KETCHIKAN - PETERSBURG - WRANGELL
SEAPA
Southeast Alaska Power Agency

THE SOUTHEAST ALASKA POWER AGENCY (SEAPA)

WORK SESSION AGENDA

February 28, 2019 9:30-11:30 am AKST
The Landing Hotel | Sunny Point Ball Room

Meeting Objectives:

The purpose of the Work Session is to study/discuss issues relating to SEAPA's operations and curtailment review. No formal actions may be taken during a Work Session.

Operational Topics Discussion / Supporting Documents

- SEAPA Calendar Year 2018 Operations Plan (Acteson / Siedman)
    - 2018 Operations Plan attached
- SEAPA 2018 Operations and Curtailment Review (Acteson / Siedman)
    - Operations & Curtailment Review attached
- SEAPA After Curtailment Review (Acteson / Siedman)
- Power Sales Agreement (PSA) Operational Review (Joel Paisner)
    - PSA attached
- Future Management Guidelines Discussion
    - 2019 Operations Plan

Financial Discussion / Supporting Documents

- Diesel Protocol History
    - 2010 1031 Joel Paisner, Ater Wynne LLP, Legal Opinion re Payment of Diesel Generation Costs
    - 2010 1027 Memo to Board from D. Carlson Re Diesel Protocol
    - 2014 0424 Motion Re Diesel Protocol (case-by-case basis)
- Options for Diesel Reimbursement (Acteson)
    - Power Point Presentation

SOUTHEAST ALASKA POWER AGENCY
Director of Engineering Report | December 2017

Date: December 4, 2017

To: Trey Acteson, Chief Executive Officer

From: Robert Siedman, P.E., Director of Engineering & Technical Services

SEAPA 2018 Operations Plan Report

Every year SEAPA presents the Operations Plan (Ops Plan) for Board approval in accordance with Section 5 of the Power Sales Agreement[1] (PSA). The annual plan forecasts expected reservoir levels for Tyee Lake and Swan Lake for the upcoming year by maximizing output from SEAPA facilities and optimizing water resources. Pursuant to the PSA, the Ops Plan gives first priority to the dedicated Firm Power Requirements of each Utility and optimizes additional dedicated output as a second priority for additional power requirements. Optimization of water resources is achieved by an algorithmic math model as represented in Figure 1.

Water Resource Algorithmic Math Model Process

Step 1: Current lake levels

Step 2: Inflow Forecasts
1. NOAA
2. USGS
3. NINO3.4

Step 3: Load Forecast
1. Temperature Forecasts
2. Scheduled Maintenance
3. STICS/Historic Loads

Step 4: Iterative Math Model
1. Case Reservoir Plots
2. Optimized Water Resources

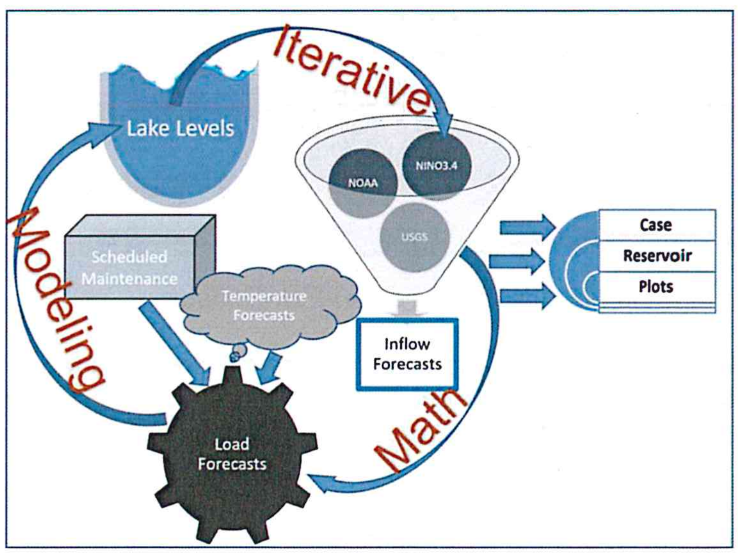

Figure 1: Math Modeling: Optimizing Water Resources

The iterative process utilized in the algorithm to optimize water resources was applied to a variety of cases. Each case was further analyzed, and a guide curve was developed. Special consideration was made to ensure optimization of water resources without risking dedicated Firm Power Requirements of

[1] Section 5 of the Power Sales Agreement states that SEAPA shall prepare annually an Operations Plan to estimate the Firm Power Requirements of the Purchasing Utilities and identify Dedicated output to maximize utilization and optimize output of each facility.

the Purchasing Utilities. The process, assumptions, and results are discussed below.

Current Lake Levels

The current lake levels on December 1, 2017 are slightly lower than the estimated 2017 Ops Plan. October 2017 was a near-record low with regard to inflows and November was a near-record high with regard to loads. This anomaly is discussed in more detail in the subsequent Inflow Forecasts section. Swan Lake's flashboards impounded water from September 24 to November 2 (40 days). This equates to approximately 3,723MWh that was gained from the Swan Lake Reservoir Expansion project. This is additional capacity that would have otherwise been lost as spilled energy. On December 1, Swan Lake reservoir was at an elevation 314.5 ft. and Tyee Lake reservoir was at an elevation of 1375 ft.

Inflow Forecasts

Inflow predictions for calendar year 2018 were performed by utilizing NOAA, NINO3.4 and historic USGS inflow data. NOAA forecasts for the months of December-January-February are predicting below normal precipitation and below normal temperatures. Figure 2 illustrates that NOAA is predicting with a 40-50% probability confidence a below normal three-month outlook.

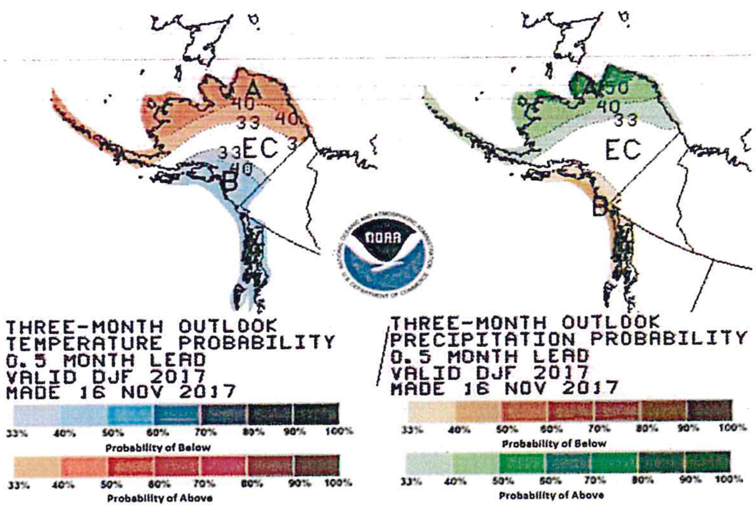

Figure 2: NOAA Dec-Jan-Feb Outlook

NOAA however put more confidence (70% probability) into the prediction that a La Nina is expected. The strength of the predicted La Nina is what SEAPA is mostly concerned with because this information can be used to model an expected inflow season.

There are dozens of institutions that have developed El Nino Southern Oscillation models (ENSO). Oceanographic temperature models such as ENSO's are used by NOAA to predict weather patterns.

The latest ENSO models show that we are currently in a moderate La Nina. Ocean temperatures are currently 0.5–1.0 ˚C below average temperatures. Cooler ocean temperatures correlate to cooler weather and lower precipitation rates in the Northwest hemisphere.

Figure 3 illustrates the International Research Institute (IRI) and Climate Prediction Centers (CPC) ENSO model. Apparent to all participating institute forecasts is a continued below average ocean temperature. Coupled with a near record low precipitation in October of this year, an El Nina is currently active and highly probable to continue.

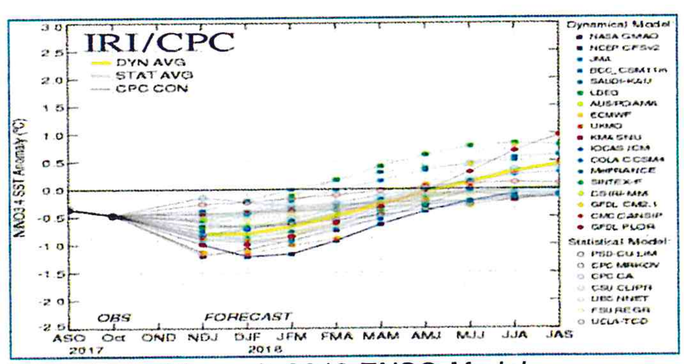

Figure 3: 2018 ENSO Model

Inflow seasons are cyclical and have a close correlation with ocean temperatures. As evident in Figure 4, ocean temperatures have been increasing over the past 50 years however the increase in temperatures appear to be consistent and predictable. The ocean's cyclical warming, and cooling patterns are termed El Nino and La Nina respectively. Between the years 2014 and 2016 the largest El Nino in history was recorded.

The second largest El Nino in recorded history occurred between the years 1996 and 1998. As evident in Figure 4, typically after a strong El Nino season, there is a reactively strong La Nina period that follows. 2015 inflows (during the last El Nino), Swan Lake and Tyee Lake reservoirs were recorded at nearly the highest in history. Both reservoirs spilled for nearly the entire season, similar to the 1997-1998 El Nino season.

Given that 2015 inflows were consistent with the strongest El Nino in history, they are considered by SEAPA to be typical of a strong El Nino season. Cyclical and predictable to a certain degree of confidence, SEAPA predicts the upcoming La Nina season in reaction to the recent El Nino to be comparable to 1999. The 1999 La Nina season was an extremely low inflow year and for the purposes of modeling inflows, was chosen as the low inflow case year for Swan Lake and Tyee Lake models.

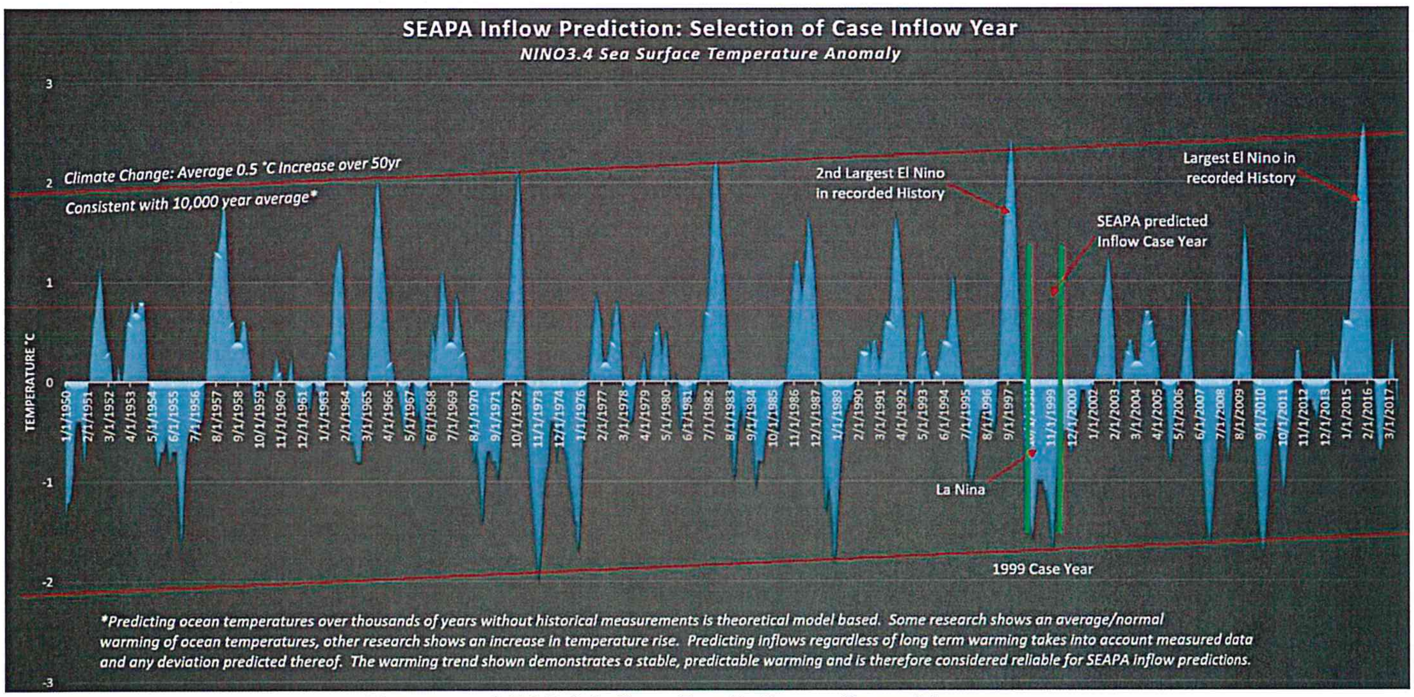

Figure 4: SEAPA Inflow Prediction – Case Year

Average inflows for both Swan Lake and Tyee Lake reservoirs were also modeled. It is highly unlikely that there will be an above average inflow for the 2018 season and therefore the low & average cases were used to determine the respective guide curves.

Case / Month	SWL Low Inflow (avg cfs)	SWL Avg Inflow (avg cfs)	TYL Low Inflow (avg cfs)	TYL Avg Inflow (avg cfs)
jan	32.8	419.4	44.9	21.9
feb	126.7	115.2	23.1	16.7
mar	147.5	162.5	21.0	21.0
apr	247.0	571.4	38.3	28.6
may	485.2	629.3	151.5	211.2
jun	543.0	545.7	354.3	396.7
jul	425.1	424.3	307.1	300.2
aug	343.1	366.1	142.0	204.4
sep	577.4	400.3	95.6	237.4
oct	357.1	340.0	383.7	273.1
nov	253.6	533.7	52.9	94.4
dec	385.9	612.7	26.1	34.4
Average Annual	327.0	426.7	136.7	153.3

Table 1: SEAPA predicted Inflow Cases for 2018

Low Inflow Cases

Table 1 illustrates the inflow inputs that were used for the Swan Lake and Tyee Lake reservoir level models. As discussed previously, the low inflow cases were based on 1999 inflows. The low average annual cfs for Swan lake was 327.0 cfs and the low average annual cfs for Tyee Lake was 136.7 cfs.

Average Inflow Cases

The average inflow case for Swan Lake was inserted into the model with an average annual cfs value of 426.7 cfs. Average inflows were based on 1919 inflows which were similar to the 100-year average. The average inflow case for Tyee Lake was inserted into the model with a cfs value of 153.3cfs. This was based on a 5-year average between 1964-1969 and is similar to that of the IECo[2].

Load Forecasts

Load forecasts and subsequent SEAPA deliveries were estimated for the 2018 calendar year with consideration to the NOAA December-January-February outlook (colder average temperatures) and the 5-year SEAPA delivery schedule (2011-2016). Two cases were developed, based on expected inflows and respective lake levels that were iteratively modeled to balance the reservoirs. Each load forecast case was calculated with a 2% increase for colder predicted winter months, averaged over the past 5-year maximums and a 0.5% increase for all remaining months. The forecasted Firm Power Requirements for the respective Utilities are as follows:

Ketchikan Forecasted Load Requirements: **99,716MWh**

Wrangell & Petersburg Load Requirements: **85,511MWh**

SEAPA Total Forecasted Loads (not including line loss): **185,227MWh**

[2] The International Engineering Company (IECo) performed a study to determine hydrologic data necessary for the design of Tyee Lake. The results included Tyee Lake inflow average estimates.

Low Inflow Load Case:

Table 2 illustrates the load forecasts for 2018 using a low inflow case (1999). With low inflows, Swan Lake was modeled in a manner to allow for full recovery of the reservoir in the Fall of 2018. This was achieved by shifting generation from Swan Lake to Tyee Lake. The result is a lower draft of Tyee Lake however as discussed in the subsequent Iterative Math Model section (and case reservoir plots section), a low inflow year modeled for 2018 will still result in a nearly full pool at Tyee by Fall of 2018.

	KTN			Swan Lake		STI		WRG-PSG			Tyee Lake	
	Expected Delivery MWh	Required Generation MWh	Required Generation Avg MW	Expected Gen from Inflow Avg MW	Expected Gen from Inflow MWh	STI Expected (balance) MWh	STI Expected (balance) Avg MW	Expected Delivery MWh	Required Generation MWh	Required Generation Avg MW	Tyee Expect Generation Avg MW	Tyee Expected Generation MWh
JAN	10870.4	11522.6	15.5	11.0	8184.0	3338.6	4.5	9176.9	9635.8	13.0	17.4	12974.4
FEB	10862.0	11513.7	17.1	10.0	6720.0	4793.7	6.4	8730.8	9167.3	13.6	20.8	13961.0
MAR	8493.3	9002.9	12.1	5.0	3720.0	5282.9	7.1	7283.8	7720.8	10.4	17.5	13003.7
APR	6594.8	6990.5	9.7	4.0	2880.0	4110.5	5.5	6282.4	6659.3	9.2	15.0	10769.8
MAY	5054.7	5358.0	7.2	4.0	2976.0	2382.0	3.2	4997.3	5297.1	7.1	10.3	7679.1
JUN	5730.8	6074.7	8.4	5.0	3600.0	2474.7	3.3	4906.7	5201.1	7.2	10.7	7675.8
JUL	7670.2	8130.4	10.9	5.0	3720.0	4410.4	5.9	7202.1	7634.2	10.3	16.2	12044.5
AUG	7011.9	7432.7	10.0	6.0	4464.0	2968.7	4.0	7445.0	7891.7	10.6	14.6	10860.3
SEP	6544.5	6937.2	9.6	6.0	4320.0	2617.2	3.5	5180.8	5491.7	7.6	11.3	8108.8
OCT	8095.6	8581.3	11.5	8.0	5952.0	2629.3	3.5	6637.0	7035.2	9.5	13.0	9664.5
NOV	9143.1	9691.6	13.5	7.3	5220.0	4471.6	6.0	7547.9	8000.8	11.1	17.3	12472.4
DEC	13644.7	14463.4	19.4	12.0	8928.0	5535.4	7.4	10120.9	10728.1	14.4	21.9	16263.5
Total	99716.0	105698.9	-	-	60684.0	45014.9	-	85511.6	90463.2	-	-	135478.1

*Table 2: SEAPA 2018 Load Forecast for **Low** Inflow Case*

Average Inflow Load Case:

Table 3 illustrates a load forecast for 2018 with inflows biased toward an average inflow year. For an average inflow, Swan Lake reservoir generates nearly 20,000MWh more than the low inflow case above. Load forecasting for Ketchikan, Petersburg and Wrangell are unchanged however loads are shifted less across the Swan-Tyee intertie from the Tyee Lake reservoir to Ketchikan.

