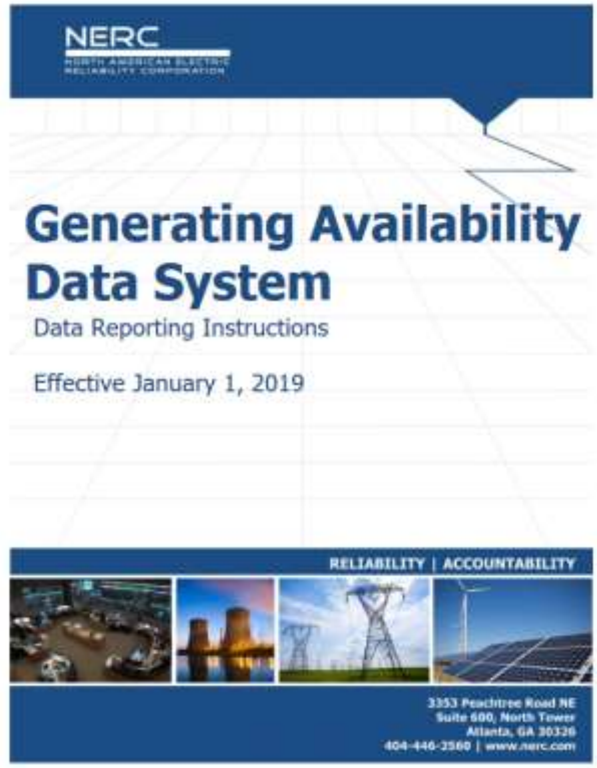
Hydro GADS

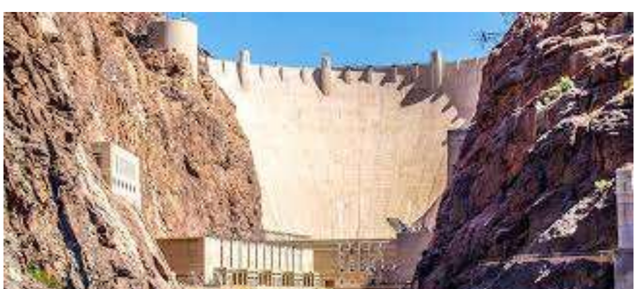
Introduction



Hydro Generating assets are included as part of the conventional GADS reporting system. These assets have been included in GADS reporting since very early on in the evolution of GADS. With the mandatory GADS reporting requirements, it became clear that different owners were reporting their unit status differently for some common operating conditions encountered with hydro units.

There were different methods used by owners to report on unit status when river flows were not high enough for all of the units in a powerhouse to operate. Some owners were recording this as forced outage due to lack of water, even though the units were run daily because the reservoir behind the dam had storage that was used. (These units would be cycled or pulsed.) Some owners reported the status of the units that were not able to run as Reserve Shutdown while some characterized this as Planned Outages because this was a known condition that repeated every year. Some owners did not report anything.

In other instances, hydro assets were attached to a reservoir that had no active storage so units could not be cycled. When these plants did not have enough water, units would be shut down for an extended period of time and not run at all. As with units capable of cycling, owners would report their unit status in a variety of ways: Forced Outage due to lack of water, Reserve Shutdown, Planned Outage, etc. In addition, because the units would be shut down for extended periods of time, there were some owners that would perform maintenance on their units when they were in this condition, but not report this as a Maintenance or Planned outage.



Hoover Dam

There are other operating scenarios that are relatively common with hydro units that are different than fossil/steam, gas turbines, combined cycle, and reciprocating engines. Specifically, these can include changes in head (fluctuating reservoir level) that cause a change in plant output that occur over hours, days, or seasonally. While this can be analogous to temperature impacts to gas turbine output, it is not a constant that can be used to predict the output deviation. Additionally, hydro units can be run as synchronous condensers (a.k.a. "motored"), and in the case of pump/turbines, pumping modes.

Also, hydro units are generally inspected on a periodic basis by their owners with no real identified maintenance need. Results of these Planned Outage inspections can identify other needs that may not have been expected. As with the cases above, inconsistency in reporting on the status of these units was a problem.

In an effort to gain better consistency in reporting, a Hydro Task Group was formed within the GADS User Group. This group was originally mobilized in 2013. The Task Group was expanded with the support of CEATI to create a larger hydro owner interest to identify issues and to provide input into the process. This effort led to recommendations that have been moved forward to the GADS User Group. These have been vetted by that group and have been approved.

The next steps are to summarize these recommendations and institute them in a revision to the Data Reporting Instructions.

Hydro Inspection Cause Code 7300

The group adopted the cause code 7300 to represent periodic inspections. This code is intended to be used for Planned Outage events for periodic (i.e. annual, every four years, etc.) inspections on hydro units. This includes inspection work on turbines, generators, breakers, governors, exciters, etc. Inspection can include minor repair and maintenance. It is recognized that often, hydro units may go several years before a more significant outage is required. For example, many new runners may not require cavitation repair for several years.

Hydro Governor for Servicing

These inspections would include the work to access units (i.e. clearances, installation of scaffolding, removal of covers, etc.) needed to conduct the inspection and minor repairs. If the inspection discovers something that must be replaced or requires significant repair that would extend the inspection in order for the unit to continue normal operations, the outage would move to a Forced Outage and the appropriate cause code would be applied. This is consistent with traditional GADS reporting requirements.

For guidance, when it moves to a Forced Outage, the 7300 can be used as a secondary cause code. The primary cause code for Forced Outage should be assigned to the appropriate cause code for the equipment that is affected.

Additional Note: You can still have a specific Planned Outage to replace or repair an item listed in the cause codes if that is what the outage is started for. For example, if the owner has a four year cavitation repair cycle, the outage for the fourth year would be a Planned Outage for Turbine Runner Cavitation Repair (cause code 7010).

Additional Note: There are Generator Inspection and Turbine Inspection cause codes in the list (4840 – generator and 7201 – turbine). These codes would be used if the outage work is specific to inspect these particular elements. 7300 is for an overall general inspection.

Additional Note: Cause code 7300 is to be used exclusively with hydro assets. It is not to be used for fossil/steam, gas, reciprocating engines, or other conventional generating assets.

Example 1:

An Owner plans to take a hydro unit down for an annual inspection. The scope of this work is to install scaffolding in the runner area to allow crews to inspect the runner for damage and perform any minor repair that is needed. The scope also calls for the generator stator to be air cleaned, and new brushes installed in the existing brush holders. The governor hydraulics are to be flushed and the fluid filtered. Last, the main generator breaker is to be checked for contact timing and adjusted so that it meets original specification. The crews are also to take measurements, and make adjustments as needed over all elements of the unit. This would be coded:

Event: PO Cause Code: 7300

Example 2:
The same annual inspection is planned with the same scope of work. During the inspection, crews discover that the wicket gates have gotten out of timing and one of them has been damaged and requires some significant repair. In this case, the work to correct the wicket gates is out of planned scope. (The scope was to inspect and perform general TLC to the gate system, not repair damage.) The entire outage time for crews to correct this condition and perform the inspection would need to be changed from a Planned Outage to a Forced Outage. In this scenario, you would need to code the entire outage to:

Event: U2 Cause Code: 7141 (wicket gate operating mechanism or positioner)

In this example, the work had intended to be a PO / 7300. However, since significant repair to a system was required to restore the normal and proper operation to the unit, the work had to move to the U2.

