METHODS TO ESTABLISH TURBO-GENERATOR OUTAGE INTERVALS

Relu Ilie

1. Introduction

Correct maintenance of generators may prevent faults and damage during operation, availability restrictions and significant financial losses. Experience has shown that planned inspection outages, tests and monitoring are extremely important in ensuring unit reliability. They may identify abnormal / accelerated aging of the generator and reduce future expenses by prompt repairs.

The recommended outage periodicity for large generators is normally included in the OEM's maintenance books. However, utilities may desire to use common rules for outage intervals, applicable to various machines or entire fleet, suitable to any flexible operation. Large standard organizations like IEC or IEEE do not issue such documents. However, the VDEW / VGB organization is publishing during the last 30 years a guideline / standard dealing with outage recommendations for turbo-generators. In addition to utilities, it has been adopted by some European OEMs as a maintenance instruction. This VGB document and its change in time is briefly described thereafter.

VDEW (The Association of the Electricity Industry) was founded in 1982 and expanded to represent the interests of around 750 German energy supply companies. In 2007, the VDEW was merged into the BDEW (Federal Association of Energy and Water Management). VGB is one of the independent professional associations included into VDEW. VGB PowerTech (recently the name changed to VGBE) is active in the generation and storage of electricity and heat. It was founded in 1920 and has today about 430 members, from 34 countries (mostly from European Union), representing an installed power plant capacity of more than 300 GW.

Among other activities, the VGB working groups are constantly developing guidelines and standards. The VDEW guideline "Recommendation for the overhaul intervals of turbo-generators" was issued in 1991 [1]. The next edition was the R-167 guideline "Overhaul recommendations for turbo-generators", published in German in 2010 [2] and translated to English in 2011. In 2021 this document was updated [3], this time as the VGB standard S-167 instead of a guideline. It seems that the last version obtained larger international OEM cooperation than the previous editions.

2. Methods overview

By the VGB document, the typical types of outages are as following:

- Short (minor) outage, without any dismantling, during of a few days,
- Medium (intermediate) outage, with partial dismantling but without rotor removal, during around 3 weeks,
- Major (main) outage, with removal of the rotor, during about 6 weeks.

(By other OEMs' recent documents, the present trend is to replace the medium outage by a borescope inspection and the major outage by a robotic inspection).

The first (initial) outage is similar in extent to a major outage; during the first operation period, the stator winding support system and other generator components experience a break-in period. Inspections similar in extent to first outages are also recommended after significant works, like replacement of main components or full rewinding.

Fixed outage intervals (recommended in the past) are often replaced today by flexible, operation mode-based outage intervals. The VGB method relies on calculating the equivalent operating hours Te, which indicates the generator stresses during a certain operating period, and thus the required inspection intervals. The equivalent operating hours are usually calculated from the start-up until the first major outage or between two successive major outages. Te is actually a sum of four terms, due to influences to the total amount of equivalent hours by:

- in-service operation,
- turning-gear regime,
- starts,
- load changes.

Each term is calculated from data recorded in the power plant (service hours, turning-gear time, number of starts) multiplied by various stress weighting factors. The weighting factors were initially determined empirically, and later have been readapted as a result of gain in experience and new data gathering technologies.

Traditionally the 1991 and 2010 editions specified one formula for Te:

$Te = T1 \bullet K1 + T2 \bullet K2 + n \bullet T3$.

One major change in the 2021 edition is that the above-mentioned influences are separately considered and evaluated for stator TeS and rotor TeR:

$TeS = T1 + n \bullet T3 \bullet KTypS + LK \bullet T3 \bullet KTypS \bullet LF \bullet (T1/8760)$
$TeR = T1 + T2 \bullet K2 + n \bullet T3 \bullet KTypR + LK \bullet T3 \bullet KTypR \bullet LF \bullet (T1/8760)$.

while the largest value of both is Te = max (TeS, TeR).

All terms, symbols and abbreviations are explicated thereafter.

3. In-service operation

Continuous operation of generators produces wear and requires adequate maintenance measures. The wear level depends by in-service time and generator design.