	KTN			Swan Lake		STI		WRG-PSG			Tyee Lake	
	Expected Delivery MWh	Required Generation MWh	Required Generation Avg MW	Expected Gen from Inflow Avg MW	Expected Gen from Inflow MWh	STI Expected (balance) MWh	STI Expected (balance) Avg MW	Expected Delivery MWh	Required Generation MWh	Required Generation Avg MW	Tyee Expect Generation Avg MW	Tyee Expected Generation MWh
JAN	10870.4	11522.6	15.5	16.0	11904.0	0.0	0.0	9176.9	9635.8	13.0	13.0	9635.8
FEB	10862.0	11513.7	17.1	18.0	12096.0	0.0	0.0	8730.8	9167.3	13.6	13.6	9167.3
MAR	8493.3	9002.9	12.1	12.0	8928.0	74.9	0.1	7283.8	7720.8	10.4	10.5	7795.7
APR	6594.8	6990.5	9.7	9.7	6984.0	6.5	0.0	6282.4	6659.3	9.2	9.3	6665.8
MAY	5054.7	5358.0	7.2	7.2	5356.8	1.2	0.0	4997.3	5297.1	7.1	7.1	5298.3
JUN	5730.8	6074.7	8.4	6.0	4320.0	1754.7	2.4	4906.7	5201.1	7.2	9.7	6955.8
JUL	7670.2	8130.4	10.9	8.0	5952.0	2178.4	2.9	7202.1	7634.2	10.3	13.2	9812.5
AUG	7011.9	7432.7	10.0	6.0	4464.0	2968.7	4.0	7445.0	7891.7	10.6	14.6	10860.3
SEP	6544.5	6937.2	9.6	0.0	0.0	6937.2	9.3	5180.8	5491.7	7.6	17.3	12428.8
OCT	8095.6	8581.3	11.5	5.0	3720.0	4861.3	6.5	6637.0	7035.2	9.5	16.0	11896.5
NOV	9143.1	9691.6	13.5	10.0	7200.0	2491.6	3.3	7547.9	8000.8	11.1	14.6	10492.4
DEC	13644.7	14463.4	19.4	11.2	8332.8	6130.6	8.2	10120.9	10728.1	14.4	22.7	16858.7
Total	99716.0	105698.9	-	-	79257.6	27405.0	-	85511.6	90463.2	-	-	117868.2

*Table 3: SEAPA 2018 Load Forecast for **Average** Inflow Case*

Scheduled Maintenance:

SEAPA does not anticipate any extended outages in calendar year 2018. Typical line maintenance, generator unit annual maintenance and substation maintenance were considered when developing the load forecasts. Swan Lake station service switchgear upgrades and Swan Lake turbine runner repairs are anticipated in the future. However, for CY2018, typical outage durations and times were modeled.

Iterative Math Model:

The Tyee Lake and Swan Lake models used to predict lake levels involve iterating through inflow scenarios and generation load sequences. Lake levels are inputted with actual levels on the day the model was run. Once inflow predictions were developed, manipulation of generation inputs was performed to balance lake levels between Tyee and Swan. The guide curve was developed by averaging the low inflow and average inflow cases, with a slight bias towards the low inflow case for early spring months.

Swan Lake Reservoir Plot (Operations Plan):

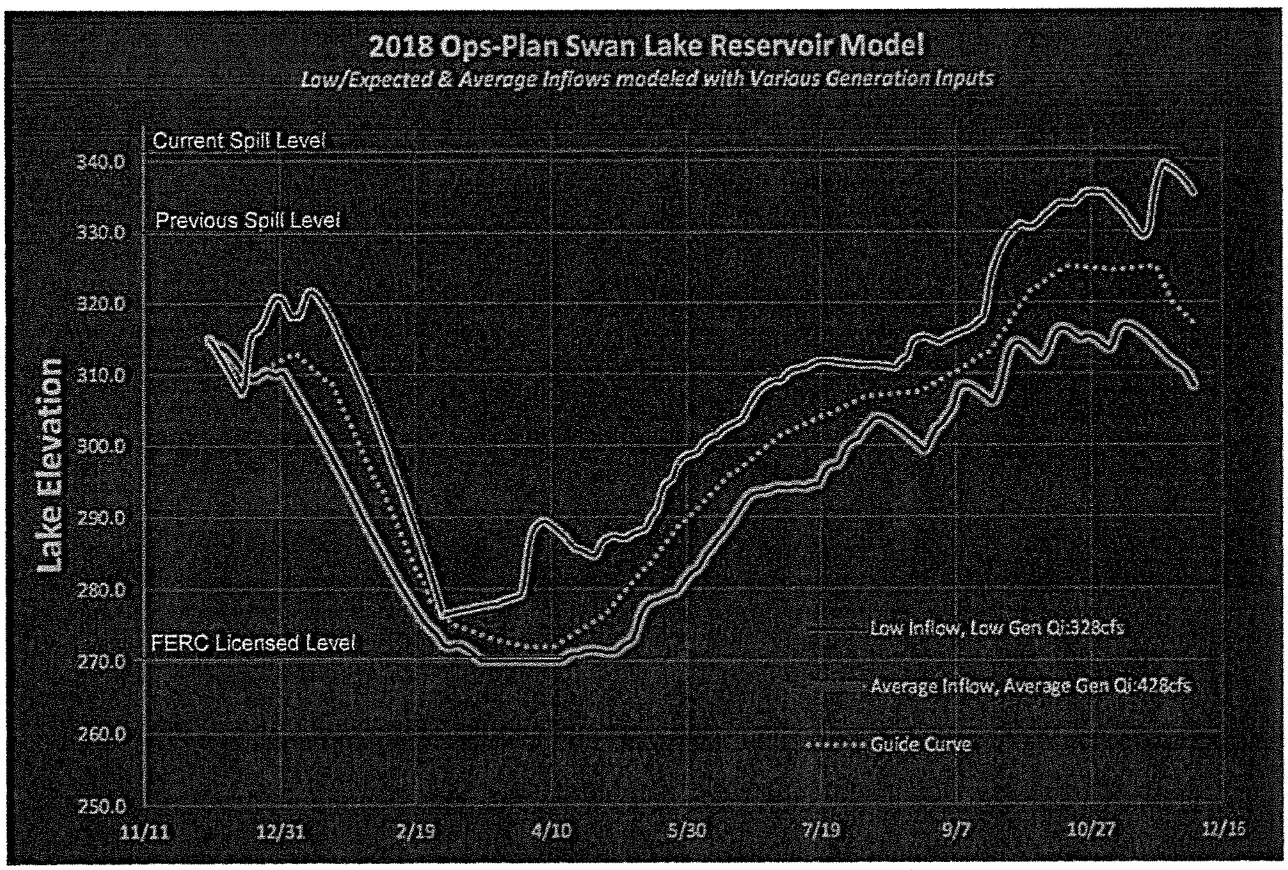

Figure 5: Swan Lake Reservoir Plot & Guide Curve

The 2018 Swan Lake reservoir model as illustrated in Figure 5 above illustrates the two case scenarios as discussed in preceding sections. The Low Inflow: Low Generation case demonstrates a possibility of very low lake levels in the Spring of 2018. This scenario could result in curtailed SEAPA sales to Ketchikan to ensure dedicated Firm Power requirements from Tyee Lake to Petersburg and Wrangell.

The Average Inflow and Average Generation case demonstrates a small probability of curtailment. As discussed in the Iterative Math Model section, the guide curve was developed as an average to both possible scenarios. The probability of each case is around 50% therefore an averaged case is reasonable to assume. The guide curve illustrates drafting Swan Lake to an elevation of 272 ft. which will result in a recovered pool elevation of 317 ft. in December of 2018. The probability of a shift from the current La Nina to an El Nino condition in calendar year 2019 is high and therefore a lower lake elevation to start CY2019 is less risky. Given the current La Nina and predicted continuation of low inflows through the 1st quarter of CY2018, generation from Swan Lake was reduced and Tyee Lake was utilized to help meet the additional power requirements of Ketchikan.

Tyee Lake Reservoir Plot (Operations Plan):

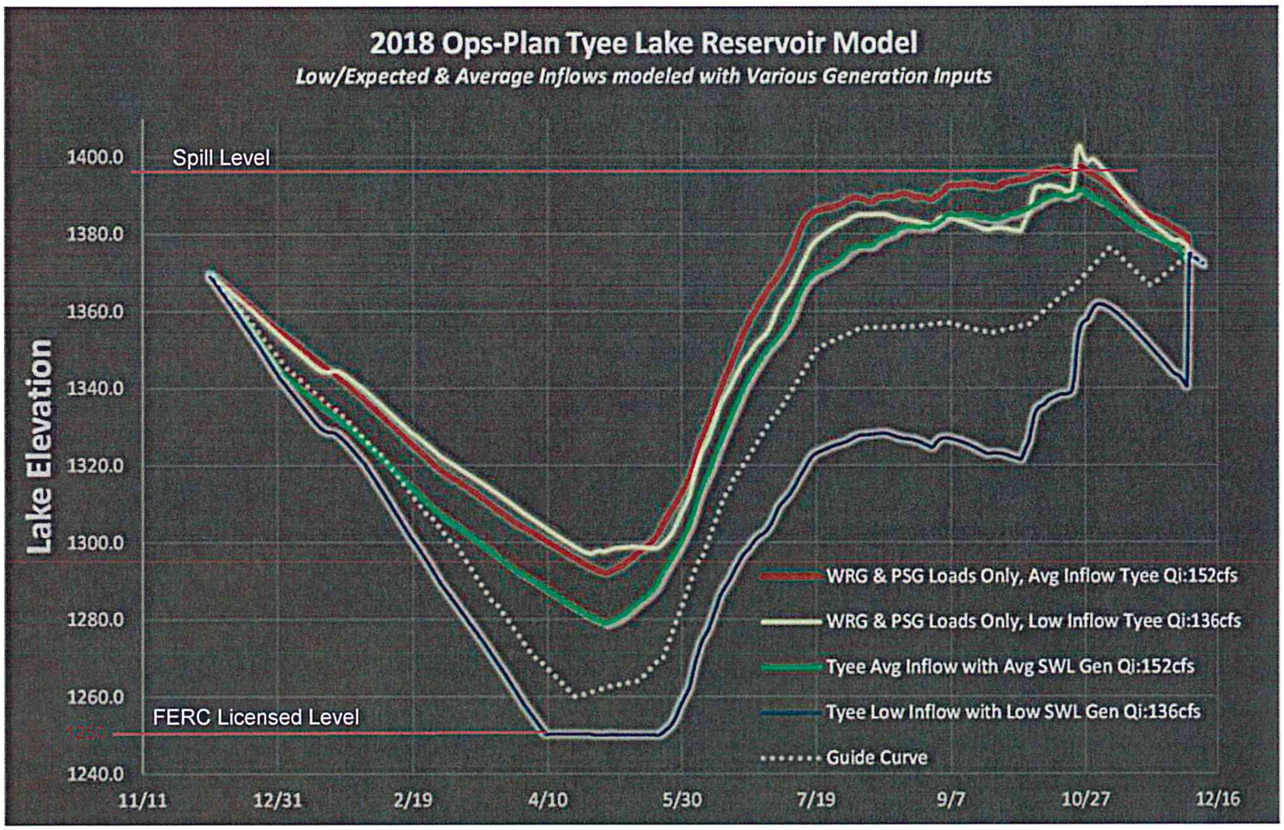

Figure 6: Tyee Lake Reservoir Plot & Guide Curve

The 2018 Tyee Lake reservoir model demonstrates 4 case scenarios. The two Petersburg and Wrangell load only plots (yellow & red) illustrate that Tyee lake would spill in both a low inflow and an average inflow year **if the STI wasn't utilized** (where **additional power wasn't sent to Ketchikan**). The Tyee Low Inflow: SWL Low Generation plot (blue) and the Tyee Average Inflow: SWL Average Generation plot (green) were both generated from direct outputs of the Swan Lake model, after multiple iterations to balance the lakes.

In the Swan Lake Low Generation plot (blue), maximizing both resources would result in drafting Tyee to the FERC licensed limit. Drafting Tyee Lake (and Swan Lake) to the FERC[3] licensed limit is important for relicensing. **It is therefore SEAPA's goal to draft the lakes on occasion as close to the FERC licensed** limit as reasonable, without adding risk or jeopardizing the probability of successful deliveries.

[3] The FERC licensed limit for Tyee Lake is elevation 1250ft. Swan Lake is 271.5ft.

Optimizing Water Resources:

Tyee Lake Draft:

Optimizing water resources is important for maximizing resource outputs and insuring FERC licensed limits are retained. It is however also SEAPA's mission to ensure dedicated outputs are delivered to meet the Firm Power Requirements of the Purchasing Utilities. In the Swan Lake reservoir model, all dedicated outputs from the facility are modeled as delivered loads to Ketchikan, thereby meeting SEAPA's mission regarding Swan Lake. In the Tyee Lake model, drafting the reservoir to the FERC licensed limit adds a measurable amount of risk in SEAPA's ability to ensure dedicated outputs are delivered to Petersburg and Wrangell thereby meeting their Firm Power Requirements. It is therefore important to draft the lake to an elevation such that a reasonable amount of contingency (days of dedicated output) are available to Petersburg and Wrangell in the event that there are zero inflows into Tyee Lake. Between the Tyee Lake elevations of 1260 ft. and 1250 ft., the amount of MWh per foot of lake is averaged to be approximately 410MWh/ft. With 10 feet of lake as a contingency (guide curve draft limit for Tyee is 1260 ft.), this leaves approximately 4,100MWh of available contingency. Assuming that at a worst-case load, (5-year maximum), in the Month of May when Tyee Lake is drafted to its lowest elevation, Petersburg and Wrangell would consume approximately 5,300MWh (including line losses). With the improbable event that Tyee Lake has zero inflows, 10 ft. of available Tyee Lake capacity used for contingency would leave Petersburg and Wrangell with 24 days of dedicated output.

Swan Lake Spill:

The Swan Lake reservoir was raised from elevation 330 ft. to elevation 345 ft. Calendar year 2017 was the first year that the benefits of this effort were realized. On September 29, Swan Lake was at an elevation of 335.8 ft. As stated earlier, this added 3,723MWh of energy captured, that would have otherwise been lost to spill. Similar to that of the 2017 Ops Plan, SEAPA plans to operate Swan Lake above elevation 330 ft. in the following manner:

- Elevations 330 ft. to 339 ft. - Both generating units will be fully available and the vertical gate will be operable. Water will be stored for future use.
- Elevations 339 ft. to 342 ft. - Both units will operate to their highest levels that loads permit to draft the reservoir back down to 339 ft. or below, this will most likely occur in spring and fall and assist with refilling Tyee Lake as increasing Swan Generation will reduce Tyee Generation for a given SEAPA delivery schedule.
- For the first few years, water above elevation 342 ft. will be immediately spilled by automatic operation. At elevation 335.8 ft. as seen in September 2017, there were little signs of Flashboard leakage. Testing is still required at higher elevations. Flashboards automatically release at elevation 347 ft.

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2018 Operations Plan Summary

Section 5 of the Long-Term Power Sales Agreement provides the following:

> **Operations Plan Development.** ... The objectives of the Operating Plan shall include maximizing the utilization of the output of the Agency Facilities and optimizing the output of the Agency Facilities in order to serve the Purchasing Utilities' Firm Power Requirements as set forth pursuant to this Agreement, through the use of water management and other efficient dispatch procedures adopted by the Agency, subject to Dedicated Parties' priority access to Dedicated Output. ... [Emphasis added]

For the reasons demonstrated in the proposed Operations Plan and pursuant to the Power Sales Agreement, SEAPA staff proposes guide curve elevations be used by the scheduling group as guides. If lake levels fall below the guide curves, SEAPA will manage water resources, in consideration of current conditions, with an overall objective of restoring lake levels to their respective guide curves. As lake levels approach the annual minimum Board approved draft limits (Tyee: 1260 ft. and Swan: 272 ft.), SEAPA and the dedicated resource holder(s) will enter into discussions as to whether curtailments will be issued. Guide curve elevations and minimum draft limits for Swan Lake and Tyee Lake are listed in Figure 5 and Figure 6 and correspond with the table below.

SEAPA 2018 Operations Plan Guide Curve Values

Mth/Day	12/5	1/5	2/5	3/5	4/1	4/28	5/28	6/15	7/5	7/21	8/24	9/18	10/18	11/20	12/4
SWL Guide Curve Elevation (ft)	315	313	295	275	272	276	289	296	302	304	308	313	325	325	317
TYL Guide Curve Elevation (ft)	1370	1343.7	1323.9	1299.3	1270	1260	1280	1312.3	1335	1351	1356	1355	1365.6	1366.7	1358.4

For reference, past Operations Plan minimum draft limits are listed below. With the predicted low inflows for CY2018, the proposed 2018 Operations Plan proposes that Swan Lake and Tyee Lake draft limits be lowered 1-foot below the approved 2017 Operations Plan.

SEAPA Historical Draft Limits				
	2014	**2015**	**2016**	**2017**
Swan Lake	275 ft.	285 ft.	275 ft.	273 ft.
Tyee Lake	1265 ft.	1280 ft.	1270 ft.	1261 ft.

Please consider the following suggested motion:

SUGGESTED MOTION
I move to approve the 2018 SEAPA Operations Plan as presented in the December 13-14, 2017 Board packet.

Date: Feb 7, 2019

To: Trey Acteson, Chief Executive Officer

From: Robert Siedman, P.E., Director of Engineering & Technical Services

SEAPA 2018 Operations & Curtailment Review

The intent of this report is to review SEAPA Operations and Tyee Curtailment decision(s) for calendar year 2018. Major milestones and decision points are discussed to include the technological tools used, forecasts, and result(s) of each decision point as it relates to the findings. Every year SEAPA presents the Operations Plan (Ops Plan) for Board approval in accordance with Section 5 of the Power Sales Agreement[1] (PSA). The annual plan forecasts expected reservoir levels for Tyee Lake and Swan Lake for the upcoming year by maximizing output from SEAPA facilities and optimizing water resources. Pursuant to the PSA, the Ops Plan gives first priority to the Dedicated Firm Power Requirements of each Utility and optimizes Additional Dedicated output as a second priority for additional power requirements.

The 2018 Operations plan approved by the Board of Directors in December 2017 predicted inflows to be much lower for the 2018 Calendar year than historical averages. An inflow case for 1999 was chosen to model both Swan and Tyee lakes because of an ensuing La Nina season forecasted by the National Oceanic Atmospheric Administration (NOAA), the International Research Institute (IRI) and the Climate Prediction Centers (CPC). In December of 2017, El Nino Southern Oscillation models (ENSO) were showing La Nina[2] conditions occurring throughout the first half of calendar year 2018 with a shift from La Nina to El Nino predicted to occur in the mid-summer months. Figure 1 illustrates the ENSO models released in December 2017 for the 2018 calendar year. In addition to oceanographic temperature models illustrating colder ocean temperatures, the NOAA 3-month temperature and precipitation outlook for December-January-February forecasted colder and drier conditions (Figure 2). As a result, SEAPA developed lake level guide curves for 2018 from models using significantly below average inflows.

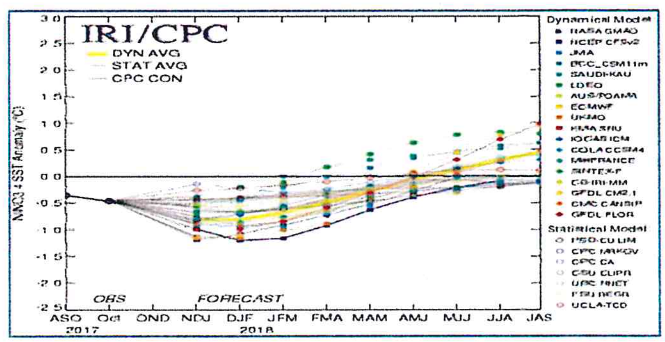

Figure 1: December 2017 ENSO Model

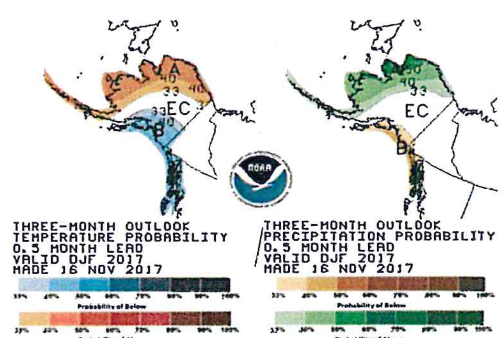

Figure 2: NOAA 3-Month Outlook

[1] Section 5 of the Power Sales Agreement states that SEAPA shall prepare annually an Operations Plan to estimate the Firm Power Requirements of the Purchasing Utilities and identify Dedicated Output to maximize utilization and optimize output of each facility.

