BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

In the Matter of the Petition of	)
	)
TILLAMOOK PEOPLE'S UTILITY	)
DISTRICT	)
	)
PETITION FOR CERTIFICATE OF	)
PUBLIC CONVENIENCE	)
AND NECESSITY	)
	)
	)

INTERVENOR TESTIMONY OF DORIS MAST

ON ISSUES

January 14, 2019

Doris Mast – Intervenor Testimony 300 on Issues

Introduction

TPUD has filed a petition for a Certificate of Public Convenience and Necessity. I am pleased to have the opportunity to present my opinions that the scope of this project cannot be justified by the load data, or capacity need and N -1 arguments as presented by TPUD. The project will cause harm to rate payers who are forced to pay for a project that is not justified or in the public interest because needs have been overstated and cheaper alternatives other than a transmission line were never seriously considered. Did you notice that rebuilding feeder 51 to deal with its capacity and reliability issues was never discussed nor is it even listed as one of the options?

1. Detailed Line Description

The application describes the 8.6 mile 115kV line. TPUD convinced the County Planning Department that a distribution line is really a low voltage transmission line in their similar use argument. Therefore, since a distribution line is a low voltage transmission line, the detailed description of the line should include the approximately 8 mile sections of feeder 51 which will need to be rebuilt to back feed power to Tillamook and Cape Mears. To compare some options, the shortest option of overhead conductors would be the 14 miles of lines if feeder 51 were to be rebuilt, option 4 would come in second with approximately 17 miles and option 3 would be 3rd at 19 miles[1]. The poles in option 4 are described as 1.5' to 3.5' in diameter. This seems much larger than the spindly poles in feeder 51. Some of the poles in option 4 are over 100' tall so the visual impact of option 4 is much larger, especially in the areas where it goes through the center of property where no poles or lines currently exist.

2. Purpose of the Proposed Transmission Line

TPUD could adequately provide service to existing and new loads by rebuilding feeder 51. Feeder 51 has been neglected. When I hear that some of the conductors on the line are over 50 years old and I learn from the 2018 Construction Work Plan that feeder 51 is the second highest loaded feeder from the Wilson River 2 substation, I do not immediately conclude that a new substation and transmission line are needed. My first reaction is that when conductors are 50 years old and that the capacity of the conductor

[1] TPUD/400, Fagen/20

is close to being reached[2], new conductors able to carry more current are needed. It is in the public interest to choose a solution that solves the stated problem with the least cost and impact. Rebuilding feeder 51 with conductors large enough to meet present and added loads would add capacity, decrease outages, and improve safety as new conductors are not as fragile as the 50-year-old ones prone to breaking in high winds or when hit by limbs. Rebuilding the existing feeder 51 is also safer than Option 4 which creates a fire hazard by going through the center of Stimson's forest in a coastal high wind area with areas of steep terrain that will be difficult to manage in a wildfire.

According to KC Fagen, in 2018 there were 1,895 meters on line 51[3]. The maximum load on feeder 51 is still under 11 MW. In the original application narrative from CH2M Hill, TPUD planned on returning 15 MW's on feeder 51 from Oceanside when Wilson River suffered outages or needed help serving loads[4]. I conclude from their stated plan that feeder 51 can be rebuilt to carry 15 MW's. The question then is, how many new meters can be added if feeder 51 is rebuilt and able to carry 15 MW's. This is a sensible question as TPUD planned this in the original application. I set up a proportion that asks if 11 MW's serve 1,895 meters at peak loads, how many meters can be served by 15 MW's?

$$\frac{11\text{ MW}}{15\text{MW}} = \frac{1{,}895\text{ Meters}}{\text{X Meters}}$$

$$\text{So} \quad \frac{15\text{MW X }1{,}895\text{ Meters}}{11\text{ MW}} = \text{X Meters}$$

$$\text{X} = 2{,}584\text{ Meters}$$

The difference between 2,584 meters and 1,895 meters tells us how many new meters can be added by rebuilding feeder 51 to the level proposed by TPUD in its application. 2,584 – 1,895 = 689 meters. So, 689 new meters can be added simply by rebuilding feeder 51. KC Fagen said 9.5 meters were added per year in the years from 2009 through 2018[5]. So, dividing the 689 additional meters by 9.5 meters/year gives an answer of 72.5 years. So merely rebuilding feeder 51 adds enough capacity to add 9.5 new meters per year for 72 years.

In Doris Mast Exhibit 301, Column C, Mast /2, I show that the new larger transformer at Wilson River 1 will provide additional capacity for the central valley for 105 years if load

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[2] See TPUD/400 Fagen/2
[3] See TPUD/400 Fagen/6
[4] See TPUD/106 Simmons/23
[5] See TPUD/400 Fagen/6

grows at 0.45% per year. On Mast/3 of Doris Mast Exhibit 301, column C, I show how the larger transformer would provide capacity to the central valley if load grew by 0.45% for the first 10 years but then increased to 0.9259% in the next 10 years. At the end of the 20 years, 25.84 MW's of capacity remained, meaning I had not even started using the 12 MW's added by the new transformer. Even correctly reading KC Fagen's Exhibit TPUD/401 Fagen/1, shows that it takes 38 years at a growth of 0.9259% before the total capacity from the larger transformer is reached. Since the original nameplate capacity was 78 MW and we add 12 MW with the larger transformer, the total capacity becomes 90 MW. Running down the column that shows the size of the peak, we see that 90 MW is not reached until after 38 years. It is not in the public interest to do eminent domain on property owners to build a substation and transmission line that will not be necessary for use in the next 38 years. Since rebuilding feeder 51 with larger conductors allows new load to be added as well as increase reliability and safety, and an already installed larger transformer at Wilson River 1 provides capacity for growth at 0.9259% (we believe growth is less than .9259%) for the next 38 years, the public interest is best served by rebuilding feeder 51. The additional cost of Option 4 cannot be justified.

3. Necessity of the Proposed Transmission Line

It is not difficult to understand that feeder 51 has the highest customers hours out after TPUD tells you that some of the conductors are over 50 years old. Were this neglect of feeder 51 to be addressed and feeder 51 were to be rebuilt with conductors sized for today's loads, both reliability and capacity problems would be diminished. The way to deal with aging infrastructure is to rebuild it, which TPUD should have done years ago. Please note that in TPUD/205 Fagen/53 the original expected lifespan of Option 4 was given as 36 years. Since the conductors on feeder 51 are over 50 years old, I am left with the surprising conclusion that distribution systems have a longer life expectancy than transmission lines. In that case, the sensible course of action is to rebuild feeder 51 which would increase reliability and add capacity while addressing aging infrastructure without adding any new easements or the need to do eminent domain on the valuable farms and forests of Tillamook County.

The TPUD board made the decision to build a transmission line. The decision was publicly announced on the back page of the Ruralite in the spring of 2008. I made Doris Mast Exhibit 306 which includes a graph showing the projected sales 2007 – 2018 which was done by TPUD in the load forecast of 2007. On the same graph I show the actual energy sales which occurred through 2017. Actual sales from 2018 have not been released yet but an expected number is given in the 2019 budget which I have used in the chart and table. The table shows the revenue shortfall that occurs as energy sales fall below the projected levels.

The 2012 load forecast captures this drop in energy sales and the new load forecast was a subdued 0.45%[6]. I was at the TPUD board meeting when the 2012 forecast was presented. When the 2012 load forecast was presented to the TPUD board, the board was upset but refused to acknowledge that if conditions had changed, their decision should be reevaluated, much as Bonneville Power did when they cancelled their Troutdale to Castlerock project.[7] TPUD took the position that their decision was sound and the fall in sales was only weather related. In other words, they disregarded the load forecast of 2012, which should have made them cautious, and moved forward to implement their decision to build a substation and transmission line to Oceanside. They disregarded falling sales as due to warmer weather. In the TPUD boardroom, the Great Recession of 2008 was ignored, the loss of a shift at Hampton Lumber was ignored and the first time David Mast told the board that the creamery's boiler was switching from electric to propane, the General Manager called him a liar during a board meeting. This was absurd! Had any of the board members bothered to drive past the creamery, they might have seen a huge new tank for holding propane. Every person on the transmission line route knew the tank was there and not one of them called David Mast a liar for talking about it. So yes, the TPUD board independently reviewed the need for a transmission line and pugnaciously stood by it. I will discuss the financial impact that disregarding the falling sales represents in a later section on financial feasibility. The decision when first made was reasonable, but to ignore that conditions have changed, to refuse public input on need during the CAG process was not reasonable. TPUD's arguments for necessity are flawed and they need to misstate data in order to make their arguments sound convincing. When the data is properly interpreted, the transmission line project cannot be justified.

Reliability

Improving the reliability of the service to Oceanside-Netarts depends on having a working substation at each end of the line.[8] We are led to believe that feeder 51 is so plagued by outages that it cannot be rebuilt and provide reliable service unless there is a substation at each end of the line. If that is correct, and we know that Wilson River is at one end of the line, how does TPUD expect feeder 51 to transfer loads in an N -1

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[6] David Mast Testimony page 1 and Exhibit David 3 on 1/12/2018

[7] The Oregonian – Oregon Business News *BPA nixes costly and controversial I-5 power line proposal* Posted May 18, 2017 Updated May 23, 2017

[8] TPUD/205 Fagen/48

situation from Oceanside substation to the central valley on feeder 51? If a car hits a pole or a tree limb breaks a conductor between the working Oceanside substation and the Wilson River substation which is suffering an outage, power cannot be fed from both sides to correct the issue and the central valley will not get the power it sent to Oceanside. What went to Oceanside stopped on feeder 51. Is it a good idea to put the larger population of the central valley with its critical load of the hospital and clinics, large commercial and large industrial at the end of the worst feeder in the system in an N -1? TPUD has shifted the reliability problem from a smaller population to a larger population with the critical load. With the original transformer size of 33 MW's the plan was to return 15 MW to the central valley. Now the smaller 22 MW transformer at Oceanside can return 15 MW when its own load is 5 MW and can return approximately 10 MW when Oceanside is at a peak of 10 MW. However, it is not reasonable to expect the worst feeder in the system to perform reliably in a N -1 outage when we are told it cannot reliably carry 5 – 11 MW's to Oceanside – Netarts. Since the transmission line and substation shift reliability issues from one set of rate payers to another set of ratepayers, the $16 million cost is not justified and the project is not in the rate payers interest. It is more practicable to find solutions that reduce outages in Oceanside and Netarts without increasing them in the central valley. Either rebuilding feeder 51 or using Option 3 would be sensible with less cost and impact. Neither would require eminent domain as they use existing easements in the road right of way.

Load Growth

Is TPUD correct in their claims that the central valley transformers are already full and the central valley needs additional capacity? In an effort to make results support claims of heavy load, in TPUD/401 Fagen/2 KC Fagen continues to start with his system peak as year 0 and add growth to each subsequent year at 0.9259% to study loading on the system. The result is neither a description of the past nor a reliable forecast of the future because proper procedure is not followed (which is take the average of the last historical 5 years and then apply an accurate rate of growth). I made Doris Mast Exhibit 304 and in section A, I listed the system peaks from 2006 – 2017 for the central valley.[9] These are actual historical peaks as they occurred and no load growth is added. I showed the % of the total capacity used each year, and also the MW's of capacity remaining before the central valley nameplate capacity of 151.9 MW's is reached. Please note that the 2009 system peak was at 58% of the 151.9 MW capacity and that 63.63 MW's of capacity remained available to accommodate load. All following years had a lower % loading and even greater capacity still remained unused. In section B I

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[9] Taken from TPUD Exhibit 403 Tab LOAD SUMS

examined the percent loading and remaining capacity under N -1 conditions where I removed the Wilson River T2 transformer with a resulting N -1 capacity of 106.7. Even with the highest peak ever, the loading is 83% and there is still 18.43 MW's of capacity remaining. TPUD says that they are already at the maximum capacity in the central valley. When actual system peaks are used the data does not support TPUD's claims. Doris Mast exhibit 305, uses system peaks to examine when the nameplate capacity in the central valley and the N -1 capacity in the central valley are reached. It takes 147 years to reach the nameplate capacity of 151.9 MW for the central valley if the growth rate is 0.45% as shown in section A. Section B shows that with a growth rate of 0.45% in the central valley the N -1 capacity of 106.7 MW in the central valley is reached in 69 years. Even assuming a growth rate of 0.9259% but using the proper method the N -1 capacity is not reached for 33 years. KC Fagen's conclusion in TPUD/401 Fagen 2 that the N -1 capacity is reached in 9 years is wrong because he read the chart incorrectly. Even done with the high growth and using the system peak as the starting point, if charts are read correctly, you would run your finger down the column with the peaks until you are just under106.7MW and the proper answer should be 17 years.[10]

There are further indications of flaws in TPUD's calculation of need for additional capacity displayed in exhibit TPUD/401 Fagen/1, which deals with the Wilson River substation. To determine when the old thermal rating of 84 was reached, look at the column called peak load. It takes 31 years for the peak to reach 84 MW when the assumed growth is 0.9259%. It takes 38 years to reach the new nameplate capacity of 90 for Wilson River T1 + T2 with the new larger transformer. And if you add the 22 MW's that will be added by building the new substation at Oceanside, 62 years will go by before the capacity at Wilson River and Oceanside is gone.[11] Since the substation and transmission line are already 38 years old before you begin to need the capacity of the new substation, no substantial benefit has been demonstrated and there is no need for the transmission line and substation to be built at a cost exceeding $16 million.

