Principles for calculating a loss factor for the Skagerrak connection

Background

The Skagerrak interconnector contains four DC cables labelled SK1 - SK4. The newest cables, SK3 and SK4, have higher transmission capacity and significantly lower energy-losses than SK1 and SK2. Due to lower losses, the operators are running most of the power-flow on the Skagerrak connection towards the two newest cables, in order to improve effectiveness of the Skagerrak operation.

When operated in unity, the four cables are able to transmit more power than the sum of each cable on its own. Thus, the max physical flow on the Skagerrak interconnector is 1632 MW, which is determined by the receiving end flow, while the sum of each cable operated independently is 1350 MW. Further, by an arrangement between Statnett and Energinet, 100 MW are currently reserved for ancillary services, and therefore the max flow allowed for the day ahead and intraday market is 1532 MW.

The relation of max flow and losses on the respective Skagerrak cables are indicated in Table 1 based on a bottom-up model (Appendix 2). The table visualises the losses of each individual HVDC pole, from SK1 through to SK4, when operated independently and where the remaining three HVDC poles, respectively, are set to zero MW. The “sums at” columns further indicate the loss factor at max flow allowed after determining the receiving end capacity (1632 MW) and additionally when the 100MW for ancillary services are removed (1532 MW). As the below Table 1 indicates, there are different sizes of losses depending on how Skagerrak is operated.

	SK1	SK2	SK3	SK4	Sum at	Sum at
Max flow	227 MW	227MW	330 MW	481 MW	1532 MW	1632 MW
Loss at max flow	6.4%	6.4%	2.8%	2.3%	3,1%	3.5%

Table 1 Losses on the Skagerrak interconnector for the individual cables run in isolation, and for the total interconnection in sum for different load levels. Take note that the max load for each cable, when run in isolation, is smaller than the max load when run.

Figure 1 is a diagram showing the configuration of the four Skagerrak cables. All numbers in the Figure 1 are derived from a case with 1532 MW of flow from NO2-DK1.

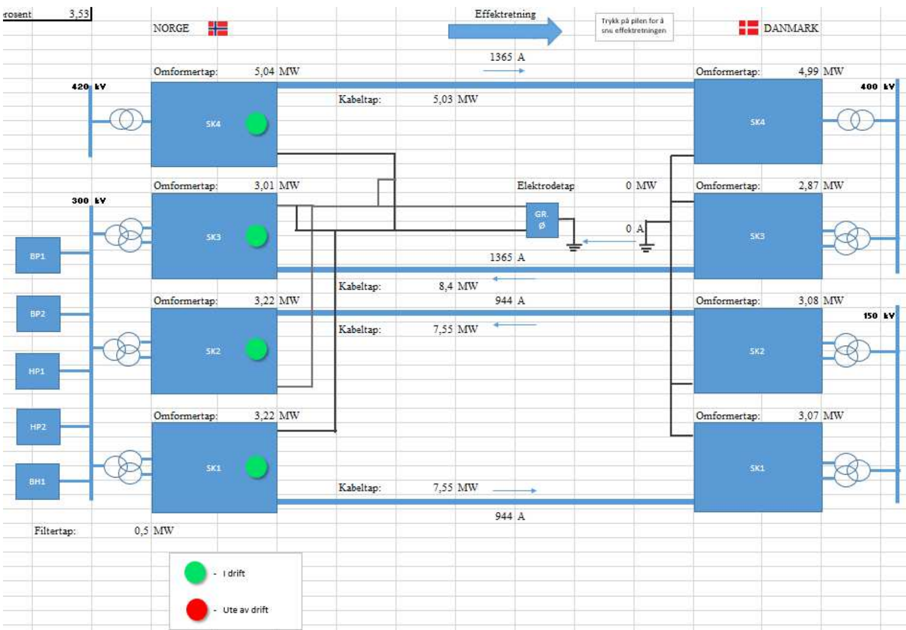


Figure 1 Configuration of the Skagerrak connections

As there are differences in the loss factor based on what assumptions are applied in the calculation thereof, Statnett and Energinet have agreed to the below methods and calculations.