[2] La Nina refers to colder than average temperatures in the ocean, generally causing colder and dryer conditions. El Nino refers to the opposite of La Nina, warmer and wetter conditions due to warmer ocean temperatures.

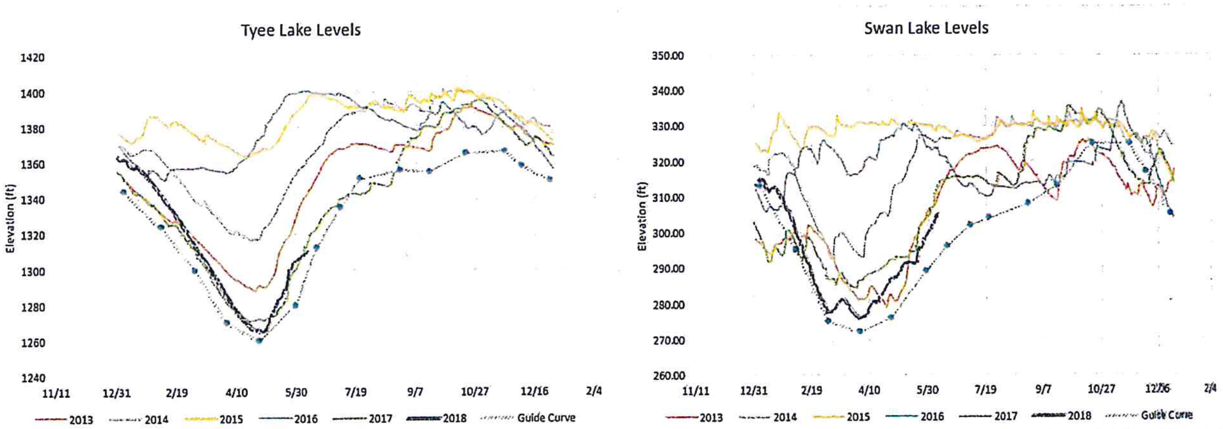

Figure 3: Tyee and Swan Lake Level Graphs: June 1st

June 2018

From the months of January to June 2018, lake levels were tracking very closely with the predicted models from the December 2017 Operation Plan. In June of 2018, both Tyee and Swan lake levels were above the conservative guide curves that were developed for 2018. Figure 3 (above) illustrates that both Tyee and Swan Lake level guide curve models were very close to actuals.

ENSO models out at the time were showing that ocean temperatures had increased to nearly 0.5 degrees centigrade above average which was an indication that the previous ENSO forecasts (from December 2017) were accurate. In addition to ocean temperatures increasing, the NOAA 3-Month look ahead for precipitation had an equal chance probability for average rainfalls and average temperatures for the months of June-July-August 2018 (Figure 4).

SEAPA typically runs extended operations lake level models on a monthly basis, or more frequently if lake levels are not tracking with respective lake level guide curves. A weekly model for the lakes is ran, on a weekly basis, and presented in the Tuesday Operations call.

Multiple scenarios are used to determine whether more efficient operational methods at Tyee and Swan Lake can be achieved to maximize utilization and optimize outputs. The June models did not indicate there to be any output optimization available, as the lakes were tracking well with the respective guide curves.

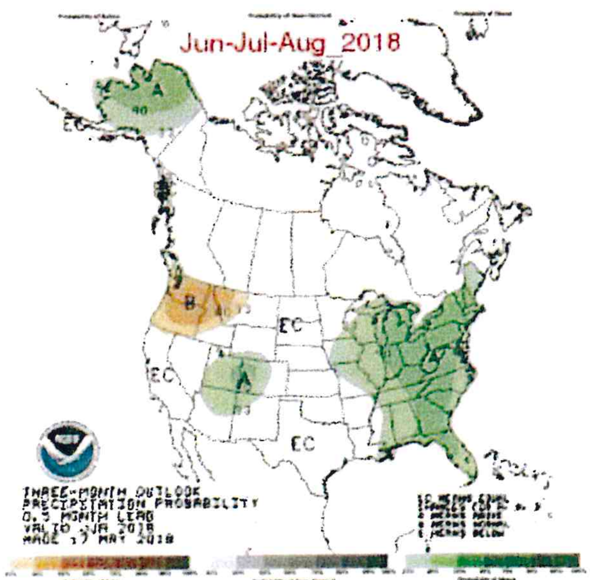

Figure 4: NOAA June-July-August Outlook

SOUTHEAST ALASKA POWER AGENCY

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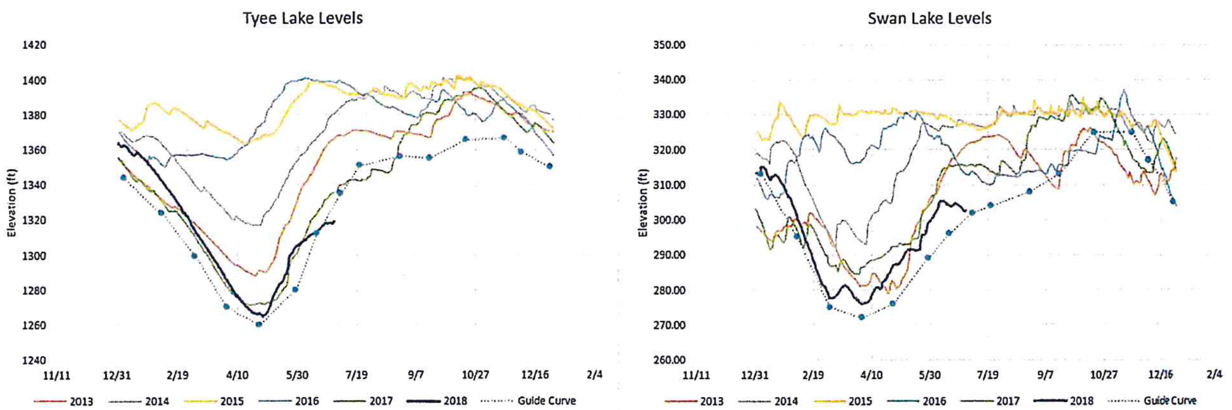


Figure 5: Tyee and Swan Lake Level Graphs: July 1st

July 2018

On July 2nd, for the first time in 2018, Tyee lake was slightly below the guide curve (Figure 5). Swan Lake elevations at the time were still above the guide curve. On July 3rd, SEAPA developed a modified STCS Operations table (Figure 6) with intent to operate Swan Lake at higher loads and a more aggressive draft rate in an effort to optimize outputs and balance the lakes.

The resultant modified Load Table increased Swan Lake generation by 5MW (on average) and reduced Tyee by 5MW respectfully. The result was a significant increase in the draft rate at Swan Lake and a reduced draft rate in Tyee. The forecasts for July-August-September in 2018 from NOAA were promising. As seen on the right, NOAA was forecasting an equal chance for average rain and average temperature for the summer months. 10-Day forecasts for July were also consistent with the NOAA forecast.

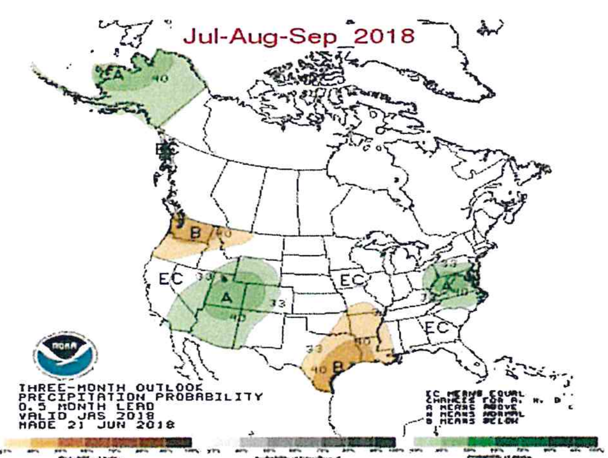
STC Table 1-Active
Updated May 2nd

STC	Slead	Slag	T1	T2	SWL Total
4.00	0.00	0.00	2.00	2.00	0.00
10.00	0.00	0.00	5.00	5.00	0.00
12.00	0.00	0.00	6.00	6.00	0.00
14.00	4.00	0.00	5.00	5.00	4.00
15.00	4.00	0.00	5.50	5.50	4.00
16.00	4.00	0.00	6.00	6.00	4.00
17.00	4.00	0.00	6.50	6.50	4.00
18.00	4.00	0.00	7.00	7.00	4.00
19.00	4.00	0.00	7.50	7.50	4.00
20.00	5.00	0.00	7.50	7.50	5.00
22.00	6.00	0.00	8.00	8.00	6.00
24.00	7.00	0.00	8.50	8.50	7.00
26.00	8.00	0.00	9.00	9.00	8.00
28.00	9.00	0.00	9.50	9.50	9.00
29.00	10.00	0.00	9.50	9.50	10.00
30.00	10.00	0.00	10.00	10.00	10.00
31.00	11.00	0.00	10.00	10.00	11.00
32.00	11.00	0.00	10.50	10.50	11.00
33.00	11.00	0.00	11.00	11.00	11.00
34.00	11.00	0.00	11.50	11.50	11.00

STC Table 1-Active
updated July 2, 2018 (Modified table 1)

STC	Slead	Slag	T1	T2
4	0.00	0.00	2.00	2.00
10	0.00	0.00	5.00	5.00
12	5.00	0.00	3.50	3.50
14	6.00	0.00	4.00	4.00
15	7.00	0.00	4.00	4.00
16	8.00	0.00	4.00	4.00
17	9.00	0.00	4.00	4.00
18	9.00	0.00	4.50	4.50
19	9.00	0.00	5.00	5.00
20	9.00	0.00	5.50	5.50
22	9.00	0.00	6.50	6.50
24	9.00	0.00	7.50	7.50
26	9.00	0.00	8.50	8.50
28	10.00	0.00	9.00	9.00
29	10.00	0.00	9.50	9.50
30	10.00	0.00	10.00	10.00
31	11.00	0.00	10.00	10.00
32	11.00	0.00	10.50	10.50
33	11.00	0.00	11.00	11.00
34	11.00	0.00	11.50	11.50

Figure 6: STCS Ops Tables: Previous vs. Modified Table



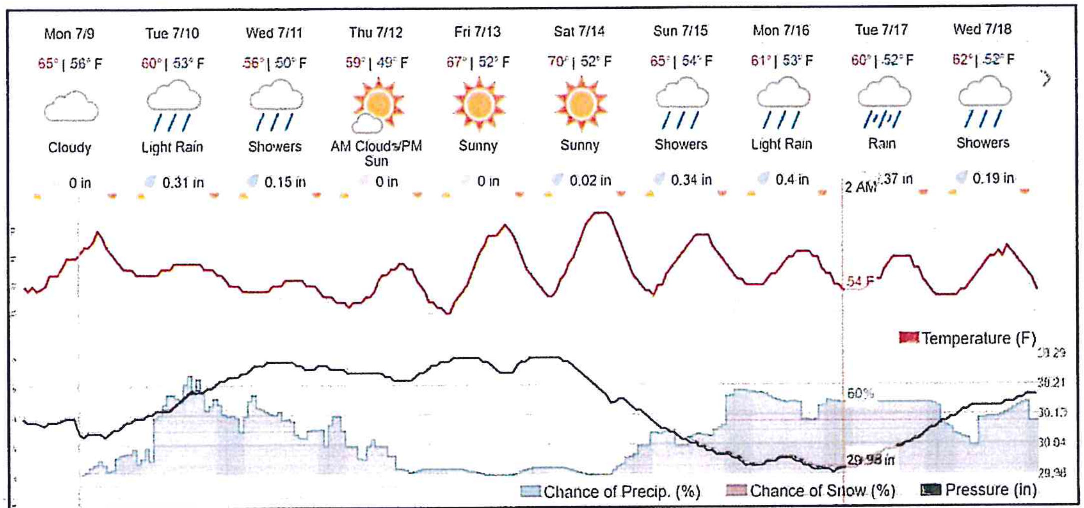


Figure 7: 10-Day forecast[3] July 9th – July 18th

Throughout the month of July, 10-day rain forecasts were consistently forecasting average rains. Figure 7 (above) illustrates the SEAPA Operations weather forecast that was discussed with the Member Utilities on July 10, during the weekly conference call. The forecast(s) were consistent with NOAA forecasts and the ENSO models. However, SEAPA began to question the weather forecasts when precipitation did not materialize. For example, the above 10-day forecast was calling for nearly two inches of rain and on July 18, rain gauges were indicating only 0.3 inches for that period, approximately 20% of what was predicted.

Considering Lake levels and draft rates at both Tyee and Swan lake, SEAPA began looking at scenarios of curtailment. Curtailing output from Tyee across the STI was something that had never been done and would have significant impacts to grid reliability (less spinning reserves and frequency support). In addition, KPU would have to begin a 24/7 diesel campaign, causing significant burden to the Ketchikan rate payers. If a curtailment were to occur, timing at which it occurred was considered crucial.

Models were developed to determine Tyee Lake levels, recovery scenarios and maximum drafts. Figure 8 (below) illustrates the model(s) that were ran in July 2018 to determine the response of Tyee Lake if SEAPA had curtailed across the STI (halted Tyee sales to Ketchikan) on July 1st. There are 8 plots (model scenarios) in the figure below. In each model scenario, the Lake Elevation was set to 1319.7ft (as seen on July 1st).

The dotted lines, in Figure 8 below represent models ran with actual historical inflow cases and loads. The solid blue line represents Tyee Lake response with 5-year average inflows and 5-year average combined loads (Petersburg/Wrangell only). The solid green line represents 10% above 5-year average inflows with 5-year average loads and the solid red line represents <u>30% below</u> 5-year average inflows with 5-year average loads. As a reference, the red line represents yearly inflows at 103.6cfs, which is lower than SEAPA's lowest recorded inflows in history for Tyee and was considered extremely conservative for modeling purposes.

[3] SEAPA uses 10-Day and 15-Day forecasts for weekly operations. The referenced chart was from Weather Underground.

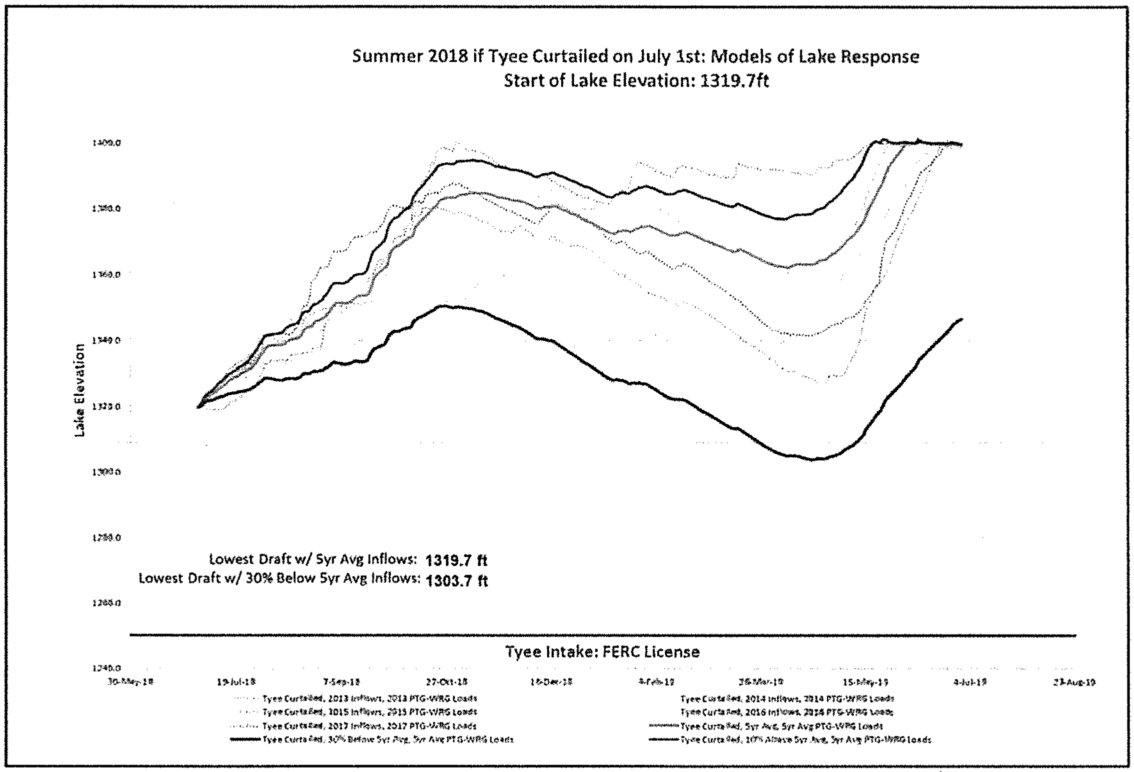


Figure 8: Model(s) of Tyee Lake Response, if Curtailed on July 1st 2018

As shown above, if curtailment of Tyee occurred in July, Tyee lake levels would have approached spill levels with average inflows (blue line) and would have drafted to only 1303.7ft with 30% below average inflows (red line). Curtailing in July would not maximize utilization and optimize output of the Tyee facility.

August 2018

On August 1st SEAPA evaluated the month of July forecasted rain, the average historical rain, and the actual rain that was recorded. The summation of forecasted rain for the month of July was 3.5 inches, far below the July 5-year average rainfall of 6-inches. The actual measured rainfall in July was only 0.45 inches. The lake levels on August 1st for both Tyee and Swan lake were drafting lower at nearly an identical rate. Figure 9 (below) illustrates the draft rate and lake levels on August 1st.

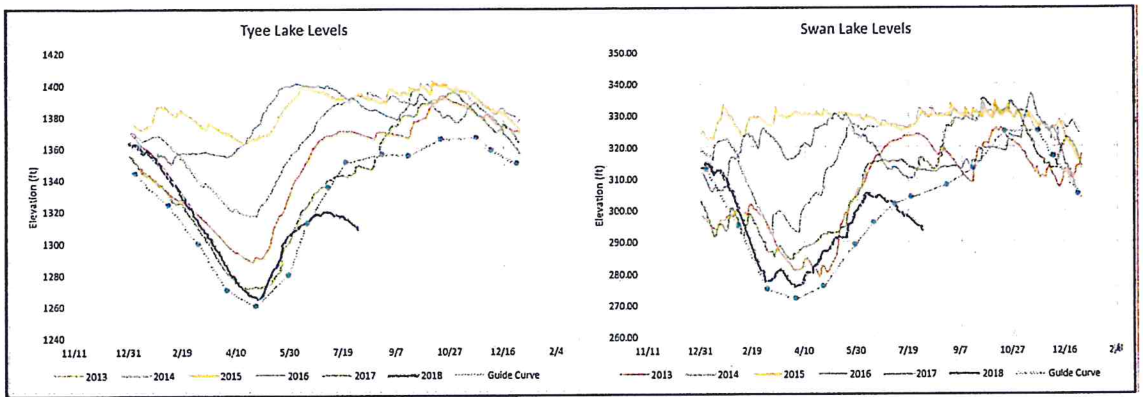
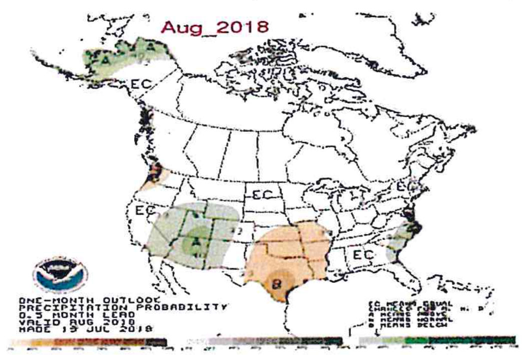


Figure 9: Tyee and Swan Lake Level Graphs: August 1st

The forecasts for August-September-November in 2018 from NOAA were still showing promise for August inflows. As seen on the right, NOAA was forecasting an equal chance for average rain and average temperature for the month. 10-Day forecasts for August were again consistent with NOAA's forecast. 6.5 inches of rain was predicted for the first half of the month by meteorologists. Figure 10 illustrates meteorological forecasts for the beginning of August as sent out by email to the Member Utilities and discussed on August 2, during the weekly Operations call.



