLACEMENT OF THE WILSON T1**
11 **TRANSFORMER AND THE ASSUMPTION THAT THE LONGEVITY OF THE NEW**
12 **CAPACITY IS 20 YEARS, EXPLAIN HOW TPUD PROPOSES TO ADJUST THE**
13 **COST OF OPTION 4 TO SHOW THAT THE ASSOCIATED 33MVA OF NEW**
14 **CAPACITY WILL NOT BE NEEDED FOR 20 YEARS, AND THEN WILL BE**
15 **GRADUALLY PUT INTO SERVICE OVER TIME UNTIL IT IS FULLY UTILIZED**
16 **AFTER 47 YEARS." WHAT IS YOUR RESPONSE?**

17 A. The additional capacity of 11.5 MVA from upgrading Wilson T1 does provide some cushion
18 before the central Tillamook valley is again out of capacity. As outlined in my responses
19 above, the revised longevity analysis for the existing system is between eight and seventeen
20 years, and most likely at the eight-year end of that spectrum. It will be three to four years
21 before the Transmission Line and substation can be placed into service, meaning TPUD has
22 only a four-year cushion before the capacity is needed, even with the Wilson T1 upgrade.
23 Once the Transmission Line project is placed in service, there will be 22MVA of additional
24 capacity to provide reliable service to the central Tillamook Valley for 38 to 48 years as
25 shown in Table 3 (for $22+5.2=27.2$ MVA and $22+11.8=33.8$ MVA, respectively) based on the
26 electric load growth trending from 2009 to 2018. The cost of Option 4 would be spread over
27 the 4 years of construction and the capacity increase would be a step increase around year 4
28 once the project was placed into service.

1 **Q. THE FIRST PART OF THE COMMISSION'S FIFTH QUESTION ASKS YOU TO**
2 **PROVIDE UPDATED CALCULATIONS FOR THE LONGEVITY OF OPTION 3 AND**
3 **OPTION 4, SHOWING AND EXPLAINING THE SELECTION OF FORMULA AND**
4 **VARIABLES. IT ALSO ASKS YOU TO EXPLAIN HOW THE PEAK AT**
5 **OCEANSIDE/NETARTS FACTORS IN THE CALCULATION. HOW DO YOU**
6 **RESPOND?**

7 A. The updated and revised longevity calculations are provided in response to the Commission's
8 second and fourth questions above. Option 3 has a longevity range of eight to seventeen and
9 Option 4 has a longevity range of thirty-eight to forty-eight years. The variation in longevity
10 is based on the assumed peak demand load increase from 2009, which is the TPUD's most
11 recent peak of 131MW, to 2018.

12 **Q. THE SECOND PART OF THE COMMISSION'S FIFTH QUESTION PROVIDES**
13 **THE FOLLOWING: "EXPLAIN WHY THE CALCULATION OF THE LONGEVITY**
14 **OF OPTION 3 DOES NOT TAKE INTO ACCOUNT THE UNUSED CAPACITY AT**
15 **THE WILSON SUBSTATION AT YOUR PEAK. (WHY TPUD DOESN'T ADD THE 12**
16 **MV A FROM OPTION 3 TO THE 2018 WINTER CAPACITY FOR WILSON T1 AND**
17 **T2 OF 84 MVA - IN MAKING THE CALCULATION.) ASSUMING THE USE OF A**
18 **0.9 PERCENT GROWTH RATE FOR TPUD'S CALCULATIONS, EXPLAIN WHY**
19 **THAT RATE IS REASONABLE BY SUBSTATION AND SYSTEM-WIDE.**

20
21 A. The unused capacity at the Wilson Substation is common for all options but does not change
22 the difference in longevity between the options. When I first reviewed the capacity issues in
23 2016, the central Tillamook valley was out of capacity given we were at 96 percent of
24 capacity using 2009 system load data. The 11.5MVA capacity addition with the replacement
25 of Wilson T1 was only an alternative scenario when the options were developed and analyzed
26 in 2016 and into 2017 (at the time TPUD developed the information for this Petition filed in
27 October of 2017). Wilson T1 was added to the transformer bid process only after there was
28 an equipment failure in late winter of 2017. The District determined that it was not cost
29 effective to replace and repair the 1972 Wilson T1 transformer. Because the District was not
30 considering replacing the Wilson T1 transformer at the time the analysis was performed in
31 2016, the additional capacity was not considered.