Doris Mast Exhibit 302, pages 1 & 2, presents exhibit TPUD/401 Fagen/1 but interpreted correctly. On page 3 of Doris Mast Exhibit 302, I checked the conclusions KC Fagen gave about TPUD/401 Fagen/1. Column A checks whether it is reasonable to say that the 11.5 MW's of capacity is gone in 8 years assuming a growth of 0.9259% and using Wilson River's highest peak ever as year 0. Since adding 12 MW's of additional capacity to the original nameplate capacity of 78 gives 90 MW's as the new nameplate capacity, stating that you have used up the 12 MW's of capacity in 8 years means you have gone

[10] Doris Mast Exhibit 303 page 1

[11] Doris Mast Exhibit 302 pages 1 and 2

from the system peak of 63.10 MW's in year 0 to 90 MW's in 8 years. At this rate of consumption, the growth rate is 4.45%. So Fagen's conclusions that no capacity remains after 8 years is not reasonable. Section B tests the second conclusion KC Fagen drew that if he assumes no growth, the new capacity of the Wilson River is gone in 17 years. The assumption that the system peak goes from 63.1 MW's to 90 MW's in 17 years would take a growth rate of 2.10%. As you can see from exhibit TPUD/401 Fagen/1, the system peak is only 73.8 MW's after 17 years (which means it has not even reached the old nameplate capacity of 78 MW's) and it does have growth added at a rate of 0.9259% per year. So, the second conclusion is not reasonable. In Section C, I checked whether the statement that the 33.5 MW's of capacity provided by building the substation with a 22 MW transformer and adding it to the 12 MW addition at Wilson River would be gone after 45 years if no growth is assumed. If the new nameplate capacity at Wilson River is 90 MW and the new Oceanside transformer is 22 MW, the new capacity is 112 MW. Section C therefore tests what the growth is if the system peak goes from 63.1 MW to 112 MW's in 45 years. The growth rate is 1.28% under his assumptions and therefore his conclusion that he will use the 33.5MW in 45 years with no growth assumed is incorrect. The system peak in his chart at 45 years is 95.5MW which means he has used only 5.5MW of the 22MW added by the new transformer at Oceanside. If you look at Doris Mast Exhibit 302 pages 1 & 2 you will see that TPUD would use up the 33.5 of extra capacity at 62 years. (78 MW old nameplate capacity + 33.5 MW = 111.5 MW.) When I interpret TPUD/401 Fagen/1, I conclude that the extra capacity from the larger transformer will be used up when the system peak reaches 90 (old nameplate capacity of 78 MW + 12 MW = new nameplate capacity of 90 MW). Running my finger down the column called Peak Load until I get to 90, I get a peak of 90 after 38 years. I conclude that if the transmission line and substation are not needed for 38 years that necessity has not been proven and no one will be harmed if a more practicable and lesser cost option is pursued.

Neither capacity nor load growth pose problems for TPUD. Since 1973 TPUD has built 3 new substations and added approximately 105 MW's of capacity while adding only 20 MW's of added sales.

Meanwhile, distribution lines have been neglected. Many are not conductored properly and cause problems under increased N -1 loads. Repairing and rebuilding the distribution conductors is less costly to the consumer and would impact no new property owners, hence, no eminent domain is necessary.

4. **Safety of the Proposed Transmission line**

Putting a transmission line through the center of Stimson forest will create a fire hazard due to the steep terrain with high coastal winds. Evacuating the population of Oceanside and Netarts would be difficult because a major road has been closed for several years due to landslides. It is not in the public interest to subject the Oceanside – Netarts rate payers to a fire hazard when a distribution line rebuild or Option 3 could increase reliability. Increasing the conductor size would add capacity which could serve the existing and future loads of Oceanside – Netarts and Whiskey Creek.

5. **Practicability**

TPUD spent 8 months working with a Citizens Advisory Group (CAG) to select a transmission line route and says the transmission line route is practicable and has the least overall impact on the community when compared to all the other transmission routes they considered. The CAG was not allowed to consider need or any non-transmission line options. Here are a few examples of topics that a CAG could have examined in order to select practicable solutions to TPUD's desire to increase reliability in Oceanside – Netarts, increase capacity in the central valley including Oceanside – Netarts, and replace aging infrastructure. Even back in 2010 when I first heard TPUD's presentations, I was concerned that all N -1 scenarios described multiple overloaded conductors and TPUD always interpreted that as a need for a new substation and transmission line. In 2010 we were even told TPUD needed a new substation at Oceanside to protect the "old" (think vintage) transformer at Wilson River 1. All of us told TPUD to buy a new larger transformer. I was appalled at the number of feeders that were not conductored properly to handle today's loads. When I noticed that 3 new substations were added since 1973, and that one of those substations was the Trask, I noticed how underutilized it was. The substations and feeders did not seem to be configured for best results. I definitely got the impression that the TPUD board was very interested in building substations and transmission lines at the expense of the distribution system. Feeder 51 has conductors over 50 years old but TPUD will only rebuild it if they get the new substation and transmission line they want. Feeder 51 is also the second highest loaded feeder from Wilson River 2.[12] If you were able to change feeder 51 to the Trask substation, it would transfer 5 – 11 MW's of load off of Wilson River 2, and in conjunction with reconductoring feeder 51 appropriately and adding the new larger transformer at Wilson River, TPUD's objectives have been met. If TPUD refuses to consider this, there are 11 feeders coming off of Wilson River. Are any

[12] 2018 TPUD Construction Work Plan page 46

of them capable of being reconfigured to a more lightly loaded substation? I think serious attention needs to be given to the fact that so many conductors are overloaded in a N -1. If a skillful reconfiguration of properly conductored feeders, along with larger transformers in the central valley where the load is, solves TPUD's overloading in the central valley during N-1, and increases reliability by updating distribution lines, adding yet another new substation and transmission line that costs $16 million and has questionable ability to return excess capacity to the central valley is not practicable. If the issues can be solved in other ways that cost less and have less impact to farms and forests and use existing rights of ways and existing easements, fewer rate payers are harmed. Other sensible choices would surely include rebuilding feeder 51 or building a version of Option 3. No other alternatives were considered seriously by the TPUD board, and they refuse to discuss need or other alternatives.

6. Justification

The proposed transmission line cannot be justified because it costs over $16 million and the 22 MW added capacity it provides will not be needed for 38 years. TPUD could meet its objectives with smaller projects such as rebuilding feeder 51, building Option 3, or switching feeders to Trask to shift more load off Wilson River. Since TPUD can meet its obligation to provide safe and reliable service to existing and future rate payers with less cost and less impact, the line cannot be justified. The smaller projects also do not cause an increased outage risk for Tillamook by using feeder 51 in an N -1 situation where it would perform poorly.

7. Spatial Information

TPUD has neglected to include a map for the project when it uses feeder 51 to deliver excess power to Cape Mears or Tillamook. I have included a crude map which does this. As you can see, when feeder 51 is added to the transmission line, it has a similar amount of overhead lines as Option 3. And simply rebuilding feeder 51 would have the least amount of overhead lines! And since rebuilding feeder 51 has a similar amount of overhead distribution line as the transmission line option which extends feeder 51 to Cape Meares, I would expect similar line losses. I would like to point out that my neighbor and myself now receive power from the dotted blue line. My neighbor's farm is crossed by the pink transmission line just before the blue new route for Cape Mears goes underneath the transmission line. My neighbor is being subjected to eminent domain so Oceanside – Netarts no longer has to receive power from feeder 51 and then he is being placed on feeder 51! Before, he was 2 – 3 miles from the substation. Now he will receive his power after a journey of approximately 15 miles. This map shows why the project is not practicable. The worst part of this story is that I found this out by reading section 5 page 41, 42 of the 2018 TPUD Construction Work Plan project 402B. TPUD has never talked to us about it!

402B **Netarts Oceanside Substation-** This project consists of building a new substation located southeast of Oceanside, adjacent to the new Netarts-Oceanside waste treatment facility. This substation will have a 115/24.9 kV, 20/26/33 MVA transformer with an LTC. There will be four (4) feeder bays with two (2) feeders initially exiting the substation. The first feeder

41

TILLAMOOK PEOPLE'S UTILITY DISTRICT
2018 Four Year Construction Work Plan *Section 5.0*

will feed the Oceanside area. The second feeder will tie into the existing three-phase line and serve the Netarts area back towards Tillamook, with the open at recloser R0032. This will decrease the load on Wilson River by approximately 9.5 MW. Moving the open to Switch Y 0324 and Y 1364 will allow the Cape Meares area to be fed from Oceanside Substation. This will add an additional 1.76 MW of load to Oceanside, bringing the total load on Oceanside to 11.26 MW. The underground regulators along Netarts Road will be needed to maintain voltage levels at Cape Meares and picking up part of Wilson River. As a result of this project, transformer loading on T1 is reduced to 72% and transformer T2 is at 94% of its upper rating during peak loads.

Estimated Cost: $3,848,039

RUS Funding: $3,848,039

The farms of Mizee, Rocha, and Aufdermauer are also on the Cape Mears feeder and will require an easement. Will they also be placed on feeder 51? Jenck is fed by the Cape Mears line just outside the Tillamook City limits. Although he is not being forced to give an easement so others don't have to receive power from feeder 51, if his neighbors resist signing an easement because they feel it is unreasonable to be forced to do so when they realize TPUD plans to place them on feeder 51, they may have his sympathies.

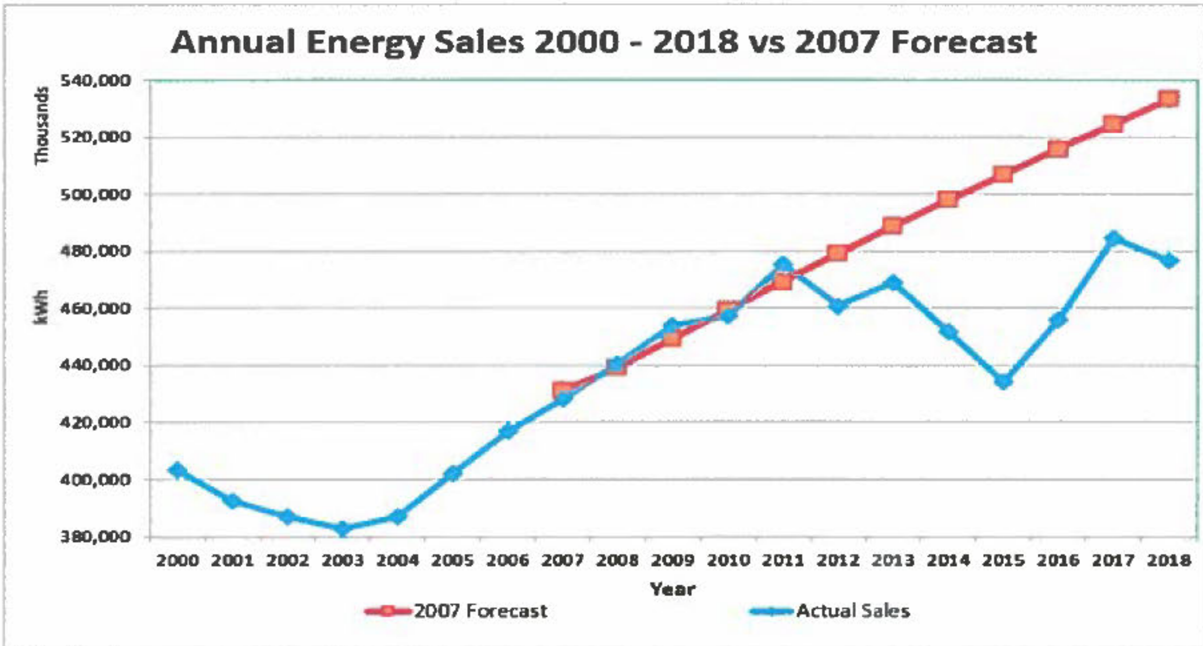
No maps were included of the feeders which would have been helpful in evaluating the system and how it fits together.

8. Cost Information

The 2018 Construction Work Plan (CWP) lists several projects that need to be done on feeder 51 so it can work with the new transmission line and substation in Oceanside. In Doris Mast Exhibit 308, I add those projects to the latest cost of the transmission line project given by in TPUD/417 Fagen/5. The Third Street Tillamook Reconductor project does not directly apply to feeder 51. However, this project is vital since using the worst feeder in the system for returning load to Tillamook under N -1 conditions has questionable reliability. Therefore, it would be essential to have dependable ability to transfer Wilson River feeders to the underutilized Trask in case load intended for Tillamook is lost when feeder 51 has an outage. In fact, the Third Street Tillamook Reconductor project along with rebuilding feeder 51 and using the newly installed larger transformer at Wilson River may be another example of a simple, low cost solution to add capacity, increase reliability, and replace aging infrastructure that TPUD could have considered but has refused to even discuss. I think asking rate payers to pay $16,885,379 for a project that has serious flaws is not justified when other lower cost solutions were not even discussed. I also think that not even listing costs for rebuilding feeder 51 was a deliberate tactic to stifle meaningful comparisons between rebuilding feeder 51 and option 4.

9. Financial Feasibility

When I think about the financial feasibility of the transmission line project, I use the term financial liability. When the TPUD board decided to build this project, they thought the steep rise in energy sales shown in the 2007 load forecast would pay for the project[13].



However, the reality is energy sales have fallen, but TPUD refuses to acknowledge this, preferring to say this is only warmer weather. I asked David Mast if he could translate the falling sales into revenue lost. He worked up a table for me which shows that the drop of energy sales caused a $24,079,703 loss in revenue. In other words, the money TPUD counted on to pay for the transmission line project was lost as sales fell.