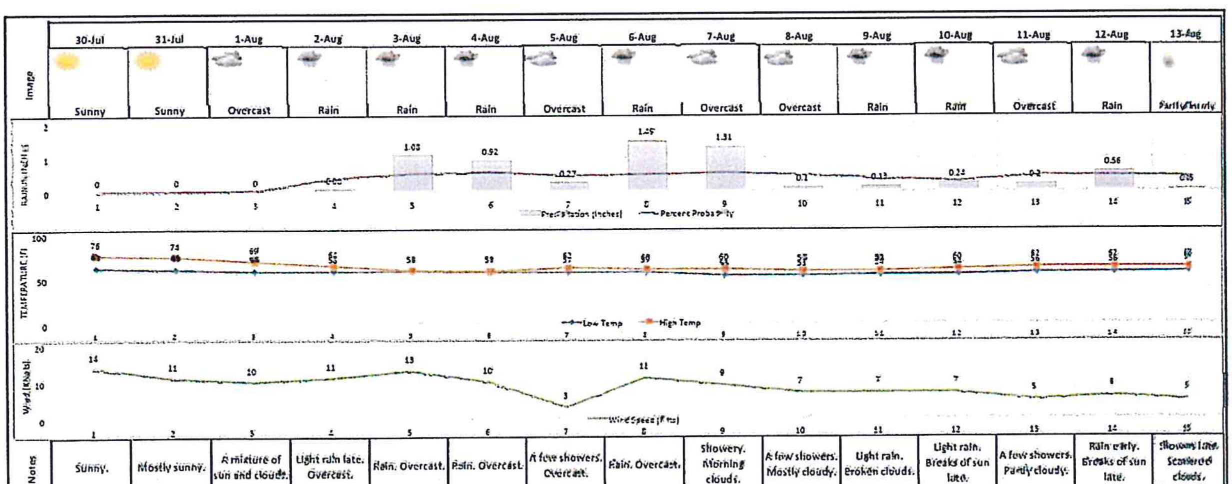


Figure 10: 15-Day forecast[4] July 30th – August 13th

[4] In August of 2018, SEAPA began using a 15-day forecasting tool. The figure referenced is from Custom Weathers Model Output Statistics (MOS) weather forecasts. Custom Weather claims a Mean Absolute Error statistic that outperforms industry standards.

Although meteorological forecasts, NOAA outlooks and seemingly increasing ocean temperatures were all favorable to normal August rainfalls, SEAPA was increasingly exploring scenarios and possible outcomes. On August 1, SEAPA ran lake level models for Tyee with the same criterion as the July 1 models. Tyee lake was at 1309.8ft, the starting point for the models.

As previously computed, the dotted lines represent models with actual historical inflow cases and loads, the solid blue line represents Tyee Lake response with 5-year average inflows, the solid green line represents 10% above 5-year average inflows and the solid red line represents <u>30% below</u> 5-year average inflows (Figure 11).

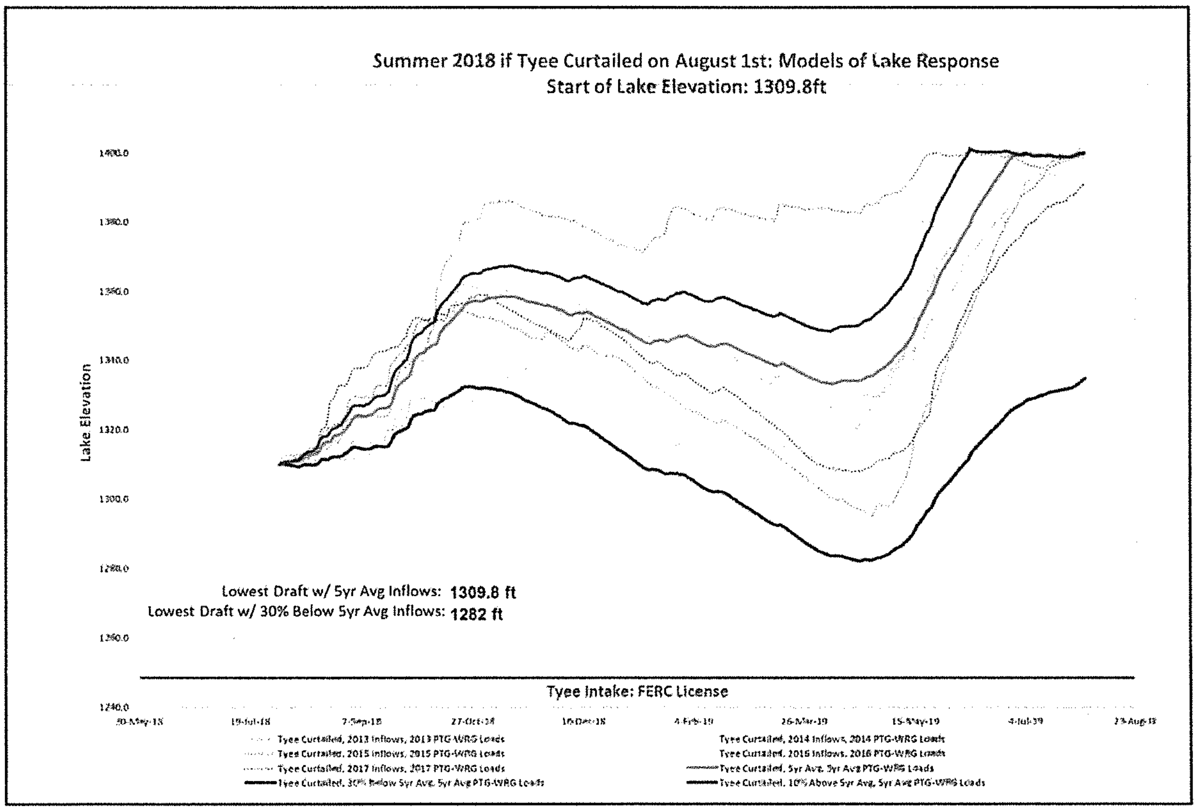


Figure 11: Model(s) of Tyee Lake Response, if Curtailed on August 1st 2018

The models shown above for Tyee Lake's response to a curtailment on August 1, 2018 illustrated that with average inflows, the lake would not have drafted below the starting point of 1309.8 ft. The extreme low inflow case using inflows at 30% below the 5-year average indicated that Tyee lake would have drafted to 1282 ft, leaving 32 feet of water in the lake.

Experts at NOAA were not indicating that precipitation was going to be below normal for August-September-October. With all resources and tools available to SEAPA, it was considered at the time, with high confidence and probability, that the lake response at Tyee if curtailed would be somewhere between the red line and blue line (average and 30% below average inflows). This indicated that somewhere between 32 feet and 59.8 feet would be left in the lake at maximum draft in the spring. Curtailment on August 1 was therefore not considered Prudent Utility Practice pursuant to the Power Sales Agreement (PSA).

With lake levels continuing to draft lower, SEAPA began running case scenarios increasingly more frequent. Curtailment of Tyee in August would have had extreme financial impacts to Ketchikan community and would not have been pursuant to the PSA. Again, timing was extremely important.

August 15, 2018

On August 15, the forecasted rain did not come to fruition. Meteorological estimates for 6.5 inches of rain were observed to be only 1.3 inches. The 15-day forecast for the remainder of August was not hydraulically favorable as well. The probability of curtailment to the South from Tyee was high and therefore timing of curtailment had become the main focus for SEAPA. The models ran on August 15 (Figure 12) illustrate that curtailment at that time, with Tyee Lake elevation at 1303.5 feet, would not have been prudent. The 5-year average inflow case illustrated a maximum draft of 1303.5 feet and the 30% below average inflow case demonstrated a maximum draft of 1274.5 feet.

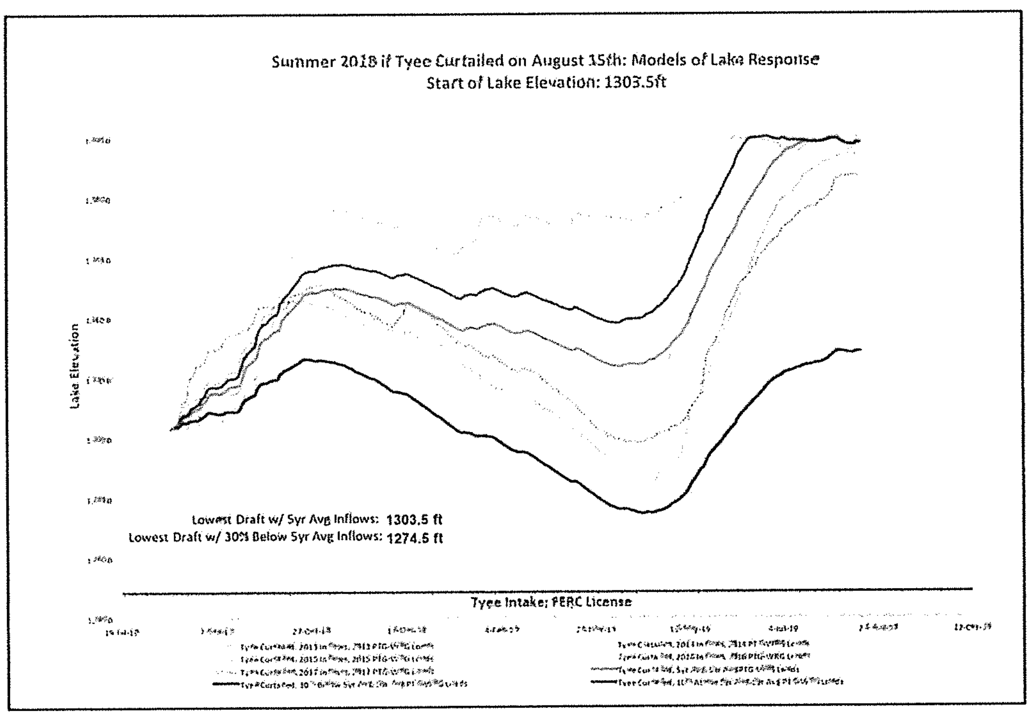


Figure 12: Model(s) of Tyee Lake Response, if Curtailed on August 15th 2018

Curtailment of Tyee to the South on August 15 would have resulted in somewhere between 24.5 feet and 53.5 feet of water left in Tyee at maximum draft. An updated NOAA forecast had not been released on August 15, therefore consistent with the previous forecast, SEAPA maintained an outlook that the probability of average inflows for September and October would be of an equal chance. With an equal chance of average precipitation, Tyee Lake levels would be closer to 1303.5 feet (blue line) than they would be to 1274.5 feet (red line) at maximum draft. Curtailment could not be justified at this time.

September 1 2018

On August 16, NOAA released the September-October-November three-month outlook (Figure 13). The forecast indicated again that there was an equal chance for average rainfalls in September. Typically, the months September through November have significant amounts of precipitation. Although the preceding summer months produced well below average rainfalls, the predicted equal chance for average precipitation in the fall would have likely prolonged generation from Tyee to the South.

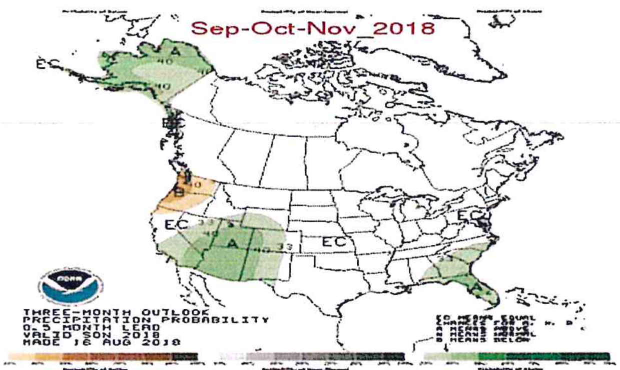


Figure 13: NOAA Sept-Oct-Nov Outlook

Updated ENSO models for September were indicating increasingly rising ocean temperatures (Figure 14). Probabilities forecasted by the IRI and CPC for the remainder of 2018 and through July of 2019 were weighted heavy for El Nino conditions (Figure 15). With all indices available to SEAPA indicating forthcoming warmer and wetter conditions, the probability of inflows being 30% below 5-year averages (red line) were much lower than the probability of inflows being closer to the 5-year average (blue line).

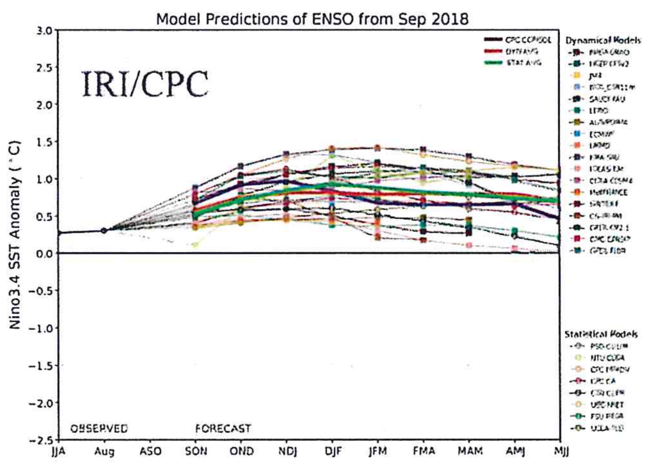


Figure 14: September 2018 ENSO Models

IRI/CPC Mid-Month Model-Based ENSO Forecast Probabilities

Season	La Niña	Neutral	El Niño
SON 2018	0%	45%	55%
OND 2018	1%	31%	68%
NDJ 2018	1%	27%	72%
DJF 2018	1%	27%	72%
JFM 2019	1%	27%	72%
FMA 2019	0%	26%	74%
MAM 2019	0%	24%	76%
AMJ 2019	0%	29%	71%
MJJ 2019	2%	36%	62%

Figure 15: IRI/CPC September 2018 – July 2019 El Nino Probabilities

Tyee Lake level response models that SEAPA ran on September 1 (Figure 16) indicated a maximum draft of 1294.1 feet for the 5-year average inflows and 1258.2 feet for the 30% below 5-year average inflows. Curtailment of Tyee to the South on September 1 would have resulted in somewhere between 8.2 feet and 44.1 feet of water left in Tyee at maximum draft. Justification of curtailment on September 1 with experts forecasting average inflows was difficult.

At 88.8% efficiency (average for Tyee Generators), the equation for Megawatt hours available in Tyee per foot of lake elevation is based on the head and equates to: $MWhr/ft = Lake\ Elevation/3.0626$.

Averaging the Megawatt hours (MWhr) per foot at Tyee from elevation 1294.1 ft to 1250 ft equates to an average of 415 MWhr/ft. With the probability of average inflows as forecasted, the 44.1 feet left in Tyee Lake would have resulted in 18,301.5 MWhr of Additional Dedicated Output. Curtailment on September 1 with SEAPA models illustrating 8.2 feet remaining for a worst-case scenario and 44.1 feet (18,301.5 MWhrs) for the probable-case scenario, could not be justified.

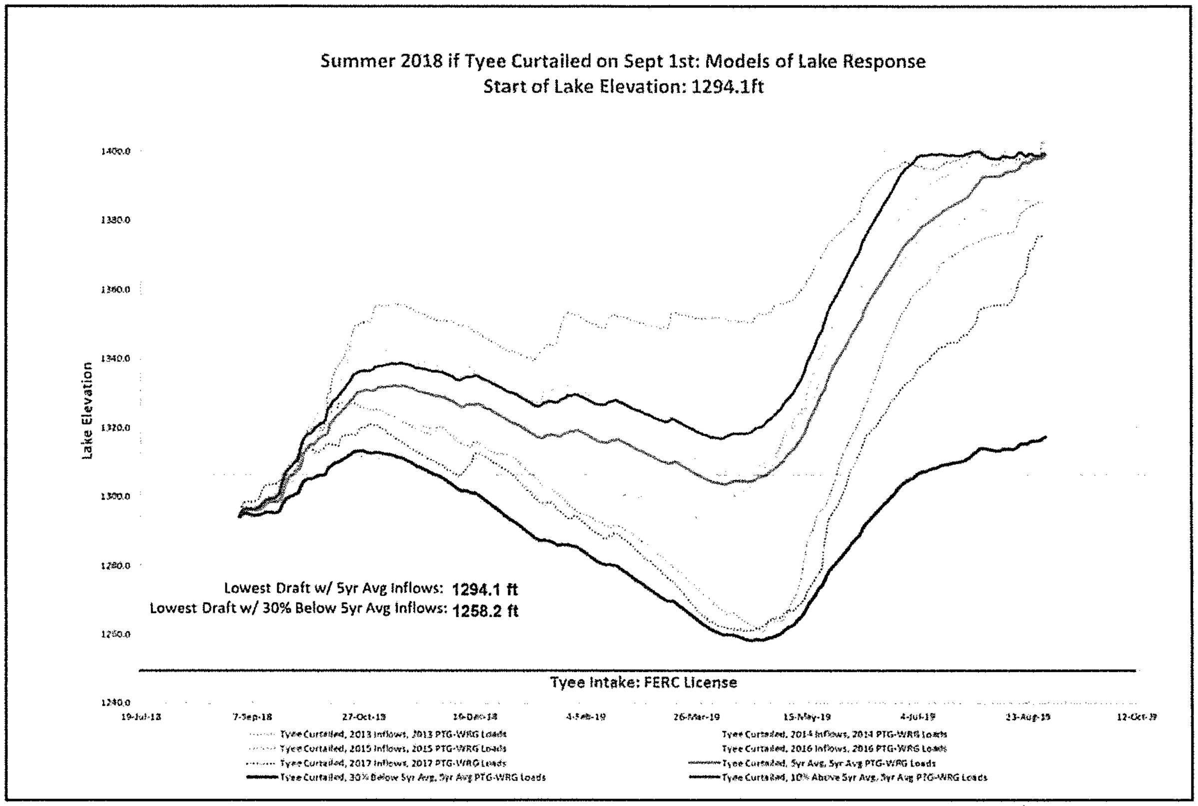


Figure 16: Model(s) of Tyee Lake Response, if Curtailed on September 1st 2018

September 15 2018

Section 17 of the PSA defines Additional Dedicated Output to be:

> "Additional Dedicated Output" means the energy and/or capacity from an Agency Facility that is in excess of the Firm Power Requirements needs of the Party or Parties designated to receive Dedicated Output from that Agency Facility, is available for use, and can be used to meet a Party's Firm Power Requirements.

A decision by SEAPA to curtail sales from Tyee to Ketchikan without strong justification would be in violation of the PSA. In accordance with the PSA, SEAPA had to demonstrate that Additional Dedicated Output from Tyee to Ketchikan was not available prior to any curtailment. A complete curtailment of Tyee output to Ketchikan had never been done before. Figure 17 (below) illustrates the Tyee Lake level response models that SEAPA ran on September 15. Tyee Lake elevation was at 1287.5 feet at the time the models were ran.