1 The use of the 0.9259% growth trend rate for the central Tillamook valley area is
2 based on the most recent load history for the central Tillamook valley area, which is served
3 by the Wilson substation (T1 and T2 transformers). The growth trend rate is also consistent
4 with our system growth rate. I have offered a full explanation of these numbers in response
5 to the Commission’s second questions above. Because TPUD’s substations and feeders have
6 not been in their normal configurations due to the equipment failure on Wilson T1, TPUD is
7 unable to use loading data from late 2017 to December of 2018, and therefore only load data
8 from 2006 to 2016 was used.

9 The load forecast that is produced by Bonneville Power Administration (“BPA”) has
10 never been used in the District’s CWP’s or long-range plans. The BPA load forecast is used
11 only by BPA to help determine short term resources for BPA, not the District, and to see if
12 the District will exceed its Tier 1 load requirements. The calculations for determining the
13 BPA load forecast look at the annual energy consumed 5 years ago and compare that to last
14 year’s annual energy consumption. Regardless of the result, a growth factor is then assigned,
15 which has been 0.5 to 0.25 percent per year.

16 The load growth projections used in the District’s work plans have always used
17 historic data trending for determining the electric requirement over the 10 to 20-year
18 planning periods. This method provides a much better look at how the utility is changing. It
19 then looks at the reasonableness of the results to ensure that the trend is not overstating or
20 understating the results. In this case, Tillamook County, along with the rest of the state of
21 Oregon, is experiencing growth and all signs point to the continued growth within Tillamook
22 County. In addition, the historic load data captures two of the most significant economic
23 down turns in Tillamook County’s recent history in 2001 and 2009. The lower peak demands
24 experienced in 2015 and 2016 were determined to be the results of warmer than usual winter
25 temperatures, which was confirmed by the higher peak of 124MW in 2017 when the

1 temperature dropped just below freezing. Because the 2017 peak demand occurred on a
2 Friday morning, it did not include the electric demand from the TCCA boiler (which was
3 switched to propane) nor the electric demand from one of the lumber mills, as it shut down a
4 part of its operation on Fridays through Sundays. These two loads would have added
5 between 3MW to 5MW to the 2017 peak. The 2009 peak demand was a result of a cold
6 winter where the temperatures dropped down to 10 degrees for several days. The
7 temperature has not reached those levels since 2009, but when the temperature does drop
8 again, there will be a new system peak given all of the new loads connected to the electric
9 grid since 2009.

10 **Q. IN ITS SIXTH AND FINAL QUESTION, THE COMMISSION ASKS YOU TO**
11 **EXPLAIN THE \$800,000 COST OF ABANDONING THE TRANSMISSION BAY**
12 **INCLUDED IN OPTIONS 1, 2, AND 3, AND TO DISCUSS OTHER OPTIONS FOR**
13 **AVOIDING THAT COST OTHER THAN BY BUILDING OPTION 4. HOW DO YOU**
14 **RESPOND?**

15 A. Based on the District's records and discussions with previous District staff, I learned that
16 when BPA removed the BPA Trask 230-115kV substations from their plans around the
17 2004 timeframe, the District already had an agreement for an interconnection and BPA
18 offered to install an extra 115kV bay at their 230-115kV Tillamook Substation at no cost
19 to the District. If this bay is not utilized by the District, however, the District is obligated
20 to repay BPA for the cost of the installation and the dismantling of the bay. BPA
21 indicated that cost for installation was \$600,000 to \$800,000. For planning purposes, the
22 District assumes the higher amount and assumes that would cover the dismantling of
23 115kV bay.

24 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

25 A. Yes, it does.