3.1. In the 1991 edition, the in-service (on-load) operation influence was calculated as:

$T1 \bullet K1$, with

T1 = service hours,
K1 = stress weighting factor for in-service state.

In that version, K1 was a discrete, generator power-dependent influence factor, between 0.7 to 1.0 (Figure 1).

Rated power S [MVA]	K1	K2	T3
S < 50	0.7	0.1	5
50 ≤ S < 250	0.8	0.1	10
250 ≤ S < 600	0.9	0.3	10
S ≥ 600	1.0	0.5	20

Figure 1 – Stress weighting factors by VGB 1991

3.2. In the 2010 edition, K1 became a constant factor K1 = 1, explained by the fact that for a generator already designed for a particular rated power continuous operation, its size influence is not required to be applied to the service time.

3.3. In the 2021 edition, K1 remains 1 and actually does not appear anymore in the formula of TeS and TeR.

4. Turning-gear regime

The turning-gear operation has a further influence on generator stressing. In case of low turning-gear speeds, the rotor winding moves relative to the rotor body in the radial direction with every rotation as a result of the force of gravity and may lead to increased wear of certain parts and to the formation of copper dust.

4.1. In the 1991 edition, the turning-gear regime influence was calculated as:

T2 • K2, with

T2 = turning-gear hours,
K2 = stress weighting factor for turning-gear state.

In 1991 edition, K2 was a discrete, generator power-dependent influence factor, between 0.1 and 0.5 (Figure 1).

If at turning-gear mechanical movements of rotor components are virtually nonexistent, the turning-gear operation causes less stress then on-load operation. With increasing rated power of the generator, more severe turning-gear stress is assumed, because longer rotors of larger generators are more susceptible to self-weight bending, in spite of turning-gear regime. Such rotors are also more sensitive than short compact bodies, because of their complex structure.

4.2. In the 2010 edition, the following formula was applied:

K2 = 1/4000 • S + 0.2, with minimum 0.2 and maximum 0.5

S being the generator rated power in MVA.

K2 was linearized with respect to the previous edition. It increases with the rated power, dependent on the rotor winding and other rotor parts being seated radially. Its maximum is limited because above a certain construction size, 4-pole generators with smaller length and larger diameter are used (Figure 2).

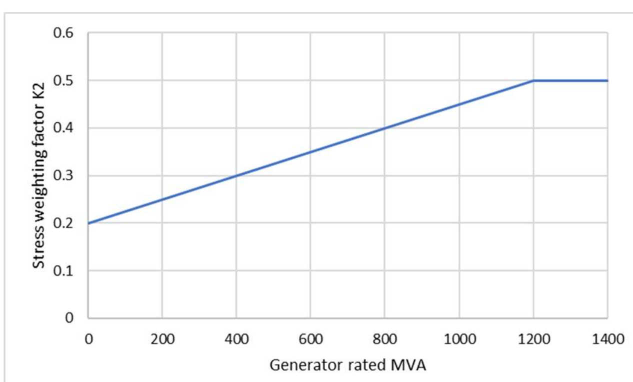

Figure 2 - Stress weighting factor for turning-gear by VGB 2010

If there are no actual records regarding turning gear hours, 50 hours per shutdown is assumed a reasonable estimate. However, it is necessary to check that service hours plus turning-gear hours do not exceed 8,500 hours per year.

4.3. In the <u>2021</u> edition, the turning-gear term is applicable only for rotor equivalent operating hours TeR. K2 formula and range above remain unchanged.

5. Starts

The stressing due to starts dependents on the preceding operating state of the generator (expansion and friction influences of temperature and centrifugal force cycles, vibration stresses, material fatigue, etc.). If the generator has completely cooled, the stresses are higher than in case of an instant new start after load shedding.

5.1. In the original <u>1991</u> edition, the starts influence was calculated as:

$n \bullet T3$, with

n = number of starts,
T3 = stress weighting hours for a start.

The weighting factor T3 was respectively estimated as 5, 10, 10, or 20 hours for 4 different rated power groups (see Figure 1).