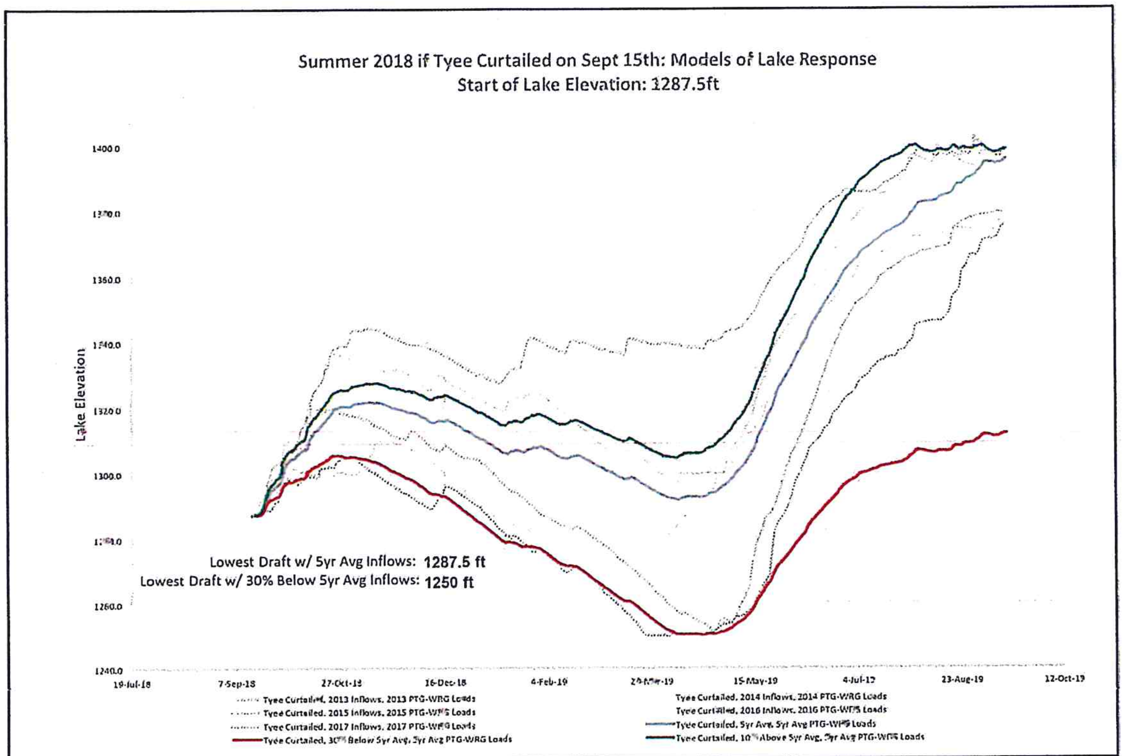


Figure 17: Model(s) of Tyee Lake Response, if Curtailed on September 15th 2018

The 5-year average lake level response model (blue line) illustrated that Tyee lake still had Additional Dedicated Output remaining, with a maximum draft of 1287.5 feet (37.5 feet of available capacity). The 30% below 5-year average lake level response model (red line) however illustrated that Tyee did not have any more Additional Dedicated Output available.

Although NOAA forecasts and ENSO models were still indicating an increasing probability of average precipitation, a high-pressure system above the Gulf of Alaska appeared to be developing (Figure 18). Short term weather forecasts (10-day) were also calling for little-to-no rain.

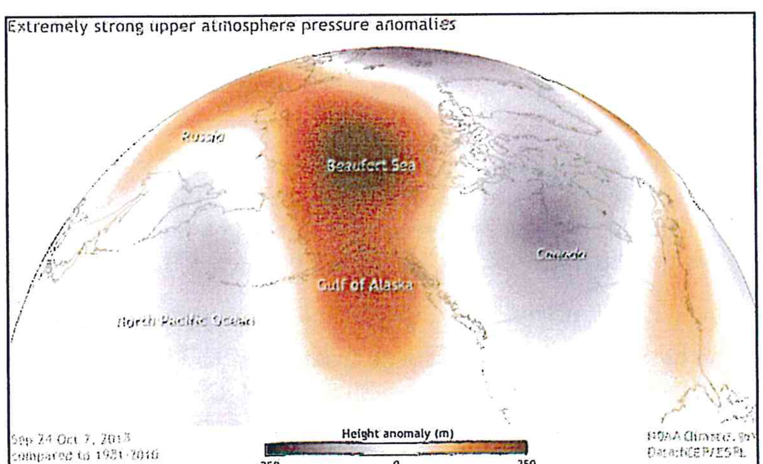


Figure 18: NOAA: High Pressure Anomaly-Sept 2018

SEAPA lake level models are based on both inflows and loads. A decrease in inflows affects lake draft rates however an increase in SEAPA loads also affects draft rates. Another consideration for SEAPA in the Tyee curtailment decision process was an apparent significant increase in KPU demand. On September 15, SEAPA performed an analysis of the loads across the L1 breaker (from Swan Lake to Ketchikan). Figure 19 (below) illustrates that KPU loads from August 15 – September 14 were 160% of the previous four-year average (top blue line). This equates to approximately 3,600MWhr above what SEAPA expected and approximately 9 feet of Tyee Lake (at 415Mwhr/ft).

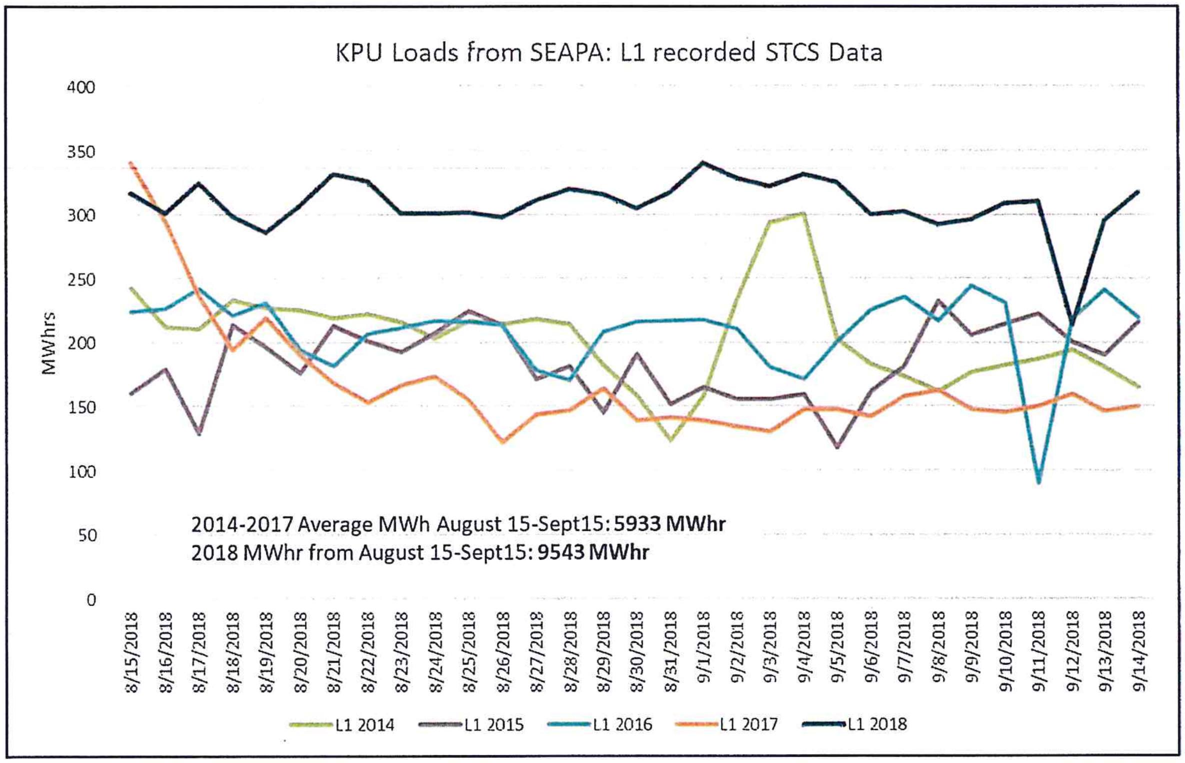


Figure 18: Analysis of Significant Increase in KPU demand: Aug 15-Sept 14

Although SEAPA models and NOAA forecasts indicated that curtailing Additional Dedicated Output from Tyee to Ketchikan in September could leave as much as 37.5 feet (15,562MWhr) of energy in the lake, SEAPA believed justification for curtailment in accordance with the PSA was appropriate for the following reasons:

Weighted factors supporting curtailment decision made on September 17:

1) Short term forecasts in September were not consistent with NOAA long-term forecasts. A high-pressure system in the Gulf of Alaska increased the probability of below average precipitation for the remainder of September and October.
2) KPU demand on the SEAPA system was 160% of average from August 15-September 14 causing both Tyee and Swan Lake's to draft at a greater rate than forecasted in the 2018 Ops Plan.
3) Confidence in average inflows (blue line in models) was reduced due to short term forecasts and recent history of inaccurate weather forecasts.

Below is a decision matrix for each decision made with regard to curtailing Additional Dedicated Output from Tyee during the Summer of 2018:

Date	1-Jul	1-Aug	15-Aug	1-Sep	15-Sep
Lake Level	1319.7	1309.8	1303.5	1294.1	1287.5
Feet remaining using Avg Inflow Model	69.7	59.8	53.5	44.1	37.5
Feet remaining using 30% below Avg Inflow Model	53.7	32	24.5	8.2	0
MWhr left in Lake: Avg Inflow Model	28925.5	24817	22202.5	18301.5	15562.5
MWhr left in Lake: 30% below AVG Inflow Model	22285.5	13280	10167.5	3403	0
Curtailment Justification	U	U	U	U	J

U: Unjustified, J: Justified

Proofing the Model

The decision to curtail Additional Dedicated Output from Tyee to Ketchikan that was made on September 17, 2018 was based on inflow predictions, forecasted loads and modeling of Tyee lake levels. Inflow predictions and load forecasts are discussed extensively in this report and were based on the best information available to SEAPA. To ensure prudent water management practice, SEAPA additionally considered the possibility of inaccuracies in the lake level forecasting models.

To validate accuracy of the Tyee model, SEAPA used actual inflow data and actual loads to generate a plot. Typically, lake level models are developed using predicted inflow data and predicted loads. With actual recorded data, a prior model year was ran and compared with that prior years actual lake levels.

In Figure 19, recorded STCS data from January 1 to December 31, 2018 were used to create the forecasted lake level response for calendar year 2018. The blue line represents the output from the model. By superimposing the model output data (blue line) onto USGS recorded Tyee daily lake levels (red line), a comparison was made with regard to accuracy.

The results were impressive. The forecasted lake levels were nearly identical to the actual recorded levels. During the spring months from March-May, the model was slightly above actual lake levels and during the winter months, the model was slightly below actual levels. The maximum percent error in the model was 0.66% on November 27 with an average error of only 0.23%.

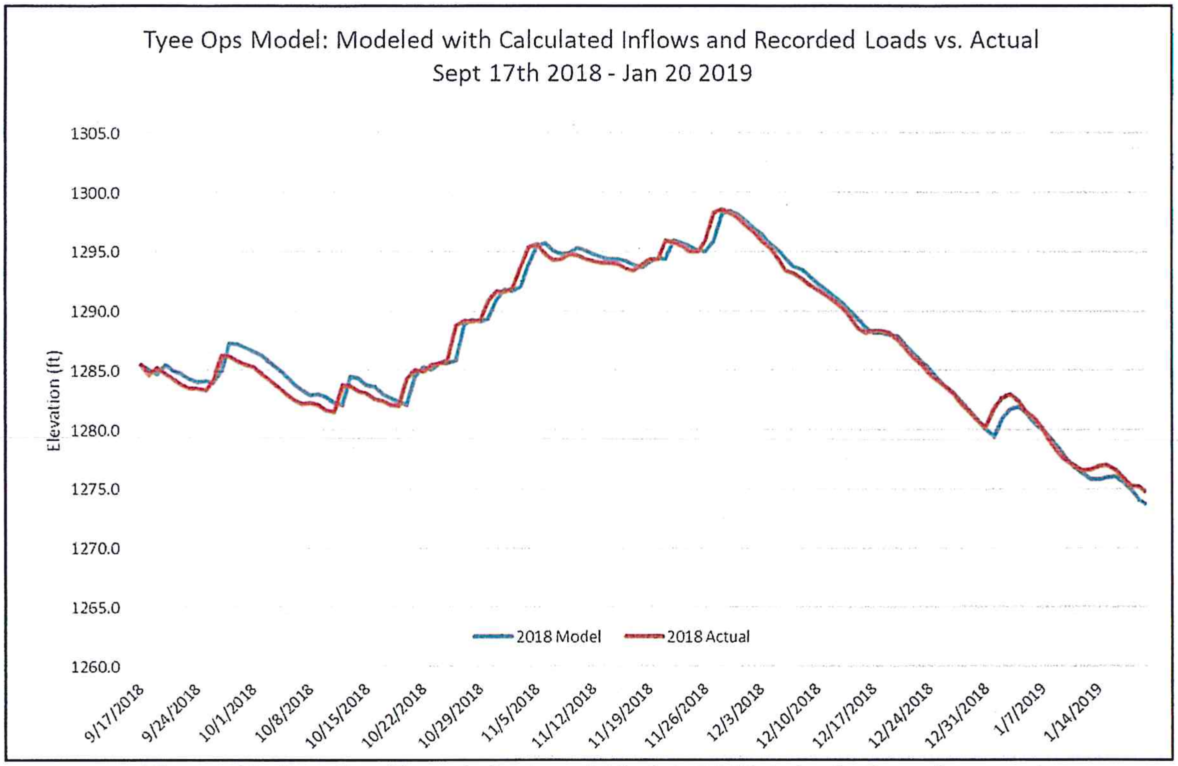


Figure 19: Proofing Tyee Lake Level Model: 2018 Actuals Superimposed

Model validation demonstrated that the existing SEAPA models were extremely accurate. With accurate inflow data and accurate load data, the models can predict lake levels within ¼ of a percent error on average over a 12-month forecast. To further confirm model validity, SEAPA contacted a third-party consultant, Chuck Howard from CddHoward Consulting Ltd. Mr. Howard was originally contracted by SEAPA in 2010 to develop the models and presented to the Board of Directors the probabilistic nature of predicting inflows on August 26, 2010.

Mr. Howard is a Water and Hydropower Management Expert and prior to his retirement, he was a member of the American Water Works Association. He has published numerous articles and developed multiple water management models for Utilities around the world. During our discussion, Mr. Howard commented that the validation performed by SEAPA demonstrates the accuracy of the model. He also reiterated the statement he made to the Board of Directors in the 2010, that "prediction of inflows could only be improved with improvements of weather forecasting."

Possible Solutions for Extreme Outliers

The 2018 inflow season was an extreme outlier and very rare. In the Summer and Fall of 2018, there were no long-term predictions that Southeast Alaska would experience below-average precipitation. As demonstrated in this report, predicting an inflow season like 2018, that occurs only once in a few decades is not possible with existing forecasting technologies. It is therefore prudent to consider operational strategies for an inflow season of this magnitude <u>without</u> significantly impacting operations and prudent practice for every other normal, predictable year. Possible considerations include:

1) Clarification of "Dedicated Output" cycle period in the PSA. Section 17h. of the PSA defines Dedicated output as follows:

    > "Dedicated Output" means the energy and capacity from a particular Agency Facility that has been designated to be supplied to a Dedicated Party or Dedicated Parties and sold at Firm Wholesale Power Rates. Dedicated Output has first priority delivery under the Operations Plan.

    Dedicated Output as defined above can be interpreted as energy and capacity that has been "designated" to be supplied to a Dedicated Party. The Operations Plan forecasts the expected loads (Firm Power Requirements) for the Calendar year, however actual loads and inflows are not controlled by SEAPA. An example is the extreme deviation from forecasted KPU loads and actual KPU loads from August 15-September 14, 2018 coupled with inflows that were far below forecasted. Section 5a. of the PSA requires SEAPA to estimate the Dedicated Output based on estimated Firm Power Requirements and estimated Inflows. "Energy" and "capacity" are not defined in terms of a period for which Dedicated Output is required. Day-to-Day, Month-to-Month, Year-to-Year, Multiyear-to-Multiyear, Draft-to-Draft and Fill-to-Fill are all possible periods to be considered, all of which have potential benefits and drawbacks.

    Recommendation:
    The Operations Plan is currently developed on a Calendar year based. This closely coincides with a typical fill-to-fill period where the lake levels are nearly at their greatest capacity for the year. If however a facility that is Dedicated does not spill, without a defined period, Dedicated Output could potentially be interpreted to span multiple years. Because Additional Dedicated Output is defined to be capacity that is in excess of designated Dedicated Output, the Board may want to consider defining the cycle for Dedicated Output to be from the beginning of the previous calendar year to the end of the current calendar year (2 years). This cycle period would allow for summation of Additional Dedicated Output in a prior calendar year, to be allocated for purposes of meeting the Firm Power Requirements in the current calendar year if required.

2) Clarification of "Additional Dedicated Output" cycle period in the PSA. Section 17a. of the PSA defines Additional Dedicated Output as follows:

> "Additional Dedicated Output" means the energy and/or capacity from an Agency Facility that is in excess of the Firm Power Requirements needs of the Party or Parties designated to receive Dedicated Output from that Agency Facility, is available for use, and can be used to meet a Party's Firm Power Requirements.

Additional Dedicated Output as defined above can be interpreted as the excess of energy or capacity that is greater than Dedicated Output from a SEAPA facility. Dedicated Output and Firm Power Requirements are 100% known for the previous calendar year however must be forecasted for the remainder of the current calendar year. Similarly, Additional Dedicated Output (and capacity sent North/South) is 100% known for the previous calendar year. In the event that the forecasted Dedicated Output is less than the forecasted Firm Power Requirements due to actual inflows being lower than forecasted inflows and/or actual loads being greater than forecasted loads, recorded Additional Dedicated Output could be used to meet a Party's Firm Power Requirements. This would require a cycle period for Additional Dedicated Output that is greater than a day, month, or even a year.

Recommendation:
If the cycle period for Additional Dedicated Output was from the beginning of the previous calendar year to the end of the current calendar year (2 years), Additional Dedicated Output that was summed from the previous calendar year could be used to satisfy the Firm Power Requirements in the current calendar year.

3) Section 3c. ("Full Requirements") of the PSA states the following:

> The Parties have a direct financial interest in ensuring the maximum practicable sales of capacity and energy from the Agency's Facilities pursuant to this Agreement. Therefore, to the extent energy and capacity are available from the Agency's Facilities to meet the portion of the Purchasing Utility's electric load requirements that exceed the available output of that Purchasing Utility's existing hydroelectric resources such Purchasing Utility shall serve those requirements with purchases of Dedicated Output or Additional Dedicated Output.

Balancing lake levels between the Tyee and Swan Lake reservoirs is crucial for maximizing utilization of the facilities to fulfill SEAPA's Full Requirements per the PSA. Flexibility to move water from North to South and South to North is a key part. By setting the cycle period for Dedicated and Additional Dedicated Output to two years, SEAPA will have flexibility to meet its mission by maximizing utilization while still meeting Firm Power Requirements as they pertain to Dedicated Output.