Gross Maximum Capacity and Net Maximum Capacity (GMC and NMC)

In surveying hydro owners, strong consensus was provided that indicates that the station service and other parasitic loads at a hydro station are extremely small when compared to the output of the plant. For most, the difference between the gross and net is less than 0.1%. This contrasts to a typical 4-5% for a fossil/steam unit.

For this reason, the default Capacity Generation Estimation Factor[1] is set to 2.00% Another way to state this is that the GMC = NMC for hydro units.

There may be circumstances where a hydro plant has a relatively large station or parasitic load that needs to be accounted for (i.e. >2%). In those cases, the Owners are strongly encouraged to enter both a Gross and Net capacity so that the unit is properly characterized.

Additional Note: The current GADS data submittal allows owners to submit their Gross and Net numbers separately and many owners do this. The above discussion only applies to the default value in Table IV-4. These values are applied when an owner only submits a Gross or a Net capability in which case the GADS system calculates the missing Gross or Net based on the table.

Gross Dependable Capacity and Net Dependable Capacity (NMC and NDC)

Discussion of these parameters is the same as the GMC and NMC above. GDC = NDC. This is the default if no other data is given. As above, owners are encouraged to fill in the specific data if this difference is greater than 2%.

Change in Operating Head

At many hydro stations, the dependable capacity is related to the head, or difference in water level of the forebay or reservoir to the tailrace. The most common influence is the level of the forebay. During normal operation, many forebay levels will change daily or even hourly. If a project is used for flood control, the forebay may be "drafted" to a low level and held there for several months in anticipation of snow melt or for other flood control purposes. Even though these fluctuations can result in a representative decrease in output, it was concluded by the GADS User Group that these changes do not need to be taken into account when reporting capabilities for hydro units.

[1] Data Reporting Instructions, Page IV-5, Table IV-4: Unit Capacity Generation Factors and MW Multipliers.

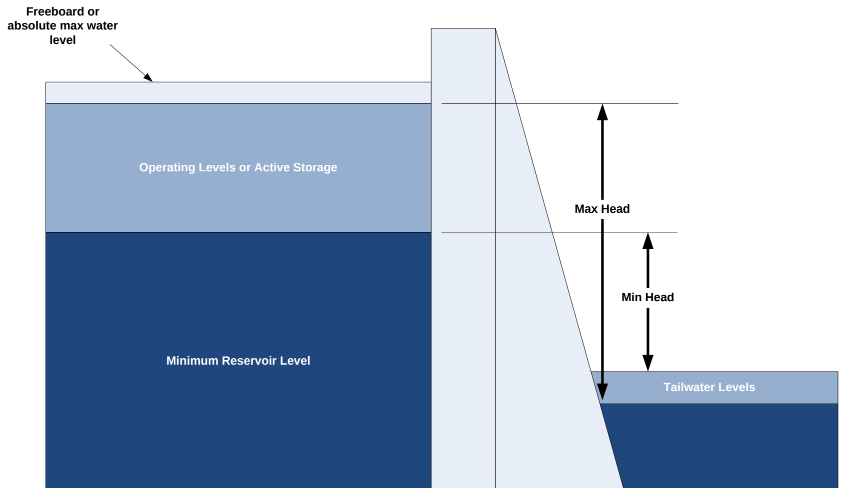
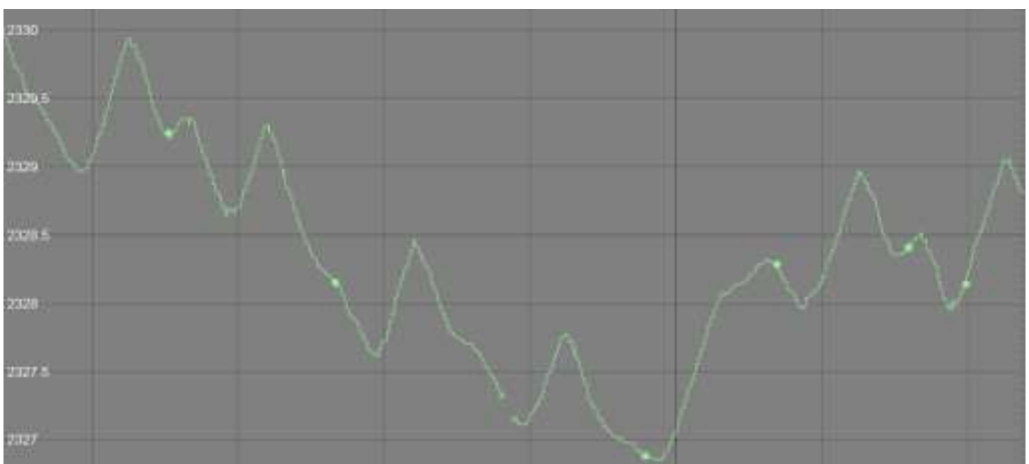


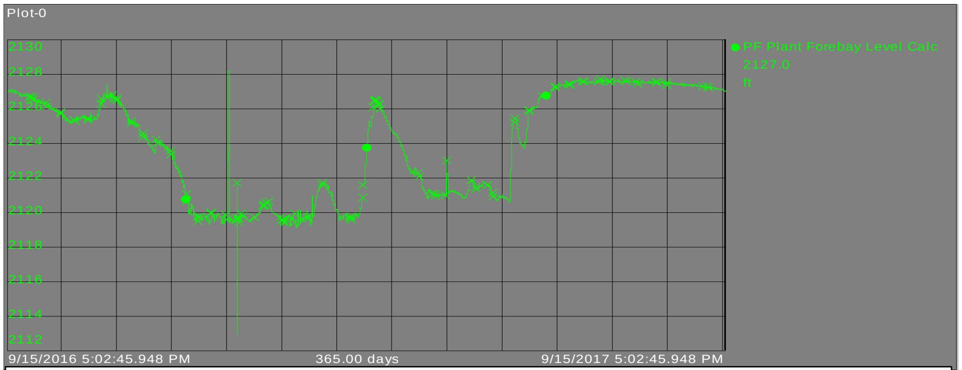
Illustration of Head Differences

The screen capture below is an illustration of how a hydro project forebay may cycle during a week. As just mentioned, while the loss of three feet of head in this example results in a drop in capacity of about 26MW's, at this particular project, it is not constant. As a practical matter, trying to collect this data and report an average or attempting to project this type of operation is a lot of effort for little benefit from a reporting (or planning) perspective. Most hydro owners will realize that every day may result in a different pattern for operation. It depends on system needs and markets that are unique for any time.



Example of Weekly Head Change
(Each vertical line is one day)

The exception here is if there is a seasonal draft for the reservoir. In some cases, where flood control is the primary mission of a dam, and power generation secondary, the reservoir is drafted, or partially emptied, to create storage for a future water surge. (This can be snow melt, rain storm or other weather event.) For these seasonal conditions that may last for a month or more, the owner is encouraged to report an estimated decrease in dependable capability.