[13] Doris Mast Exhibit 306 page1

THE IMPACT OF ACTUAL SALES BEING LOWER THAN THE 2007 FORECAST ON THE REVENUE STREAM

Year	2007 Forecast of Annual Electricity Sales	Expected Revenue	Rate/kW	Actual Annual Electricity Sales	Actual Revenue from TPUD 407 FAGEN/1	Rate/kW	Expected Revenue - Actual Revenue = Shortfall
		A			B		C
	MW	$	$	MW	$	$	$
2007	431,009	$ 28,164,986	$0.0653	428,316	$ 27,989,008	$0.0653	$ (175,978)
2008	438,957	$ 28,431,091	$0.0648	440,203	$ 28,511,794	$0.0648	$ 80,703
2009	449,195	$ 29,501,215	$0.0657	453,997	$ 29,816,590	$0.0657	$ 315,375
2010	459,385	$ 30,899,016	$0.0673	457,084	$ 30,744,227	$0.0673	$ (154,789)
2011	469,176	$ 32,073,138	$0.0684	475,451	$ 32,502,101	$0.0684	$ 428,963
2012	479,099	$ 34,289,900	$0.0716	460,768	$ 32,977,895	$0.0716	$ (1,312,005)
2013	488,681	$ 36,204,069	$0.0741	468,865	$ 34,736,010	$0.0741	$ (1,468,059)
2014	498,058	$ 37,311,636	$0.0749	451,861	$ 33,850,826	$0.0749	$ (3,460,810)
2015	506,993	$ 40,146,001	$0.0792	434,204	$ 34,382,272	$0.0792	$ (5,763,729)
2016	515,843	$ 41,472,573	$0.0804	455,919	$ 36,654,853	$0.0804	$ (4,817,720)
2017	524,540	$ 41,761,141	$0.0796	484,381	$ 38,563,884	$0.0796	$ (3,197,257)
2018	533,487	$ 42,699,195	$0.0800	476,584	$ 38,144,800	$0.0800	$ (4,554,395)
TOTAL		$422,953,963			$ 398,874,260		$(24,079,703)

David Mast found the actual energy sales from 2007 – 2017 in TPUD/407 Fagen/1. Results for 2018 were estimated in the 2019 budget. By comparing the actual annual electric sales to the actual revenue from those sales, he derived a $ rate/kW. This is shown in section B. He then applied this rate to the 2007 projected energy sales to get the 2007 expected revenue in section A. In section C, he subtracts the actual revenue in section B from the projected revenue in section A to show the revenue shortfall caused by the drop of energy sales. The **$24,079,703** TPUD thought they would have to finance this project did not come.

We started attending board meetings in 2011. We have witnessed TPUD raise rates twice because falling sales and increased costs from BPA lowered net profit to levels where they needed to increase revenues just to be able to meet operating cost. This happened with the old level of debt. From the budget we can see only $100,000 of the transmission line cost has been in the budget.[14] We know from the TPUD webpage on projects, that the Neskowin project may reach $30 million dollars cost. Combined with the $16 million cost for the Oceanside project, TPUD will be servicing $46 million in debt over the next 25 – 35 years as it is added to the budget. And they are spending more on other projects. The 2018 Construction Work Plan was over $60 million. These costs are spread over a 25-year period as they are added. Unless growth rates begin to rise or TPUD decreases their operating expense (and I see no evidence of that - $10 million for

[14] TPUD/407 Fagen/36

office remodel, $3 million dollars to replace meters only 8 years old), the rate payer will continue to see higher rates over the next 25 years. I will be paying these rate increases from my social security. Adding large amounts of new debt in a time of falling revenue is not in the public interest unless the project is clearly needed, which TPUD has failed to demonstrate.

Since TPUD pledged the revenues from the rate payers to secure the RUS bonds at 4% interest, it is crucial to ensure the rate payer is not forced to fund a $16 million project based on faulty growth projections, or on overstated loading, forcing rate payers to finance over $16 million at 4% interest for added capacity they don't actually need, or for solving reliability issues that could be solved for less cost with other options, whether it is rebuilding feeder 51, reconfiguring feeders, or using Option 3.

10. Potential Condemnation

It is clear to me that TPUD **WANTS** this new substation and transmission line project. In fact, they **WANT** the project so badly that they refused to allow anyone to question the **NEED** for the project at the CAG. Why? Was TPUD afraid that CAG members might decide it was foolish to choose the best route when there was no need for the project? No property owner should face condemnation proceedings, or be forced to accept an easement for a transmission line when they know other alternatives satisfy TPUD's needs for increasing reliability, ensure adequate capacity for the central valley (including Oceanside – Netarts coastal communities) and replace aging infrastructure and do so while remaining in the road right of way. It is appalling to consider Eric Peterson's land could be condemned for the transmission line easement in order to remove Oceanside – Netarts from feeder 51 and then to turn around and place Eric Peterson on feeder 51.

11. Alternate Routes

TPUD formed the CAG and spent 8 months to look at transmission routes. No other non-transmission line solutions were discussed. The CAG was expressly told they were not to consider need. When property is to be condemned, this procedure is unacceptable. Since TPUD is willing to spend 8 months to evaluate transmission line routes and unwilling to have even one workshop to examine other non-transmission line options, the Petition for Certificate of Public Convenience and Necessity should be denied.

12. Additional Information OAR 860-025-0030 1 (h)

TPUD **WANTS** the transmission line and therefore has determined it is in its customers best interests to construct the line. On the application TPUD said they considered

Option 3. But Option 3 was described to the rate payers only after TPUD had already decided to construct the transmission line route. We never heard of Options 1, 2, and 3 until the October 13, 2016 "Tillamook to Oceanside TRANSMISSION LINE PROJECT BOARD WORKSHOP". In previous intervenor testimony, I have shown that TPUD's calculations on Option 3 were flawed. Why is rebuilding feeder 51 not even considered as an option? Why is there no discussion of reconfiguring feeders from Wilson River to the Trask substation which is very lightly loaded in order to reduce loading on Wilson River? The transmission line is built to divert from 5 MW to 11 MW of load for Oceanside from the Wilson River. Are there feeders currently served by Wilson River that can be shifted which achieves a similar reduction in loading on the Wilson River? When David Mast looked up OAR 860-025-0030 he found that it listed the following requirement "Other transmission lines and substations of petitioner connecting or serving or capable of being adopted to connect or serve the areas covered by the proposed transmission line." This requirement has not been met. Option 3 could be used without condemnation. Other options not even considered could do this if the TPUD board considered **NEED** instead of **WANT**. Therefore, the Petition for Certificate of Public Convenience and Necessity should be denied.

13. Land Use Information

The staff for the Tillamook County Planning commission stated that they didn't need to determine if there are other or better options and that process should have been done at an earlier time. All they were doing is making sure the application was filed correctly and needed permits were properly applied for. Well, that was interesting to be scolded that we should have brought it up earlier when TPUD had denied us the right to bring it up. The TPUD determined **NEED** would not be discussed in any public forum, after all the TPUD had already determined the need and the route before holding any meetings. The CAG was only held after their first route was turned down by the Tillamook City Council which was upheld by LUBA. I was at a TPUD board meeting when Kurt Mizee asked for a workshop on Option 3 and the TPUD board told him to bring it up at the Tillamook County Planning hearing.

The county staff then went on to make disparaging remarks about Option 3 as though it were to be a transmission line to be built and not extending already existing distribution lines which would be connected to feeder 51. There is a huge difference between adding 2 miles of distribution line using existing road right of way such as Option 3 would, or rebuilding feeder 51 which adds no new easements or poles, and building an 87-pole transmission line **crossing over farm land NOT in the road right of way and crossing through the center of 4 miles of forest.**

Staff determined that they didn't have to determine if there are other better options. All they did was to make sure TPUD's paperwork was correct. Staff determined that the impact to Stimpson forest was not significant because Stimson owned 90,000 acres throughout Oregon. What a flawed thought process. Staff had no jurisdiction over the 90,000 acres in the rest of the state and no legal right to assess impact based on property over which no one recognizes their authority. Had staff restricted themselves to the Stimson property in Tillamook County which they do have jurisdiction over, they should have considered Stimson's testimony that the impact to his property was huge and they should have denied the conditional use permit. I hope LUBA sees these flaws of process and overturns the county.

Concluding Thoughts

In TPUD/400 Fagen/13 and 14, I learned that TPUD has changed the project as they first applied for at the PUC and for which they were granted a conditional use permit by the county of Tillamook. The application was to add 33 MW's at Oceanside and return 15 MW's on feeder 51 for N -1. The new plan is to install 22 MW's with 11-15MWs for serving the Oceanside load and 10-7MWs available to return to Tillamook on feeder 51 and counting the 11.5 MWs of capacity added by the larger transformer at Wilson River as part of the plan for a total of 33.5MWs. The price tag will still be $16 million and the transmission line is now a fancy distribution line. TPUD really needs to justify that the transmission line now diverts 10 MWs less load than originally planned for with only a small reduction in price(33MW-22MW). They should reconsider other cheaper options now that they have changed the plan. They have adequate capacity but they need to work on the distribution feeders to work more efficiently with the three new substations in the central valley. If you were able to reconfigure feeders off of Wilson River to sum up to 7 – 15 MW's, you would achieve the same result for less impact, and would not need eminent domain. Reliability can be improved and aging infrastructure can be replaced with less cost to the public and with less impact than either of the transmission line projects. I think TPUD should be denied a Certificate of Public Convenience and Necessity for both transmission line plans.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

EXHIBIT 301

TO THE TESTIMONY OF DORIS MAST

LONGEVITY OF WILSON RIVER

January 14, 2019

COMPARATIVE LONGEVITY OF WILSON RIVER T1 & T2 TO REACH 78MW, 84MW, 90MW

A					B					C				
Year	# Of Years For Annual Coincident Peak To Reach Capacity	Old Nameplate Capacity of 78 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growth	Year	# Of Years For Annual Coincident Peak To Reach Capacity	Winter Thermal Rating of 84 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growth	Year	# Of Years For Annual Coincident Peak To Reach Capacity	New Nameplate Capacity of 90 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growt h
2013			57.61		2013			57.61		2013			57.61	
2014			60.85		2014			60.85		2014			60.85	
2015			49.64		2015			49.64		2015			49.64	
2016			53.91		2016			53.91		2016			53.91	
2017			57.68		2017			57.68		2017			57.68	
2018	0	78.00	55.94		2018	0	84.00	55.94		2018	0	90.00	55.94	
2019	1	78.00	56.19	0.45%	2019	1	84.00	56.19	0.45%	2019	1	90.00	56.19	0.45%
2020	2	78.00	56.44	0.45%	2020	2	84.00	56.44	0.45%	2020	2	90.00	56.44	0.45%
2021	3	78.00	56.70	0.45%	2021	3	84.00	56.70	0.45%	2021	3	90.00	56.70	0.45%
2022	4	78.00	56.95	0.45%	2022	4	84.00	56.95	0.45%	2022	4	90.00	56.95	0.45%
2023	5	78.00	57.21	0.45%	2023	5	84.00	57.21	0.45%	2023	5	90.00	57.21	0.45%
2024	6	78.00	57.47	0.45%	2024	6	84.00	57.47	0.45%	2024	6	90.00	57.47	0.45%
2025	7	78.00	57.72	0.45%	2025	7	84.00	57.72	0.45%	2025	7	90.00	57.72	0.45%
2026	8	78.00	57.98	0.45%	2026	8	84.00	57.98	0.45%	2026	8	90.00	57.98	0.45%
2027	9	78.00	58.24	0.45%	2027	9	84.00	58.24	0.45%	2027	9	90.00	58.24	0.45%
2028	10	78.00	58.51	0.45%	2028	10	84.00	58.51	0.45%	2028	10	90.00	58.51	0.45%
2029	11	78.00	58.77	0.45%	2029	11	84.00	58.77	0.45%	2029	11	90.00	58.77	0.45%
2030	12	78.00	59.03	0.45%	2030	12	84.00	59.03	0.45%	2030	12	90.00	59.03	0.45%
2031	13	78.00	59.30	0.45%	2031	13	84.00	59.30	0.45%	2031	13	90.00	59.30	0.45%
2032	14	78.00	59.57	0.45%	2032	14	84.00	59.57	0.45%	2032	14	90.00	59.57	0.45%
2033	15	78.00	59.84	0.45%	2033	15	84.00	59.84	0.45%	2033	15	90.00	59.84	0.45%
2034	16	78.00	60.10	0.45%	2034	16	84.00	60.10	0.45%	2034	16	90.00	60.10	0.45%
2035	17	78.00	60.37	0.45%	2035	17	84.00	60.37	0.45%	2035	17	90.00	60.37	0.45%
2036	18	78.00	60.65	0.45%	2036	18	84.00	60.65	0.45%	2036	18	90.00	60.65	0.45%
2037	19	78.00	60.92	0.45%	2037	19	84.00	60.92	0.45%	2037	19	90.00	60.92	0.45%
2038	20	78.00	61.19	0.45%	2038	20	84.00	61.19	0.45%	2038	20	90.00	61.19	0.45%
2039	21	78.00	61.47	0.45%	2039	21	84.00	61.47	0.45%	2039	21	90.00	61.47	0.45%
2040	22	78.00	61.75	0.45%	2040	22	84.00	61.75	0.45%	2040	22	90.00	61.75	0.45%
2041	23	78.00	62.02	0.45%	2041	23	84.00	62.02	0.45%	2041	23	90.00	62.02	0.45%
2042	24	78.00	62.30	0.45%	2042	24	84.00	62.30	0.45%	2042	24	90.00	62.30	0.45%
2043	25	78.00	62.58	0.45%	2043	25	84.00	62.58	0.45%	2043	25	90.00	62.58	0.45%
2044	26	78.00	62.86	0.45%	2044	26	84.00	62.86	0.45%	2044	26	90.00	62.86	0.45%
2045	27	78.00	63.15	0.45%	2045	27	84.00	63.15	0.45%	2045	27	90.00	63.15	0.45%
2046	28	78.00	63.43	0.45%	2046	28	84.00	63.43	0.45%	2046	28	90.00	63.43	0.45%
2047	29	78.00	63.72	0.45%	2047	29	84.00	63.72	0.45%	2047	29	90.00	63.72	0.45%
2048	30	78.00	64.00	0.45%	2048	30	84.00	64.00	0.45%	2048	30	90.00	64.00	0.45%
2049	31	78.00	64.29	0.45%	2049	31	84.00	64.29	0.45%	2049	31	90.00	64.29	0.45%
2050	32	78.00	64.58	0.45%	2050	32	84.00	64.58	0.45%	2050	32	90.00	64.58	0.45%
2051	33	78.00	64.87	0.45%	2051	33	84.00	64.87	0.45%	2051	33	90.00	64.87	0.45%
2052	34	78.00	65.16	0.45%	2052	34	84.00	65.16	0.45%	2052	34	90.00	65.16	0.45%
2053	35	78.00	65.46	0.45%	2053	35	84.00	65.46	0.45%	2053	35	90.00	65.46	0.45%
2054	36	78.00	65.75	0.45%	2054	36	84.00	65.75	0.45%	2054	36	90.00	65.75	0.45%
2055	37	78.00	66.05	0.45%	2055	37	84.00	66.05	0.45%	2055	37	90.00	66.05	0.45%
2056	38	78.00	66.34	0.45%	2056	38	84.00	66.34	0.45%	2056	38	90.00	66.34	0.45%
2057	39	78.00	66.64	0.45%	2057	39	84.00	66.64	0.45%	2057	39	90.00	66.64	0.45%
2058	40	78.00	66.94	0.45%	2058	40	84.00	66.94	0.45%	2058	40	90.00	66.94	0.45%
2059	41	78.00	67.24	0.45%	2059	41	84.00	67.24	0.45%	2059	41	90.00	67.24	0.45%
2060	42	78.00	67.55	0.45%	2060	42	84.00	67.55	0.45%	2060	42	90.00	67.55	0.45%
2061	43	78.00	67.85	0.45%	2061	43	84.00	67.85	0.45%	2061	43	90.00	67.85	0.45%
2062	44	78.00	68.16	0.45%	2062	44	84.00	68.16	0.45%	2062	44	90.00	68.16	0.45%
2063	45	78.00	68.46	0.45%	2063	45	84.00	68.46	0.45%	2063	45	90.00	68.46	0.45%
2064	46	78.00	68.77	0.45%	2064	46	84.00	68.77	0.45%	2064	46	90.00	68.77	0.45%
2065	47	78.00	69.08	0.45%	2065	47	84.00	69.08	0.45%	2065	47	90.00	69.08	0.45%
2066	48	78.00	69.39	0.45%	2066	48	84.00	69.39	0.45%	2066	48	90.00	69.39	0.45%
2067	49	78.00	69.70	0.45%	2067	49	84.00	69.70	0.45%	2067	49	90.00	69.70	0.45%
2068	50	78.00	70.02	0.45%	2068	50	84.00	70.02	0.45%	2068	50	90.00	70.02	0.45%
2069	51	78.00	70.33	0.45%	2069	51	84.00	70.33	0.45%	2069	51	90.00	70.33	0.45%
2070	52	78.00	70.65	0.45%	2070	52	84.00	70.65	0.45%	2070	52	90.00	70.65	0.45%
2071	53	78.00	70.97	0.45%	2071	53	84.00	70.97	0.45%	2071	53	90.00	70.97	0.45%
2072	54	78.00	71.29	0.45%	2072	54	84.00	71.29	0.45%	2072	54	90.00	71.29	0.45%