The formula expresses that during start and load increase, different expansion coefficients of copper and iron cause relative movements of copper conductors in stator and rotor with respect to the iron parts, or deformation of the copper due to mechanical stresses. The stresses due to starts are length-dependent and hence are larger on longer bars, i.e. increase with generator size.

5.2. When implementing the <u>2010</u> edition, these 4 different factors were converted into one factor, linearly dependent on apparent power MVA:

$T3 = 0.015 \bullet S + 7$, with minimum 10 hours and maximum 25 hours

S being the generator rated power in MVA.

By the experience gained from the 1991 edition, the minimum value of T3 was raised from 5 to 10 hours, in order to correct the stress and outage intervals for small generators to realistic values. In addition, peak load gas turbine generators were better represented by this update (Figure 3).

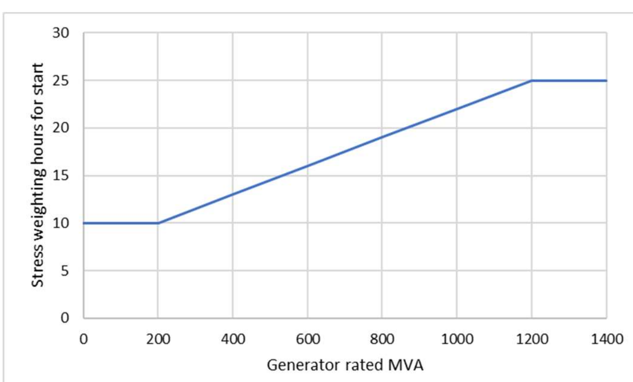

Figure 3 - Stress weighting hours for a start by VGB 2010

The type of cooling influence was indirectly considered via the machine size MVA; on larger generators, the value is roughly constant, because direct liquid cooling produces a more uniform heating of components.

5.3. In the 2021 edition it became apparent that a direct relationship to the output size of the generators is not always effective; this relationship is only valid to a limited extent due to the optimization of the cooling and the electrical design. For example, the output range of indirect air-cooled generators overlaps that of direct hydrogen / water-cooled generators. Therefore, in the 2021 edition cooling type factors KTypS and KTypR were introduced separately, for stator and rotor, and the starts influence to the equivalent hours was calculated as:

n • T3 • KTypS, respectively n • T3 • KTypR.

KTypS = cooling type factor stator, with a lower limit of 0.7
KTypR = cooling type factor rotor, with a lower limit of 0.7

In the new definition of T3, the dependence on rated power is no longer taken into account and it is considered now a constant factor:

T3 = 17.5 hours, as the average of 2010 edition maximum and minimum values.

KTypS and KTypR depend on the cooling medium used, type of cooling (direct or indirect) and generator size MVA. The temperature varies significantly across the insulation system, between that of cooling medium and that of copper. For example, in case of indirectly cooled stator windings, the temperature difference in air cooling is significantly smaller than in hydrogen cooling, since the specific heat capacity and heat dissipation capability of air is lower than that of hydrogen (Figure 4).

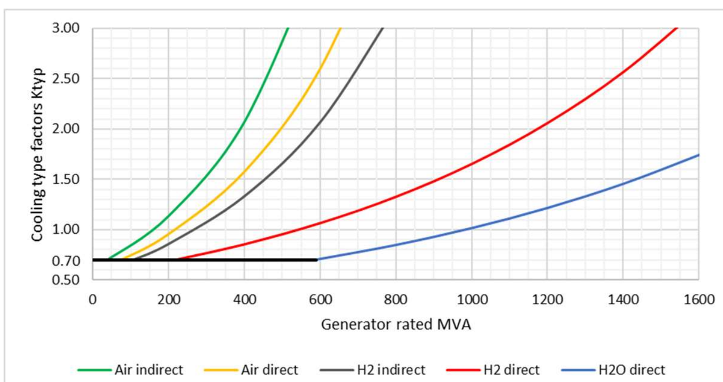

Figure 4 – Cooling type factors by VGB 2021

For each type of stator or rotor cooling, a power range was selected as a reference in which experience has shown that the corresponding thermal loads are safely reduced by such cooling. In the family of curves above, the weighting factor KTyp is set to 1 for this reference. The lower limit has been set at KTyp = 0.7. After calculating typical load cycles for different generator types, the factor KTyp was determined empirically for the different cooling types. For example, the effects of the load cycles on the equivalent operating hours of an indirect air-cooled stator at 450 MVA are valued more than twice as high as for a direct hydrogen-cooled stator.

