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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,

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

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

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

Q. HAVE YOU ALREADY PROVIDED TESTIMONY IN THIS PROCEEDING?

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

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

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

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

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

A. TPUD's capacity concerns are not system-wide and are limited to three areas within the District's service territory. Capacity concerns exist: (1) in the central Tillamook valley where electric power originates from the Wilson, Trask, and Garibaldi substations; (2) in the Oceanside/Netarts area where electric power originates from the Wilson substation; and (3) in the Neskowin area located in south Tillamook County, where the electric power originates from the Nestucca substation.

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

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

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

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

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

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

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

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

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

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

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

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[1] *See* Exh. TPUD/401 (WT1 WT2 tab at line 27).
[2] *See* Exh. TPUD/401 (WT1 WT2 tab at line 18).

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

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

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

The District does not retain individual feeder data for more than a few years and therefore does not have load data at the feeder level that can be used to look at how electric 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).

available data (the number of electric services) to determine the change in electric usage in the Oceanside/Netarts area, which is serviced by Feeder W51. The total number of electric services on Feeder W51 in 2018 was 1,895, and that number increased by 95 services from 2009 through September 2018 as shown in Exhibit No. TPUD/405.[6] This equates to an average of 9.5 (95 meters divided by 10 years) new electric services per year and a growth rate of 0.53 percent per year in the Oceanside/Netarts area over the past 10 years.[7]

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

A. Yes. TPUD has recently received applications for electric services for the development of 111 new residential lots[8] and a new commercial business[9] in the Oceanside/Netarts area. Currently, there are 13 residential lots and a commercial lot under construction. In addition, earth work has started on a 66 residential lot development that is included in the above referenced 111 new residential lots. Developers estimate the residential lot development will be completed within the next 3 to 5 years. Even if the District experiences growth at half that rate (112/2/5 = 11.2 new meters per year), the rate of new services would exceed the current 10-year average. This demonstrates that the Oceanside/Netarts area has been and is continuing to grow.

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

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6 *See* Charts tab in the spreadsheet.

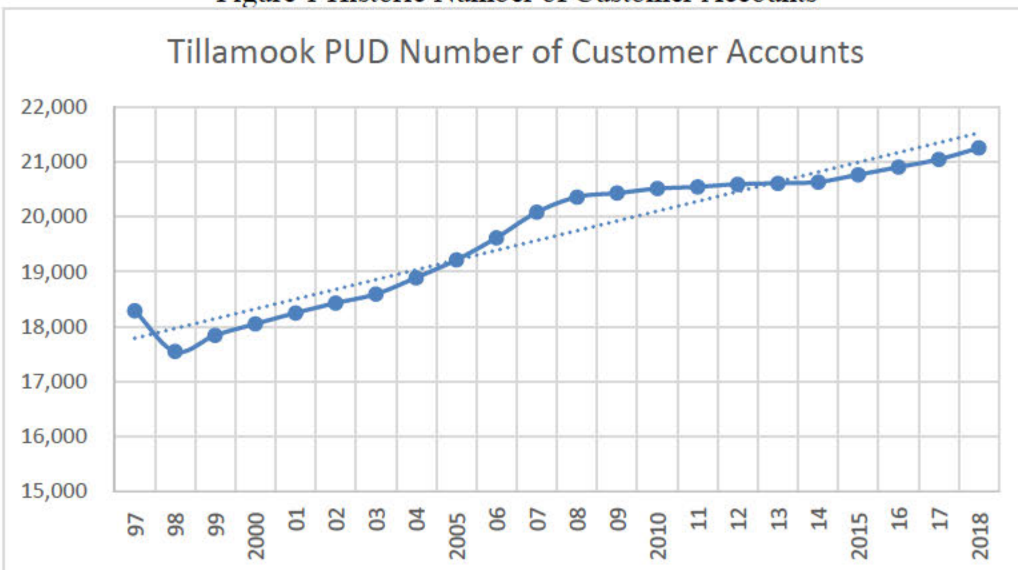
7 95 (new services) divided by original services (1,898-95) divided by 10 years.

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).