Calculating a linearised loss factor for the Skagerrak connection

Losses on HVDC borders consisting of multiple poles, such as Skagerrak, shall be aggregated for each border. On these multi-pole borders the losses depend on the configuration of the DC circuit as well as the load sharing between the poles. This methodology proposes on a *proportional* loading of each pole of the HVDC border (e.g. 50% total multi-pole loading corresponds to 50% on each of the individual poles).

When the market clearing model (Euphemia) considers implicit losses, only a proportional factor of the flow can be included. This means that the square function has to be linearised near a typical operating point. In theory the factor could be updated for every hour based on a flow forecast. In reality this is not considered as a realistic approach worth the effort as it may require changes at the NEMO, missing transparency for the market participants and additional processes at the TSO while not necessarily providing any significant socioeconomic benefit. Thus, the below methodology describes, how the TSOs intend to calculate and apply the loss factor on the Skagerrak interconnector.

Function of the loss factor

The real losses on the DC cables are non-linear in relation to the flow. However, due to limitations in the market algorithm, the losses have to be represented by a linear relation (loss factor) to the flow in the following form:

Loss factor = "Real losses at reference flow (MW)" / "Reference flow (MW)"

Yet, as there are various ways of calculating the real loss factor, and also what reference flow/ linearisation point to be used, the following chapters will clarify Energinet and Statnett's argumentation and decision.

No-load losses

One of the factors that affect the loss factor calculation is the decision on integrating the converter losses at zero flow. With the converter losses at zero flow the linearisation of the loss factor has the base of zero flow, where there already is an amount of energy that is lost just due to having the interconnectors operational. Ignoring the no-load loss at the start of flow from the interconnector, the calculation will have the minimum flow as a basis. This will result in a difference in the linearisation, or rather the approximation, towards the reference flow.

The choice for Energinet and Statnett is to include the no-load losses in the linearisation. It is reasoned that including the no-load losses in the linearisation will lead to a result, where the error in estimation based on the reference flow will be minimized. Especially, due to the fact that there will not be many hours with partial load, thus, there will be a better approximation towards the real losses.

Approach for calculating the real losses

The real losses on the Skagerrak interconnector might be calculated either by a "top down", or a "bottom up" approach.

"Top down" approach

The "top down" calculation (see appendix 1), is based on applying a statistical estimator on real time measurements and gives a statistical estimation that resembles the actual flow. This method provides us with a statistical relation between flow and losses, depictured in Figure 2.

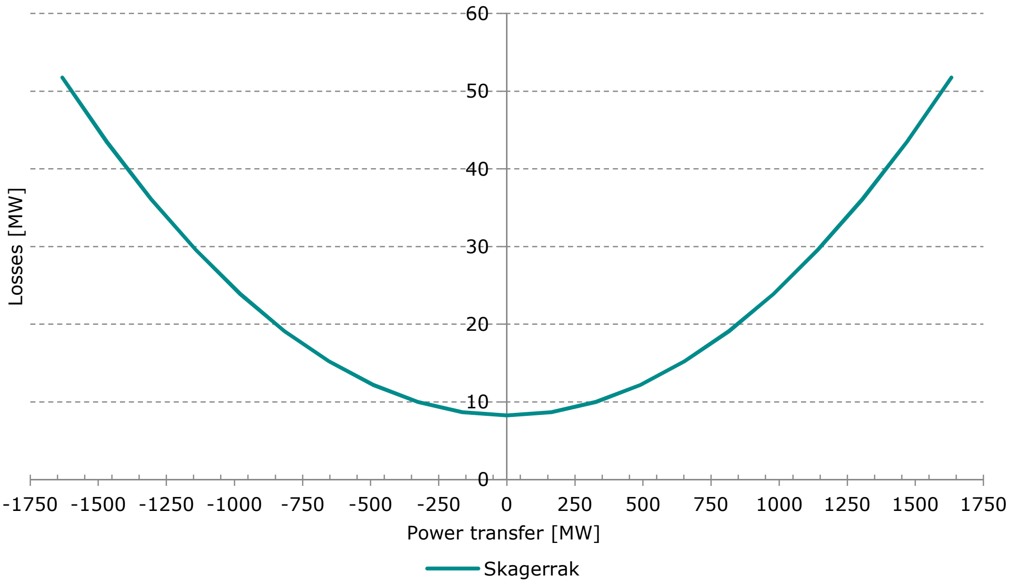


Figure 2 Estimated relation between flow and losses

"Bottom up"