COMPARATIVE LONGEVITY OF WILSON RIVER T1 & T2 TO REACH 78MW, 84MW, 90MW

A					B					C				
Year	# Of Years For Annual Coincident Peak To Reach Capacity	Old Nameplate Capacity of 78 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growth	Year	# Of Years For Annual Coincident Peak To Reach Capacity	Winter Thermal Rating of 84 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growth	Year	# Of Years For Annual Coincident Peak To Reach Capacity	New Nameplate Capacity of 90 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growt h
2073	55	78.00	71.61	0.45%	2073	55	84.00	71.61	0.45%	2073	55	90.00	71.61	0.45%
2074	56	78.00	71.93	0.45%	2074	56	84.00	71.93	0.45%	2074	56	90.00	71.93	0.45%
2075	57	78.00	72.25	0.45%	2075	57	84.00	72.25	0.45%	2075	57	90.00	72.25	0.45%
2076	58	78.00	72.58	0.45%	2076	58	84.00	72.58	0.45%	2076	58	90.00	72.58	0.45%
2077	59	78.00	72.90	0.45%	2077	59	84.00	72.90	0.45%	2077	59	90.00	72.90	0.45%
2078	60	78.00	73.23	0.45%	2078	60	84.00	73.23	0.45%	2078	60	90.00	73.23	0.45%
2079	61	78.00	73.56	0.45%	2079	61	84.00	73.56	0.45%	2079	61	90.00	73.56	0.45%
2080	62	78.00	73.89	0.45%	2080	62	84.00	73.89	0.45%	2080	62	90.00	73.89	0.45%
2081	63	78.00	74.23	0.45%	2081	63	84.00	74.23	0.45%	2081	63	90.00	74.23	0.45%
2082	64	78.00	74.56	0.45%	2082	64	84.00	74.56	0.45%	2082	64	90.00	74.56	0.45%
2083	65	78.00	74.90	0.45%	2083	65	84.00	74.90	0.45%	2083	65	90.00	74.90	0.45%
2084	66	78.00	75.23	0.45%	2084	66	84.00	75.23	0.45%	2084	66	90.00	75.23	0.45%
2085	67	78.00	75.57	0.45%	2085	67	84.00	75.57	0.45%	2085	67	90.00	75.57	0.45%
2086	68	78.00	75.91	0.45%	2086	68	84.00	75.91	0.45%	2086	68	90.00	75.91	0.45%
2087	69	78.00	76.25	0.45%	2087	69	84.00	76.25	0.45%	2087	69	90.00	76.25	0.45%
2088	70	78.00	76.60	0.45%	2088	70	84.00	76.60	0.45%	2088	70	90.00	76.60	0.45%
2089	71	78.00	76.94	0.45%	2089	71	84.00	76.94	0.45%	2089	71	90.00	76.94	0.45%
2090	72	78.00	77.29	0.45%	2090	72	84.00	77.29	0.45%	2090	72	90.00	77.29	0.45%
2091	73	78.00	77.63	0.45%	2091	73	84.00	77.63	0.45%	2091	73	90.00	77.63	0.45%
2092	74	78.00	77.98	0.45%	2092	74	84.00	77.98	0.45%	2092	74	90.00	77.98	0.45%
2093	75	78.00	78.33	0.45%	2093	75	84.00	78.33	0.45%	2093	75	90.00	78.33	0.45%
2094	76	78.00	78.69	0.45%	2094	76	84.00	78.69	0.45%	2094	76	90.00	78.69	0.45%
2095	77	78.00	79.04	0.45%	2095	77	84.00	79.04	0.45%	2095	77	90.00	79.04	0.45%
2096	78	78.00	79.40	0.45%	2096	78	84.00	79.40	0.45%	2096	78	90.00	79.40	0.45%
2097	79	78.00	79.75	0.45%	2097	79	84.00	79.75	0.45%	2097	79	90.00	79.75	0.45%
2098	80	78.00	80.11	0.45%	2098	80	84.00	80.11	0.45%	2098	80	90.00	80.11	0.45%
2099	81	78.00	80.47	0.45%	2099	81	84.00	80.47	0.45%	2099	81	90.00	80.47	0.45%
2100	82	78.00	80.84	0.45%	2100	82	84.00	80.84	0.45%	2100	82	90.00	80.84	0.45%
2101	83	78.00	81.20	0.45%	2101	83	84.00	81.20	0.45%	2101	83	90.00	81.20	0.45%
2102	84	78.00	81.56	0.45%	2102	84	84.00	81.56	0.45%	2102	84	90.00	81.56	0.45%
2103	85	78.00	81.93	0.45%	2103	85	84.00	81.93	0.45%	2103	85	90.00	81.93	0.45%
2104	86	78.00	82.30	0.45%	2104	86	84.00	82.30	0.45%	2104	86	90.00	82.30	0.45%
2105	87	78.00	82.67	0.45%	2105	87	84.00	82.67	0.45%	2105	87	90.00	82.67	0.45%
2106	88	78.00	83.04	0.45%	2106	88	84.00	83.04	0.45%	2106	88	90.00	83.04	0.45%
2107	89	78.00	83.42	0.45%	2107	89	84.00	83.42	0.45%	2107	89	90.00	83.42	0.45%
2108	90	78.00	83.79	0.45%	2108	90	84.00	83.79	0.45%	2108	90	90.00	83.79	0.45%
2109	91	78.00	84.17	0.45%	2109	91	84.00	84.17	0.45%	2109	91	90.00	84.17	0.45%
2110	92	78.00	84.55	0.45%	2110	92	84.00	84.55	0.45%	2110	92	90.00	84.55	0.45%
2111	93	78.00	84.93	0.45%	2111	93	84.00	84.93	0.45%	2111	93	90.00	84.93	0.45%
2112	94	78.00	85.31	0.45%	2112	94	84.00	85.31	0.45%	2112	94	90.00	85.31	0.45%
2113	95	78.00	85.69	0.45%	2113	95	84.00	85.69	0.45%	2113	95	90.00	85.69	0.45%
2114	96	78.00	86.08	0.45%	2114	96	84.00	86.08	0.45%	2114	96	90.00	86.08	0.45%
2115	97	78.00	86.47	0.45%	2115	97	84.00	86.47	0.45%	2115	97	90.00	86.47	0.45%
2116	98	78.00	86.86	0.45%	2116	98	84.00	86.86	0.45%	2116	98	90.00	86.86	0.45%
2117	99	78.00	87.25	0.45%	2117	99	84.00	87.25	0.45%	2117	99	90.00	87.25	0.45%
2118	100	78.00	87.64	0.45%	2118	100	84.00	87.64	0.45%	2118	100	90.00	87.64	0.45%
2119	101	78.00	88.03	0.45%	2119	101	84.00	88.03	0.45%	2119	101	90.00	88.03	0.45%
2120	102	78.00	88.43	0.45%	2120	102	84.00	88.43	0.45%	2120	102	90.00	88.43	0.45%
2121	103	78.00	88.83	0.45%	2121	103	84.00	88.83	0.45%	2121	103	90.00	88.83	0.45%
2122	104	78.00	89.23	0.45%	2122	104	84.00	89.23	0.45%	2122	104	90.00	89.23	0.45%
2123	105	78.00	89.63	0.45%	2123	105	84.00	89.63	0.45%	2123	105	90.00	89.63	0.45%
2124	106	78.00	90.03	0.45%	2124	106	84.00	90.03	0.45%	2124	106	90.00	90.03	0.45%
2125	107	78.00	90.44	0.45%	2125	107	84.00	90.44	0.45%	2125	107	90.00	90.44	0.45%
2126	108	78.00	90.84	0.45%	2126	108	84.00	90.84	0.45%	2126	108	90.00	90.84	0.45%
			0.450%					0.450%					0.450%	

COMPARATIVE LONGEVITY OF WILSON RIVER T1 & T2 USING TWO DIFFERENT GROWTH RATES

A

Year	# Of Years For Annual Coincident Peak To Reach Capacity	Old Nameplate Capacity of 78 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growth
2013			57.61	
2014			60.85	
2015			49.64	
2016			53.91	
2017			57.68	
2018	0	78.00	55.94	
2019	1	78.00	56.19	0.45%
2020	2	78.00	56.44	0.45%
2021	3	78.00	56.70	0.45%
2022	4	78.00	56.95	0.45%
2023	5	78.00	57.21	0.45%
2024	6	78.00	57.47	0.45%
2025	7	78.00	57.72	0.45%
2026	8	78.00	57.98	0.45%
2027	9	78.00	58.24	0.45%
2028	10	78.00	58.51	0.45%
2029	11	78.00	59.05	0.93%
2030	12	78.00	59.60	0.93%
2031	13	78.00	60.15	0.93%
2032	14	78.00	60.70	0.93%
2033	15	78.00	61.27	0.93%
2034	16	78.00	61.83	0.93%
2035	17	78.00	62.41	0.93%
2036	18	78.00	62.98	0.93%
2037	19	78.00	63.57	0.93%
2038	20	78.00	64.16	0.93%
Remaining Capacity			13.84	
% Remaining Capacity			17.75%	
		0.4500%	0.9259%	

B

Year	# Of Years For Annual Coincident Peak To Reach Capacity	Winter Thermal Rating of 84 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growth
2013			57.61	
2014			60.85	
2015			49.64	
2016			53.91	
2017			57.68	
2018	0	84.00	55.94	
2019	1	84.00	56.19	0.45%
2020	2	84.00	56.44	0.45%
2021	3	84.00	56.70	0.45%
2022	4	84.00	56.95	0.45%
2023	5	84.00	57.21	0.45%
2024	6	84.00	57.47	0.45%
2025	7	84.00	57.72	0.45%
2026	8	84.00	57.98	0.45%
2027	9	84.00	58.24	0.45%
2028	10	84.00	58.51	0.45%
2029	11	84.00	59.05	0.93%
2030	12	84.00	59.60	0.93%
2031	13	84.00	60.15	0.93%
2032	14	84.00	60.70	0.93%
2033	15	84.00	61.27	0.93%
2034	16	84.00	61.83	0.93%
2035	17	84.00	62.41	0.93%
2036	18	84.00	62.98	0.93%
2037	19	84.00	63.57	0.93%
2038	20	84.00	64.16	0.93%
Remaining Capacity			19.84	
% Remaining Capacity			23.62%	
		0.450%	0.9259%	