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

Figure 1 Historic Number of Customer Accounts



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

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

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

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

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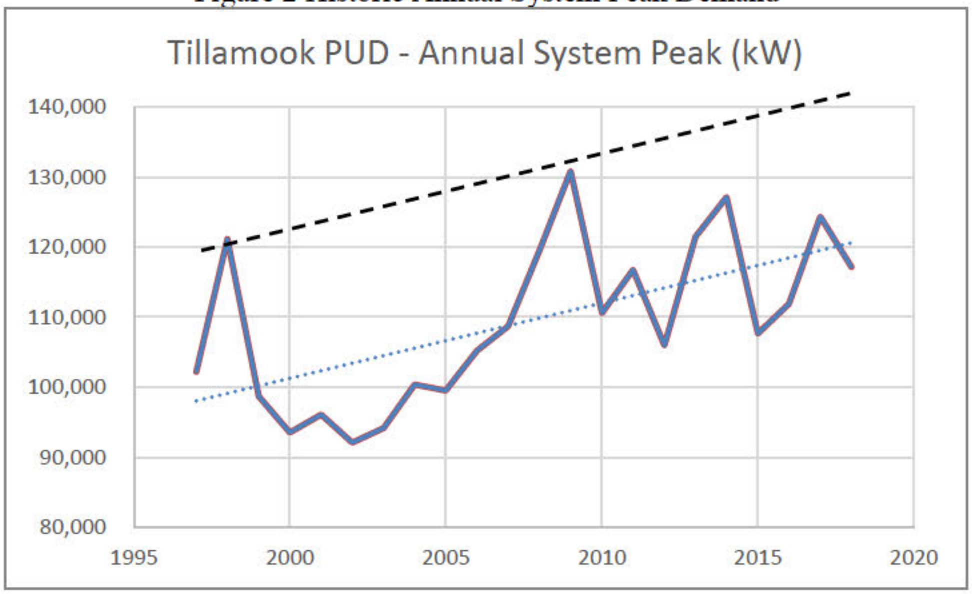
[11] Exh. TPUD/402 (Summaries – Graphs), using the calculation (120-98)/98/(2018-1997)*100 = 1.06%).

Figure 2 Historic Annual System Peak Demand



The trending of the annual system energy (average electric usage) as shown on the Figure 3 indicates the 1997 trend peak value at 405,000MW/hr and 495,000MW/hr in 2018.[12] This equates to a growth rate of 1.05% per year.[13]

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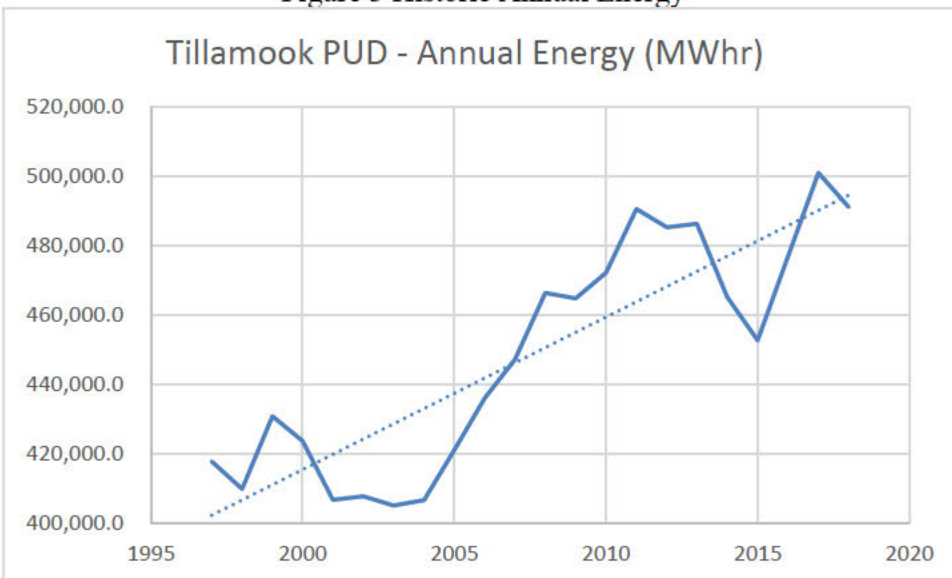
[12] Exh. TPUD/402 (Summaries – Graphs).
[13] Using the calculation (495,000-405,000)/405,000/(2018-1997)*100 = 1.05%.

Figure 3 Historic Annual Energy



The trending of coincident hourly loads (average electric usage) from Wilson T1 and T2 is shown in Figure 4 and indicates that the Wilson substation loads are growing at 0.9259% per year.[14] Wilson substation was constructed in 2005 and energized in 2006 and there is no data prior to 2006 for the older substations that Wilson replaced.