6. Load changes

Frequent, large and rapid load changes (in active or reactive power) cause transient temperature differences between the different component parts of the generator. This can lead to relative displacements and thermo-mechanical stresses in different areas of the generator, and the resulting effects are strongly dependent on machine design, cooling type and extent of load changes.

6.1. The 1991 edition didn't take into consideration the load change influence.

6.2. In the 2010 edition, the load-change influence appeared for the first time as an Appendix, following increased requirements for flexible operation, characterized by frequent starts and cyclic loads. A simplified theoretical approach was presented, while experience was expected to be gained in coming years.

The stress due to sudden active or reactive load step changes was considered similar to additional starts, but with a weaker weighting factor. The change in stator or rotor current was calculated, and the temperature in conductor was assumed to change with the square of the current. This temperature change causes (among other things) a change in the mechanical stresses or linear expansion, and thus served in this simplified approach as a measure of the winding stress.

The 2010 guideline presented in Appendix an initial estimate of weighting factors for various sudden load step changes: a) active load change at constant reactive power; b) reactive load change at constant active power; c) both active and reactive power change at constant cos φ. For each case the change in stator and rotor current in per-unit of rated values is determined using the generator capability diagram. The simplified calculation of winding temperature change is the square of the current change, expressed in per-unit of initial (rated) temperature. The maximum value of the temperature changes in the stator and rotor was defined as the stress weighting factor for load change KLW (values from 0 to 1).

Five operation classes are indicated in the 2010 edition, as: base load, low-medium load, medium-upper load, peak load, and industrial power stations. Each group is characterized by typical annual service hours, turning-gear time and number of starts. For various rated MVA generator examples and operating modes, Te is calculated based on an assumed number of annual active power load cycles, at a certain rate (some 20% and some 50%). (A load cycle is considered starting from rated load operation, a lowering of the power, the continued operation with lowered power and a run-up back to rated load operation). The typical annual number of active power load cycles was considered up to 150.

Thus, the following additional equivalent operating hours result for load changes:

Σ (nLWi • KLWi) • T3,   with

nLWi = number of load changes in case of sudden change in power i
KLWi = weighting factor for load change in case of sudden change in power i
i = index of a certain sudden change in power.

6.3. In the 2021 edition, the load change influence is not any more experimental and optional, but it is introduced in the standard formulas for TeS and TeR. The partial load changes are evaluated similarly to starts (which actually are full load changes); their stress is significantly influenced by the cooling type and cooling medium, being taking into consideration through the newly introduced evaluation factors KTyp and by T3 = 17.5 h as described above:

LK • T3 • KTypS • LF • (T1/8760), respectively LK • T3 • KTypR • LF • (T1/8760)

LK = load cycle index (load change ratio) per 8,760 hours,
LF = load change factor = 0.6 (see below),
T1/8760 = extrapolation to actual in-service time.

- One method for a detailed investigation of cyclic load change influence on equivalent hours is typically possible using the data provided by modern control systems. By this approach, the sudden load changes are recorded in a time series, added-up in defined amplitude classes, and evaluated into application-specific operating mode bands. The technique normally used is the "rain-flow counting method" (a standardized cycle counting method normally used in fatigue strength analysis). The cycles are counted according to the two dimensions amplitude and mean value, stored in a two-dimensional matrix, and can be evaluated individually or altogether. The method counts completed cycles, regardless of their intermediate steps.

  For the weighting factor K of a sudden load change, the approach from 2010 edition is continued in that the temperature change in a conductor is simplified to the square of the current change. If the current is reduced from the initial rated one by ΔI, the change from the initial temperature is $\Delta\vartheta \approx 1^2 - (1 - \Delta I)^2$. If the initial current is any percentage value I, the temperature change is accordingly proportional to a weighting factor $K \approx I^2 - (I - \Delta I)^2$.