Seasonal Change in Forebay Level
(Each vertical line is one month)

Additional Note: A similar condition exists for gas turbines in which ambient air conditions can affect the dependable capability of those units. Gas turbines are required to report any change in dependable capability due to changes in ambient temperatures. This can be argued as analogous to forebay fluctuations in hydro. While this may seem to be a similar situation, hydro reporting does not require these adjustments. (The possible exception is for seasonal changes as discussed above.)

Lack of Water for Peaking/Pulsing Units

Hydro plants that have active storage behind them and have a range of reservoir levels that they are allowed to operate within should be categorized as Peaking or Pulsing (Shaping, Regulating, Load Following, etc.) These can be characterized as plants that may be shut down (or mostly shut down) during some parts of the day or week, and then run at nearly full output for some parts of the day or week. Another description can be when units are shut down so that water can be stored (or restored) for a later operation – that day or tomorrow.

These types of plants would normally have a range of allowed forebay levels that they are required to operate within. These can be in the form of daily, weekly, or even monthly requirements. As an example, a plant can draft from the reservoir up to three feet as long as the operator never goes below the three foot limit in any given day. Another example is three feet in any given day and no more than four feet in a week. (In this last example, you could draft three feet in day one, one foot in day two, refill in day three and four, and then draft two feet in day five, and another two feet in day six, refilling in day seven.)

Peaking plants like these are typically designed to have enough water to run at full, or near full, capability for two to four months. After that, units are shut down for periods of time and then started to meet peak loads or market demands. Often these are for relatively short duration. As the water into the reservoir continues to decrease as the drier season sets in, multiple units can be shut down for periods of time. However, their status is still available as they may be called on to provide short duration capacity/energy into the system. There is no set definition of the duration of capacity they must provide as that can be determined by regional needs and ISO/RTO/Markets but usually these are two to four hours.

As these units are shut down so that water can be stored or restored, the units are to be placed in a Reserve Shutdown state. This means they are capable of operating at full load when called upon. The only issue is a dispatch issue on how much and how long.

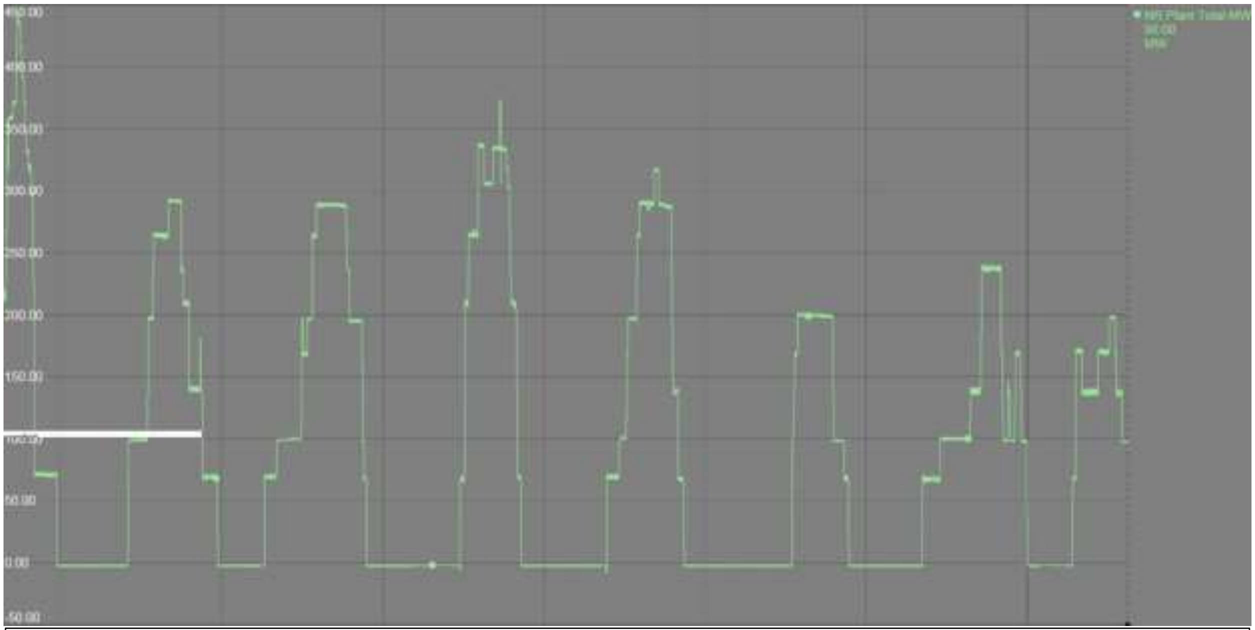


Illustration of a multiple unit Plant in a Peaking or Pulsing Mode
When units are shut down, they are placed in RS

It is possible with this type of operation that a unit can be in an RS state for several days without running. What is important to understand in this operational mode is that if needed, the unit(s) can be all turned on without violation of FERC license or other operational agreements, or imposing emergency measures that warrant a deviation of these licenses or agreements.

If a unit is placed in Reserve Shutdown due to water being stored or restored, and the decision is made to take the unit out of service for Planned Outage or Maintenance Outage work, the Reserve Shutdown would need to transition to a PO or MO with the appropriate cause code.

Example 3:

A four unit powerhouse is running one unit constantly, but it is changing output continuously due to AGC controls. During the day, to meet peak loads, the other three units are started at 1000 hours and then shut down at 1800 hours.

The next day, because the reservoir did not fill to the same level as the previous day, the unit schedule changed some. One unit is still used for AGC. Two of the units come on at 1000 hours and the last unit comes on at 1200 hours. The three units are all shut down at 1800 hours.

	Hours																							
Day 1	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	00
Unit 1																								
Unit 2	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Unit 3	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Unit 4	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Day 2																								
Unit 1																								
Unit 2	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Unit 3	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Unit 4	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS								RS	RS	RS	RS	RS	RS

This would be coded:

Day 1
Unit 1: no events – the unit is running.
Unit 2: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS
Unit 3: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS
Unit 4: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS

Day 2
Unit 1: no events – the unit is running.
Unit 2: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS
Unit 3: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS
Unit 4: hours 01 to 11 - RS; no event between hours 12 to 18; hours 19 to 00 - RS

Even though there is not enough water to run all of the units all the time, there is no lack of water cause code used here as the unit could be run if needed. (This does not include extreme measures which may be allowed by license or regulatory agencies agreeing to waive their requirements for the greater good.)

Example 4:

This example is similar except that late at night, a sudden loss or a generating unit somewhere on the system requires an injection of additional capacity. In this case, at the end of Day 1, two units are operated for four hours to cover this unexpected loss.

Because two units had to be run unplanned, the decision by dispatch for the next day is to keep one of the units shut down all day to allow for the reservoir to re-fill. This dispatch is illustrated below.

Hours

Day 1	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	00
Unit 1																								
Unit 2	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS		
Unit 3	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS		
Unit 4	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Day 2																								
Unit 1																								
Unit 2			RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Unit 3			RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Unit 4	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS

This would be coded:

Day 1
Unit 1: no events – the unit is running.
Unit 2: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 22 - RS;
No event between hours 23 and 00
Unit 3: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 22 - RS;
No event between hours 23 and 00
Unit 4: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS

Day 2
Unit 1: no events – the unit is running.