The "bottom up" approach is implemented in a model/tool (see Appendix 2, the user interface is depicted in Figure 1). In this tool, all the components of the Skagerrak interconnector is modelled in detail[1] and the losses are calculated for different flows based on the real operation of the four cables forming the interconnector. The tool is based on the configuration depicted in Figure 1 and allows for disconnecting one or several of the cables, and an endogenous distribution of the flow on the connected cables.

Comparison of approaches

The bottom up model is more precise, as it represents a detailed calculation on a "component level", and it provides some optionality in terms of the possibility of shifting the loss factor if any of the different cables might be in an outage state. On the down side, this model will not capture different control settings applied within the year.

The statistical model will capture the fact that such different settings in the control systems (for example the distribution of flow on the four different cables) will vary within a year and influence the real losses. On the down side, the statistical model will have to be updated with a yearly frequency.

Both approaches estimate a linearised loss factor of ca. 3.2% at 1632 MW. In the "bottom up" tool, the 1632 MW of total flow is associated with operating the interconnector with a flow of 208 MW on each of SK1 and SK2, 500 MW on SK3 and finally 715 MW on SK4 according to the parameters set in the model.

Determine the reference flow

Independent of the approach, a linearised loss factor is required for application in the day ahead and intraday market. Due to the non-linearity of the real losses, this will cause an underestimation of the losses when the real flow is above the reference flow/linearisation point, and an overestimation whenever the real flow is below the estimation point. Thus, in principle, the TSOs should aim at a reference flow for the linearised loss factor calculation that will minimize the linearisation error.

[1] Take note that the bottom up model requires the input of all the components, and is based on the detailed information available on these, which are results gathered under certain conditions, that might not necessarily apply in all situations.

The below describes the arguments the TSOs encountered with regards to setting a reference flow.

In theory, it could be important to distinguish between different hours of the day or between different seasons. However, the difference in resulting loss factors by such differentiation seems small (as calculated by the "bottom up model"), and would probably create more uncertainty than gain. The evidence for this is depicted in Table 2.

	2013	*2014*	*2015*	*2016*	*2017*
Yearly	2.2%	2.2%	2.5%	2.5%	2.4%
Hours 08-16	2.2%	2.2%	2.5%	2.6%	2.4%
Hours 17-07	2.2%	2.2%	2.5%	2.5%	2.4%
Month 04-09	2.2%	2.2%	2.5%	2.5%	2.4%
Month 10-03	2.2%	2.2%	2.5%	2.6%	2.4%

Table 2 Calculated loss factors based on different time periods, "bottom up" model

The first row indicates the loss factor calculated based on a yearly average for the years 2013-2017, while the following rows present similar calculations for different time periods within each year. The difference between the years is not large, and the difference between time periods is even smaller. Based on these calculations, there is little reason to apply different loss factors for different time periods within a year.

Another relevant set of questions is how to calculate the yearly average. The options being:

a) Yearly average based on all hours
b) Yearly average based on all hours with a non-zero flow
c) Yearly median for all hours
d) Yearly median for all hours with a non-zero flow.

Calculated results for these options are presented in Table 3.

	2013	2014	2015	2016	2017
Yearly Average	2.2%	2.2%	2.5%	2.5%	2.4%
Yearly Average – non-zero flow	2.2%	2.3%	2.5%	2.6%	2.5%
Yearly Median	2.3%	2.3%	2.5%	2.7%	2.5%
Yearly Median – non-zero flow	2.3%	2.4%	2.6%	2.8%	2.5%

Table 3 Calculated loss factors based on different statistical selections, "Bottom up" model

The results in the above Table 3 indicate that the TSOs find the results quite consistent without significant deviations between the different statistical selection criteria. However, the calculation based on yearly median values using only hours with a flow different from zero, are producing slightly higher loss factors than the rest. It might be argued that this would be a better selection criteria because the error produced in high flow situations are larger due to the convexity of the real losses. Although, it does not seem very pronounced, “Yearly Median – non-zero flow” is the preferred method for calculating the reference flow for Energinet and Statnett.