SOUTHEAST ALASKA POWER AGENCY
Operations Plan | 2019

Date: November 29, 2018

To: Trey Acteson, Chief Executive Officer

From: Robert Siedman, P.E., Director of Engineering & Technical Services

SEAPA 2019 Operations Plan Report

Every year SEAPA presents the Operations Plan (Ops Plan) for Board approval in accordance with Section 5 of the Power Sales Agreement[1] (PSA). The annual plan forecasts expected reservoir levels for Tyee Lake and Swan Lake for the upcoming year by maximizing output from SEAPA facilities and optimizing water resources. Pursuant to the PSA, the Ops Plan gives first priority to the dedicated Firm Power Requirements of each Utility and optimizes additional dedicated output as a second priority for additional power requirements. Optimization of water resources is achieved by an algorithmic math model as represented in Figure 1.

Water Resource Algorithmic Math Model Process

Step 1: Current lake levels

Step 2: Inflow Forecasts
1. NOAA
2. USGS
3. NINO3.4

Step 3: Load Forecast
1. Temperature Forecasts
2. Scheduled Maintenance
3. STICS/Historic Loads

Step 4: Iterative Math Model
1. Case Reservoir Plots
2. Optimized Water Resources

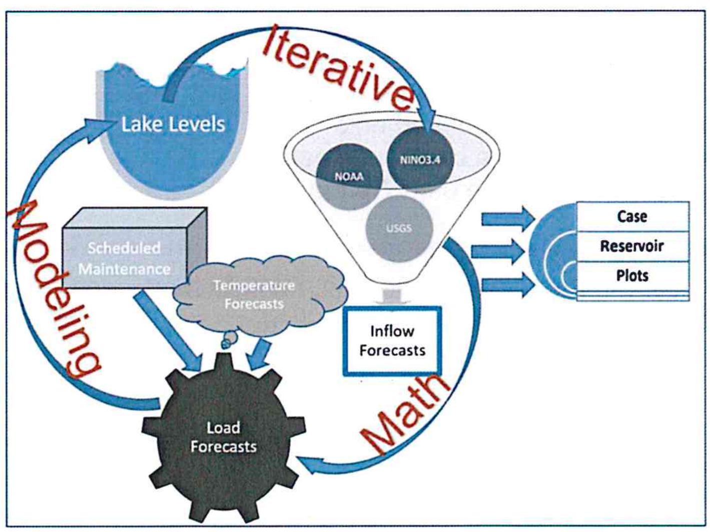


Figure 1: Math Modeling: Optimizing Water Resources

The iterative process utilized in the algorithm to optimize water resources was applied to a variety of cases. Each case was further analyzed, and a guide curve was developed. Special consideration was

[1] Section 5 of the Power Sales Agreement states that SEAPA shall prepare annually an Operations Plan to estimate the Firm Power Requirements of the Purchasing Utilities and identify Dedicated output to maximize utilization and optimize output of each facility.

made to ensure optimization of water resources without risking dedicated Firm Power Requirements of the Purchasing Utilities. The process, assumptions, and results are discussed below.

Current Lake Levels

The current lake levels as of November 29, 2018 were much lower than the estimated 2018 Ops Plan. This is due to record low rain and inflows for the season. According to the latest Drought Monitor analysis, Southeast Alaska is in a "Severe Drought" condition. Although we are transitioning from a moderate La Nina to an El Nino with Sea Surface Temperatures (SST) well above average, a long-lasting high-pressure system over Alaska has caused typical September and October storms to be diverted.

As a result of the recent extreme upper atmospheric pressures (Figure 2), September rainfalls were only 2.54 inches (normally 11.2) and October rainfalls were only 5.96 inches (normally 12). In November, the high-pressure system began to subside and resulted in near average rainfalls of 9.9 inches (normally 10.7). November inflows provided some recovery of lake levels. However, as discussed in the subsequent sections, current lake levels and predicted inflows do not support Tyee Lake's ability to meet additional power requirements of Ketchikan. As a result, a diesel campaign in Ketchikan is likely in the early Spring.

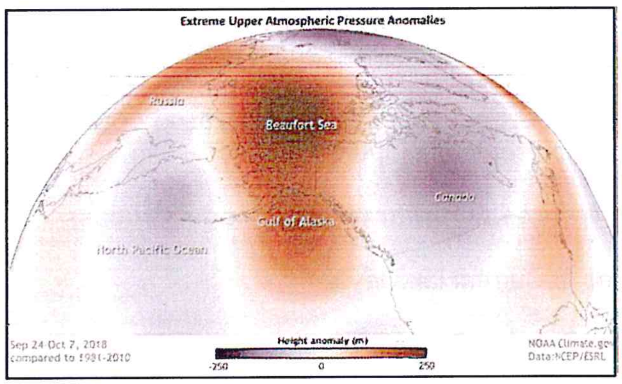
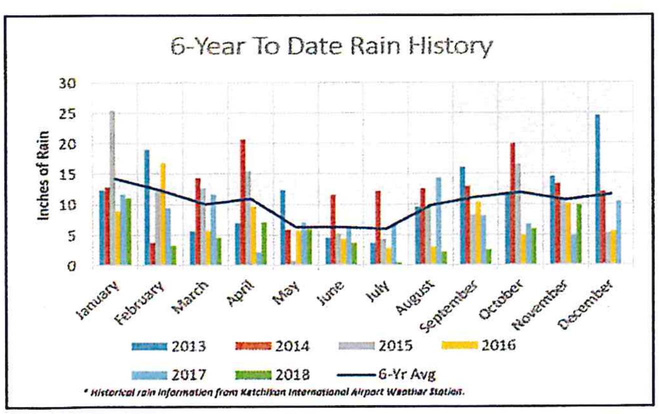


Figure 2: NOAA Climate pressure map

Rain Fall – Inflows for 2018

As discussed in the preceding section, rainfalls have been extremely low. The Ketchikan International Airport Weather Station recorded a 40-year record low rainfall of only 56.55 inches to date.

Figure 3: 6-Year to Date Rain History



The chart to the left (Figure 3) illustrates a 6-year comparison of rainfall by month. As evidenced in this chart, the months of July-August-September-October were far below the 6-year running average. The 2018 Operations Plan predicted an extremely low inflow year however a record low was unforeseen to both SEAPA and Weather Forecasters. As a result, on September 17, SEAPA began limiting sales from Tyee to Ketchikan. This will likely continue into the 2nd quarter of next calendar year.

Inflow Forecasts

Inflow predictions for calendar year 2019 were performed by utilizing NOAA, NINO3.4 and historic USGS inflow data. NOAA forecasts for the months of December-January-February are predicting above normal precipitation and above normal temperatures. Figure 4 illustrates that NOAA is predicting with an 80-90% probability confidence an above normal three-month outlook.

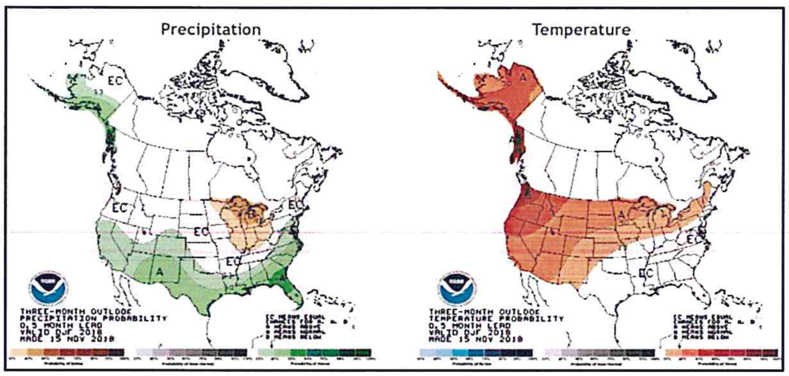


Figure 4: NOAA Dec-Jan-Feb Outlook

NOAA is also predicting (80% probability) that an El Nino is expected. The duration of the predicted El Nino is what SEAPA is mostly interested with because this information can be used to model an expected inflow season.

There are dozens of institutions that have developed El Nino Southern Oscillation models (ENSO). Oceanographic temperature models such as ENSO's are used by NOAA to predict weather patterns.

The latest ENSO models show that we are currently moving from a moderate La Nina into a Moderate El Nino. Ocean temperatures are currently 0.4–1.0 ˚C above average temperatures. Warmer ocean temperatures correlate to warmer weather and higher precipitation rates in the Northwest hemisphere.

Figure 5 illustrates the International Research Institute (IRI) and Climate Prediction Centers (CPC) ENSO model. Apparent to all participating institute forecasts is a continued above average ocean temperature. Coupled with a near average precipitation in November of this year, an El Nino is currently active and highly probable to continue.

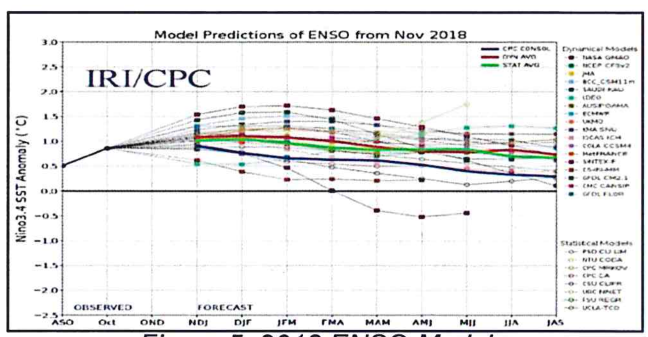


Figure 5: 2018 ENSO Model

Inflow seasons are cyclical and have a close correlation with ocean temperatures. As evident in Figure 6, ocean temperatures have been increasing over the past 50 years however the increase in temperatures appear to be consistent and predictable. The ocean's cyclical warming, and cooling patterns are termed El Nino and La Nina respectively. Between the years 2014 and 2016 the largest El Nino in history was recorded.

The second largest El Nino in recorded history occurred between the years 1996 and 1998. As evidenced in Figure 6, typically after a strong El Nino season, there is a reactively strong La Nina period that follows. Due to the lack of 2018 inflows (during this past La Nina period), Swan Lake and Tyee Lake reservoir elevations were recorded at nearly the lowest in history. Neither reservoir recovered by September of this season, resulting in suspended additional output from Tyee to Ketchikan.

Figure 6 illustrates the NINO3.4 SST for the past 68 years. The red jagged line illustrates the ENSO model for 2019 with current ocean temperature conditions supporting the model predictions, indicating a warmer and wetter forecasted season. The SSTs displayed and forecasted are cyclical and predictable to a certain degree of confidence. Given NOAAs 80-90% confidence level, SEAPA predicts the upcoming El Nino season will be comparable to 2014 (as shown in figure 6).

The 2014 El Nino season was slightly above average for inflows and for the purposes of modeling, was chosen as the probable inflow case year for Swan Lake and Tyee Lake models.

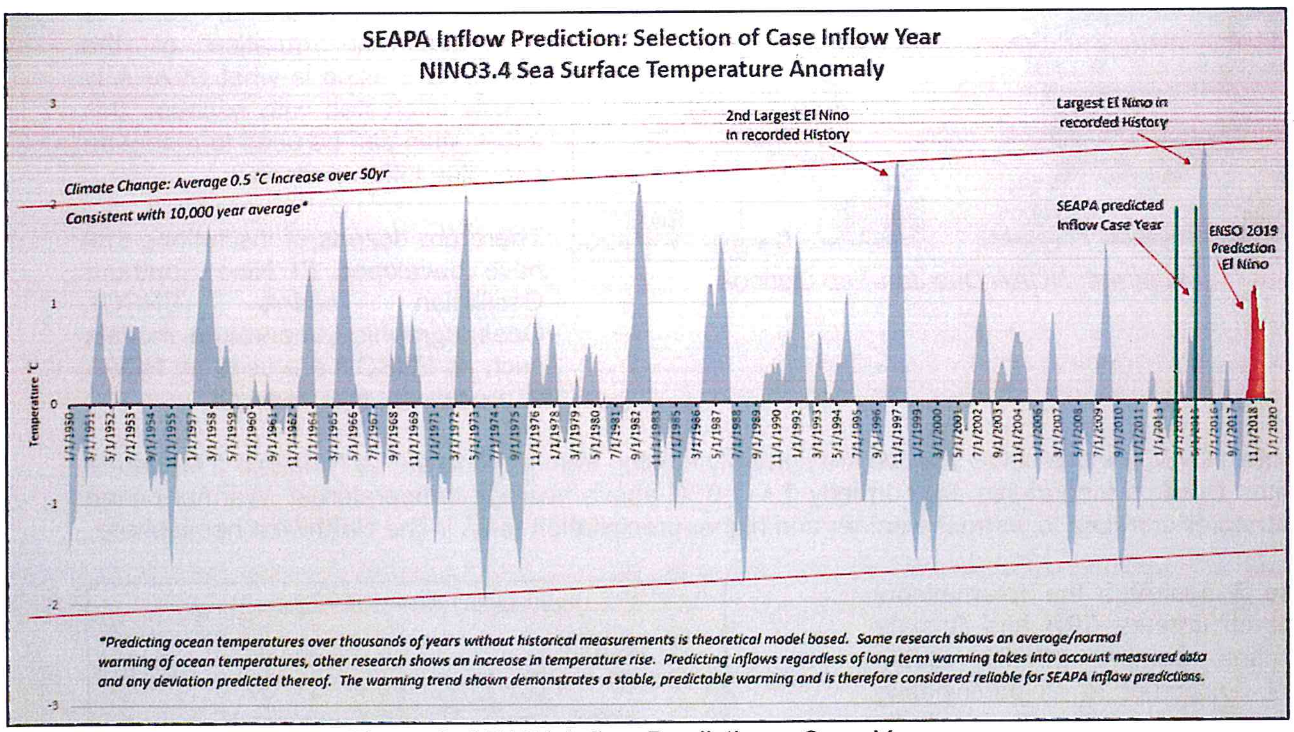


Figure 6: SEAPA Inflow Prediction – Case Year

SEAPA's predicted low inflows for both Swan Lake and Tyee Lake reservoirs were also modeled. It is highly unlikely that there will be below average inflows for the 2019 season and therefore the probable (2014) & average (IECo & CAI)[2] cases were used to determine the respective guide curves.

[2] The International Engineering Company (IECo) performed a study to determine hydrologic data necessary for the design of Tyee Lake. The results included Tyee Lake inflow average estimates. Commonwealth Associates Inc. (CAI) developed an inflow average for Swan Lake based on rain gauges and river gage data of the area as part of the STI planning effort.

Case / Month	SWL CAI Inflow (avg cfs)	SWL 2014 Inflow	TYL IECo Inflow (avg cfs)	TYL 2014 Inflow (avg cfs)
jan	372.0	466.3	48.8	117.7
feb	191.0	52.0	36.4	22.9
mar	240.0	372.0	32.5	54.2
apr	374.0	646.0	68.8	120.7
may	537.0	564.9	199.4	309.6
jun	489.0	355.9	324.7	275.2
jul	313.0	434.4	291.7	234.7
aug	346.0	480.0	241.2	133.7
sep	539.0	666.1	227.9	222.8
oct	526.0	944.2	245.6	242.3
nov	365.0	467.0	126.4	65.3
dec	419.0	435.5	76.1	87.1
Average Annual	394.0	493.0	159.0	257.0

Table 1: SEAPA predicted Inflow Cases for 2018

Average Inflow Cases

Table 1 illustrates the inflow inputs that were used for the Swan Lake and Tyee Lake reservoir level models. As discussed previously, the inflow cases were selected based on NOAA predictions for 2019. The annual cfs for Swan lake was 392.6 cfs and the average annual cfs for Tyee Lake was 160.0 cfs.

2014 Inflow Cases

The probable inflow case for Swan Lake was inserted into the model with an average annual cfs value of 521.9 cfs. Probable inflows were based on 2014 inflows. The probable inflow case for Tyee Lake was inserted into the model with a cfs value of 157.2 cfs. This was based on ongoing and predicted warmer and wetter conditions.

Load Forecasts

Load forecasts and subsequent SEAPA deliveries were estimated for the 2019 calendar year with consideration to the NOAA December-January-February outlook (warmer average temperatures) and the 7-year SEAPA delivery schedule (2011-2018). Typically, the Operations Plan considers multiple load cases to balance the lakes across the STI (Swan-Tyee Intertie) transmission line and maximize the outputs of Tyee and Swan lake per the PSA. Under current lake level conditions however, balancing the lakes is not possible. Tyee Lake's Dedicated Output, pursuant to the PSA, will be reserved and remain dedicated to Petersburg and Wrangell to meet Firm Power Requirements of the respective Utilities until reservoir conditions support change. As a result, net power transferred across the STI will not occur for the foreseeable future. The forecasted Firm Power Requirements for the respective Utilities, based on 2014 loads, are as follows:

Ketchikan Expected Loads: **87,923MWh**

Petersburg/Wrangell Expected Loads: **78,221MWh**

SEAPA Total Expected Loads: **166,144MWh**

Low Inflow Load Case:

Table 2 illustrates the load forecasts for 2019 which demonstrates zero transfer of energy across the STI. Section 5 of the PSA discusses development of the Operations Plan on an annual basis with a caveat for the plan to be reviewed periodically as needed. Given the recent severe drought circumstances and current net zero STI power transfer conditions, SEAPA will continue to review lake levels weekly and recommends that the Operations Plan be revisited once lake levels support Additional Dedicated sales.

	KTN			Swan Lake		STI		WRG-PSG			Tyee Lake	
	Expected Delivery MWh	Required Generation MWh	Required Generation Avg MW	Expected Gen from Inflow Avg MW	Expected Gen from Inflow MWh	STI Expected (balance) MWh	STI Expected (balance) Avg MW	Expected Delivery MWh	Required Generation MWh	Required Generation Avg MW	Tyee Expect Generation Avg MW	Tyee Expected Generation MWh
JAN	8558.0	9071.5	12.2	12.2	9071.5	0.0	0.0	7166.2	7596.2	10.2	10.2	7596.2
FEB	10649.0	11287.9	15.2	0.0	0.0	0.0	0.0	7407.9	7852.4	11.7	11.7	7852.4
MAR	10018.0	10619.1	14.3	9.0	6696.0	0.0	0.0	4960.6	5258.3	7.1	7.1	5258.3
APR	7191.0	7622.5	10.2	4.0	2976.0	0.0	0.0	5480.6	5809.4	8.1	8.1	5809.4
MAY	5397.0	5720.8	7.7	7.7	5720.8	0.0	0.0	7510.4	7961.0	10.7	10.7	7961.0
JUN	5953.0	6310.2	8.5	8.5	6310.2	0.0	0.0	8333.4	8833.4	12.3	12.3	8833.4
JUL	6200.0	6572.0	8.8	8.8	6572.0	0.0	0.0	7697.4	8159.2	11.0	11.0	8159.2
AUG	6687.0	7088.2	9.5	9.5	7088.2	0.0	0.0	7315.3	7754.2	10.4	10.4	7754.2
SEP	6023.0	6384.4	8.6	8.6	6384.4	0.0	0.0	7247.6	7682.4	10.7	10.7	7682.4
OCT	4868.0	5160.1	6.9	6.9	5160.1	0.0	0.0	6251.1	6626.2	8.9	8.9	6626.2
NOV	7723.0	8186.4	11.0	11.0	8186.4	0.0	0.0	3968.4	4206.5	5.8	5.8	4206.5
DEC	8656.0	9175.4	12.3	12.3	9175.4	0.0	0.0	4882.3	5175.3	7.0	7.0	5175.3
Total	87923.0	93198.4	-	-	73340.9	0.0	-	78221.3	82914.6	-	-	82914.6

Table 2: SEAPA 2019 Load Forecast

Scheduled Maintenance:

SEAPA does not anticipate any extended outages in calendar year 2019. Typical line maintenance, generator unit annual maintenance and substation maintenance were considered when developing the load forecasts. Swan Lake station service switchgear upgrades and Swan Lake turbine runner repairs are anticipated in the future. However, for CY2019, typical outage durations and times were modeled.