Unit 2: no event between hours 01 to 02; hours 03 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS
Unit 3: no event between hours 01 to 02; hours 03 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS
Unit 4: hours 01 to 00 - RS

Example 5:

This is the same as Example 4 except that with the knowledge that the fourth unit will not be run that day, the decision is made to take the unit out of service to address some minor problems with sticking that is occurring on the unit brakes. The unit is cleared for this work at 1100 hrs and is returned three hours later at 1300 hrs.

Hours

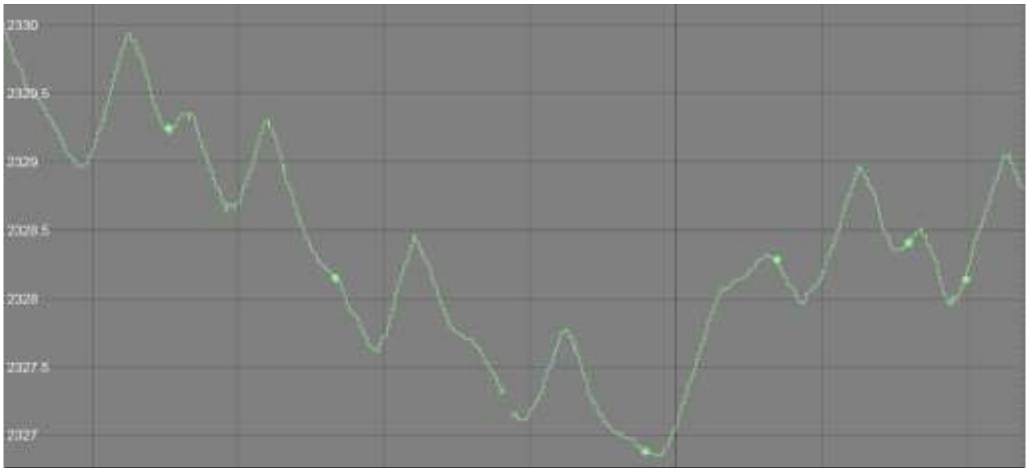
Day 1	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	00
Unit 1																								
Unit 2	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS		
Unit 3	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS		
Unit 4	RS	RS	RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Day 2																								
Unit 1																								
Unit 2			RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Unit 3			RS	RS	RS	RS	RS	RS	RS										RS	RS	RS	RS	RS	RS
Unit 4	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	MO	MO	MO	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS	RS

This would be coded:

Day 1
Unit 1: no events – the unit is running.
Unit 2: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 22 - RS;
No event between hours 23 and 00
Unit 3: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 22 - RS;
No event between hours 23 and 00
Unit 4: hours 01 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS

Day 2
Unit 1: no events – the unit is running.
Unit 2: no event between hours 01 to 02; hours 03 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS
Unit 3: no event between hours 01 to 02; hours 03 to 09 - RS; no event between hours 10 to 18; hours 19 to 00 - RS
Unit 4: hours 01 to 10 - RS; hours 11 to 13 event: MO, cause code: 4590 (generator brakes); hours 14 to 00 - RS

In these examples, unless the unit is removed from service for a Forced Outage, Maintenance Outage, or a Planned Outage, the units would be in Reserve Shutdown mode and fully capable to run, but dispatch is not asking them to run. This is true even though the water in the reservoir may be filling. The purpose of Example 4 is to give the sense that these units could be called on if the system needed the energy or market opportunities presented themselves.



Example of Weekly Head Change
(Each vertical line is one day)

Additional Note: It is possible that a plant like this might go one or two days without any unit actually generating as its reservoir is re-filling. However, these units would still be in Reserve Shutdown and they could be called to run. This illustration shows a plant that may be in this cicumstance. The reservoir storage was used heavily for several days and now plant operation is being limited to allow the reservoir to increase storage indicated by the rising level.

Additional Note: If a peaking plant is drafted for reasons (i.e. flood control) and the reservoir reaches a low limit and the reservoir must be maintained at that low level, the plant then enters a "run of river" mode and the events will also need to reflect that operating mode. This is described in the next section.

Lack of Water for Run of River Plants

Many hydro plants do not have active storage that allows the type of operation described in the Peaking/Pulsing type of plant operation. For many plants, a reservoir level is established as part of their FERC operating License or other Regulatory agency operating requirements. In these cases, the output of the plant can be described as "whatever is coming into the reservoir, must continuously go out" at the same rate. This places the plant output at whatever the natural stream flows are or in many cases, what the release of any upstream plants might be.

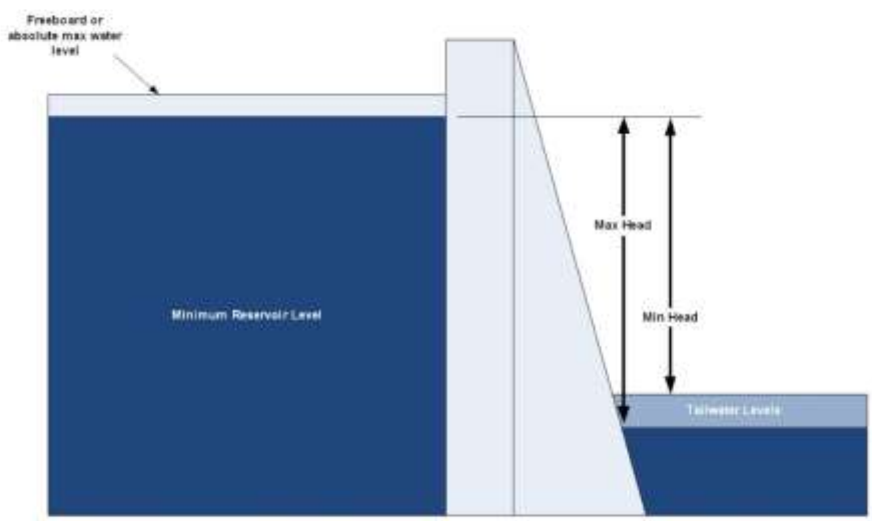
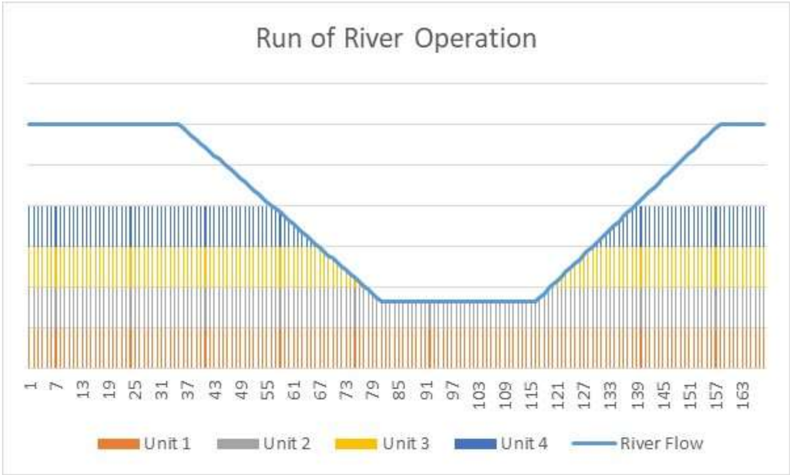