C

Year	# Of Years For Annual Coincident Peak To Reach Capacity	New Nameplate Capacity of 90 MW	Yearly Load Forecast 0.45% Growth	Yearly % Growt h
2013			57.61	
2014			60.85	
2015			49.64	
2016			53.91	
2017			57.68	
2018	0	90.00	55.94	
2019	1	90.00	56.19	0.45%
2020	2	90.00	56.44	0.45%
2021	3	90.00	56.70	0.45%
2022	4	90.00	56.95	0.45%
2023	5	90.00	57.21	0.45%
2024	6	90.00	57.47	0.45%
2025	7	90.00	57.72	0.45%
2026	8	90.00	57.98	0.45%
2027	9	90.00	58.24	0.45%
2028	10	90.00	58.51	0.45%
2029	11	90.00	59.05	0.93%
2030	12	90.00	59.60	0.93%
2031	13	90.00	60.15	0.93%
2032	14	90.00	60.70	0.93%
2033	15	90.00	61.27	0.93%
2034	16	90.00	61.83	0.93%
2035	17	90.00	62.41	0.93%
2036	18	90.00	62.98	0.93%
2037	19	90.00	63.57	0.93%
2038	20	90.00	64.16	0.93%
Remaining Capacity			25.84	
% Remaining Capacity			28.72%	
		0.450%	0.9259%	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

EXHIBIT 302

TO THE TESTIMONY OF DORIS MAST

CORRECT INTERPERTATION OF EXHIBIT

TPUD/401 FAGEN/1

January 14, 2019

COMBINED CAPACITY OF WILSON RIVER + OCEANSIDE

CORRECTION TO TPUD/401 KC FAGEN/1

Year	Peak Load	MW	Total MW	
0	63.10	-	-	
1	63.68	0.58	0.58	
2	64.27	0.59	1.17	
3	64.87	0.60	1.77	
4	65.47	0.60	2.37	
5	66.08	0.61	2.98	
6	66.69	0.61	3.59	
7	67.31	0.62	4.21	
8	67.93	0.62	4.83	
9	68.56	0.63	5.46	
10	69.19	0.63	6.09	
11	69.83	0.64	6.73	
12	70.48	0.65	7.38	
13	71.13	0.65	8.03	
14	71.79	0.66	8.69	
15	72.46	0.66	9.36	
16	73.13	0.67	10.03	
17	73.80	0.68	10.70	
18	74.49	0.68	11.39	
19	75.18	0.69	12.08	
20	75.87	0.70	12.77	
21	76.57	0.70	13.47	
22	77.28	0.71	14.18	
23	78.00	0.72	14.90	OLD NAMEPLATE CAPACITY - 78 MW
24	78.72	0.72	15.62	
25	79.45	0.73	16.35	
26	80.19	0.74	17.09	
27	80.93	0.74	17.83	
28	81.68	0.75	18.58	
29	82.43	0.76	19.33	
30	83.20	0.76	20.10	
31	83.97	0.77	20.87	OLD WINTER THERMAL RATING - 84 MW
32	84.74	0.78	21.64	
33	85.53	0.78	22.43	
34	86.32	0.79	23.22	
35	87.12	0.80	24.02	
36	87.93	0.81	24.83	
37	88.74	0.81	25.64	
38	89.56	0.82	26.46	NEW NAMEPLATE CAPACITY - 90 MW
39	90.39	0.83	27.29	
40	91.23	0.84	28.13	
41	92.07	0.84	28.97	
42	92.93	0.85	29.83	
43	93.79	0.86	30.69	
44	94.66	0.87	31.56	
45	95.53	0.88	32.43	
46	96.42	0.88	33.32	
47	97.31	0.89	34.21	
48	98.21	0.90	35.11	
49	99.12	0.91	36.02	
50	100.04	0.92	36.94	
51	100.96	0.93	37.86	
52	101.90	0.93	38.80	
53	102.84	0.94	39.74	
54	103.79	0.95	40.69	

COMBINED CAPACITY OF WILSON RIVER + OCEANSIDE

CORRECTION TO TPUD/401 KC FAGEN/1

Year	Peak Load	MW	Total MW
55	104.75	0.96	41.65
56	105.72	0.97	42.62
57	106.70	0.98	43.60
58	107.69	0.99	44.59
59	108.69	1.00	45.59
60	109.70	1.01	46.60
61	110.71	1.02	47.61
62	111.74	1.03	48.64
63	112.77	1.03	49.67
64	113.81	1.04	50.71
65	114.87	1.05	51.77
66	115.93	1.06	52.83
67	117.01	1.07	53.91
68	118.09	1.08	54.99
69	119.18	1.09	56.08
70	120.29	1.10	57.19
71	121.40	1.11	58.30
72	122.52	1.12	59.42
73	123.66	1.13	60.56
74	124.80	1.14	61.70
75	125.96	1.16	62.86
76	127.12	1.17	64.02
77	128.30	1.18	65.20
78	129.49	1.19	66.39
79	130.69	1.20	67.59
80	131.90	1.21	68.80
81	133.12	1.22	70.02
82	134.35	1.23	71.25
83	135.60	1.24	72.50
84	136.85	1.26	73.75
85	138.12	1.27	75.02
86	139.40	1.28	76.30
87	140.69	1.29	77.59
88	141.99	1.30	78.89
89	143.31	1.31	80.21
90	144.63	1.33	81.53
	0.9259%		

22 MW OCEANSIDE + 90 MW WILSON RIVER - 112 MW

TESTING THE CONCLUSIONS FROM TPUD/401 FAGEN/1 FOR REASONABLENESS

A			B			C		
Years	*System Peak Goes From 63.1 to 90 MW in 8 Years*	*Yearly % Growth*	*Years*	*System Peak Goes From 63.1 to 90 MW in 17 Years*	*Yearly % Growth*	*Years*	*System Peak Goes From 63.1 to 112 MW in 45 Years*	*Yearly % Growth*
0	63.10		0	63.10		0	63.10	
1	65.91	4.45%	1	64.43	2.10%	1	63.91	1.28%
2	68.84	4.45%	2	65.78	2.10%	2	64.73	1.28%
3	71.90	4.45%	3	67.16	2.10%	3	65.55	1.28%
4	75.10	4.45%	4	68.57	2.10%	4	66.39	1.28%
5	78.45	4.45%	5	70.01	2.10%	5	67.24	1.28%
6	81.94	4.45%	6	71.48	2.10%	6	68.10	1.28%
7	85.58	4.45%	7	72.98	2.10%	7	68.98	1.28%
8	89.39	4.45%	8	74.51	2.10%	8	69.86	1.28%
9	93.37	4.45%	9	76.08	2.10%	9	70.75	1.28%
10	97.52	4.45%	10	77.68	2.10%	10	71.66	1.28%
			11	79.31	2.10%	11	72.58	1.28%
			12	80.97	2.10%	12	73.50	1.28%
			13	82.67	2.10%	13	74.45	1.28%
			14	84.41	2.10%	14	75.40	1.28%
			15	86.18	2.10%	15	76.36	1.28%
			16	87.99	2.10%	16	77.34	1.28%
			17	89.84	2.10%	17	78.33	1.28%
			18	91.73	2.10%	18	79.33	1.28%
			19	93.65	2.10%	19	80.35	1.28%
						20	81.38	1.28%
						21	82.42	1.28%
						22	83.47	1.28%
						23	84.54	1.28%
						24	85.62	1.28%
						25	86.72	1.28%
						26	87.83	1.28%
						27	88.95	1.28%
						28	90.09	1.28%
						29	91.25	1.28%
						30	92.41	1.28%
						31	93.60	1.28%
						32	94.80	1.28%
						33	96.01	1.28%
						34	97.24	1.28%
						35	98.48	1.28%
						36	99.74	1.28%
						37	101.02	1.28%
						38	102.31	1.28%
						39	103.62	1.28%
						40	104.95	1.28%
						41	106.29	1.28%
						42	107.65	1.28%
						43	109.03	1.28%
						44	110.43	1.28%
						45	111.84	1.28%
						46	113.27	1.28%
						47	114.72	1.28%
	4.450%			2.100%			1.280%	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

EXHIBIT 303

TO THE TESTIMONY OF DORIS MAST

CORRECT INTERPERTATION OF EXHIBIT

TPUD/401 FAGEN/2

January 14, 2019

CORRECTION TO KC FAGEN'S EXHIBIT
TPUD/401 FAGEN 2

Year	Peak Load WT: Growth/Yr	MW Increase Year	Total MW Increase
0	90.60	-	-
1	91.44	0.84	0.84
2	92.29	0.85	1.69
3	93.14	0.85	2.54
4	94.00	0.86	3.40
5	94.87	0.87	4.27
6	95.75	0.88	5.15
7	96.64	0.89	6.04
8	97.53	0.89	6.93
9	98.44	0.90	7.84
10	99.35	0.91	8.75
11	100.27	0.92	9.67
12	101.20	0.93	10.60
13	102.13	0.94	11.53
14	103.08	0.95	12.48
15	104.03	0.95	13.43
16	105.00	0.96	14.40
17	105.97	0.97	15.37
18	106.95	0.98	16.35
19	107.94	0.99	17.34
20	108.94	1.00	18.34
21	109.95	1.01	19.35
22	110.97	1.02	20.37
23	111.99	1.03	21.39
24	113.03	1.04	22.43
25	114.08	1.05	23.48
26	115.13	1.06	24.53
27	116.20	1.07	25.60
28	117.27	1.08	26.67
29	118.36	1.09	27.76
30	119.46	1.10	28.86
31	120.56	1.11	29.96
32	121.68	1.12	31.08
33	122.80	1.13	32.20
34	123.94	1.14	33.34
35	125.09	1.15	34.49
36	126.25	1.16	35.65
37	127.42	1.17	36.82
38	128.60	1.18	38.00
39	129.79	1.19	39.19
40	130.99	1.20	40.39
41	132.20	1.21	41.60
42	133.43	1.22	42.83
43	134.66	1.24	44.06
44	135.91	1.25	45.31
45	137.17	1.26	46.57
46	138.44	1.27	47.84
47	139.72	1.28	49.12
48	141.01	1.29	50.41
	0.9259%		

N -1 MAXIMUM CAPACITY 106.7 IS REACHED (beside year 17)

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

EXHIBIT 304

TO THE TESTIMONY OF DORIS MAST

USING ACTUAL PEAKS TO SEE CAPACITY LOADING

January 14, 2019

USING SYSTEM PEAKS TO EXAMINE THE NAMEPLATE CAPACITY IN THE CENTRAL VALLEY (A) AND USING SYSTEM PEAKS TO EXAMINE THE CAPACITY IN THE CENTRAL VALLEY AVAILABLE TO DO N -1 (B)

A				B			
Year	Combined Coincident Peak Load WT1 & WT2, Garibaldi, Trask	Loading as a % of Total Capacity of 151.9	MW of Remaining Capacity To Reach Nameplate Capacity of 151.9	Year	Combined Coincident Peak Load WT1 & WT2, Garibaldi, Trask	Loading as a % of N-1 Capacity of 106.7	MW of Remaining Capacity at N-1 Capacity of 106.7
2006	68.33	45%	83.57	2006	68.33	64%	38.37
2007	72.32	48%	79.58	2007	72.32	68%	34.38
2008	79.48	52%	72.42	2008	79.48	74%	27.22
2009	88.27	58%	63.63	2009	88.27	83%	18.43
2010	72.96	48%	78.94	2010	72.96	68%	33.74
2011	78.42	52%	73.48	2011	78.42	73%	28.28
2012	73.80	49%	78.10	2012	73.80	69%	32.90
2013	81.14	53%	70.76	2013	81.14	76%	25.56
2014	83.50	55%	68.40	2014	83.50	78%	23.20
2015	69.20	46%	82.70	2015	69.20	65%	37.50
2016	75.11	49%	76.79	2016	75.11	70%	31.59
2017	81.94	54%	69.96	2017	81.94	77%	24.76

Combined Coincident Peak Peak Load WT1 & WT2, Garibaldi, Trask from TPUD 403, WT1-WT2 LOADS - Tab LOAD SUMS

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

EXHIBIT 305

TO THE TESTIMONY OF DORIS MAST

LONGEVITY ANALYSIS OF THE CENTRAL VALLEY

January 14, 2019

USING SYSTEM PEAKS TO DETERMINE REMAINING CAPACITY TO DO N -1 AND NAMEPLATE CAPACITY IN THE CENTRAL VALLEY WITH GROWTH ADDED

