Reply Testimony of Doris Mast (Doris Mast/200)

I offer the following reply testimony to the testimony of PUC Staff. My testimony is organized by the portion of the Staff testimony to which I am replying.

I will address issue 2, necessity, as discussed in Staff/200 Hanhan/7. Lines 7 through 9 say the project is necessary in order to increase reliability, accommodate load growth by adding system capacity and address aging infrastructure. I will begin with the goal of addressing system capacity. I will argue that Option 3 adds sufficient capacity to accommodate load growth. Last fall the TPUD Board approved the purchase of 4 new transformers. One of these transformers will replace the current Wilson River T1 with a larger transformer and this will occur this September 2018. The capacity for the central valley will increase by 12 MW. According to my calculations, this capacity will be consumed in 28 years assuming growth of 0.9% per year or 89 years assuming 0.29% per year.

I made a chart of the annual average MW load from the monthly loads given in the TPUD Board reports. Since TPUD combined T1 and T2 for their 0.9% growth trend, I added T1 and T2 for this chart. Since 2017 was the last year of historical load, I added 12 MW to the 2017 load of 41.52, which was 53.52 MW. I then used PUD's growth trend of 0.9% per year until the load was close to 53.52. After 28 years the growth was 53.35. I made another column using a growth forecast of 0.289%. This growth rate consumed the 12 MW of additional capacity in 87 years. If you assume a load growth of 1.97%, the 12 MW of additional capacity is consumed in 13 years (Chart on Page 14). The PUD response to DR-40 that the capacity would be consumed in 13 years at a growth rate of 0.9% is not correct.

I also did a loading model of the central valley substations with the larger T1 transformer scheduled to be installed this September, using the 2009 all-time system peak loads. A growth factor of +0.289% was used for the following years because that is the growth number BPA was using for forecasting in their models. To test my conclusions that the extra capacity would last at least 28 years, I did an N – 1.

			DORIS'S N - 1					
0.289% Annual Load Growth from 2009				28	0.289% Annual Load Growth from 2009			
	Load (MVA	W 2018	% Loading			Load (MV/	W 2018	% Loading
Garibaldi	15.32	25.00			Garibaldi	22.50	25.00	90%
Wilson T1	23.19	45.00			Wilson T1	40.00	45.00	89%
Wilson T2	45.12	45.00			Wilson T2			
Trask	11.77	37.00			Trask	32.89	37.00	89%
Total	95.39	152.00	63%		Total	95.39	107.00	89%

The N – 1 shows a loading of 89% of NAMEPLATE CAPACITY 28 years after the larger transformer was installed. My model assumed that the larger transformer was installed in 2009 and I added growth as stated above for 28 years. Exchanging a larger transformer for the current obsolete T1 is a good way to add capacity to the central valley without building a transmission line.

Fagen's cost decision is not sensible because he is paying for demand that may not materialize, or unneeded capacity. Here are Fagen's calculations. He merely divided the cost of the project by the added capacity and concluded that the transmission line was a better choice because it had a lower cost per unit.

$$\frac{\text{Cost of Project}}{\text{Capacity added}} = \frac{\text{10 million}}{\text{30MW}} = \text{\$0.30 per MW of added capacity for the Transmission Line}$$

$$\frac{\text{6 million}}{\text{12MW}} = \text{\$0.50 per MW of added capacity for option 3}$$

In lines 1 – 5 on Staff/200 Hanhan/12. TPUD is said to have chosen the transmission line because it would have the lowest per unit cost of capacity and possess a longer useful life. We disagree. Why is paying for capacity that doesn't get used a better purchase? To answer, we compare the cost of each option to actual usage. Consulting DR41-8 and extending BPA's forecast of the MW's Tillamook will use in the next 33 years and then dividing the cost of each option by the expected usage gives us an idea how much that project cost is for each MW we used.

$$\frac{\text{Cost of Option 3}}{\text{Projected usage for next 33 years}} = \frac{\text{6 million}}{\text{16,524,077MW}} = \$0.36/\text{MW}$$

If we pay $6 million for option 3, we will pay $0.36 more for @MW used. The transmission line is

$$\frac{\text{13 million}}{\text{16,524,077MW}} = \$0.78/\text{MW}$$

If we spend $13M on the transmission line we will pay $0.78 more for each MW we use. Option 3 is a better economic choice when actual usage is compared to cost. Each consumer will pay $0.42 less per MW used if option 3 is chosen instead of the transmission line.