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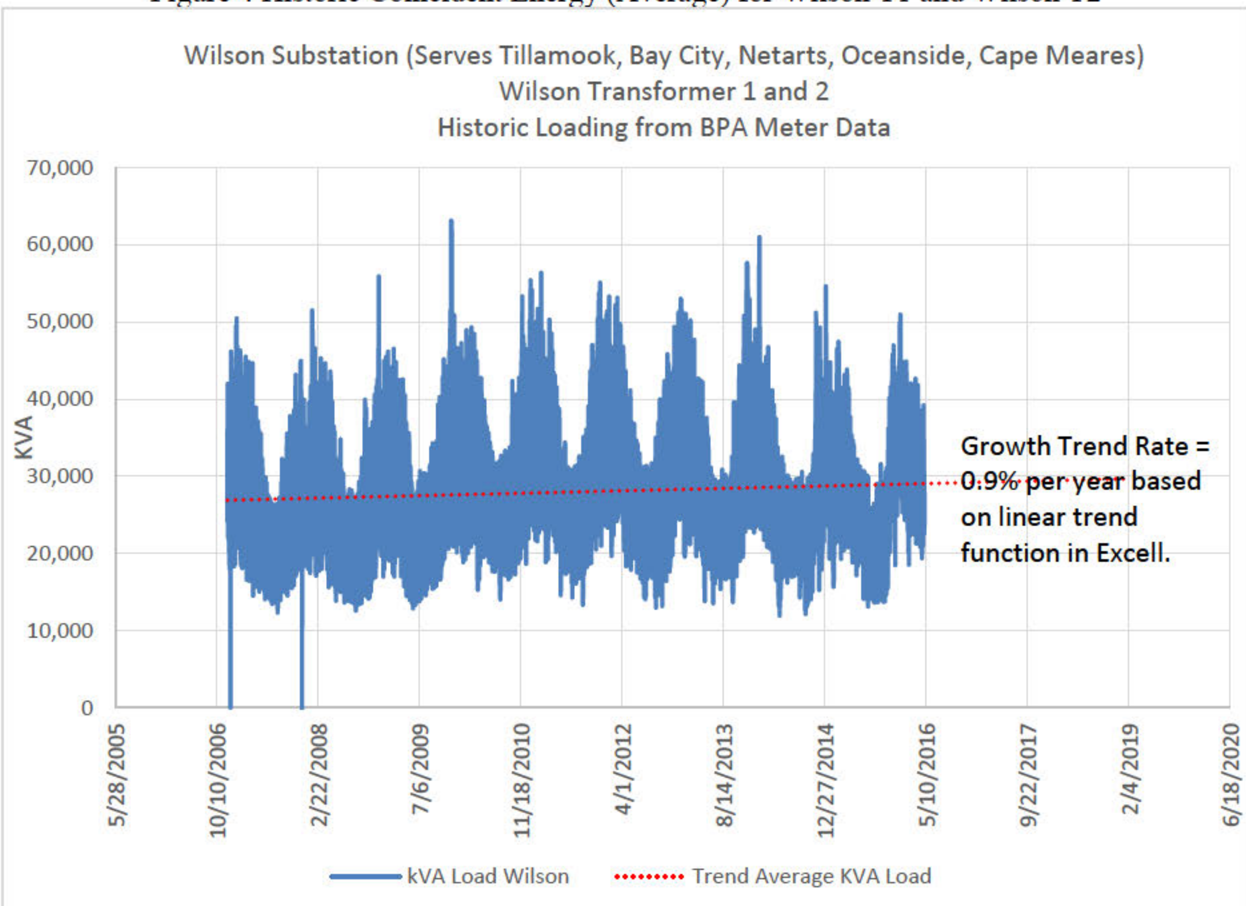
[14] Exh. TPUD/414 (Growth Trend and Chart Total tabs). The 0.9529% per year figure is based on the following calculation using the trend line in Figure 4: (29,500-27,000)/27,000/(2016-2006)*100=0.9259% per year.