A

Year	# Of Years For Annual Coincident Peak To Reach Nameplate Capacity	New Nameplate Capacity of 151.9 MW - With Oceanside 173.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.450%
2013			81.14	
2014			83.50	
2015			69.20	
2016			75.11	
2017			81.94	
2018	0	151.90	78.18	
2019	1	151.90	78.53	0.45%
2020	2	151.90	78.88	0.45%
2021	3	151.90	79.24	0.45%
2022	4	151.90	79.59	0.45%
2023	5	151.90	79.95	0.45%
2024	6	151.90	80.31	0.45%
2025	7	151.90	80.67	0.45%
2026	8	151.90	81.04	0.45%
2027	9	151.90	81.40	0.45%
2028	10	151.90	81.77	0.45%
2029	11	151.90	82.14	0.45%
2030	12	151.90	82.51	0.45%
2031	13	151.90	82.88	0.45%
2032	14	151.90	83.25	0.45%
2033	15	151.90	83.62	0.45%
2034	16	151.90	84.00	0.45%
2035	17	151.90	84.38	0.45%
2036	18	151.90	84.76	0.45%
2037	19	151.90	85.14	0.45%
2038	20	151.90	85.52	0.45%
2039	21	151.90	85.91	0.45%
2040	22	151.90	86.29	0.45%
2041	23	151.90	86.68	0.45%
2042	24	151.90	87.07	0.45%
2043	25	151.90	87.46	0.45%
2044	26	151.90	87.86	0.45%
2045	27	151.90	88.25	0.45%
2046	28	151.90	88.65	0.45%
2047	29	151.90	89.05	0.45%
2048	30	151.90	89.45	0.45%
2049	31	151.90	89.85	0.45%
2050	32	151.90	90.26	0.45%
2051	33	151.90	90.66	0.45%
2052	34	151.90	91.07	0.45%
2053	35	151.90	91.48	0.45%
2054	36	151.90	91.89	0.45%
2055	37	151.90	92.31	0.45%
2056	38	151.90	92.72	0.45%
2057	39	151.90	93.14	0.45%
2058	40	151.90	93.56	0.45%
2059	41	151.90	93.98	0.45%
2060	42	151.90	94.40	0.45%
2061	43	151.90	94.83	0.45%
2062	44	151.90	95.25	0.45%
2063	45	151.90	95.68	0.45%
2064	46	151.90	96.11	0.45%
2065	47	151.90	96.55	0.45%
2066	48	151.90	96.98	0.45%
2067	49	151.90	97.42	0.45%
2068	50	151.90	97.85	0.45%
2069	51	151.90	98.30	0.45%
2070	52	151.90	98.74	0.45%
2071	53	151.90	99.18	0.45%
2072	54	151.90	99.63	0.45%
2073	55	151.90	100.08	0.45%
2074	56	151.90	100.53	0.45%
2075	57	151.90	100.98	0.45%
2076	58	151.90	101.43	0.45%

B

Year	# Of Years For Annual Coincident Peak To Reach N - 1 Capacity	N -1 Capacity of 106.7 MW - With Oceanside 128.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.450%
2013			81.14	
2014			83.50	
2015			69.20	
2016			75.11	
2017			81.94	
2018	0	106.70	78.18	-
2019	1	106.70	78.53	0.45%
2020	2	106.70	78.88	0.45%
2021	3	106.70	79.24	0.45%
2022	4	106.70	79.59	0.45%
2023	5	106.70	79.95	0.45%
2024	6	106.70	80.31	0.45%
2025	7	106.70	80.67	0.45%
2026	8	106.70	81.04	0.45%
2027	9	106.70	81.40	0.45%
2028	10	106.70	81.77	0.45%
2029	11	106.70	82.14	0.45%
2030	12	106.70	82.51	0.45%
2031	13	106.70	82.88	0.45%
2032	14	106.70	83.25	0.45%
2033	15	106.70	83.62	0.45%
2034	16	106.70	84.00	0.45%
2035	17	106.70	84.38	0.45%
2036	18	106.70	84.76	0.45%
2037	19	106.70	85.14	0.45%
2038	20	106.70	85.52	0.45%
2039	21	106.70	85.91	0.45%
2040	22	106.70	86.29	0.45%
2041	23	106.70	86.68	0.45%
2042	24	106.70	87.07	0.45%
2043	25	106.70	87.46	0.45%
2044	26	106.70	87.86	0.45%
2045	27	106.70	88.25	0.45%
2046	28	106.70	88.65	0.45%
2047	29	106.70	89.05	0.45%
2048	30	106.70	89.45	0.45%
2049	31	106.70	89.85	0.45%
2050	32	106.70	90.26	0.45%
2051	33	106.70	90.66	0.45%
2052	34	106.70	91.07	0.45%
2053	35	106.70	91.48	0.45%
2054	36	106.70	91.89	0.45%
2055	37	106.70	92.31	0.45%
2056	38	106.70	92.72	0.45%
2057	39	106.70	93.14	0.45%
2058	40	106.70	93.56	0.45%
2059	41	106.70	93.98	0.45%
2060	42	106.70	94.40	0.45%
2061	43	106.70	94.83	0.45%
2062	44	106.70	95.25	0.45%
2063	45	106.70	95.68	0.45%
2064	46	106.70	96.11	0.45%
2065	47	106.70	96.55	0.45%
2066	48	106.70	96.98	0.45%
2067	49	106.70	97.42	0.45%
2068	50	106.70	97.85	0.45%
2069	51	106.70	98.30	0.45%
2070	52	106.70	98.74	0.45%
2071	53	106.70	99.18	0.45%
2072	54	106.70	99.63	0.45%
2073	55	106.70	100.08	0.45%
2074	56	106.70	100.53	0.45%
2075	57	106.70	100.98	0.45%
2076	58	106.70	101.43	0.45%

C

Year	# Of Years For Annual Coincident Peak To Reach N -1 Capacity	N -1 Capacity of 106.7 MW - With Oceanside 128.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.9259%
2013			81.14	
2014			83.50	
2015			69.20	
2016			75.11	
2017			81.94	
2018	0	106.70	78.18	-
2019	1	106.70	78.90	0.93%
2020	2	106.70	79.63	0.93%
2021	3	106.70	80.37	0.93%
2022	4	106.70	81.11	0.93%
2023	5	106.70	81.86	0.93%
2024	6	106.70	82.62	0.93%
2025	7	106.70	83.39	0.93%
2026	8	106.70	84.16	0.93%
2027	9	106.70	84.94	0.93%
2028	10	106.70	85.73	0.93%
2029	11	106.70	86.52	0.93%
2030	12	106.70	87.32	0.93%
2031	13	106.70	88.13	0.93%
2032	14	106.70	88.94	0.93%
2033	15	106.70	89.77	0.93%
2034	16	106.70	90.60	0.93%
2035	17	106.70	91.44	0.93%
2036	18	106.70	92.29	0.93%
2037	19	106.70	93.14	0.93%
2038	20	106.70	94.00	0.93%
2039	21	106.70	94.87	0.93%
2040	22	106.70	95.75	0.93%
2041	23	106.70	96.64	0.93%
2042	24	106.70	97.53	0.93%
2043	25	106.70	98.44	0.93%
2044	26	106.70	99.35	0.93%
2045	27	106.70	100.27	0.93%
2046	28	106.70	101.19	0.93%
2047	29	106.70	102.13	0.93%
2048	30	106.70	103.08	0.93%
2049	31	106.70	104.03	0.93%
2050	32	106.70	105.00	0.93%
2051	33	106.70	105.97	0.93%
2052	34	128.90	106.95	0.93%
2053	35	128.90	107.94	0.93%
2054	36	128.90	108.94	0.93%
2055	37	128.90	109.95	0.93%
2056	38	128.90	110.96	0.93%
2057	39	128.90	111.99	0.93%
2058	40	128.90	113.03	0.93%
2059	41	128.90	114.08	0.93%
2060	42	128.90	115.13	0.93%
2061	43	128.90	116.20	0.93%
2062	44	128.90	117.27	0.93%
2063	45	128.90	118.36	0.93%
2064	46	128.90	119.46	0.93%
2065	47	128.90	120.56	0.93%
2066	48	128.90	121.68	0.93%
2067	49	128.90	122.80	0.93%
2068	50	128.90	123.94	0.93%
2069	51	128.90	125.09	0.93%
2070	52	128.90	126.25	0.93%
2071	53	128.90	127.42	0.93%
2072	54	128.90	128.60	0.93%
2073	55	128.90	129.79	0.93%
2074	56	128.90	130.99	0.93%
2075	57	128.90	132.20	0.93%
2076	58	128.90	133.42	0.93%

USING SYSTEM PEAKS TO DETERMINE REMAINING CAPACITY TO DO N -1 AND NAMEPLATE CAPACITY IN THE CENTRAL VALLEY WITH GROWTH ADDED

A

Year	# Of Years For Annual Coincident Peak To Reach Nameplate Capacity	New Nameplate Capacity of 151.9 MW - With Oceanside 173.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.450%
2077	59	151.90	101.89	0.45%
2078	60	151.90	102.35	0.45%
2079	61	151.90	102.81	0.45%
2080	62	151.90	103.27	0.45%
2081	63	151.90	103.74	0.45%
2082	64	151.90	104.20	0.45%
2083	65	151.90	104.67	0.45%
2084	66	151.90	105.14	0.45%
2085	67	151.90	105.62	0.45%
2086	68	151.90	106.09	0.45%
2087	69	151.90	106.57	0.45%
2088	70	151.90	107.05	0.45%
2089	71	151.90	107.53	0.45%
2090	72	151.90	108.01	0.45%
2091	73	151.90	108.50	0.45%
2092	74	151.90	108.99	0.45%
2093	75	151.90	109.48	0.45%
2094	76	151.90	109.97	0.45%
2095	77	151.90	110.47	0.45%
2096	78	151.90	110.96	0.45%
2097	79	151.90	111.46	0.45%
2098	80	151.90	111.96	0.45%
2099	81	151.90	112.47	0.45%
2100	82	151.90	112.97	0.45%
2101	83	151.90	113.48	0.45%
2102	84	151.90	113.99	0.45%
2103	85	151.90	114.51	0.45%
2104	86	151.90	115.02	0.45%
2105	87	151.90	115.54	0.45%
2106	88	151.90	116.06	0.45%
2107	89	151.90	116.58	0.45%
2108	90	151.90	117.11	0.45%
2109	91	151.90	117.63	0.45%
2110	92	151.90	118.16	0.45%
2111	93	151.90	118.69	0.45%
2112	94	151.90	119.23	0.45%
2113	95	151.90	119.76	0.45%
2114	96	151.90	120.30	0.45%
2115	97	151.90	120.85	0.45%
2116	98	151.90	121.39	0.45%
2117	99	151.90	121.94	0.45%
2118	100	151.90	122.48	0.45%
2119	101	151.90	123.03	0.45%
2120	102	151.90	123.59	0.45%
2121	103	151.90	124.14	0.45%
2122	104	151.90	124.70	0.45%
2123	105	151.90	125.26	0.45%
2124	106	151.90	125.83	0.45%
2125	107	151.90	126.39	0.45%
2126	108	151.90	126.96	0.45%
2127	109	151.90	127.53	0.45%
2128	110	151.90	128.11	0.45%
2129	111	151.90	128.69	0.45%
2130	112	151.90	129.26	0.45%
2131	113	151.90	129.85	0.45%
2132	114	151.90	130.43	0.45%
2133	115	151.90	131.02	0.45%
2134	116	151.90	131.61	0.45%
2135	117	151.90	132.20	0.45%
2136	118	151.90	132.79	0.45%
2137	119	151.90	133.39	0.45%
2138	120	151.90	133.99	0.45%
2139	121	151.90	134.59	0.45%

B

Year	# Of Years For Annual Coincident Peak To Reach N - 1 Capacity	N -1 Capacity of 106.7 MW - With Oceanside 128.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.450%
2077	59	106.70	101.89	0.45%
2078	60	106.70	102.35	0.45%
2079	61	106.70	102.81	0.45%
2080	62	106.70	103.27	0.45%
2081	63	106.70	103.74	0.45%
2082	64	106.70	104.20	0.45%
2083	65	106.70	104.67	0.45%
2084	66	106.70	105.14	0.45%
2085	67	106.70	105.62	0.45%
2086	68	106.70	106.09	0.45%
2087	69	106.70	106.57	0.45%
2088	70	**128.90**	**107.05**	0.45%
2089	71	**128.90**	**107.53**	0.45%
2090	72	**128.90**	**108.01**	0.45%
2091	73	**128.90**	**108.50**	0.45%
2092	74	**128.90**	**108.99**	0.45%
2093	75	**128.90**	**109.48**	0.45%
2094	76	**128.90**	**109.97**	0.45%
2095	77	**128.90**	**110.47**	0.45%
2096	78	**128.90**	**110.96**	0.45%
2097	79	**128.90**	**111.46**	0.45%
2098	80	**128.90**	**111.96**	0.45%
2099	81	**128.90**	**112.47**	0.45%
2100	82	**128.90**	**112.97**	0.45%
2101	83	**128.90**	**113.48**	0.45%
2102	84	**128.90**	**113.99**	0.45%
2103	85	**128.90**	**114.51**	0.45%
2104	86	**128.90**	**115.02**	0.45%
2105	87	**128.90**	**115.54**	0.45%
2106	88	**128.90**	**116.06**	0.45%
2107	89	**128.90**	**116.58**	0.45%
2108	90	**128.90**	**117.11**	0.45%
2109	91	**128.90**	**117.63**	0.45%
2110	92	**128.90**	**118.16**	0.45%
2111	93	**128.90**	**118.69**	0.45%
2112	94	**128.90**	**119.23**	0.45%
2113	95	**128.90**	**119.76**	0.45%
2114	96	**128.90**	**120.30**	0.45%
2115	97	**128.90**	**120.85**	0.45%
2116	98	**128.90**	**121.39**	0.45%
2117	99	**128.90**	**121.94**	0.45%
2118	100	**128.90**	**122.48**	0.45%
2119	101	**128.90**	**123.03**	0.45%
2120	102	**128.90**	**123.59**	0.45%
2121	103	**128.90**	**124.14**	0.45%
2122	104	**128.90**	**124.70**	0.45%
2123	105	**128.90**	**125.26**	0.45%
2124	106	**128.90**	**125.83**	0.45%
2125	107	**128.90**	**126.39**	0.45%
2126	108	**128.90**	**126.96**	0.45%
2127	109	**128.90**	**127.53**	0.45%
2128	110	**128.90**	**128.11**	0.45%
2129	111	**128.90**	**128.69**	0.45%
2130	112	128.90	129.26	0.45%
2131	113	128.90	129.85	0.45%
2132	114	128.90	130.43	0.45%
2133	115	128.90	131.02	0.45%
2134	116	128.90	131.61	0.45%
2135	117	128.90	132.20	0.45%
2136	118	128.90	132.79	0.45%
2137	119	128.90	133.39	0.45%
2138	120	128.90	133.99	0.45%
2139	121	128.90	134.59	0.45%