Earlier we established that longevity of option 3 is similar to the transmission line, and that the larger transformer provides needed capacity at the load centers of the central valley and gives enough capacity to cover N – 1 contingency. Now we have refuted the argument that the transmission line is a better purchase based on unit cost.

The narrative in Staff/200 Hanhan/10 in line 9 -17 of how the proposed transmission line addresses TPUD's concerns can also be applied to Option 3. The additional 12 MW of capacity added to Wilson River allows TPUD to meet load at peak hours and it makes room on its system for new development. The redundant power source can be added by the distribution feeder coming from Trask, so sections of line can be taken out of service for maintenance or repair without disruption to all customers on that line.

I believe that Option 3 is more sensible than the transmission line for 3 reasons;

1. The dollar cost is less so customer rate increases would be lower.
2. It would meet less opposition to being built with fewer impacts to valuable farms and forests, two important engines of the Tillamook economy.
3. TPUD has not given any documentation to support the claim of expected growth in Oceanside-Netarts. How many multi-phase housing developments (if any) are planned in Oceanside-Netarts vs Manzanita-Nehalem or Pacific City? How many building permits for each area? Speaking as a resident, Highway 131, the only major route to Oceanside has experienced several prolonged closures in the past decade because of landslides and sinkholes. I would prefer a beach house I could get to and one where I am not trapped at if 131 closes and I need to return to my permanent address.

Lines 11 – 14 in staff/200 Hanhan/11 regarding N – 1 contingency analysis are incorrect. DR-21, Sheet 2 is a spreadsheet from TPUD showing their calculations. If you compare the capacities of all of these models to the chart provided in TPUD's response to DR-32, you will see that the capacities used come from the 2nd column from the left titled Nameplate Capacity 2018 (Top MVA Rating).

Transformer	Nameplate Capacity 2014 (Top MVA Rating)	Nameplate Capacity 2018 (Top MVA Rating)	2014 Winter Capacity (MVA)	2018 Winter Capacity (MVA)
Beaver	7	5	8	5.5
Garibaldi	25	25	31.4	27
Mohler	20	22	27.7	27.7
Hebo	20	22	28.1	28.1
Nestucca	20	22	28.1	28.1
Trask River	33	37	46.8	36
Wilson River T1	40	33	45	36
Wilson River T2	46	45	50	48
Nehalem	25	28	28	28
South Fork	7	6	Not listed	9.3
Totals	243	245	293.1	273.7

Since none of the calculations provided use the capacity from either the 2014 Winter Capacity Column nor the 2018 Winter Capacity Column, the statement that the loading is at 92% of combined winter capacity is wrong. TPUD's N – 1 data in DR-21 Sheet 2 cells A2-D7 represents a 2009 load and was TPUD's all-time system high. You can correctly say that the T1 is at 93% of individual transformer loading prior to the N – 1 because the capacity used is from the nameplate capacity column. In cells A9 – D15 and cells F10 – I15 the T2 is removed and the T2 load is redistributed. You can correctly say that the Garibaldi, T1 and Trask transformers are loaded at 92% of transformers capacity. The total capacity is 140.

	A	B	C	D	E	F	G	H	I
1	TPUD System Capacity								
2		Load (MVA	Capacity (MV	% Loading		Synergi	Load (MV	Capacity (M	% Loading
3	Garibaldi	14.15	25	57%	26.8	Garibaldi	14.57	25	58%
4	Wilson T1	21.43	33.3	64%	35.7	Wilson T1	21.43	33.3	64%
5	Wilson T2	41.70	44.8	93%	48.0	Wilson T2	41.35	44.8	92%
6	Trask	10.87	36.9	29%	39.6	Trask	10.77	36.9	29%
7	Total	88.15	140.0	63%		Total	88.12	140.0	63%
8									
9	N-1 - Capacity - No Load Growth from 2009								
10		Load (MVA	Capacity (MV	% Loading		Synergi	Load (MV	Capacity (M	% Loading
11	Garibaldi	14.15	25			Garibaldi	23.69	25	95%
12	Wilson T1	21.43	33.3			Wilson T1	31.65	33.3	95%
13	Wilson T2	41.70	0			Wilson T2	0.00	0	
14	Trask	10.87	36.9			Trask	32.51	36.9	88%
15	Total	88.15	95.2	93%		Total	87.85	95.2	92%
16									

On Doris's N – 1, I used the 2009 year load but changed the capacity to the 2014 Winter Capacity with a total capacity of 173.20. You can correctly say the results of the N – 1 show Garibaldi, Wilson T1 and Trask are loaded to 72% of the combined winter capacity, NOT 92% as reported in Staff/200 Hanhan/11, line 13!