Iterative Math Model:

The Tyee Lake and Swan Lake models used to predict lake levels involve iterating through inflow scenarios and generation load sequences. Lake levels are inputted with actual levels on the day the model was run. Once inflow predictions are developed, manipulation of generation inputs is typically performed to maximize utilization of the outputs for Tyee and Swan. Guide curves are generally developed by averaging the probable inflow and low inflow cases, with a slight bias towards the low inflow case for early spring months. Under current conditions and until conditions change, the guide curves do not reflect balancing the lakes across the STI. It is therefore again prudent to revisit the Operations Plan once conditions change.

Swan Lake Reservoir Plot (Expected Inflows):

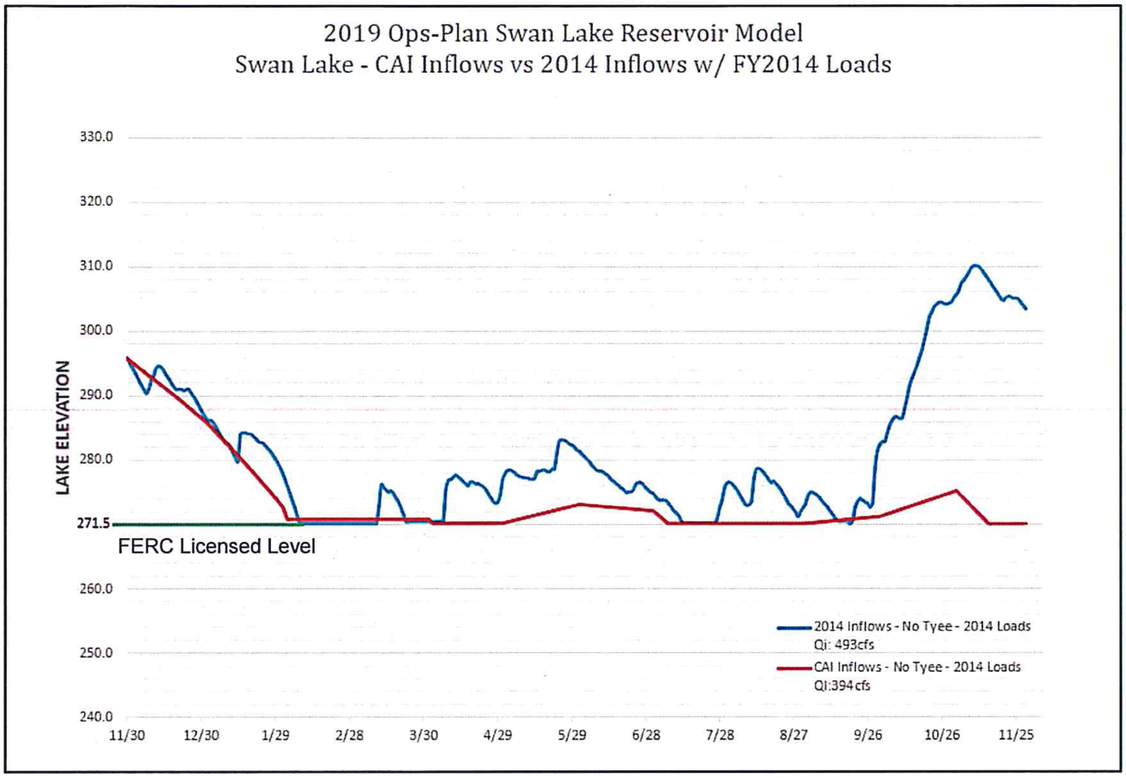


Figure 7: Swan Lake Reservoir Plot:

The 2019 Swan Lake reservoir model as illustrated in Figure 7 above illustrates the two case scenarios as discussed in preceding sections. Both scenarios were modeled to illustrate recovery scenarios for Swan Lake without the STI or other methods of supplemental generation to meet Ketchikan's Firm Power Requirements. Modeling inflows using the CAI inflow case (yellow line) illustrate that Swan Lake will not recover for the duration of the 2019 calendar year if all available inflows into the lake are used to support Ketchikan loads without Additional Dedicated Output from Tyee. In the case of using 2014 inflows (as predicted), Swan Lake recovers partly in the Spring however lake levels drop back down in the Summer under the same conditions.

It is well known from historical lake levels and Ketchikan load profiles prior to the installation of the STI transmission line that Swan Lake does not have the capacity to meet the Firm Power Requirements of Ketchikan without Additional Dedicated Output from Tyee. On a typical year, Tyee Lake has capacity to provide Additional Dedicated Output. Pursuant to the PSA and with consideration of the current conditions, SEAPA hosted a meeting with KPU's Electric Division Manager on November 29. The intent of the meeting was to discuss KPU Supplemental Diesel Generation case scenarios to minimize overall use of Diesel, maximize utilization of Swan Lakes output and avoid future spill. The outcome of coordinating KPU Supplemental Diesel Generation is discussed below.

Coordination of KPU Supplemental Diesel Generation:

Ketchikan's Firm Power Requirements are typically provided by SEAPA in accordance with the PSA by utilizing Swan Lake's Dedicated Output and Tyee Lake's Additional Dedicated Output. However, under the current water conditions, Tyee does not currently have Additional Dedicated Output available. It was therefore prudent to formalize integration of KPU Supplemental Diesel Generation to ensure compliance with the Power Sales Agreement.

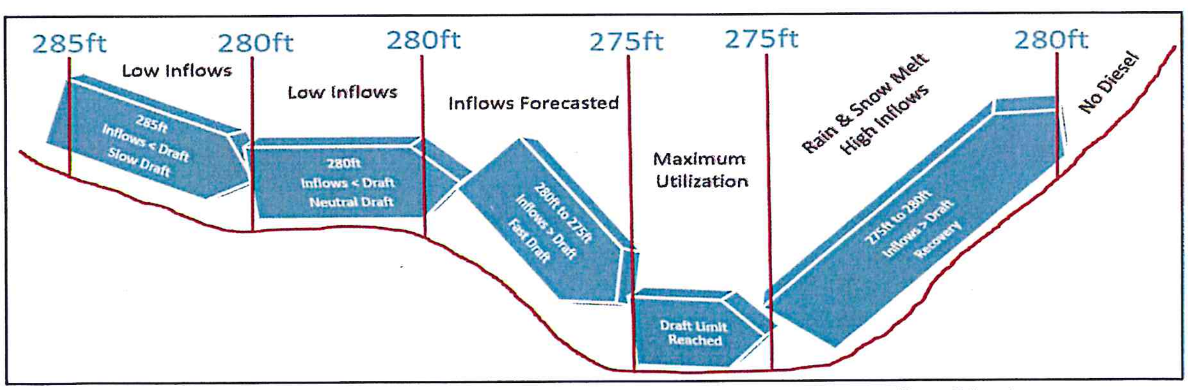
If draft rates at Swan Lake are high enough that the Maximum Draft Limit approved by the Board of Directors will likely be reached, SEAPA will issue a curtailment notification for each lake level instance and circumstance as listed below. Upon notification, the following KPU Supplemental Diesel Generation plans can be used:

Lake Elevation 285ft (Slow Draft): Whereas draft rates at Swan Lake and SEAPA 10-day rain inflow forecasts are apparent to <u>not</u> be great enough to maintain a Swan Lake elevation of 285ft, KPU Supplemental Diesel Generation may be used to reduce the rate of draft with intent of drafting Swan Lake to elevation 280ft.

Lake Elevation 280ft (Neutral Draft): Whereas draft rates at Swan Lake and SEAPA 10-day rain inflow forecasts are apparent to <u>not</u> be great enough that Supplemental Generation is required to maintain an elevation of 280ft, KPU Supplemental Diesel Generation may be used to maintain Swan Lake Elevation at 280ft until SEAPA 10-day rain inflow forecasts demonstrate that inflows will be greater than draft rates.

Lake Elevation 280ft to 275ft (Fast Draft): Whereas SEAPA 10-day rain inflow forecasts demonstrate that inflows will be greater than draft rates, KPU Supplemental Diesel Generation shall be reduced to allow that the Board of Directors approved Maximum Draft Limit of Swan Lake may be reached, ensuring that SEAPA hydrogeneration is not displaced by KPU Supplemental Diesel Generation.

Lake Elevation 280ft and Rising (Recovery): Whereas the Swan Lake elevation is below 280ft and SEAPA 10-day rain inflow forecasts demonstrate Swan Lake levels are rising, KPU Supplemental Diesel Generation shall terminate at Swan Lake elevation 280ft, as continued KPU Supplemental Diesel Generation directly displaces SEAPA hydrogeneration.



Coordination of KPU Supplemental Diesel Generation Chart

Swan Lake Reservoir Plot (With KPU Supplemental Diesel Generation):
A model was developed to demonstrate Swan Lake levels if KPU decides to coordinate KPU Supplemental Diesel Generation (Figure 8). The model was developed for illustrative purposes. Lake level elevations as described above were used to demonstrate in this scenario the likely recovery of Swan Lake in the late Spring of 2019 (with KPU Supplemental Diesel Generation). As discussed, Additional Dedicated Output from Tyee will not be available to Ketchikan until approximately that date and therefore SEAPA is recommending to the Board of Directors that the Operations Plan be revisited during a future Board Meeting in 2019 to discuss Reservoir Model plots and Additional Dedicated Output from Tyee.

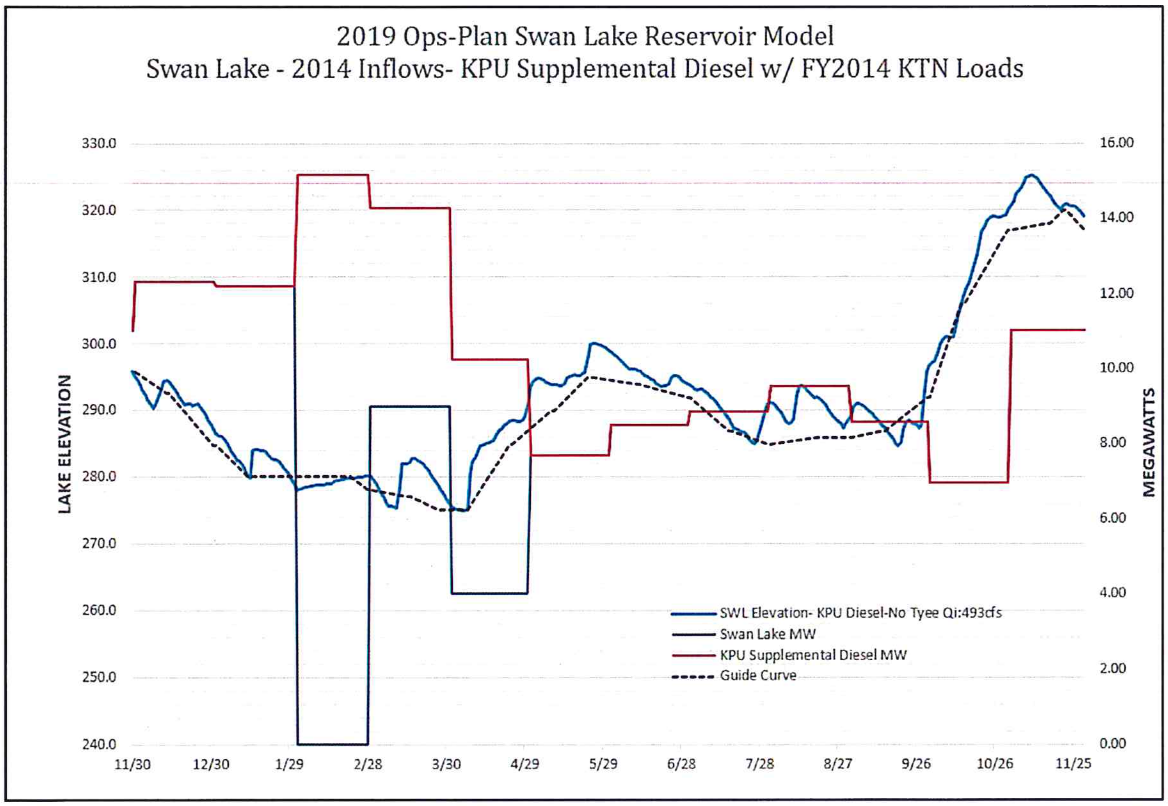


Figure 8: Swan Lake Reservoir Plot with KPU Supplemental Diesel

Tyee Lake Reservoir Plot (Operations Plan):

The 2019 Tyee Lake reservoir model (Figure 9) demonstrates 2 case scenarios. Both models represent Petersburg and Wrangell loads only, with two inflow cases. The Tyee 2014 inflow case with 2014 loads represents the probable case with Tyee Lake draft elevations drafting to elevation 1265 ft. The Tyee IECo inflow case with 2014 loads represents the worst-case scenario with lake elevations drafting to the FERC licensed elevation limit of 1250 ft.

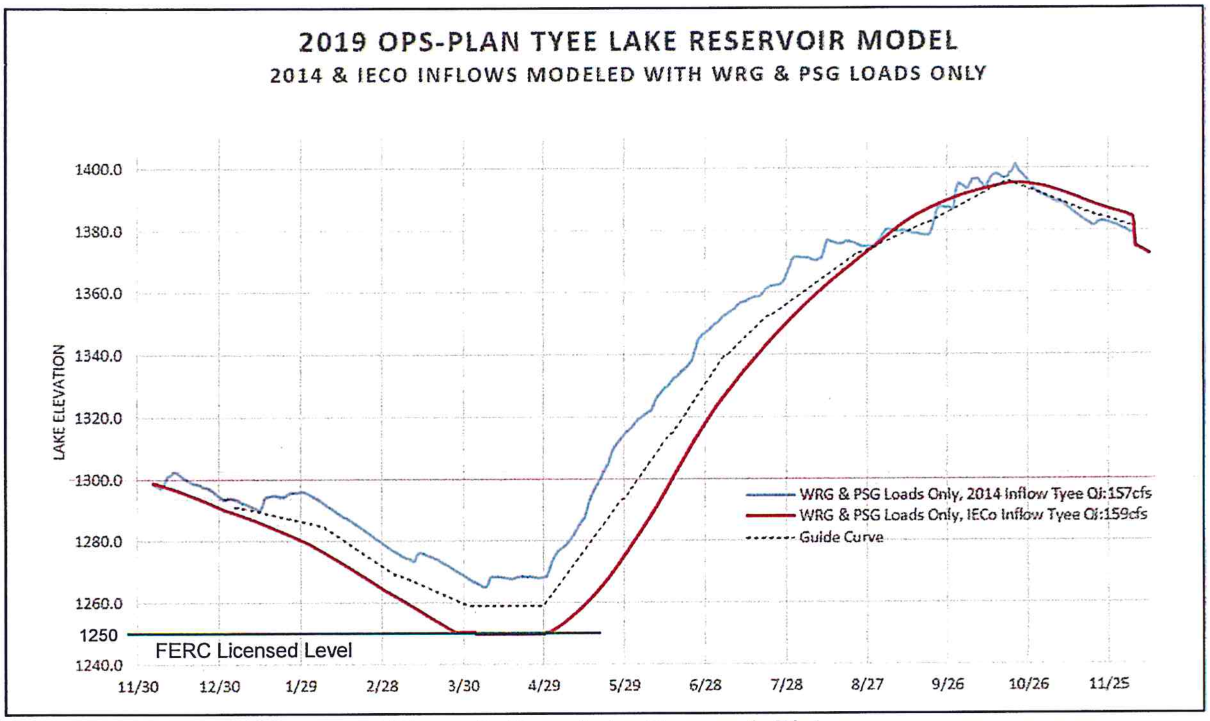


Figure 9: Tyee Lake Reservoir Plots

Optimizing Water Resources:

Tyee Lake Draft:

Optimizing water resources is important for maximizing resource outputs as required by the Power Sales Agreement (Section 5: Operations Plan) and insuring FERC licensed limits are retained. It is however also SEAPA's mission to ensure dedicated outputs are delivered to meet the Firm Power Requirements of the Purchasing Utilities. In August-September of 2018, SEAPA continually developed Tyee Lake models using Petersburg and Wrangell loads only. The models illustrated that Tyee Lake's Additional Dedicated Output would not be available to Ketchikan after the end of September and throughout the Winter of 2018-2019 to meet the Firm Power Requirements of Petersburg and Wrangell. On September 17, 2018, SEAPA began a net-zero transfer of energy across the STI. Since implementation of the net-zero operations strategy, the total balance of megawatts sent South from Tyee to Ketchikan has been nearly zero with the same subsequent energy transfer from Swan Lake to the North. The overall result is dedication of remaining Tyee Lake Capacity to Petersburg and Wrangell and Swan Lake to Ketchikan until conditions support otherwise.

Swan Lake Spill:

The Swan Lake reservoir was raised from elevation 330 ft. to elevation 345 ft. Calendar year 2017 was the first year that the benefits of this effort were realized. In September of 2017, Swan Lake reached an elevation of 335.8 ft. This added 3,723MWh of energy captured, that would have otherwise been lost to spill. With recent water conditions, the energy captured in 2017 has already and will in the future continue to displace Diesel Generation (up to the maximum energy captured). Similar to that of the 2018 Ops Plan, SEAPA plans to operate Swan Lake above elevation 330 ft. in the following manner:

- Elevations 330 ft. to 339 ft. - Both generating units will be fully available and the vertical gate will be operable. Water will be stored for future use.
- Elevations 339 ft. to 342 ft. - Both units will operate to their highest levels that loads permit to draft the reservoir back down to 339 ft. or below, this will most likely occur in spring and fall and assist with refilling Tyee Lake as increasing Swan Generation will reduce Tyee Generation for a given SEAPA delivery schedule.
- For the first few years, water above elevation 342 ft. will be immediately spilled by automatic operation. At elevation 335.8 ft. as seen in September 2017, there were little signs of Flashboard leakage. Testing is still required at higher elevations. Flashboards automatically release at elevation 347 ft.

2019 Operations Plan Summary

Section 5 of the Long-Term Power Sales Agreement provides the following:

> **Operations Plan Development.** ... The objectives of the Operating Plan shall include maximizing the utilization of the output of the Agency Facilities and optimizing the output of the Agency Facilities in order to serve the Purchasing Utilities' Firm Power Requirements as set forth pursuant to this Agreement, through the use of water management and other efficient dispatch procedures adopted by the Agency, subject to Dedicated Parties' priority access to Dedicated Output. ... [Emphasis added]

For the reasons demonstrated in the proposed Operations Plan and pursuant to the Power Sales Agreement, SEAPA staff proposes guide curve elevations be used by the scheduling group as guides. If lake levels fall below the guide curves, SEAPA will manage water resources, in consideration of current conditions, with an overall objective of restoring lake levels to their respective guide curves. As lake levels approach the annual minimum Board approved draft limits (Tyee: 1260 ft. and Swan: 275 ft.), SEAPA and the dedicated resource holder(s) will enter into discussions as to whether curtailments will be issued by SEAPA. Guide curve elevations and minimum draft limits for Swan Lake and Tyee Lake are listed in Figure 8 and Figure 9 and correspond with the table below.