  However, recorded temperature and current values have shown that the approach of a proportional change in conductor temperature with the square of stator or rotor current provides practically too large values. On the one hand, the temperature range does not start at zero, but is limited downwards for load changes by the cold gas or cold-water temperature. On the other hand, the thermal time constants of the generator components lead to an asymptotic approach to the new temperature after a load change (Figure 5).

  The temperature changes recorded by measurements are between 50% and 70% of the temperature changes calculated from the currents. A load change factor LF = 0.6 is therefore recommended when using the 2021 standard.

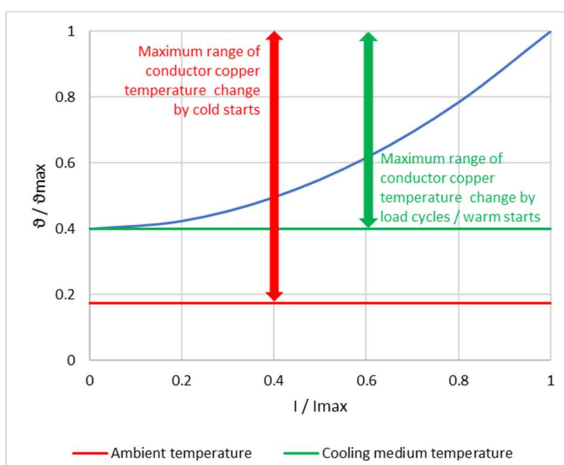

Figure 5 - Copper temperature change as a function of current change by VGB 2021

Coming back to the weighting factor K, it can be shown that it can be also expressed as dependent on the mean current value Im (between the initial and the final current change), as well as on the current change ΔI, as:

$K \approx 2 \cdot Im \cdot \Delta I$.

Factor K = 1 means a start from 0 to 100 % (average 50 %, sudden load change 100 %). The K factors are therefore limited to the maximum value of 1.

The result of the rain-flow counting method is a two-dimensional matrix with the sudden current change ΔI class being shown on the y-axis and the corresponding mean current value Im class on the x-axis. Each matrix cell contains the number of counted load cycles, which are multiplied by separate weighting factors K according to the formula above. If these products are added-up per each line, "sudden load change class sum" are obtained per each ΔI class. All individual sudden load changes class sums are added to the load cycle index LK per 8,760 hours, for a particular machine. Depending on the operational use of a power plant (number of load changes with different current changes ΔI and different mean values Im), a different load cycle index LK will result.

- Another method - pragmatic but usually sufficient - for <u>rough evaluation</u> of load cycle influence is to relate the specific application-mode generator to an operational load change class. The 2021 standard's authors concluded that the previously 2010 division into base load, lower medium load, medium upper load, peak load and industrial power plant is no longer suitable. The new grid codes and renewable energies, increasingly determine the operating conditions of the generator. The load change groups based on the operating conditions specified by the grid, are now combined into 4 typical load change classes, according to the load cycle index LK (as described above).

  The weighting factor K for sudden load change was introduced in the 2010 guideline Appendix depending on the sudden power change. As previously shown, the weighting factors are now taken into account both as a function of the current jump and as a function of the mean current, i.e. two-dimensional. The load cycle index LK thus represents the total load cycle load of an operating generator in the sudden load changes classes considered.

  Firstly, the load change classes have been evaluated for any small 2% sudden change in current. However, current changes below 8 % of the rated current do not cause any significant temperature changes and stress in the winding. Additionally, current change classes in the range of 0.8 to 1 are start-ups from a standstill and must be removed here since starts are shown separately in the formula for determining the equivalent operating hours. Thus, the relevant load change classes to influence the equivalent operating hours, are excluded for current changes < 8 % and > 80 %.

  The calculations of the load cycle indexes were carried out for various power plant operation scenarios and so LK resulted from 30 to 400 load cycles per year, which have been grouped in 4 load change classes (Figure 6).