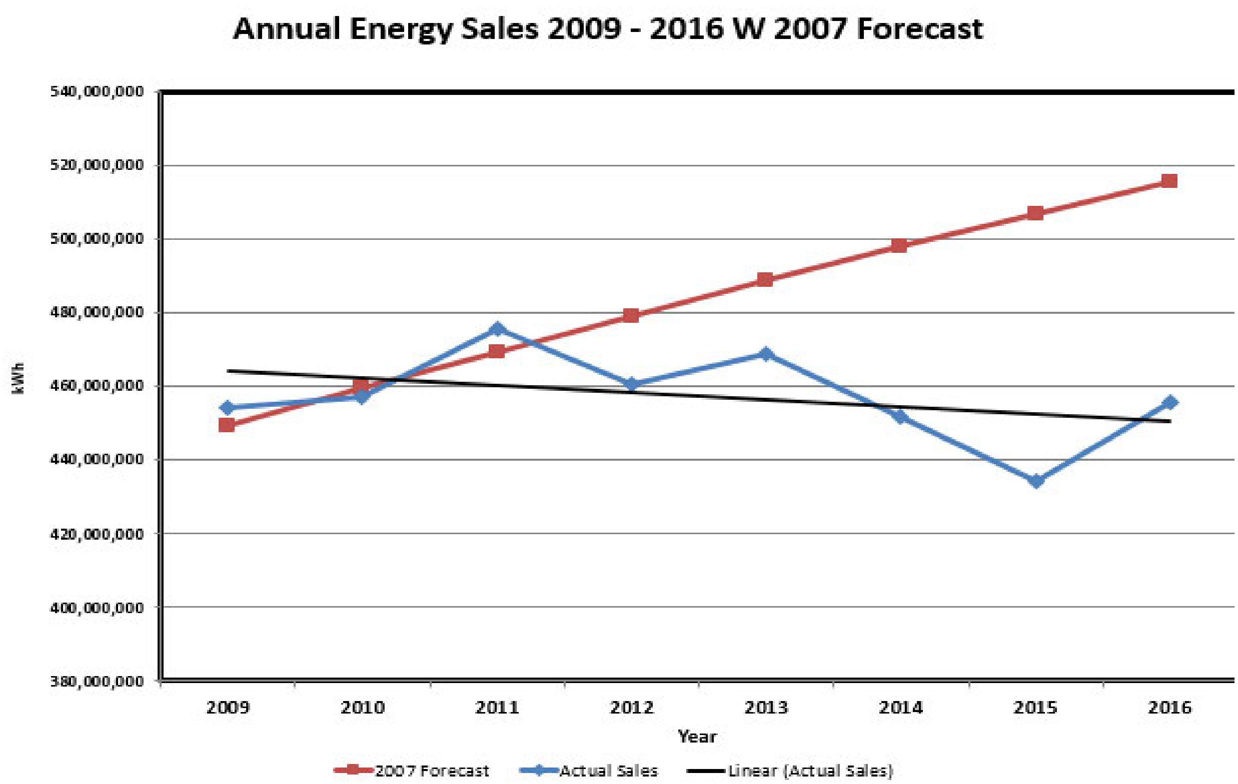
			DORIS'S N - 1					
TPUD System Capacity					Doris's N-1 No Load Growth			From
	Load (MVA	2014 Winter	% Loading		Synergi	Load (MV/	2014 Winter	% Loading
Garibaldi	14.15	31.40	45%		Garibaldi	22.61	31.40	72%
Wilson T1	21.43	45.00	48%		Wilson T1	32.40	45.00	72%
Wilson T2	41.70	50.00	83%		Wilson T2		0.00	0%
Trask	10.87	46.80	23%		Trask	33.11	46.80	71%
Total	88.15	173.20	51%		Total	88.12	123.20	72%

In cells A18 – D24, TPUD assumed a load growth of 0.9% and added it to the 2009 load. The numbers in cells F19 – I24 show the same numbers used in TPUD/205 Fagen/53 which were presented at the October 2016 workshop as representing 2016 loads. However, when we checked the spreadsheet the formula showed 9 years of growth had been added. There are 7 years from 2009 to 2016 so my load numbers are slightly smaller. TPUD's N – 1 shows Garibaldi, Wilson River 1 and Trask are loaded to 96% of transformer capacity (with 9 years growth added). Doris's N – 1 shows Garibaldi, Wilson River 1 and Trask are loaded to 74% of combined winter capacity.