SEAPA 2018 Operations Plan Guide Curve Values

Mth/Day	12/5	1/5	2/5	3/5	4/1	4/28	5/28	6/15	7/5	7/21	8/24	9/18	10/18	11/20	12/4
SWL Guide Curve Elevation (ft)	295.8	284.8	295	280.0	275.0	285.0	295.0	296	292.0	287.0	286.0	287.0	287.0	318.0	317.0
TYL Guide Curve Elevation (ft)	1297	1291.2	1285.1	1269.3	1261	1260	1280	1293.6	1314.7	1352.4	1372.8	1382.2	1395.7	1384.7	1381.2

For reference, past Operations Plan minimum draft limits are listed below. With the predicted low inflows for CY2019, the proposed 2019 Operations Plan proposes that Swan Lake and Tyee Lake draft limits be consistent with 2016 & 2018 draft limits respectively.

SEAPA Historical Draft Limits						
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
Swan Lake	275 ft.	285 ft.	275 ft.	273 ft.	272 ft.	275 ft
Tyee Lake	1265 ft.	1280 ft.	1270 ft.	1261 ft.	1260 ft.	1260 ft

Please consider the following suggested motion:

SUGGESTED MOTION
I move to approve the 2018 SEAPA Operations Plan as presented in the December 12-13, 2018 Board packet.

ATERWYNNE LLP

MEMORANDUM

TO: Dave Carlson, CEO, Southeast Alaska Power Agency

FROM: Joel Paisner, Ater Wynne LLP

DATE: October 31, 2010

RE: Payment of Diesel Generation Costs

I. QUESTIONS

1. In connection with the Southeast Alaska Power Agency's ("SEAPA" or the "Agency") obligations to provide continuous electrical service to its Purchasing Utilities under the Long Term Power Sales Agreement ("PSA"), is the Agency required to pay for diesel generation run by the Purchasing Utilities?

2. In connection with SEAPA's obligations to provide continuous electrical service to its Purchasing Utilities under the PSA, is the Agency prohibited from paying for diesel generation costs, in certain board-determined circumstances?

II. DISCUSSION AND ANSWER

Electric Power is to be continuously available by the Agency to its Purchasing Utilities at the agreed upon Delivery Point for each particular system. PSA, Section 4. However, this obligation is limited by the following exceptions:

> (a) Interruptions or restrictions of deliveries caused by the reasonable need of the Agency or its Purchasing Utilities to "inspect, maintain, repair, test or otherwise service its facilities or equipment in accordance with Prudent Utility Practice and standards." Id. Such interruptions shall excuse the Agency from its obligations under the Operations Plan.
>
> (b) When a cause or event is *not in the control* of the Agency.(emphasis added)

PSA Section 4(a). Each party to the PSA is obligated to reasonably limit any planned interruptions or restrictions in service, provide reasonable notice of planned outages, and to plan such known outages during light load periods.

The PSA limits the Agency's legal obligation regarding continuity of service to the Purchasing Utilities, and it is not obligated to pay for the outages and restrictions outlined above. Additionally, the PSA states that it "shall not create on the part of the Purchasing Utilities and the Agency any legal duty to maintain continuity of electric power service to any Purchaser's retail customers." Id at Section 4(a)(iii). In other words, if delivery of electric power to the Purchasing Utilities is interrupted, either through planning or causes beyond the control of the

Agency, the Agency is not responsible to pay for any outages for these excused circumstances. There is no obligation under the PSA to pay either the Purchasing Utilities for the cost impacts from such outages or pay the customers of the Purchasing Utilities for such outages.

The Purchasing Utilities remedy for system disturbances is to refuse to accept power from the Agency until reliability is restored. See PSA, Section 4(c). It is not refusal to pay for impacts from excused interruptions as defined in the PSA.

The question related to this is whether the Agency, in certain defined circumstances *may* pay for system outages, interruptions and restrictions. The PSA itself does not address this question, as it simply defines the core obligations between the Agency and its Purchasing Utilities. It is the Agency bylaws that govern this question. The bylaws define which decisions require unanimous approval of the Board of Directors, which require a super majority (4 of 5) and which require a simple majority vote (3 of 5).

For example, unanimous decisions are those that alter the bylaws, or release of a party from its obligation to take Firm Power. Supermajority decisions are those that relate to the addition of hydroelectricity or transmission, approval of the Operations Plan, the sale of surplus power, or entering into long term service or operations contracts.

The proposal reviewed by this memorandum relates to an overall diesel generation plan and protocol. In it, the proposal is that under certain circumstances – Agency proposed water management, or Agency proposed repair and facility replacement, or others yet to be discussed, that the Agency budget for the cost of each Purchasing Utility's diesel generation costs due to the agreed upon Agency action. To the extent these payments are included in a budget adopted by the Board, the bylaws do not prohibit such payments. However, in the event such payments are made pursuant to, and part of the Operations Plan, a supermajority must approve such plan, as is required in the Bylaws. See Bylaws, Section 2.11(e).

III. CONCLUSION

The PSA establishes the overall obligations between the Agency and its Purchasing Utilities regarding the sale of electric power. The Agency sells its electric power on a continuous basis, however the PSA recognizes that events occur outside the direct control of the Agency, and excuses delivery of electric power in those circumstances. An example of such excused circumstances was the recent storm that impacted the Swan – Tyee Intertie and the operations at Swan Lake. Clearly those circumstances are beyond any party's control, and any impacts are to be born by each of the parties. Thus, generally, if any Purchasing Utility is required to use diesel generation to supply its customers, under the PSA, it is obligated to pay for such costs. This has been a historical practice of the Agency and its Purchasing Utilities as well.

The PSA does not address the question regarding whether the Agency, in certain defined and approved circumstance may pay for the diesel generation at a Purchasing Utility. Referring to the Agency bylaws, as part of the budgeting process, the Agency may include the costs of diesel generation that may occur. As proposed, the practice of including diesel generation costs at a Purchasing Utility impacted due to an approved repair, replacement or restoration project is well within the authority of the Board to consider. It is important to note that in the event such plans to contribute to diesel generation costs are part of the annual Operations Plan, the approval of such policies must be pursuant to a supermajority of the Board.

If you have any questions or further concerns, do not hesitate to let me know.

Southeast Alaska Power Agency

DATE: October 27, 2010

TO: SEAPA Board of Directors

FROM: Dave Carlson

SUBJECT: Diesel Protocol

The purpose of this memo is to provide background and discussion points for the development of an agreed-upon Diesel Protocol or policy. As you are aware, diesels are used to generate power due to a number of circumstances. Even though all of the member utilities have diesel generation in place to provide back-up when local or Agency hydro power is unavailable, this generation is costly and has public relations concerns. It is fair to say that <u>everyone</u> is working on the same goal of reducing diesel generation to the maximum extent possible. Nonetheless, diesel generation is required and is an integral component of the overall generation mix. This memo will attempt to define the sets of conditions when diesel generation is required and also provide discussion points to be used in the development of a Diesel Protocol.

I expect this document to spawn some extensive discussions before an agreed-upon Protocol is developed. Any protocol or policy that is developed and agreed to by the Board would be in the form of a resolution.

It is important to remember that the member utilities share in the benefits and risks associated with the Agency's operations. Benefits can flow to the utilities via the wholesale power rate, rebates, meeting reserve requirements, etc. Benefits could also be delivered to the member utilities in other ways including the offset of diesel generation costs in agreed-upon circumstances.

<u>Background</u>: With the completion of the Swan-Tyee Intertie, as well as capital projects that are currently underway or recently completed at both the Swan Lake and Tyee Lake projects, there have been several occasions when the member utilities have had to run diesels because the Agency-owned hydro projects or transmission lines were taken out of service and thereby SEAPA hydro power was unavailable for delivery. Additionally, there could be occasions when it may be advantageous to run diesels for the overall benefit of a more efficient, long-term water management schedule.

The Long-Term Power Sales Agreement ("LTPSA") recognizes that interruptions or restrictions of deliveries (of power) will occur to allow the Agency or a Purchasing Utility to inspect, maintain, repair, test, or otherwise service its facilities or equipment. There is no obligation or requirement that the Agency pay for the diesel generated by a member utility to replace the power unavailable from an Agency-owned hydro project.

While the Agency is under no obligation to pay for diesel generation costs incurred by the member utilities, there may be instances when it could be in everyone's interest to have the

Agency pay for specific and agreed-upon diesel generation costs. This could include cases when sharing of risk seems appropriate. These and other circumstances when diesel generation occurs are addressed in this memo.

Discussion: The following is a summary of the issues and situations that may require diesel generation. There is also the need to develop a policy for how these diesel generation costs are invoiced. The issues and situations are summarized below:

1. Diesel generation required due for a planned capital project or planned maintenance at Agency-owned hydro projects or transmission lines.
2. Diesel generation required due to an unplanned event or outage resulting in the unavailability of power deliveries from Agency-owned facilities.
3. Diesel generation 'recommended' by the Agency due to Operations Plan/Water Management.
4. Diesel generation 'necessary' to support reserve requirements.
5. Diesel generation dispatch from one utility to other interconnected utilities when Agency power is not available.
6. Billing procedures for approved diesel generation by a utility.

There are, no doubt, additional issues and subsets to the above that will be identified as each of these issues are evaluated. The following is a brief discussion regarding each of the issues:

1. **Diesel Generation Required for a Planned Capital Project or Planned Maintenance at Agency-Owned Hydro Projects or Transmission Lines**: The Agency has recently completed, or is in the process of completing, several projects at the hydro facilities that required the hydro project to be offline resulting in the unavailability of power deliveries to a member utility.

   With the new substation construction at Swan Lake and Tyee Lake, incentives were placed in the contract to reduce the number of outage hours thereby reducing the amount of diesel generation by the local utilities. We have also had occurrences when the contractor for a specific capital project agreed to pay for diesel generation costs and the local utility (in this case, Ketchikan) was reimbursed for diesel generation. (Discussion regarding billing procedures is discussed below.)

   Under the LTPSA, the Agency has no obligation to pay for a utility's diesel generation costs if power from an Agency-owned facility is unavailable. However, there are cases when a budget for a planned capital project, upon approval of the Board, could contain an allowance for expected diesel generation costs that a utility is expected to incur as a result of the capital project.

   If the Board agrees that it is acceptable and reasonable that diesel generation costs should be paid by the Agency for planned capital projects, I recommend this be conditioned as follows:

   a. The budget for a specific capital or R&R project that will result in the need for a member utility to generate power with diesel should include a line item for 'expected' diesel generation costs.
   b. The budget for the capital or R&R project with the diesel generation component must be approved by the Board.

c. Invoices for diesel generation submitted to the Agency for payment are approved by the CEO providing they meet the requirements in 'a' and 'b' above.
d. Diesel generation costs for capital or R&R projects that do not include a budget for diesel generation costs will require Board approval prior to payment. This could be for projects where there was not expected to be an interruption of power from an Agency facility but events occur that result in the need for diesel generation by a member utility. If the Board deems it reasonable that a member utility should be reimbursed for unanticipated diesel generation costs, a line item should be added to the Agency's annual budget to cover these costs.

With respect to the planned & scheduled annual maintenance outages (usually in May and June), I recommend that we continue to work to keep these outages as short as possible with the member utilities continuing to pay for diesel generation costs during these outages. However, with that said, this is certainly a topic that deserves board input and discussion. Would it be appropriate for the Agency to budget and pay for some level of diesel generation during these types of planned outages?

2. **Diesel Generation Required Due to an Unplanned Event or Outage Resulting in the Unavailability of Power Deliveries from Agency-Owned Facilities:** In this situation, these are unplanned events that occur from time to time that require utilities to turn on their diesels to meet load and also restore the system. Generally, these are short outages but do require a member utility, or utilities, to incur costs for diesel generation. There is no obligation that the Agency is required to reimburse the utilities for these diesel generation expenses.

   Before providing any recommendations, we need to conduct some research to determine the magnitude of diesel generation costs that have been incurred over the past several years. My impression is that this has not been a huge expense, and I would appreciate input from the member utilities regarding these past costs.

3. **Diesel Generation 'Recommended' by the Agency Due to Operations Plan/Water Management**: In this situation, the Agency could recommend that a member utility should burn diesel in order to maintain or keep water levels at a project from declining below levels agreed to in the Operations Plan. Admittedly, this is a very sensitive issue for the Agency and perhaps even more importantly for the member utilities. There is a significant political hurdle to overcome with the perception that burning diesel should only occur as a last resort. This coupled with the highly unpredictable weather and precipitation forecasts exacerbate this even further. However, it is imprudent to operate projects and manage water reservoirs in a manner that increases the overall cost of power to the ratepayer.

   This subject has already received a good deal of discussion and will require much more but it is important that an agreed-upon framework is developed regarding when diesel generation should be initiated in order to prudently execute water management plans within the interconnected system. Because of the dedicated output provisions in the LTPSA, this will initially affect Ketchikan. Ketchikan is understandably nervous about running diesel and charging their ratepayers a surcharge when there is still water in the reservoirs. However, there will be (and has been) times during the year when our water management model shows that it would be prudent to burn diesel. Consequently, there will need to be some good discussion and an approach developed to address the allocation of risk to both the Agency and the member utilities with respect to these diesel runs. The question of who should pay for the diesel if it turns out the Agency is wrong in its diesel-burn request (i.e., an unexpected rain or series of rain events occur such as the events in late September and October of this year) needs discussion and agreement. Conversely, should Ketchikan be required to pay for the loss of generating efficiency should the Agency turn out to be correct (the rain events do not occur as hoped)?

An example of a diesel request follows: During January 2009 high loads and low inflows caused the rate of draft at Swan Lake to exceed the guide curve draft rate for several weeks. To preserve head, and to re-establish a rate of draft on the guide curve, SEAPA suggested to KPU that they generate with diesel to the extent that Swan generation would be limited to one unit. KPU did not want to burn diesel early in the winter season because the public would not understand a diesel surcharge when Swan Lake and Tyee Lake were not drafted, and rate payers were in the process of paying previous surcharges. This case was a peculiar event as Tyee would not be able to supplement Swan as much as usual later in the winter due to the rewind project. In the end, a strong storm increased inflows and loads decreased. What if the weather pattern had remained cold and dry? KPU absorbed the risk that weather would turn warm and wet in sufficient time that the rewind constraint would not cause an extended period of diesel generation. The risk trade-off was a greater diesel generation level in the future if diesel is not used now to a limited degree. This example is typical of water management issues and also shows that each case is specific in nature, and that a supplemental diesel reimbursement for water management issues needs to be judged on a case-by-case basis.

4. **Diesel Generation 'Necessary' to Support Reserve Requirements:**

   a. Spin Reserve: With the increase of conversions to electric heating, there will be occasions in the very near future when there is not enough installed hydro capacity within the interconnected system to meet these loads and provide spinning reserve. SEAPA has presently been providing this spin reserve for the member utilities. The member utilities that have their own hydro (Ketchikan & Petersburg) generally do not supply this reserve themselves and rely on SEAPA's capacity to provide this spin. SEAPA is currently under a spin reserve rule to continuously provide 4 MW of on-line reserve capacity. Our installed full reservoir capacity is 50 MW. After deductions for voltage support this capacity drops to 46 MW. In mid-winter this capacity drops to 44 MW because of reduced head in the reservoirs. If the net load to SEAPA exceeds 40 MW in mid-winter, SEAPA can meet this load, but the 4 MW spin reserve criteria will not be met. Should we waive the spin reserve rule during very high loads, which is the most critical time to provide reserves, or should diesel supplement the generation mix such that spin reserve is provided?

   b. Contingency Reserve Storage: There is currently a draft limit imposed at Swan Lake that when at or near elevation 280, diesel generation should be initiated to preserve water in Swan Lake for emergencies. If there is sufficient storage in Tyee to refill Swan after the Swan elevation drops below Elevation 280, then why burn the diesel up front? The attenuated risk is now a failure of the Tyee equipment or the Tyee to Bailey transmission path. If Tyee fails and KPU diesel fails, there is still adequate diesel capacity spread across the system to recharge the reservoirs. This example could be one where the option of shared resources reduces diesel generation costs.

5. **Diesel Generation Dispatch from One Utility to Other Interconnected Utilities when Agency Power is Not Available**: This is a discussion that needs to take place primarily between the utilities. In situations when an event occurs resulting in an unplanned outage affecting the entire system, there could be good reason and justification to have one utility run diesels to support all the interconnected utilities. Operational issues and system reliability issues need to be addressed, of course, to determine if this is even feasible. Assuming it is, however, the utilities would need to agree and develop a protocol on the dispatch and billing for this power.

6. **Billing Procedures for Approved Diesel Generation by a Utility**: An agreed-upon procedure for invoicing the costs of diesel generation should be developed. The obvious components that could be included in these billing charges include:

   - Cost of diesel
   - Cost of lube oils
   - Cost of labor
   - Amortized capital costs
   - Administration and Overhead

   My recommendation with respect to billing is to keep it simple and include only the cost of diesel with an associated credit for the energy that would have been purchased at the current wholesale power rate (6.8 cents/kWh).

I look forward to some good discussion at the meeting. We are breaking new ground here and are in the first steps in the development of a Diesel Protocol policy. As policy makers, I would appreciate your initial thoughts regarding whether SEAPA should consider including diesel expenses within its budgets in certain agreed-upon situations. There are obvious operational discussions that will have to take place among the utilities at the Reliability Committee meetings. I believe we should strive for solutions that benefit and make sense for the ratepayers and our member utilities.

Southeast Alaska Power Agency

EDATE: April 16, 2014

TO: SEAPA Board of Directors

FROM: Trey Acteson, CEO

RE Diesel Protocol

At the March 3-4, 2014 board meeting, following board approval of an invoice for diesel fuel expenses, staff was directed to prepare an outline and recommendation for the board's consideration on a process for staff to follow to address any future diesel reimbursement requests.

The diesel protocol issue has come before the board at several board meetings over the past four years with no consensus to date. During this period, there have been occasional reimbursement requests for diesel fuel expenses and the board has reviewed them on a case-by-case basis. The board took action in each case, determining whether to pay the invoice in full, in part, or not at all.

I have attached to this memo documents previously presented to the board to help familiarize new board members with the topic of diesel protocol. The documents represent considerable time, effort, and research by staff and SEAPA's counsel on the issue. They describe the purpose, background, and application; plus highlight potential unintended consequences. There is also a legal review that looks at PSA obligations and whether SEAPA has the ability to pay diesel reimbursement. Additionally, there is a draft resolution that captures a diesel protocol framework that was previously discussed by the board. Any new outline or framework would likely mirror the content of these documents.

It is my recommendation moving forward that although the Agency is under no obligation to reimburse for diesel, until such time that a formal resolution on diesel protocol is adopted by the board, requests for diesel reimbursement be presented to the board for determination on a case-by-case basis. Staff will not pre-authorize the payment of any invoice prior to the board's approval and will be available to discuss each circumstance under consideration.

Until a formal resolution is adopted, I have prepared a suggested motion for your consideration.

SUGGESTED MOTION
Until a formal diesel protocol resolution is adopted by SEAPA's Board of Directors, SEAPA staff may not pre-authorize any payment for diesel fuel expenses but may present any invoices for diesel fuel expenses to the board for its consideration of payment on a case-by-case basis.

Attachments:
- 2013 0620 Memo to Board from Acteson Re Diesel Protocol
- 2012 0201 Memo to Board from Carlson Re Diesel Protocol
- 2010 1027 Memo to Board from Carlson Re Diesel Protocol
- 2010 1031 Memo to Carlson from Ater Wynne Re Payment of Diesel Generation Costs
- 2011 0209 Memo to Board from Carlson Re Diesel Protocol Resolution
- Draft Resolution No. 2011-035 Regarding Diesel Protocol