<u>Loss factor at reference flow</u>

The below Table 4 presents the loss factor that is calculated based on the respective approach at the reference flow of 946 MW, which was calculated with aforementioned assumption (yearly median, only non-zero flow).

Reference flow (year)	Top Down	Bottom Up
2015	2,5 %	2,6 %
2016	2,6 %	2,7 %
2017	2,4 %	2,5 %

Table 4 Calculated loss factors based on the specified approaches and the reference flow at the given year.

As was the case before, the two approaches lead to a similar loss factor given the reference flow of the different years.

In conclusion as the "bottom up" approach provides the loss factor with the parameter settings, the data should be fitted with the top down approach, in order to approximate the real loss best possible.

For the future this will also provide the possibility to update the loss factor as explained in the following.

Process for update of loss factors

In any case, it should be possible for the TSOs to adjust the loss factor on a yearly basis but also dependent on certain planned or unplanned events. For example, if modifications of the HVDC line configuration lead to a change of the loss factor by more than e.g. 20 % (for instance due to a cable failure or adding a new pole) and the situation is expected to persist for more than one month the TSOs should be able to request NEMOs to update the factors with a one week notice after notifying the NEMOs and NRAs.

Further, the allocation of reserves on an HVDC border could affect the capacity made available to the market. This may also lead to an updated calculation of the loss factors. The update shall follow the principles in this methodology.

Loss factor on the NorNed interconnector

Implicit losses were implemented on the NorNed interconnector on November 18 2015. The methodology for calculating a loss factor was similar to the above proposals for the Skagerrak interconnector. The average losses on the NorNed interconnector are estimated by the quadratic equation:

(1) $Y_x = 0.000043 * x^2 + 0.00618 * x +1.4971$

The marginal loss is then provided by the equation:

(2) $Y_x = 0.000086 * x + 0.00618$

The reference flow level was set at the lower end of the midrange flow (300-400 MW) at 300 MW, providing a linearised loss factor at 3.2% that is implemented in the market algorithm. For 350 MW, the loss factor would have been 3.6%, and at 4.1 % at 400 MW.

In addition to the marginal loss, the fixed losses for energizing the interconnector (not a part of the marginal loss factor) is proposed to be procured separately.

From the discussion with the Dutch regulator it is clear that their biggest concern regarding the loss factor calculation is related to the choice of reference flow. From their perspective, it should not be based on the maximum flow, as it in most cases would lead to an underestimation of the losses. Thus, the TSOs of the NorNed cable chose an arithmetic median, as the reference flow. With regards to the marginal losses method chosen it is apparent that it is most accurate, compared to the top down or bottom approach, when the actual flow is equal to the reference flow. However, this does not occur often.

Conclusion

Based on the above consideration, Energinet and Statnett conclude on the following principles for calculating the loss factor on the Skagerrak interconnector.

The TSOs intend to include the converter no-load loss in the linearisation. Further, in finding the reference flow, the TSOs will not distinguish between different time-periods within a year, and in order to keep the loss factor both transparent and predictable, it seems favourable to include a loss factor with a yearly adjustment process for the market algorithm. Further, allowing an event based adjustment due to certain circumstances, such as the need for persisting modifications of the HVDC line configuration. As a statistical selection criteria (selection of the reference flow), the yearly median based on hours with a non-zero flow is chosen.

The real losses to be related to the reference flow could be derived by either model, either the "top down" or the "bottom up". In this respect, the “bottom up” model is chosen as the initial model, fitted with the data of the “top down” approach. Further, future updates are based on the “top down” approach. Thus, the TSOs choose a flexible approach, which both will have the detailed calculation on a “component level”, provide optionality in terms of shifting the loss factor if any of the different cables might be in an outage stage, while still allowing to capture variance in control settings based on updates of measurements within the year.