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

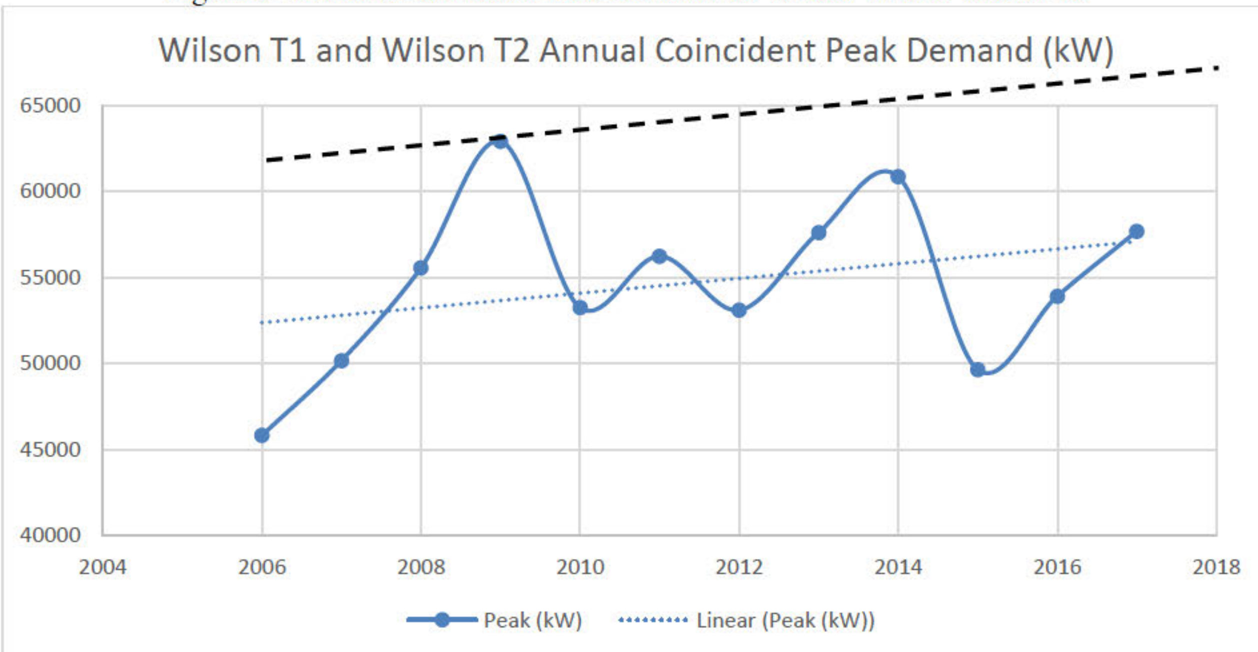


I also analyzed annual coincident peak demand for Wilson T1 and Wilson T2.[15] The growth trend, as shown in Figure 5, is 0.8848 percent per year. The dashed linear trend line in Figure 5 has a value of 52,400 in 2006 and 57,500 in 2017. Based on these figures, the annual growth trend rate is 0.8849% 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.

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



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

The historic coincident peak load for Wilson T1 and Wilson T2 was 63.1MVA[17] on December 10, 2009 at 8 a.m. When escalated annually by the growth trend rate of 0.009259 (0.9259%), the resulting peak load for the following year would be 63.7MVA.[18] This 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).

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

Q. WHAT IS YOUR TAKE-AWAY FROM THIS ANALYSIS

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

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

As structured now, the total 33.5MVA from Option 4 would provide approximately 12-15MVA of capacity for the Oceanside/Netarts area that will be sufficient for existing loads and future load growth. It would also provide approximately 7 to 10MVA of capacity that can be used to service electric customers within the City of Tillamook without having to add any voltage-boosting equipment and using feeder W51 after it is rebuilt.

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

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

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

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

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

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 Demand[20]

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 8.7MVA[21] 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).

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

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

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

[22] Exh. TPUD/401 (cell S6).

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

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

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

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

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

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

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

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

The routes for both feeders pass through forested areas for several miles each and along roads for most of their entire length. The original route for T51 used the old Netarts transmission line route along Matejeck Road where portions of the route were located along roads that have low traffic levels. Similarly, feeder W51 traverses along the State Highway Route 131 roadway, which has high traffic levels. However, during the permitting process with Tillamook County, the County planning staff, and ultimately the Board of Commissioners, recognized that the old Netarts route passed through areas that the County had designated as sensitive environmental areas and along estuaries, which raised doubt that the line could be permitted. Attached as Exhibit 413 is the County's final decision and findings permitting the Transmission Line.[23]

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

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

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

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

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

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

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

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

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

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

A. As I noted earlier, while the likelihood that both lines under Option 3 would be out of service at the same time is relatively lower than a single outage, it remains a possibility. The redundant line in Option 3 does mitigate the reliability risk on the existing line but shares some of the same reliability issues. For example, both lines consist of long lengths of overhead distribution in forested and high vehicle traffic areas. While a vehicular accident would not take out both lines at the same time, a wind storm like what is typical in the central Tillamook valley has the possibility to do so.