Load cycle index LK		Load change class	Power plant operation scenario
30	30 - 60	**1**	Small load changes e.g. nuclear plants average of 45
40			
50			
60			
70	70 - 180	**2**	Moderate load changes e.g. lignite coal plants This is the most common class average of 120
80			
90			
100			
110			
120			
130			
140			
150			
160			
170			
180			
190	190 - 290	**3**	Increased load changes e.g. hard coal plants, average of 240
200			
210			
220			
230			
240			
250			
260			
270			
280			
290			
300	300 - 400	**4**	Large load changes, e.g. e.g. peak load plants average of 350
310			
320			
330			
340			
350			
360			
370			
380			
390			
400			

Figure 6 - Assignment of load cycle index LK to load change class and operation scenario by VGB 2021

On the basis of this representation, an estimation of the assignment should be possible in order to determine a relevant value for the load change class. Within the 4 groups, another gradual differentiation may be possible; otherwise, the average value can also be used.

Since the load change classes shown here were calculated for 8,760 hours of load operation, in the equivalent hours formula they have to be extrapolated to the actual service time T1 by the factor T1 / 8,760 (to eliminate the influence of different downtimes or turning gear operation).

7. Sequence of outages

The equivalent operating hours calculated as above are used to estimate the extent of stress to which the generator has been exposed by its design and mode of operation, and accordingly to establish the outage intervals.

Abnormal operational stresses (e.g. short-circuits near generator, faulty synchronization, overspeed, etc.) or influences of machine-specific factors (usually indicated by OEMs in maintenance book, TILs and bulletins) may lead to reduced outage intervals. On the other hand, risk-based outage intervals may consider the benefits of delaying maintenance (usually financial or related to system reserves) against the associated risks.

In general maintenance is carried out in regular cycles. In this way a maximum service life and a low level of wear can be expected for the maintained machines. Between two successive major outages, it is recommended to carry-out one or more short and medium outages. This leads to a sequence of short, medium and major outages, which can be chosen flexibly and whose intervals do not have to be identical.

The last outage prior to a major outage should be used for diagnostics in order to optimally prepare for the major outage.

Separate stipulations are to be formulated e.g. for turbo-generators of units in cold reserve, stand-by generators or similar.

7.1. In the 1991 edition, the major outage was recommended to be performed after:

- 40,000 to 60,000 equivalent operating hours,

while the initial inspection should be done after 10,000 to 20,000 equivalent operation hours.

7.2. In the 2010 edition, the major outage is recommended to be performed after:

- 50,000 to 70,000 equivalent operating hours for existing generators, dependent on actual condition
- up to 80,000 equivalent operating hours for new generators firstly operated in 2010 or later
- up to 100,000 equivalent operating hours if contractually stipulated, evaluated on an individual basis.

Independently of the recommendations indicated above, the calendarial time between successive outages should not exceed the following values:

- Short outages 3 years
- Medium outages 6 years
- Major outages 12 years.

In case of new machines, it is recommended to carry out the first major outage after 10,000 to 20,000 equivalent operating hours, before the warranty expires.

7.3. In the 2021 edition, the major outage is recommended to be performed after:

- 50,000 to 70,000 equivalent operating hours for existing generators, depending on actual condition
- 80,000 to 100,000 equivalent operating hours for new generators (not clear what new means).

The maximum calendrical times between successive outages remain identical to those in the previous edition.

For new machines, it is recommended to carry out the first major outage after 8,000 to 10,000 equivalent operating hours, before the warranty expires.

8. Examples of equivalent operating hours

In Figure 7, the equivalent operating hours have been calculated for 10 example generators, using the 2010 VGB guideline (without load change consideration) in comparison with the 2021 VGB standard (with load change contribution). In addition to the total equivalent operating hours, the percent of different influences (equation terms) have been separately evaluated.

The example generators are of various rated MVA powers S, have different cooling types for stator KTypS and rotor KTypR, and diverse operational data: service hours, turning-gear time and number of starts. They belong to different operation scenarios (load change classes) in terms of load cycle index LK per 8,760 hours.