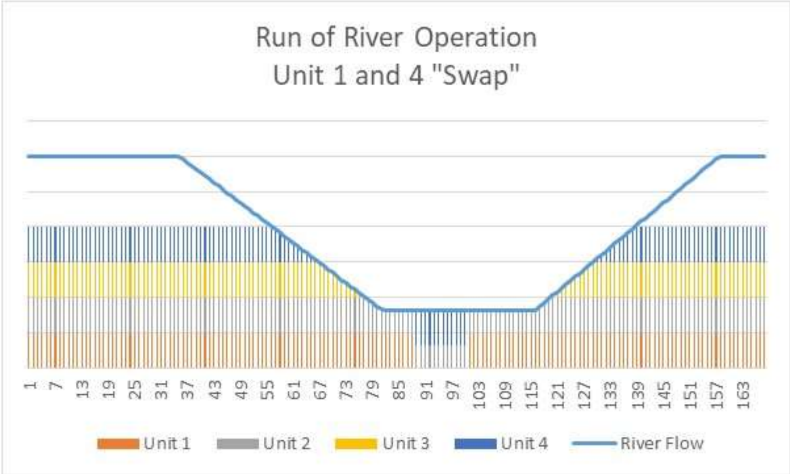
Illustration for Run of River Plant
Note the Reservoir Level has no latitude for fluctuation

For these plants, as the stream flow decreases, units are required to be backed off and shut down in order to keep the reservoir level (i.e. forebay) at a constant elevation. In general, plant operators will gradually reduce the output of one unit until there is not enough water to operate the unit. At the time, the one unit will be shut down and another unit will be gradually reduced, and then another, etc. When there is no longer enough water, the unit would be placed in a Forced Outage condition due to lack of water.



This is illustrated in the graphic below. In this illustration, Unit 4 runs until the water is insufficient and it is shut down. Unit 3 is the same, and Unit 2 is required to run at part load.

As a practical matter, many operations practice "swapping" units so that operating hours tend to balanced out between the units. Using the illustration here, when there is only enough water to run two units, the operator may choose to run Unit 4 and shut down Unit 1. This is illustrated in the graph below. You can see around time tag 91 that Unit 1 was taken off and Unit 4 was turned on. Around time tag 100, the units were again swapped.



For all of these conditions described, when a unit must be shut down because there is insufficient water to run all the units and there is no reservoir that would allow the units to run, these shut downs are to be categorized as a Forced Outage due to a lack of water.

There is a similar condition that can occur when units are shut down due to diversion of water to another channel for fish, wildlife, recreation, aesthetics, water supply, irrigation, or other purposes. In these types of operations, FERC License conditions or other regulatory requirements dictate that water priority is to be served to another use other than energy production. In some instances, this may require the entire plant to be shut down and all available water is diverted. In other cases, there may still be enough water to operate one or more units and still fulfill the regulatory obligations. Similar to the scenarios described above, when units need to be shut down due to water being diverted away for power production reasons, the unit is to be categorized as a Forced Outage due to a lack of water due to regulatory requirements.

In both of these instances, the reason for the lack of water is considered to be outside management control. For those plants that are exclusively run of river, if stream flows fall to where units must be shut down, these would be characterized by:

> U3 (Forced Outage that could have been delayed over the weekend) and cause code 9135 – Lack of Water.

For those unit outages that are due to water being diverted away from the generating units for regulatory purposes, they would be characterized by:

> U3 and cause code 9696 – Other miscellaneous operational environmental limits – hydro and pumped storage.

(Note: while 9696 is not precisely the description, it is representative for this event.)

Lack of Water Amplification Code – WC - Water Condition

With the development and evolution of Wind GADS reporting, the concept of Resource Unavailable Turbine Hours was created. This was created to address those times where there was nothing wrong with the equipment, but it was not producing because there was no wind blowing (i.e. no resource). The lack of wind is clearly outside management's control, just like stream flow levels and regulatory requirements for hydro plants. The acronym RUTH is used to identify this event in Wind GADS.

After much discussion, it was determined that a new event type that could be used for hydro was not practical for several reasons. It would create a new event that is different from historical events and would therefore compromise some of the data integrity of the existing data sets. Also, there was the matter of GADS software suppliers and ISO/RTO groups and the modifications to their code that would have to be implemented to create a new Event Code for hydro.

It was finally determined that a new Amplification Code (Amp Code or AC) could be identified and used in conjunction with the conventional GADS reporting criteria that would meet the requirements outlined above. It was determined to use the Amplification Code WC = "water condition" to describe these times when there is a lack of water for natural or regulator reasons at a run of river plant.

An additional benefit of this method is that if Planned Outage work or Maintenance Outage work was scheduled during this period of time – which would make the most sense – it would provide a way to identify the work being done in this lack of water condition.

Similar to RUTH in wind, the use of this amplification code provides a mechanism for hydro owners to characterize their units from an "equipment" perspective and allows planners and reliability operators to characterize the units from a "resource" perspective. In simple terms, if a unit is shut down due to lack of water, from a "resource" perspective that unit is not available for production and is viewed as a forced outage, due to lack of fuel and outside of management control. However, from an "equipment" perspective, the hours that the unit does not have water would not affect the unit reliability for plant performance metrics purposes used by the owner.

This concept is already covered in the conventional GADS equations. These are referred to as the "X" Equations in Appendix F of the DRI.[2] These "X" equations are presented to allow owners to remove those events that are

[2] Data Reporting Instructions (DRI); Appendix F: Performance Indexes and Equations; 2021 version

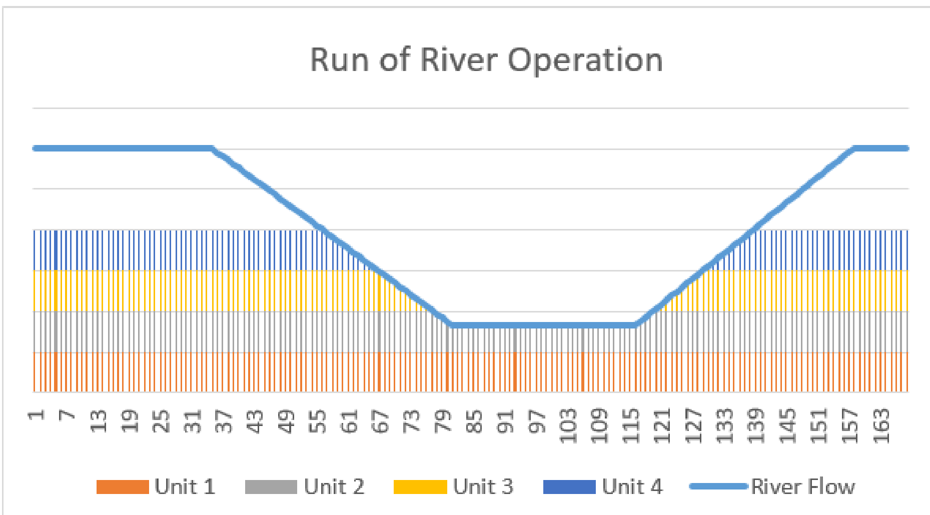
outside management control (OMC). Lack of Water (9135) and Regulatory (9405) are two of several OMC events that can be carved out by the definitions used for these "X" equations.