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

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

In order to assess Option 3 reliability with industry standards, I compared the reliability of Option 3 to existing reliability of feeder W51 and to the average reliability of TPUD's system. Compared to W51's existing reliability, the reliability of Option 3 would be rated as "good" in my opinion. However, given that the existing reliability of feeder W51 is 8.8[25] 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.

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

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

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

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

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

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

While wind and solar are becoming more prevalent, these non-wire technologies are intermittent power sources and the level of local generation in the Oceanside/Netarts areas required for a firm source of electricity would be cost-prohibitive. Back-up battery banks for storage or diesel generation can be used to reduce the intermittency of solar and wind. However, these technologies are very expensive and require significantly higher levels of operations and maintenance than a transmission line or substation. Battery storage options cost in the range of $1 million per MWhr[26] where the Oceanside/Netarts would need 11 MW multiplied by the expected duration of the outage. Average outage times are around 3-4 hours[27] with longer outages taking 6-8 hours, meaning the cost of battery storage would be approximately $44 million ($1M*11MW*4hours).

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

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[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.

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

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

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

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

A. The projects listed in the 2018-2021 Construction Work Plan ("CWP"), Table 2-1-1, that are included in Option 4 are projects 201B, 402B, and 810B. These projects are highlighted in blue in Exhibit 418 included with my testimony. There are no projects listed in the CWP Table 2-1-1 that are required for Option 3.

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

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

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

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

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

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

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

With respect to "severance damages," I believe the Commission is referring to what the statutes call "damage to remaining land." In some instances, a taking of a portion of a property can have an impact to the portion of the property that remains with the underlying owner. This is typically not the case, however, where the interest being taken is only an easement interest and the underlying property owner continues to be able to use the property. In the situation we have, where we are largely crossing large lots with farm and forest uses, the physical and legal characteristics of the larger parcel and its functionality will be essentially unchanged in the before and after situations. There will be no change in access. The highest and best use of the remainder of the parcel is unaffected by the project acquisitions. We therefore do not anticipate any supportable basis for which a property owner will be able to assert damages to the remaining land.

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

With respect to attorney fees, I am also informed that these are very hard to predict. If a case were to go all the way to trial, the fees could be large. However, it is my understanding that, for linear projects involving easement interest on multiple parcels, the condemnation proceedings rarely go to trial. There are many procedural steps involved in condemnation intended to have the parties work together. This begins with a "40-day Offer" letter where the governmental entity (i.e. TPUD) will make an official offer to the property owner based on the actual appraisal it obtains. Later in the proceeding, the governmental entity has the ability to make an "Offer of Compromise" which serves as a highest and best offer that the government believes can be proven at trial and, as long as that number is achieved, the property owner's entitlement to attorney fees is cut off. It is also my understanding that most parties in condemnation conduct traditional settlement talks.

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

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

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

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

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

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

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

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

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

The load growth projections used in the District's work plans have always used historic data trending for determining the electric requirement over the 10 to 20-year planning periods. This method provides a much better look at how the utility is changing. It then looks at the reasonableness of the results to ensure that the trend is not overstating or understating the results. In this case, Tillamook County, along with the rest of the state of Oregon, is experiencing growth and all signs point to the continued growth within Tillamook County. In addition, the historic load data captures two of the most significant economic down turns in Tillamook County's recent history in 2001 and 2009. The lower peak demands experienced in 2015 and 2016 were determined to be the results of warmer than usual winter temperatures, which was confirmed by the higher peak of 124MW in 2017 when the temperature dropped just below freezing. Because the 2017 peak demand occurred on a Friday morning, it did not include the electric demand from the TCCA boiler (which was switched to propone) nor the electric demand from one of the lumber mills, as it shut down a part of its operation on Fridays through Sundays. These two loads would have added between 3MW to 5MW to the 2017 peak. The 2009 peak demand was a result of a cold winter where the temperatures dropped down to 10 degrees for several days. The temperature has not reached those levels since 2009, but when the temperature does drop again, there will be a new system peak given all of the new loads connected to the electric grid since 2009.

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

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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.