C

Year	# Of Years For Annual Coincident Peak To Reach N -1 Capacity	N -1 Capacity of 106.7 MW - With Oceanside 128.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.9259%
2077	59	128.90	134.66	0.93%
2078	60	128.90	135.91	0.93%
2079	61	128.90	137.17	0.93%
2080	62	128.90	138.44	0.93%
2081	63	128.90	139.72	0.93%
2082	64	128.90	141.01	0.93%
2083	65	128.90	142.32	0.93%
2084	66	128.90	143.63	0.93%
2085	67	128.90	144.96	0.93%
2086	68	128.90	146.31	0.93%
2087	69	128.90	147.66	0.93%
2088	70	128.90	149.03	0.93%
2089	71	128.90	150.41	0.93%
2090	72	128.90	151.80	0.93%
2091	73	128.90	153.21	0.93%
2092	74	128.90	154.62	0.93%
2093	75	128.90	156.06	0.93%
2094	76	128.90	157.50	0.93%
2095	77	128.90	158.96	0.93%
2096	78	128.90	160.43	0.93%
2097	79	128.90	161.92	0.93%
2098	80	128.90	163.42	0.93%
2099	81	128.90	164.93	0.93%
2100	82	128.90	166.46	0.93%
2101	83	128.90	168.00	0.93%
2102	84	128.90	169.55	0.93%
2103	85	128.90	171.12	0.93%
2104	86	128.90	172.71	0.93%
2105	87	128.90	174.31	0.93%
2106	88	128.90	175.92	0.93%
2107	89	128.90	177.55	0.93%
2108	90	128.90	179.19	0.93%
2109	91	128.90	180.85	0.93%
2110	92	128.90	182.53	0.93%
2111	93	128.90	184.22	0.93%
2112	94	128.90	185.92	0.93%
2113	95	128.90	187.64	0.93%
2114	96	128.90	189.38	0.93%
2115	97	128.90	191.13	0.93%
2116	98	128.90	192.90	0.93%
2117	99	128.90	194.69	0.93%
2118	100	128.90	196.49	0.93%
2119	101	128.90	198.31	0.93%
2120	102	128.90	200.15	0.93%
2121	103	128.90	202.00	0.93%
2122	104	128.90	203.87	0.93%
2123	105	128.90	205.76	0.93%
2124	106	128.90	207.67	0.93%
2125	107	128.90	209.59	0.93%
2126	108	128.90	211.53	0.93%
2127	109	128.90	213.49	0.93%
2128	110	128.90	215.46	0.93%
2129	111	128.90	217.46	0.93%
2130	112	128.90	219.47	0.93%
2131	113	128.90	221.50	0.93%
2132	114	128.90	223.56	0.93%
2133	115	128.90	225.62	0.93%
2134	116	128.90	227.71	0.93%
2135	117	128.90	229.82	0.93%
2136	118	128.90	231.95	0.93%
2137	119	128.90	234.10	0.93%
2138	120	128.90	236.27	0.93%
2139	121	128.90	238.45	0.93%

USING SYSTEM PEAKS TO DETERMINE REMAINING CAPACITY TO DO N -1 AND NAMEPLATE CAPACITY IN THE CENTRAL VALLEY WITH GROWTH ADDED

A					B					C				
Year	# Of Years For Annual Coincident Peak To Reach Nameplate Capacity	New Nameplate Capacity of 151.9 MW - With Oceanside 173.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.450%	Year	# Of Years For Annual Coincident Peak To Reach N - 1 Capacity	N -1 Capacity of 106.7 MW - With Oceanside 128.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.450%	Year	# Of Years For Annual Coincident Peak To Reach N -1 Capacity	N -1 Capacity of 106.7 MW - With Oceanside 128.9	Combined Coincident Peaks of WT1 WT2 Trask Garibaldi	Yearly % Growth 0.9259%
2140	122	151.90	135.20	0.45%	2140	122	128.90	135.20	0.45%	2140	122	128.90	240.66	0.93%
2141	123	151.90	135.81	0.45%	2141	123	128.90	135.81	0.45%	2141	123	128.90	242.89	0.93%
2142	124	151.90	136.42	0.45%	2142	124	128.90	136.42	0.45%	2142	124	128.90	245.14	0.93%
2143	125	151.90	137.03	0.45%	2143	125	128.90	137.03	0.45%	2143	125	128.90	247.41	0.93%
2144	126	151.90	137.65	0.45%	2144	126	128.90	137.65	0.45%	2144	126	128.90	249.70	0.93%
2145	127	151.90	138.27	0.45%	2145	127	128.90	138.27	0.45%	2145	127	128.90	252.01	0.93%
2146	128	151.90	138.89	0.45%	2146	128	128.90	138.89	0.45%	2146	128	128.90	254.34	0.93%
2147	129	151.90	139.52	0.45%	2147	129	128.90	139.52	0.45%	2147	129	128.90	256.70	0.93%
2148	130	151.90	140.14	0.45%	2148	130	128.90	140.14	0.45%	2148	130	128.90	259.08	0.93%
2149	131	151.90	140.78	0.45%	2149	131	128.90	140.78	0.45%	2149	131	128.90	261.47	0.93%
2150	132	151.90	141.41	0.45%	2150	132	128.90	141.41	0.45%	2150	132	128.90	263.90	0.93%
2151	133	151.90	142.05	0.45%	2151	133	128.90	142.05	0.45%	2151	133	128.90	266.34	0.93%
2152	134	151.90	142.68	0.45%	2152	134	128.90	142.68	0.45%	2152	134	128.90	268.80	0.93%
2153	135	151.90	143.33	0.45%	2153	135	128.90	143.33	0.45%	2153	135	128.90	271.29	0.93%
2154	136	151.90	143.97	0.45%	2154	136	128.90	143.97	0.45%	2154	136	128.90	273.81	0.93%
2155	137	151.90	144.62	0.45%	2155	137	128.90	144.62	0.45%	2155	137	128.90	276.34	0.93%
2156	138	151.90	145.27	0.45%	2156	138	128.90	145.27	0.45%	2156	138	128.90	278.90	0.93%
2157	139	151.90	145.92	0.45%	2157	139	128.90	145.92	0.45%	2157	139	128.90	281.48	0.93%
2158	140	151.90	146.58	0.45%	2158	140	128.90	146.58	0.45%	2158	140	128.90	284.09	0.93%
2159	141	151.90	147.24	0.45%	2159	141	128.90	147.24	0.45%	2159	141	128.90	286.72	0.93%
2160	142	151.90	147.90	0.45%	2160	142	128.90	147.90	0.45%	2160	142	128.90	289.37	0.93%
2161	143	151.90	148.57	0.45%	2161	143	128.90	148.57	0.45%	2161	143	128.90	292.05	0.93%
2162	144	151.90	149.24	0.45%	2162	144	128.90	149.24	0.45%	2162	144	128.90	294.76	0.93%
2163	145	151.90	149.91	0.45%	2163	145	128.90	149.91	0.45%	2163	145	128.90	297.49	0.93%
2164	146	151.90	150.58	0.45%	2164	146	128.90	150.58	0.45%	2164	146	128.90	300.24	0.93%
2165	147	151.90	151.26	0.45%	2165	147	128.90	151.26	0.45%	2165	147	128.90	303.02	0.93%
2166	148	173.90	151.94	0.45%	2166	148	128.90	151.94	0.45%	2166	148	128.90	305.83	0.93%
2167	149	173.90	152.63	0.45%	2167	149	128.90	152.63	0.45%	2167	149	128.90	308.66	0.93%
2168	150	173.90	153.31	0.45%	2168	150	128.90	153.31	0.45%	2168	150	128.90	311.52	0.93%
2169	151	173.90	154.00	0.45%	2169	151	128.90	154.00	0.45%	2169	151	128.90	314.40	0.93%
2170	152	173.90	154.69	0.45%	2170	152	128.90	154.69	0.45%	2170	152	128.90	317.31	0.93%
2171	153	173.90	155.39	0.45%	2171	153	128.90	155.39	0.45%	2171	153	128.90	320.25	0.93%
2172	154	173.90	156.09	0.45%	2172	154	128.90	156.09	0.45%	2172	154	128.90	323.21	0.93%
2173	155	173.90	156.79	0.45%	2173	155	128.90	156.79	0.45%	2173	155	128.90	326.21	0.93%
2174	156	173.90	157.50	0.45%	2174	156	128.90	157.50	0.45%	2174	156	128.90	329.23	0.93%
2175	157	173.90	158.21	0.45%	2175	157	128.90	158.21	0.45%	2175	157	128.90	332.27	0.93%
2176	158	173.90	158.92	0.45%	2176	158	128.90	158.92	0.45%	2176	158	128.90	335.35	0.93%
2177	159	173.90	159.63	0.45%	2177	159	128.90	159.63	0.45%	2177	159	128.90	338.46	0.93%
2178	160	173.90	160.35	0.45%	2178	160	128.90	160.35	0.45%	2178	160	128.90	341.59	0.93%
2179	161	173.90	161.07	0.45%	2179	161	128.90	161.07	0.45%	2179	161	128.90	344.75	0.93%
2180	162	173.90	161.80	0.45%	2180	162	128.90	161.80	0.45%	2180	162	128.90	347.95	0.93%
2181	163	173.90	162.53	0.45%	2181	163	128.90	162.53	0.45%	2181	163	128.90	351.17	0.93%
2182	164	173.90	163.26	0.45%	2182	164	128.90	163.26	0.45%	2182	164	128.90	354.42	0.93%
2183	165	173.90	163.99	0.45%	2183	165	128.90	163.99	0.45%	2183	165	128.90	357.70	0.93%
2184	166	173.90	164.73	0.45%	2184	166	128.90	164.73	0.45%	2184	166	128.90	361.01	0.93%
2185	167	173.90	165.47	0.45%	2185	167	128.90	165.47	0.45%	2185	167	128.90	364.35	0.93%
2186	168	173.90	166.22	0.45%	2186	168	128.90	166.22	0.45%	2186	168	128.90	367.73	0.93%
2187	169	173.90	166.96	0.45%	2187	169	128.90	166.96	0.45%	2187	169	128.90	371.13	0.93%
2188	170	173.90	167.72	0.45%	2188	170	128.90	167.72	0.45%	2188	170	128.90	374.57	0.93%
2189	171	173.90	168.47	0.45%	2189	171	128.90	168.47	0.45%	2189	171	128.90	378.04	0.93%
2190	172	173.90	169.23	0.45%	2190	172	128.90	169.23	0.45%	2190	172	128.90	381.54	0.93%
2191	173	173.90	169.99	0.45%	2191	173	128.90	169.99	0.45%	2191	173	128.90	385.07	0.93%
2192	174	173.90	170.76	0.45%	2192	174	128.90	170.76	0.45%	2192	174	128.90	388.64	0.93%
2193	175	173.90	171.52	0.45%	2193	175	128.90	171.52	0.45%	2193	175	128.90	392.23	0.93%
2194	176	173.90	172.30	0.45%	2194	176	128.90	172.30	0.45%	2194	176	128.90	395.87	0.93%
2195	177	173.90	173.07	0.45%	2195	177	128.90	173.07	0.45%	2195	177	128.90	399.53	0.93%
2196	178	173.90	173.85	0.45%	2196	178	128.90	173.85	0.45%	2196	178	128.90	403.23	0.93%
2197	179	173.90	174.63	0.45%	2197	179	128.90	174.63	0.45%	2197	179	128.90	406.96	0.93%
			0.450%					0.450%					0.9259%	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