The two methodologies for Skagerrak and NorNed are similar in relation to calculation of both reference flow and the linearised loss component.

The loss factor based on the above described methodology estimates a loss factor at 2.5 % at the reference flow of 946 MW (in year 2017) for Skagerrak.

Appendix 1: Top-Down Approach

IMPLICIT LOSSES – LOSS FACTORS ON HVDC BORDERS FOR MARKET CLEARING

Transmission losses on HVDC lines can with good approximation be estimated from a function proportional to the square of the flow (load losses) plus a constant factor (no-load losses). Figure 1 shows an example of measured losses on the Great Belt HVDC line.

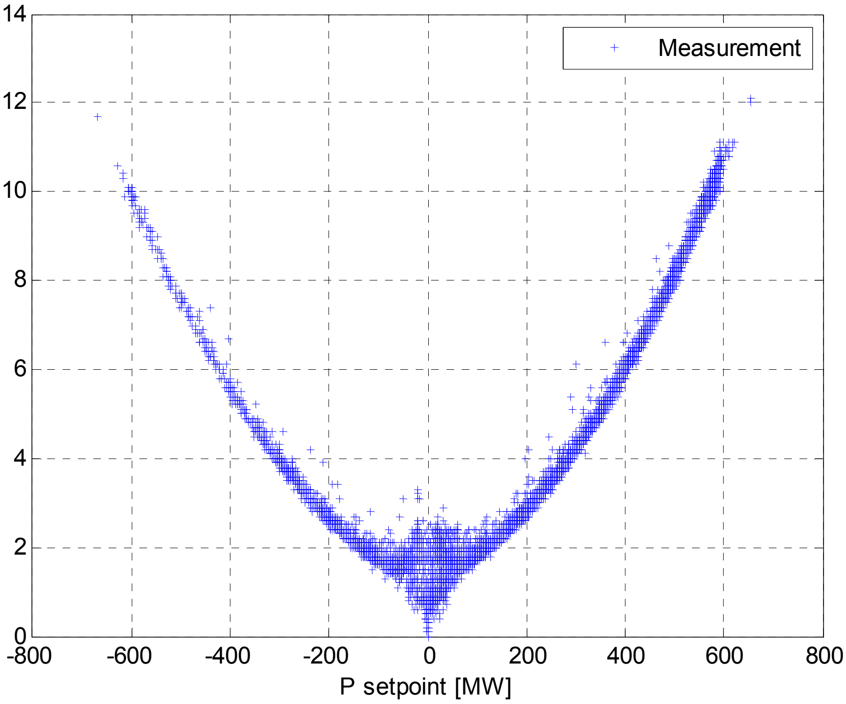


Figure 1 Example of measured losses on Great Belt (SB) for different power flows. Based on settlement data (MWh/h).

Losses can be slightly dependent on the direction of power. A *symmetrical* loss curve is considered. Based on this approximation method the estimated loss curves of the existing Danish HVDC lines are shown in Figure 2.