Using a similar logic as presented above, in order to keep the integrity of the existing system in place, it was determined that a separate set of equations for hydro assets that use this amplification code would be developed. The primary rationale for this is the correlation this event has with RUTH in the wind GADS reporting, the result being the ability to define "resource" and "equipment" performance metrics which are appropriately representative for their respective purposes.

Additionally, this provides a way for owners to place units in a Planned or Maintenance Outage when there is no water available and capture that event. Owners can then take units out of service without impacting their operating requirements.

Example 6:

The plant in the illustration below is a four unit plant. Due to reducing water releases from an upstream plant, the stream flows fall below the full capacity of the four units. Unit 4 is shut off on June 1 at 1400 hours (time tag 61 on the graph). Flows are high enough on November 1 at 2200 hours (time tag 127) and the unit is successfully started up and returns to normal operating service - at less than full load, but the unit is capable of full load.



This would be coded:

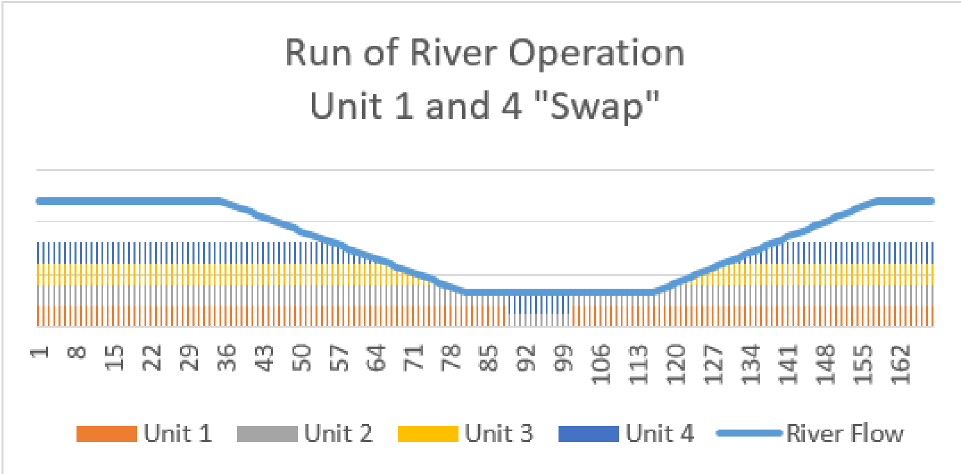
On June 1 at 1400 hours, Event: U3 Cause Code: 9135 Amp Code: WC

Unit 4 would remain in this status until November 1 at 2200 hours at which time this event ends.

Example 7:

The illustration below is for the same plant. As before, water conditions due to upstream releases do not allow all of the units to operate any longer due to lack of water. As before, Unit 4 is shut off on June 1 at 1400 hours (time tag 61 on the graph). On August 1 at 0600 hours (time tag 92) operations decides to reduce the operating hours on Unit 1 and shuts down Unit 1 and successfully starts up Unit 4. Now Unit 2 and Unit 4 are the operating units. Unit 4 is run for one month and on August 31 at 0600 hours Unit 1 is successfully returned to service and Unit 4 is shut down.

Flows are high enough on November 1 at 2200 hours (time tag 127) and Unit 4 is successfully started up and returns to normal operating service – at less than full load, but the unit is capable of full load



This should be coded:

Unit 1:

August 1 at 0600 hours; Event: U3, Cause Code: 9135, Amp Code: WC
August 31 at 0600 hours - Returned to Service (no event)

Unit 4:

June 1 at 1400 hours; Event: U3, Cause Code: 9135, Amp Code: WC
August 1 at 0600 hours - Returned to Service (no event)
August 31 at 0600 hours; Event: U3, Cause Code: 9135, Amp Code: WC
November 1 at 2200 hours - Returned to Service (no event)

Example 8:

This is exactly the same as Example 7 except that this time, Unit 1 is taken out of service and some Maintenance Work is performed on the fuses in the excitation rectifier bridge (Cause Code 4609)

This should be coded:

Unit 1:

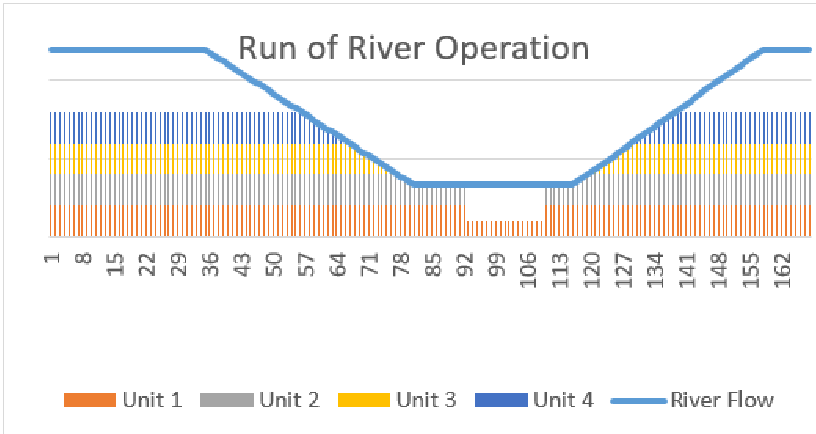
August 1 at 0600 hours; Event: MO, Cause Code: 4609, Amp Code: WC
August 31 at 0600 hours - Returned to Service (no event)

Unit 4 (no difference from above):

June 1 at 1400 hours; Event: U3, Cause Code: 9135, Amp Code: WC
August 1 at 0600 hours - Returned to Service (no event)
August 31 at 0600 hours; Event: U3, Cause Code: 9135, Amp Code: WC
November 1 at 2200 hours - Returned to Service (no event)

Importantly, note that the Maintenance Outage event (MO) still has the Amp Code WC attached to it as this maintenance work was performed when there was not enough water to operate this run of river plant. The implications of this are to be covered in the Equations section.

Example 9:
This is a similar situation as Example 7 above. In this example, a local agreement requires that on June 1 at 0600 hours until July 15 at 2200 hours the plant provide a minimum flow into a bypass reach to accommodate fish passage. This requires Unit 2 to be shut down and Unit 1 to be run at reduced load during this period of time.



This should be coded:

Unit 1:

June 1 at 0600 hours - No event, the plant continues to run Unit 1 at reduced load

Unit 2:

June 1 at 0600 hours, Event: U3, Cause Code: 9696, Amp Code: WC
July 15 2200 hours - Returned to Service (no event)

Unit 4:

June 1 at 1400 hours, Event: U3, Cause Code: 9135, Amp Code: WC
August 1 0600 hours - Returned to Service (no event)

Additional Note: For a complete description/coding for this event, Unit 3 would also be moved to a U3/9135/WC record with the appropriate time stamp. It would mimic the record for Unit 4. It was not included in the examples to shorten the example.