Nr	Gen power MVA	Operation scenario	Stator cooling	Ktyp stator	Rotor cooling	Ktyp rotor	T1 h/year	K2	T2 h/year	n /year	LK /8760 h	2010 Te h/year	2010 Service %	2010 Turn gear %	2010 Starts %	2021 Te h/year	2021 Service %	2021 Turn gear %	2021 Starts %	2021 Load change %	2021/ /2010 Te/Te %
1	1600	Small load changes	H_2O dir	1.74	H_2O dir	1.74	8200	0.5	300	3	45	8425	97%	2%	1%	9210	89%	2%	1%	8%	109%
2	1200	Moderate load changes	H_2O dir	1.21	H_2 dir	2.06	8000	0.5	350	10	120	8425	95%	2%	3%	10907	73%	2%	3%	22%	129%
3	800	Moderate load changes	H_2O dir	0.85	H_2 dir	1.33	8000	0.4	350	10	120	8330	96%	2%	2%	9899	81%	1%	2%	15%	119%
4	800	Moderate load changes	H_2 dir	1.33	H_2 dir	1.33	8000	0.4	350	10	120	8330	96%	2%	2%	9899	81%	1%	2%	15%	119%
5	800	Moderate load changes	H_2 dir	1.33	H_2 dir	1.33	4000	0.4	1000	30	120	4970	80%	8%	11%	5860	68%	7%	12%	13%	118%
6	400	Moderate load changes	H_2 dir	0.85	H_2 dir	0.85	8000	0.3	350	10	120	8235	97%	1%	2%	9238	87%	1%	2%	11%	112%
7	800	Increased load changes	H_2 dir	1.33	H_2 dir	1.33	8000	0.4	350	10	240	8330	96%	2%	2%	11427	70%	1%	2%	27%	137%
8	1200	Large load changes	H_2O dir	1.21	H_2 dir	2.06	5800	0.5	3000	15	350	7675	76%	20%	5%	12855	45%	12%	4%	39%	167%
9	300	Large load changes	Air dir	1.22	Air dir	1.22	3000	0.275	4000	200	400	6400	47%	17%	36%	10149	30%	11%	42%	17%	159%
10	200	Large load changes	Air dir	0.95	Air dir	0.95	3000	0.250	4000	200	400	6000	50%	17%	33%	8711	34%	11%	38%	16%	145%

T3= 17.5 LF= 0.60

Figure 7 – Examples of equivalent operating hours calculation by VGB 2010 vs 2021

A similar comparison has been performed in Figure 8 based on some units' real data.

UNIT	Gen. power MVA	Period	Cooling stator	Ktyp Stator	Cooling rotor	Ktyp Rotor	T1 h	K2	T2 h	n	LK per 8760 h	Te VGB 2010 h	Te VGB 2021 h	VGB 2021/ VGB 2010
Eshkol 2	175	2012-2021	Air indir	1.05	Air dir	0.90	64383	0.24	14366	433	120	**72052**	**84305**	117%
											240		**93935**	130%
Gezer 40	550	2012-2021	H2O dir	0.70	H2 dir	1.01	57695	0.34	17405	382	120	**69395**	**76386**	110%
											240		**82464**	119%
Orot Rabin 5	647	2012-2021	H2O dir	0.74	H2 indir	2.29	72380	0.36	3400	68	120	**74746**	**85689**	115%
											240		**95041**	127%

Figure 8 – Examples of equivalent operating hours calculation by VGB 2010 vs 2021

The comparison shows that the equivalent operating hours calculated according to 2021 standard are consistently higher (by 9% - 67%) than those estimated by 2010 guideline, obviously leading to more frequent outages. The change is mostly a result of considering now the influence of load-changes; it is higher for higher load cycle indexes.

9. References

[1] Richtlinie *Empfehlungen für die Revisionsintervalle von Turbogeneratoren*, VDEW, 1991

[2] Richtlinie *Revisionsempfehlungen für Turbogeneratoren*, VGB R-167, 2010

[4] Standard *Revisionsempfehlungen für Turbogeneratoren*, VGB S-167, 2021