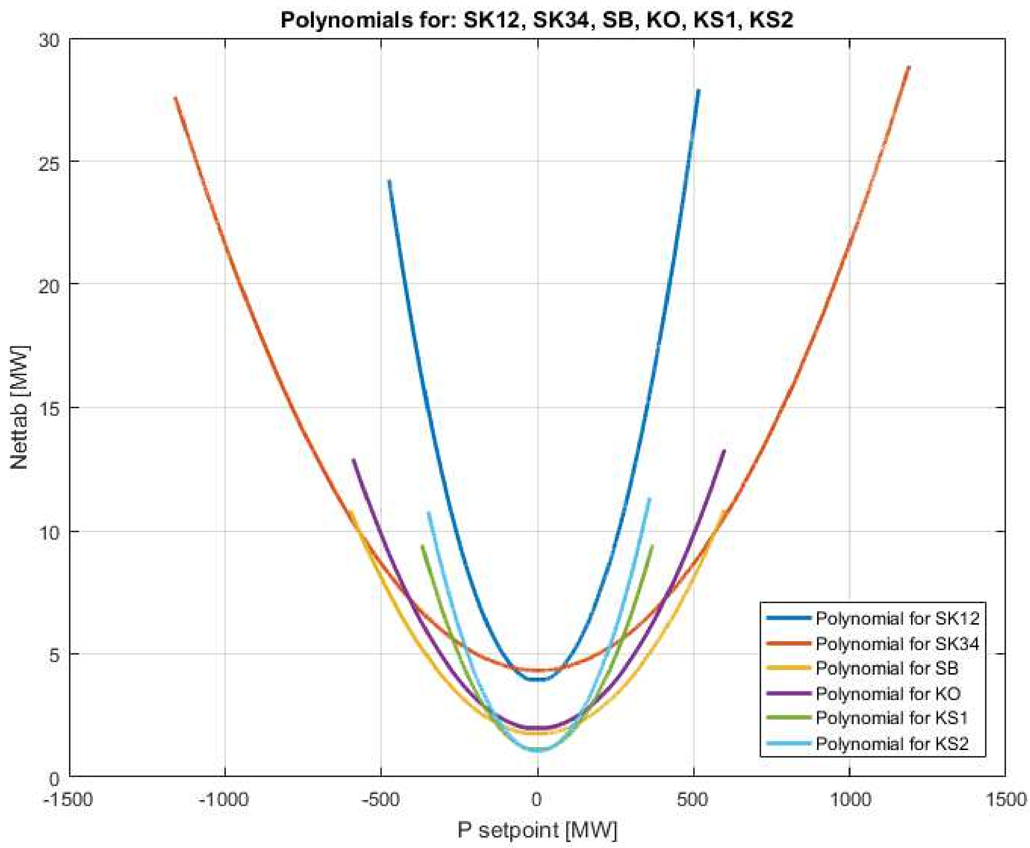


Figure 2 Total losses on existing HVDC lines Skagerrak (SK12, SK34), Storebælt (SB), Kontek (KO), Konti-Skan (KS1, KS2).

Dataset from 2014-2016

When the market clearing model (Euphemia) considers implicit losses only a proportional factor of the flow can be included. This means that the square function has to be linearised near a typical operating point. In theory the factor could be updated for every hour based on a flow forecast. In reality this is not considered as a realistic approach worth the effort as it may require changes at the NEMO and additional processes at the TSO while providing low socio economic benefit.

Losses on HVDC borders consisting of multiple poles (Skagerrak and KontiSkan) shall be aggregated for each border. On these multi-pole borders the losses depend on the configuration of the dc circuit as well as the load sharing between the poles. This methodology proposes on a *proportional* loading of each pole of the HVDC border (e.g. 50% total multi-pole loading corresponds to 50% on each of the individual poles).

Based on these considerations, the loss factor is calculated by *the HVDC losses at rated NTC divided by the NTC*. This is justified by the fact that the HVDC lines have a “high” utilisation factor and that “average losses” are not at “average flow” due to the losses increasing by the square of the flow.

The resulting square loss curves are shown in Figure 3 and Figure 4.