	A	B	C	D	E	F	G	H	I
18	N-1 Capacity - 0.9% Annual Load Growth from 2009								
19		Load (MVA	Capacity (MV/	% Loading		Synergi	Load (MV/	Capacity (M	% Loadin
20	Garibaldi	15.30	25		1.081	Garibaldi	22.76	25	91%
21	Wilson T1	23.17	33.3		1.081	Wilson T1	33.25	33.3	100%
22	Wilson T2	45.07	0		1.081	Wilson T2	0.00	0	
23	Trask	11.75	36.9		1.081	Trask	35.33	36.9	96%
24	Total	95.29	95.2	100%		Total	91.34	95.2	96%
25									

				Years of Growth					Years of Growth
0.9% Annual Load Growth from 2009				7	Doris's N-1 -7 Yrs 0.9% Growth From 2009				7
	Load (MVA	2014 Winter Capacity	% Loading		Synergi	Load (MV	2014 Winter Capacity	% Loading	
Garibaldi	15.04	31.40			Garibaldi	22.76	31.40	72%	
Wilson T1	22.78	45.00			Wilson T1	33.25	45.00	74%	
Wilson T2	44.32	50.00			Wilson T2	0.00	0.00		
Trask	11.56	46.80			Trask	35.33	46.80	75%	
Total	93.71	173.20	54%		Total	91.34	123.20	74%	

In my calculations of N – 1 I accepted TPUD's use of a 0.9% load growth added to the 2009 load to arrive at a 2016 load. However, 2009 – 2016 is a historical period and the load growth for those years can be calculated and they are **-0.31%** annual not +0.90% annual. Following is a graph showing the growth trend of 2009 -2016. I wanted to remind everyone that the 0.9% assumed growth did not actually occur in this time frame. The existing system provides adequate capacity to cover N – 1 contingency and will be further improved in September after the installation of the larger transformer.



Lines 1 – 6 in Staff/200 Hanhan/10 echo what I have been hearing from TPUD since 2010. As a property owner I am frustrated at the obdurate attitude that the only solution is a transmission line. A transmission line is one solution but inferior in some ways to Option 3. The new larger 12 MW transformer would be added to Wilson River, part of the central valley which takes 72% of the annual KW load and has 12,362 customers. So, Option 3 places increased capacity next to the load it serves!

Lines 3 – 8 of Staff/200 Hanhan/9 states that TPUD is expecting load growth in the coastal areas but particularly in the Oceanside Netarts area. Earlier, I raised the issue of poor road access to the area because of landsides and sinkholes on 131. The Bayshore Drive road into Oceanside has been closed several years due to landsides. 131 is the last way in and out of Netarts-Oceanside. If TPUD builds the transmission line and a high wind event or other event causes lines to break and cause a fire in the 4 miles where the line traverses the forest from Bayocean to Oceanside, how many people will be unable to evacuate? Option 3 not only eliminates this risk but reduces impact to the forest by saving 40 acres of trees.

Tillamook County is concerned about affordable housing. Affordable housing is more likely to be close to Tillamook rather than Oceanside. With a limited budget for car expenses and gasoline, affordable housing will need to be closer to health care and the hospitals, grocery stores and jobs. Option 3 puts increased capacity close to this area at a lower dollar cost than the transmission line and at lower rate increases to the customers.

Summary

In my first testimony as an intervenor, I addressed the reliability concerns that Option 3 would solve. I will not repeat that testimony but I will remind you that Fagen gave Option 3 a rating of good for reliability in TPUD/205 Fagen/53.

TPUD/205
Fagen/53

SUMMARY OF OPTIONS

	Option 1	Option 2	Option 3	Option 4
Cost (Million)	$0.8	$3.8 - $4.2	$5.5 – $6.0	$9-$10.5
Capacity Addition	0 MVA	0 MVA	12 MVA	33 MVA
$/MVA	0	0	0.5	0.3
Reliability	None	Good	Good	Excellent
Longevity	0 years	2 years	13 years	33 years

CONCLUSION: The Tillamook to Oceanside transmission line project provides the lowest cost per unit of capacity (MVA) and has the life expectancy of 33 years (2.8 times the non-transmission line option).