EXHIBIT 306

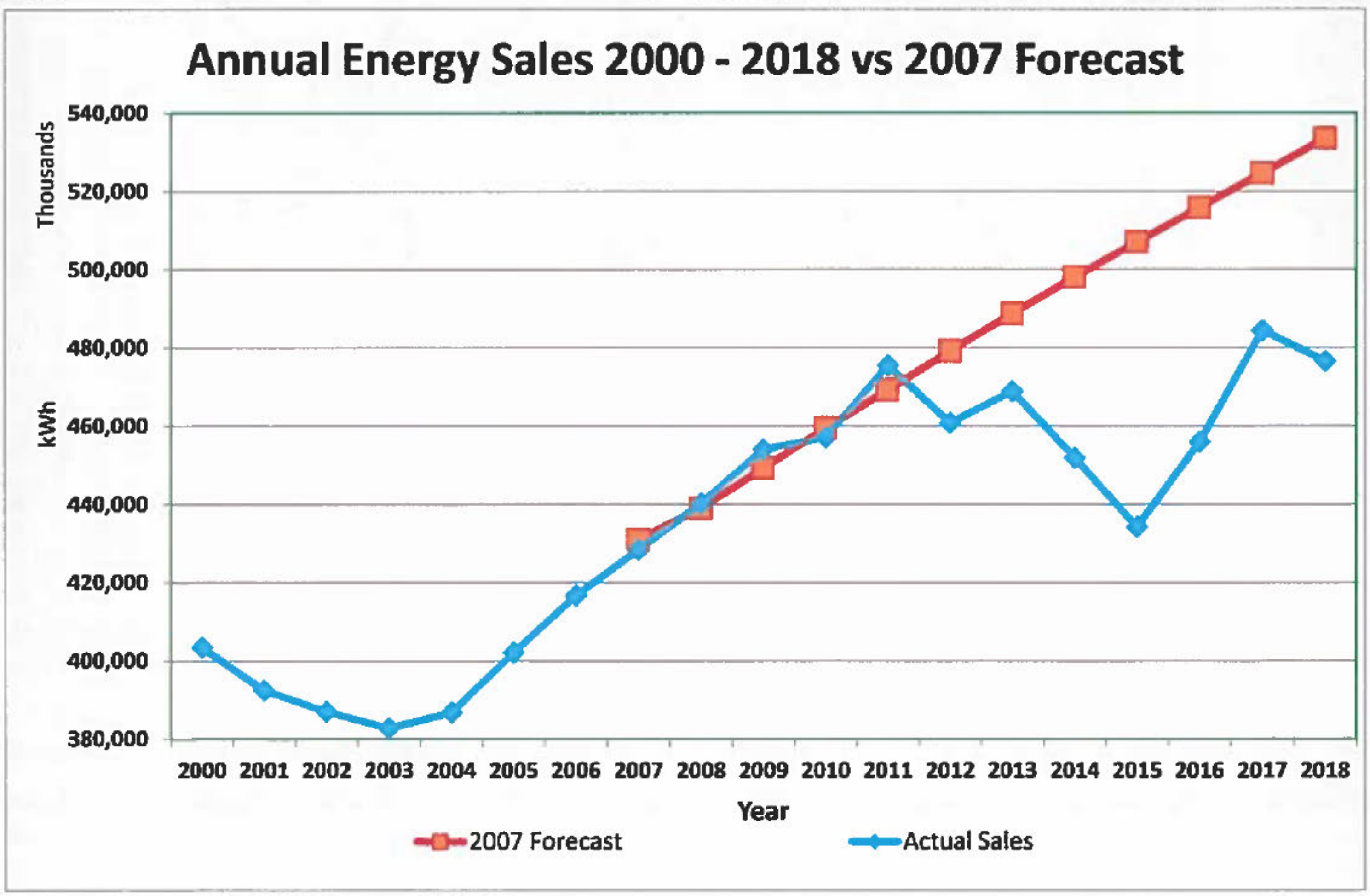
TO THE TESTIMONY OF DORIS MAST

REVENUE LOSS FROM FALLING SALES

January 14, 2019

THE IMPACT OF ACTUAL SALES BEING LOWER THAN THE 2007 FORECAST ON THE REVENUE STREAM

Year	2007 Forecast of Annual Electricity Sales	Expected Revenue	Rate/kW	Actual Annual Electricity Sales	Actual Revenue from TPUD 407 FAGEN/1	Rate/kW	Expected Revenue - Actual Revenue = Shortfall
		A			B		C
	MW	$	$	MW	$	$	$
2007	431,009	$ 28,164,986	$ 0.0653	428,316	$ 27,989,008	$ 0.0653	$ (175,978)
2008	438,957	$ 28,431,091	$ 0.0648	440,203	$ 28,511,794	$ 0.0648	$ 80,703
2009	449,195	$ 29,501,215	$ 0.0657	453,997	$ 29,816,590	$ 0.0657	$ 315,375
2010	459,385	$ 30,899,016	$ 0.0673	457,084	$ 30,744,227	$ 0.0673	$ (154,789)
2011	469,176	$ 32,073,138	$ 0.0684	475,451	$ 32,502,101	$ 0.0684	$ 428,963
2012	479,099	$ 34,289,900	$ 0.0716	460,768	$ 32,977,895	$ 0.0716	$ (1,312,005)
2013	488,681	$ 36,204,069	$ 0.0741	468,865	$ 34,736,010	$ 0.0741	$ (1,468,059)
2014	498,058	$ 37,311,636	$ 0.0749	451,861	$ 33,850,826	$ 0.0749	$ (3,460,810)
2015	506,993	$ 40,146,001	$ 0.0792	434,204	$ 34,382,272	$ 0.0792	$ (5,763,729)
2016	515,843	$ 41,472,573	$ 0.0804	455,919	$ 36,654,853	$ 0.0804	$ (4,817,720)
2017	524,540	$ 41,761,141	$ 0.0796	484,381	$ 38,563,884	$ 0.0796	$ (3,197,257)
2018	533,487	$ 42,699,195	$ 0.0800	476,584	$ 38,144,800	$ 0.0800	$ (4,554,395)
TOTAL		$ 422,953,963			$ 398,874,260		$ (24,079,703)



BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

EXHIBIT 307

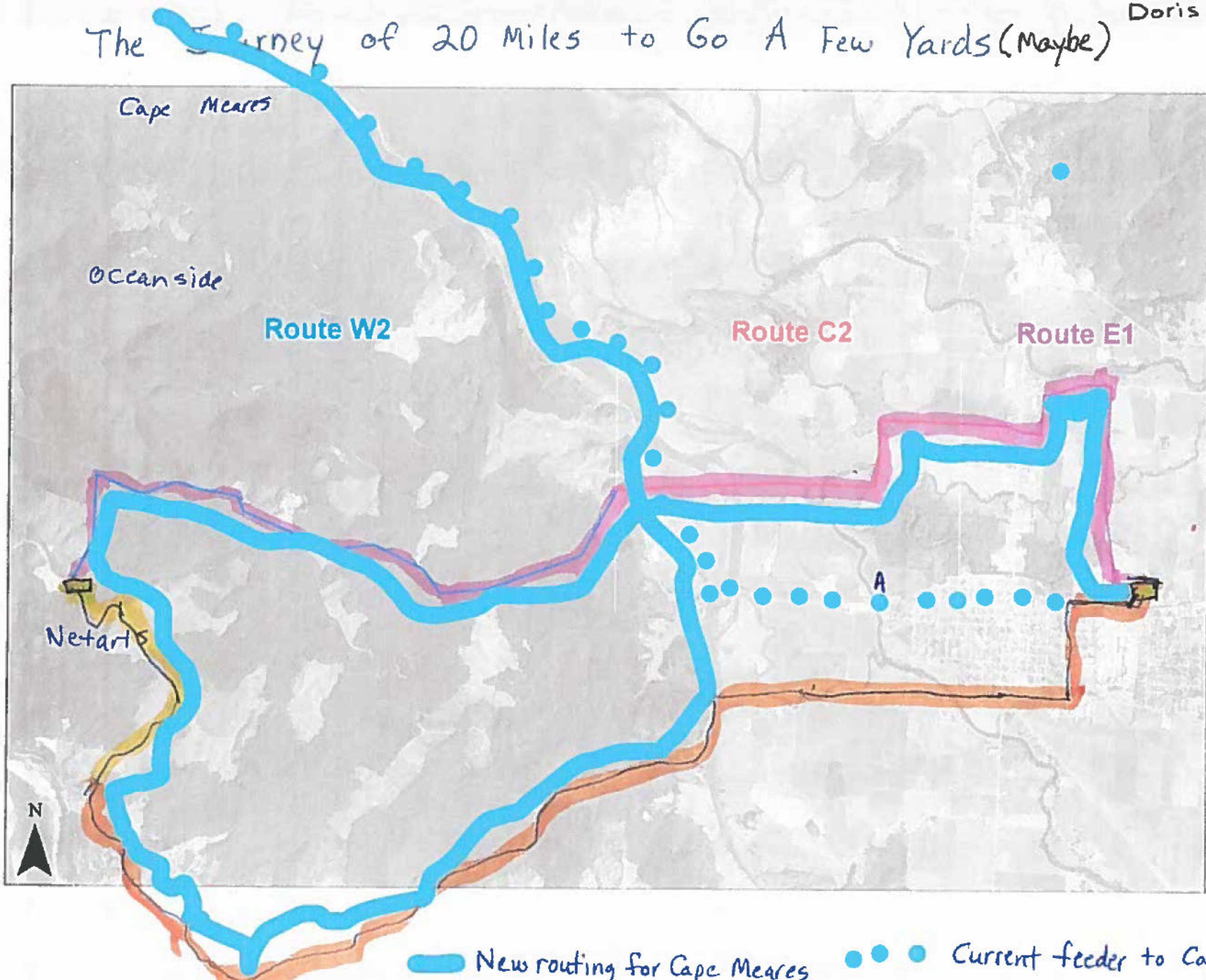
TO THE TESTIMONY OF DORIS MAST

MAP OF FEEDER 51 ADDED TO THE TRANSMISSION LINE

January 14, 2019

The Journey of 20 Miles to Go A Few Yards (Maybe)

Doris Mast/307
Mast/1



New routing for Cape Meares

Current feeder to Cape Meares

Transmission Line

New Distribution Link from Substation to Feeder 51

Feeder 51

Substation

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PCN-2

EXHIBIT 308

TO THE TESTIMONY OF DORIS MAST

TRANSMISSION LINE COST ESTIMATE

WITH REBUILDING OF FEEDER 51 ADDED

January 14, 2019

Tillamook People's Utility District
Tillamook Oceanside Transmission Line Project
Cost Estimates 2018

Item	Notes		Estimated Costs
Transmission line	Esimate TriAxis Engineering	Includes 10% contingency	$ 9,023,700
Substations	Esimate TriAxis Engineering	Includes a 20% contingency	$ 2,933,000
Easements	Esimate Tillamook PUD	50% adder included to Real Market Value	$ 302,000
Permitting/Legal	Esimate Tillamook PUD	$250,000 has already been paid for permitting and legal costs.	$ 500,000
Tillamook PUD	Esimate Tillamook PUD	$150,000 has already been spent on the permitting and design effort to date.	$ 450,000
Underground Get-a-Ways	Esimate Tillamook PUD	Based on TPUD estimating program and recent underground work performed by TPUD	$ 1,440,817
Total TOTL Construction			$ 14,649,517

From TPUD 2018 Construction Work Plan

*316B **Netarts Highway Rebuild**- This project consists of rebuilding 4.75 miles of three phase #3/0 AAAC and 2A Cu to three phase 652.4 AAAC, 24.9 kV, from 2 01 10 35 5801 west to Netarts and the beginning of project 201B (Netarts Feeder getaway). Approximately 1.30 miles of this section is double circuit 2A Cu. As an alternative, 465.4 AAAC was considered for this circuit. However, 652.4 AAAC provides better load transfer capabilities of Wilson River feeders to the new Netarts substation.

Estimated Cost: $943,408
RUS Funding: $943,408

$ 943,408

324B **Happy Camp Rebuild**- This project consists of rebuilding approximately 1.5 miles of existing three-phase #6 BHD Cu with three-phase 4/0 AAAC. This project will begin at the end of the Oceanside feeder getaway (Pole 2-01-10-30-1501) extending south to pole location 2-01-10-31-6406. A 700-feet section of 1/0 AL URD will need to be replaced with 500 MCM AL URD between poles 2-01-10-30-2400 and 2-01-10-30-2401. This project is required to provide a feeder tie between the Oceanside Feeder and Netarts Feeder. Without this project portions of this line would be loaded to 134% of its rating when all of the Netarts feeder is transferred to the Oceanside feeder.

Estimated Cost: $382,454
RUS Funding: $382,454

$ 382,454

306 **Miller to TRR Rebuild**- This project consists of upgrading existing 3/0 AAAC three phase to 652 AAAC three phase between poles 2-01-09-30-3102 and 2-01-10-36-8800 (approximately .4 miles) and upgrading existing #6 BHD three phase to 465 AAAC three phase between poles 2-01-10-25-8101 to 2-01-10-25-8121 (approximately .07 miles). This is needed for load transfers from the future Netarts-Oceanside Substation and Wilson River Substation, or Wilson River Substation and Trask Substations.

Estimated Cost: $327,818
RUS Funding: $327,818

$ 327,818

Tillamook People's Utility District
Tillamook Oceanside Transmission Line Project
Cost Estimates 2018

307 **Tone Road Rebuild-** This project consists of rebuilding 1 mile of three phase #3/0 AAAC to three phase 652.4 AAAC, 24.9 kV, from 2 01 10 25 1105 east to pole 2 01 10 36 8705. Upgrading this line will provide better load transfer capabilities of Wilson River feeders to the new Netarts substation.

Estimated Cost: $273,182 — $ 273,182

RUS Funding: $273,182

315 **Third Street Tillamook Reconductor-** This project consists of rebuilding 1 mile of three phase #6 BHD Cu to three phase 4/0 AAAC, 24.9 kV, from pole 2-01-09-29-4506 east to pole 2-01-09-28-5500. Upgrading this line will provide better load transfer capabilities of Wilson River feeders to Trask substation.

Estimated Cost: $309,000 — $ 309,000

RUS Funding: $309,000

Total TOTL Construction — $ 16,885,379

2019 BUDGET FROM TPUD/407 - Fagen/36

TPUD/407 Fagen/36	Netarts Oceanside Transmission line			$ 11,033,490
	2014 - 2017	$	833,490	
	2018	$	100,000	
	2019	$	1,100,000	
	2020	$	4,000,000	
	2021	$	5,000,000	
	Oceanside Substation + Getaway			$ 6,000,000
	2014 - 2017	$	-	
	2018	$	-	
	2019	$	-	
	2020	$	2,000,000	
	2021	$	4,000,000	
	Highway 131 Rebuild			$ 470,000
	2014 - 2017	$	-	
	2018	$	-	
	2019	$	-	
	2020	$	230,000	
	2021	$	240,000	
	TOTAL IN 2019 BUDGET			$ 17,503,490