Additional Note: Some hydro plants experience times where the river flows are too high and units must be shut down due to lack of operating head. (These would typically be plants that are relatively low gross head with tail water conditions that rise when river flows are high. The combination creates a condition where there is not enough operating head (i.e. pressure to the runner) for the unit to produce power.) In these cases, the cause code 9000 – Flood along with the Amp Code WC should be used.

Tailwater Too High (cause code 9138 – High Water Level in Tailrace)
There are operating conditions with hydro turbines that can occur where the tailwater elevation becomes too high and the turbine does not have enough head (i.e. elevation difference between the forebay and tailwater levels) to operate reliably and the unit is shut down. This is not a common issue but does come up with some plants. When this operating condition occurs, the shutdown should be coded as a forced outage, U3, and given the cause code 9138.

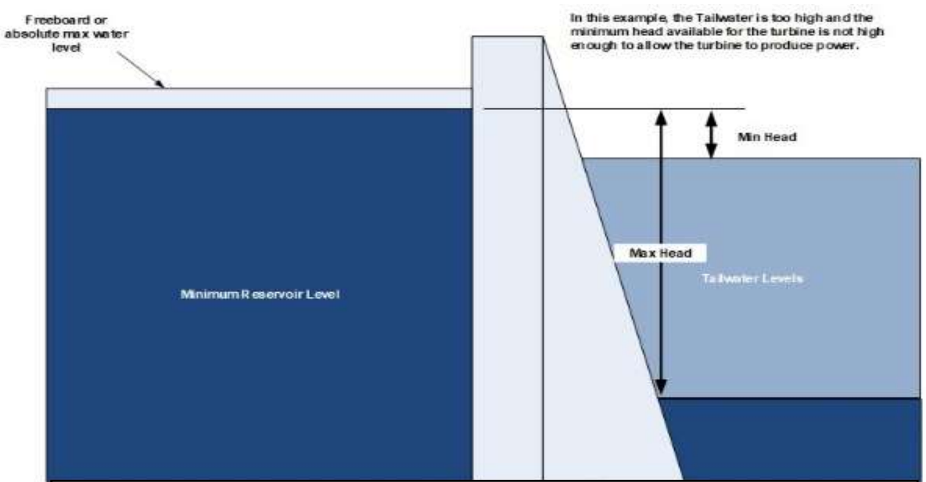


Illustration of High Tailwater Condition

Generally, this condition can occur when river flows are high due to flooding conditions that could be caused by severe rain storms or spring freshets when snow melt causes rivers to swell. If the tailwater channel below the turbine discharge area is constrained or the tailwater channel below the dam is constrained, the water is "backed up" and the tailwater level will rise. On a relatively low head dam, it is possible that the tailwater elevation rises to the point where there is not enough net head for the turbine to run. It is also possible that the turbines are unstable during these low head conditions which would also cause a shutdown.

Tailrace or Tailwater Issues (Cause Code 7180 – Tailrace)

GADS also has Tailrace cause code 7180. This is intended for a different purpose than code 9138. Another potential problem that is sometimes encountered at hydro plants is if the tailrace is too low to allow backpressure to build up on the turbine discharge that can cause water pressure fluctuations and an unstable turbine. While this condition can be alleviated with vacuum break valves or similar, some plants are not equipped with these devices and a lack of tailwater can prevent the unit from being placed on-line due to the instability. This should be coded as U1 or U2, cause code 7180.

Another use for this cause code would be if there was construction in the tailrace area to remove restrictions caused by debris in the tail channel. (I.e. a dredging project or debris removal project). In these cases, this could be a Planned Outage (PO) or could be a Maintenance Outage (MO) if it is in response to a land slide or other natural event.

Powerhouse Derate with Multiple Units

(This discussion can apply to any power station that has multiple Units and an overall station output limit is directed by an outside entity, typically it would be a transmission limitation.)

In a multiple unit powerhouse, there can be a limitation placed on the total output of the powerhouse that is not to be exceeded. There are many times where this limit may not pose a practical limit from an operational limit due to a lack of water. When this occurs, the limitation is to be stated as a derate on a unit or combination of units until the amount of the derate of the units is matched with the limit imposed on the powerhouse.

The examples below are set up to help illustrate how this is handled. There are some imbedded assumptions in this example. The first is that the plant is a peaking or pulsing plant. The second assumption is all units are fully available to generate to their full capability if called upon.

In the examples below, there is a three unit powerhouse with each unit's net dependable capacity (NDC=GDC) is 100 MW. There are two examples, one is the plant is limited to 240 MW output even though the plant could produce 300 MW. The other example is the plant is limited to 180 MW even though the plant could produce 300 MW.

There are three circumstances that are used to illustrate how a derate would be applied. These do not represent all of the possible combinations, but are intended to show the intent of how a plant limitation would be handled.

Constraint	Unit Size			
	100 MW	100 MW	100MW	
240 MW	On	Off	Off	A derate is required [note 1]
	On	On	Off	A derate is required [note 2]
	On	On	On	A derate is required [note 3]
180 MW	Off	On	Off	A derate is required [note 4]
	On	Off	On	A derate is required [note 5]
	On	On	On	A derate is required [note 6]

note 1	In this case, the plant needs to be derated 60 MW. You could choose to derate one off-line unit 60 MW, or split the derate between the two off-line units (i.e. derate 30 MW each, 20 MW on one unit or 40 MW on the other, etc.)
note 2	This is similar to note 1 except in this case the unit that is not operating would carry the full 60 MW derate. (However, you could elect to derate the two operating units and limit their output and reduce the amount of derate on the non-operating unit.)
note 3	As above, this would be spread according to how the units are operated. You may choose to limit the output of Unit 3 to only 40 MW. Alternatively, you could de-rate each of the units to 80 MW output.
note 4	Similar to Note 1, this would require the derate be set on one or split between both of the units.
note 5	In this case, there is not enough capacity available for the two units to operate so a derate would have to be set on the non-operating unit and the remainder either assigned or divided to the other two operating units.
note 6	As above, this would be spread according to how the units are operated.

In these examples, the derate would be coded as an immediate forced derate, D1, as this is imposed by an authority, not equipment condition. The most likely cause code would be 3619 – Other switchyard equipment – external (OMC). No Amp Code would be required.

Additional Note: If the same 300 MW plant is a run of river plant, the units would only be coded this way if there was water available that would allow generation to be above the 240 MW limit. If river flows are low enough so that only two units could operate, as an example, there would be no derate necessary. Using the 180 MW example above, if the river flows would only allow 200 MW of output, the plant would be derated by 20 MW over its current circumstance. The units would be coded:

Unit 1 – no events, operating as normal

Unit 2 – D1 (20MW), cause code 3619- Other switchyard equipment – external (OMC), no Amp Code

Unit 3 - U3, cause code 9135 – Lack of Water, Amp Code WC – Water Conditions

Hydro Equations

As stated above, there are times for run of river projects when units are out of service due to a lack of water. However, these units could be operated so their capability from an equipment perspective should reflect the lack of water condition. The circumstances here mirror the concept of RUTH in the Wind GADS reporting. In Wind, two sets of parallel equations were developed. One to report performance on the resource (includes RUTH hours), and one to report performance on the equipment (excludes RUTH hours). This same concept is currently being considered with Solar GADS as well. (How to account for hours when the sun is not shining.)