I examined his data on longevity and disputed his answer of 13 years for Option 3. Longevity should be from 28 – 87 years depending on the growth factor chosen. After the installation of the larger transformer in September of 2018 the capacity will increase in the central valley where it is needed to accommodate load growth! Option 3 provides adequate capacity to cover N – 1 contingency. TPUD should and must rebuild feeder 51 but a $13 million transmission line is not necessary to rebuild the line. Therefore, the transmission line is not needed to add capacity or improve reliability. TPUD has not demonstrated that without the transmission line they cannot meet growth needs or improve reliability or rebuild Feeder 51. The substation and transmission line should not be deemed by the commission to be necessary and convenient.

/s/Doris Mast

OPTIONS CONSIDERED

Option 1
- Do nothing

Option 2
- Improve system to provide redundant 26kV feeders to Netarts and Oceanside
- Strengthen tie points between Wilson and Trask substations
- Perform improvements to resolve voltage and loading issues

Option 3
- Same improvements as Option 2
- Replace Wilson T1 with equivalent size of Wilson T2 (44 MVA)

Option 4
- Construct the Tillamook to Oceanside transmission line and a 33 MVA substation

DR -21

Wilson Substation – Contingenency Plan Transformer 2 Out of Service						
Non-Transmission Line Alternatives						
Alternative 1					**Unit Cost**	**Total**
No work					$0	$0
Reimburse BPA for 115kV Bay at Wilson						
$600,000 to $800,000						$ 800,000
					Total	$ 800,000
Alternative 2					**Unit Cost**	**Total**
1. Construct a new 24.9kV circuit from Trask to Oceanside						
a. Rebuild from Hwy 101 along Gienger, Tillamook River, and Matejeck roads to 465 AAAC three phase						
	2.5	miles			$ 180,000	$ 450,000
b. Construct new line from Matejeck Road to Highway 131 via existing transmission line right of way.						
	4.025	miles			$ 100,000	$ 402,500
	4.025	miles	Right-of-way clearing		$ 15,000	$ 60,375
	1	miles	Roads		$ 25,000	$ 25,000
c. Construct new underground line from Highway 131 to Oceanside via existing USF roads						
	4.5	Miles			$ 250,000	$ 1,125,000
d. Install Recloser at Tillamook River & Matejeck.						
2. Rebuild Trask T68						
a. Rebuild BPA Transmission Line						
	4.6	Miles			$ 350,000	$ 1,610,000
b. Rebuild T68 to 465AAAC						
	4.6	Miles			$ 70,000	$ 322,000
					Subtotal	$ 3,995,000
				Contingency	30%	$ 1,199,000
				Contingency	50%	$ 1,998,000
Reimburse BPA for 115kV Bay at Wilson						
$600,000 to $800,000						$ 800,000
					Total Low End	$ 5,994,000
					Total High End	$ 6,793,000

Alternative 3					**Unit Cost**	**Total**
1. Same improvements as Alternative 2						$ 3,995,000
2. Replace WT1 with 24/34/44						
	$ 1,800,000	each			$ 1,800,000	$ 1,800,000
					Subtotal	$ 5,795,000
				Contingency	30%	$ 1,739,000
				Contingency	50%	$ 2,898,000
Reimburse BPA for 115kV Bay at Wilson						
$600,000 to $800,000						$ 800,000
					Total Low End	$ 8,334,000
					Total High End	$ 9,493,000
Alternative 4						
1. Construct 8.75 miles of transmission line					**Unit Cost**	**Total**
	8.75	Miles			$ 400,000	$ 3,500,000
2. Construct Oceanside Substation						
	1	each			$ 3,000,000	$ 3,000,000
3. Construction Distribution Feeder						
	2	miles			$ 250,000	$ 500,000
					Subtotal	$ 7,000,000
				Contingency	30%	$ 2,100,000
				Contingency	50%	$ 3,500,000
					Total Low End	$ 9,100,000
					Total High End	$ 10,500,000
Low end and high end assume a 30% and 50% contingency allowance on the estimated construction cost.						

Longevity Analysis of the Larger T1 Transformer

LARGER WILSON RIVER TRANSFORMER

			Wilson River 1 & 2 Combined From TPUD Board Report		Wilson River 1 & 2 Combined From TPUD Board Report		Wilson River 1 & 2 Combined From TPUD Board Report	
Year	*# Of Years*	*12 MW of Additional Load*	*0.289% Growth BPA Forecast*	*Yearly % Growth*	*TPUD 0.9% Growth Trend*	*Yearly % Growth*	*TPUD 1.9% Growth Trend*	*Yearly % Growth*
2012			47.05		47.05		47.05	
2013			43.54		43.54		43.54	
2014			43.25		43.25		43.25	
2015			40.01		40.01		40.01	
2016			40.70		40.70		40.70	
2017			41.52		41.52		41.52	
2018	1	53.52	41.64	0.29%	41.89	0.90%	42.33	1.97%
2028	11	53.52	42.86	0.29%	45.82	0.90%	51.45	1.97%
2029	12	53.52	42.98	0.29%	46.23	0.90%	52.47	1.97%
2030	13	53.52	43.10	0.29%	46.64	0.90%	53.50	1.97%
2031	14	53.52	43.23	0.29%	47.06	0.90%	54.55	1.97%
2032	15	53.52	43.35	0.29%	47.49	0.90%	55.63	1.97%
2033	16	53.52	43.48	0.29%	47.92	0.90%	56.72	1.97%
2034	17	53.52	43.60	0.29%	48.35	0.90%	57.84	1.97%
2035	18	53.52	43.73	0.29%	48.78	0.90%	58.98	1.97%
2040	23	53.52	44.37	0.29%	51.02	0.90%	65.02	1.97%
2041	24	53.52	44.49	0.29%	51.48	0.90%	66.31	1.97%
2042	25	53.52	44.62	0.29%	51.94	0.90%	67.61	1.97%
2043	26	53.52	44.75	0.29%	52.41	0.90%	68.94	1.97%
2044	27	53.52	44.88	0.29%	52.88	0.90%	70.30	1.97%
2045	28	53.52	45.01	0.29%	53.35	0.90%	71.69	1.97%
2046	29	53.52	45.14	0.29%	53.83	0.90%	73.10	1.97%
2047	30	53.52	45.27	0.29%	54.32	0.90%	74.54	1.97%
2048	31	53.52	45.40	0.29%	54.81	0.90%	76.01	1.97%
2098	81	53.52	52.46	0.29%	85.78	0.90%	201.59	1.97%
2099	82	53.52	52.61	0.29%	86.55	0.90%	205.57	1.97%
2100	83	53.52	52.76	0.29%	87.33	0.90%	209.62	1.97%
2101	84	53.52	52.91	0.29%	88.12	0.90%	213.75	1.97%
2102	85	53.52	53.06	0.29%	88.91	0.90%	217.96	1.97%
2103	86	53.52	53.22	0.29%	89.71	0.90%	222.25	1.97%
2104	87	53.52	53.37	0.29%	90.52	0.90%	226.63	1.97%
2105	88	53.52	53.53	0.29%	91.33	0.90%	231.09	1.97%
2106	89	53.52	53.68	0.29%	92.16	0.90%	235.65	1.97%
2107	90	53.52	53.84	0.29%	92.99	0.90%	240.29	1.97%

MWh PURCHASES FOR THE NEXT 33 YEARS

BASED ON BPA 2018 FORECAST FOR TPUD

Tillamook PUD
Total Retail Load Forecast
Energy
2018-2038

	Fiscal Year	MWh	aMW	Growth
	2012	488,878	55.66	-
	2013	477,036	54.46	-2.15496%
	2014	482,694	55.10	1.18600%
	2015	447,697	51.11	-7.25023%
	2016	467,598	53.23	4.15980%
	2017	504,738	57.62	8.23849%
1	2018	481,023	54.91	-4.69860%
2	2019	482,209	55.05	0.24653%
3	2020	484,908	55.20	0.28512%
4	2021	484,589	55.32	0.20804%
5	2022	485,784	55.45	0.24656%
10	2027	491,804	56.14	0.24663%
15	2032	499,455	56.86	0.28535%
20	2037	504,070	57.54	0.20800%
25	2042	510,317		
26	2043	511,576		
27	2044	512,837		
28	2045	514,102		
29	2046	515,370		
30	2047	516,641		
31	2048	517,915		
32	2049	519,193		
33	2050	520,473		
		16,524,077		
		$ 6,000,000	$ 13,000,000	
		$ 0.363	0.7867	
	AAGR 5 Year (2012-2017)			**0.69567%**
	AAGR 5 Year (2018-2038)			**0.24656%**
	AAGR 10 Year (2018-2038)			**0.25045%**
	AAGR 20 Year (2018-2038)			**0.24663%**