The current GADS system provides for a system of “X” equations that are specifically designed to create the performance measures that exclude those events that are outside management control (OMC). In concept, these are similar to the resource or equipment perspectives that are captured in Wind GADS using RUTH. However, these “X” equations would include all OMC events (such as the transmission limit discussed above) and it would be extra effort for both programmers and users to extract those “Water Condition” outages from the equations.

After considerable deliberation and vetting by different groups, it was determined that two sets of equations should be developed for hydro, one for “equipment” and one for “resource”, to determine the appropriate measures that would use the WC amp code as the qualifier. In short, the equipment equations would remove those hours when water was not available to operate the units, but the units were fully capable. With this methodology, it provides for outages during water conditions to not count against the equipment but still clearly assess the resources true availability from a planning or analysis perspective.

This method will also preserve the historically reported GADS data of the hydro assets. Data will continue to be reported as it had before. Only the new amp code will be added for those specific water conditions.

A series of equations for hydro will be developed that reflect the energy time diagram below. As can be seen, for run of river hydro stations there are the WC events as well.

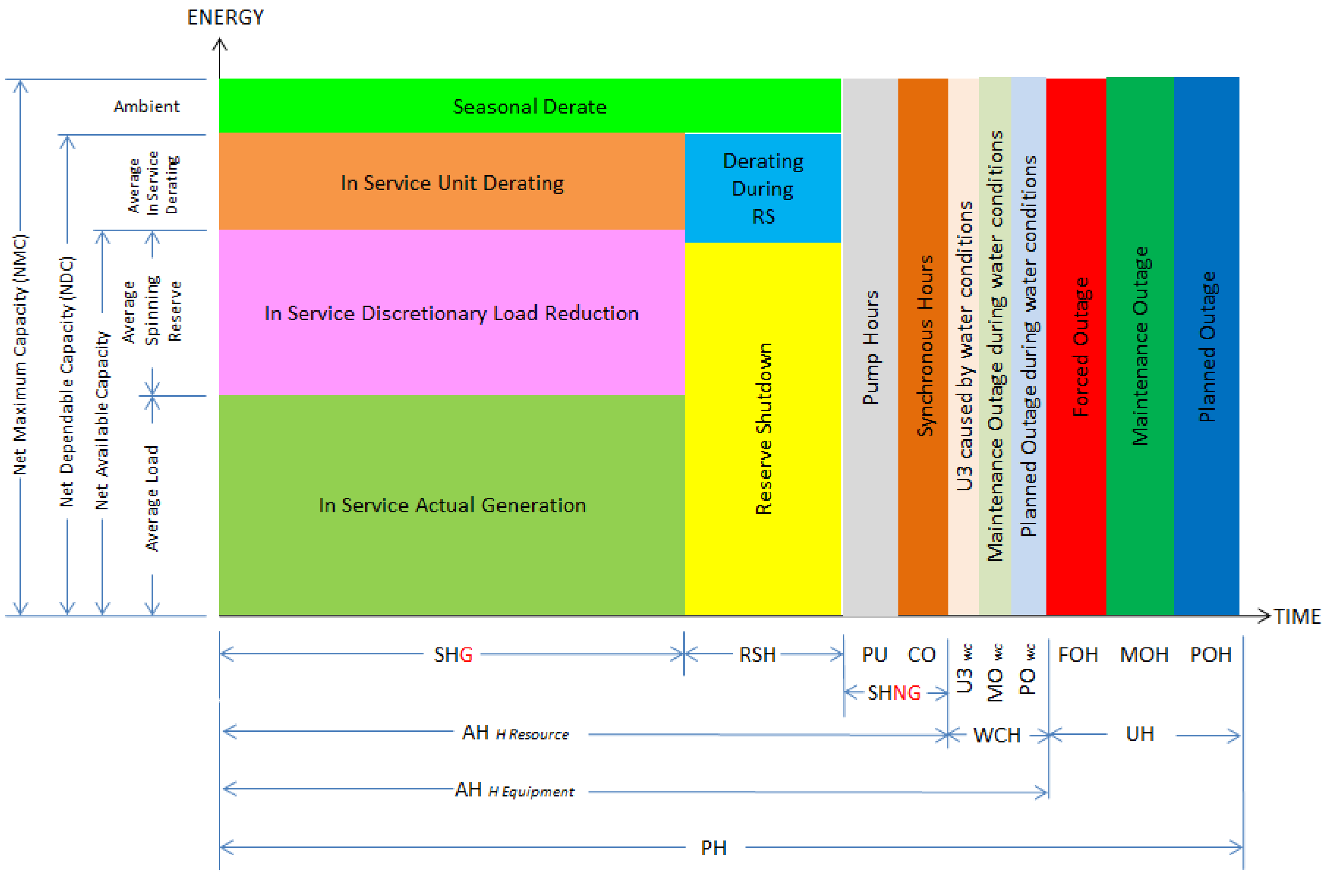


Figure 1: Hydro Unit Energy-Time Diagram

Abbreviations:

AH H Resource – Available Hours, hydro resource
AH H Equipment – Available Hours, hydro equipment
CO – Synchronous Condensing Hours
FOH – Forced Outage Hours
MOH – Maintenance Outage Hours
MO wc – Maintenance Outage Hours during water conditions
PH – Period Hours
POH – Planned Outage Hours
PO wc – Planned Outage Hours during water conditions
PU – Pumping Hours
RSH – Reserve Shutdown Hours
SHG – Service Hours generating
SHNG – Service Hours non-generating
U3 wc – U3 forced outage during water conditions
UH - Unplanned Hours
WCH – Water Condition Hours

As an example, in conventional GADS the Availability Factor (AF) is defined as:

$$AF = \frac{AH}{PH} X100\%$$

AH – Available Hours

PH – Period hours

$$AH = RSH + SH + +Sync\ Cond\ Hours + Pumping\ Hours$$

Substituting

$$AF = \frac{RSH + SH + +Sync\ Cond\ Hours + Pumping\ Hours}{PH} X100\%$$

This is as defined in Appendix F of the GADS DRI.

For run of river hydro, the Availability Factor from a resource perspective would be identical

$$AF_{h\ Resource} = \frac{RSH + SH + +Sync\ Cond\ Hours + Pumping\ Hours}{PH} X100\%$$

With the WC amp code, there are now some hours which would be counted as available for run of river hydro plants. For Run of River, those hours that are separated by the WC amp code would also be considered available hours. With this stipulation, the Available Hours for equipment would be:

$$AH_{h\ Equipment} = RSH + SH + Sync\ Cond\ hours + Pumping\ Hours + U3_{WC} + PO_{WC} + MO_{WC}$$

Substituting this into the equation for Availability Factor for hydro equipment:

$$AF_{h\ Equipment} = \frac{RSH + SH + Sync\ Cond\ hours + Pumping\ Hours + U3_{WC} + PO_{WC} + MO_{WC}}{PH} X100\%$$

A set of equations that characterize run of river hydro in this way would be developed similarly.

Additional Note: For peaking or pulsing hydro plants, the traditional equations would apply and these equations that account for water conditions would not be used.