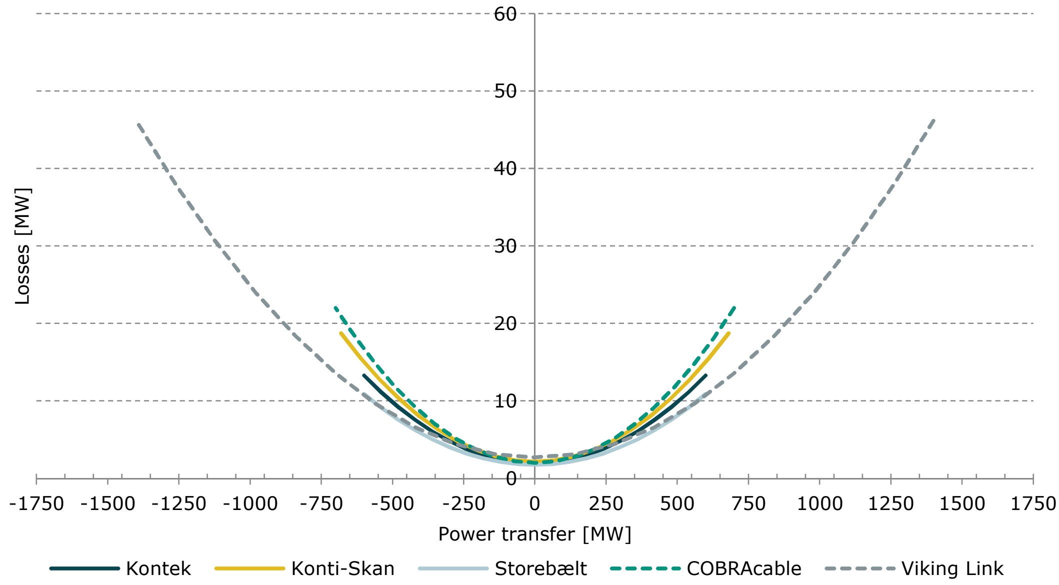


Figure 3 Estimated total losses on existing (solid line) and future (dashed line) HVDC lines for "normal" capacity HVDC borders.

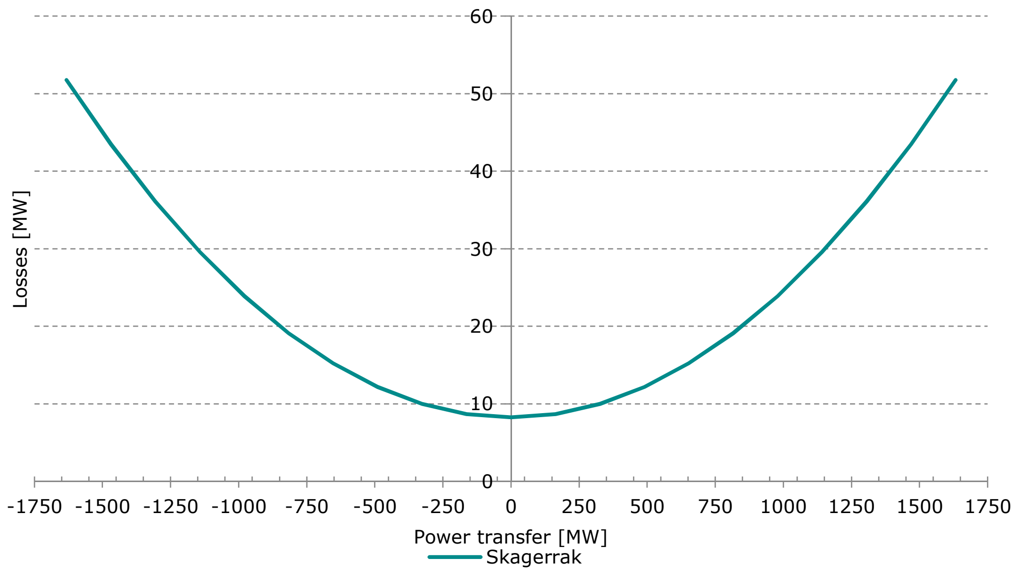


Figure 4 Estimated total losses on Skagerrak

The losses on the future links (dashed lines) are estimated and shall be updated prior to commissioning.

Kriegers Flak back-to-back HVDC link (2018) are not considered in the above as the tie lines on this connection will consist of two AC cables while the back-to-back link is located inside the Core region.

The resulting loss factors are indicated in the Table 1 below, which are calculated based on the max flow.

	Existing HVDC borders					New HVDC borders	
	Kontek	KontiSkan	Skagerrak	Great Belt		COBRAcable	Viking Link
Border	DK2-GE	DK1-SE3	DK1-NO2	DK1-DK2		DK1-NL	DK1-NL
NTC from-to	-600	-680	-1632	-600		-700	-1400
NTC to-from	600	740	1632	600		700	1400
Loss factor	0.022	0.028	0.032	0.018		0.031	0.033

Table 1 Existing and new HVDC borders - NTC and loss factor

The above table and related loss factors have to be updated, once there is a decision on having symmetrical capacities or not.

The loss factors are rounded to the two most significant decimal places.

Figure 5 and Figure 6 show the losses which will be considered implicitly in the market clearing.

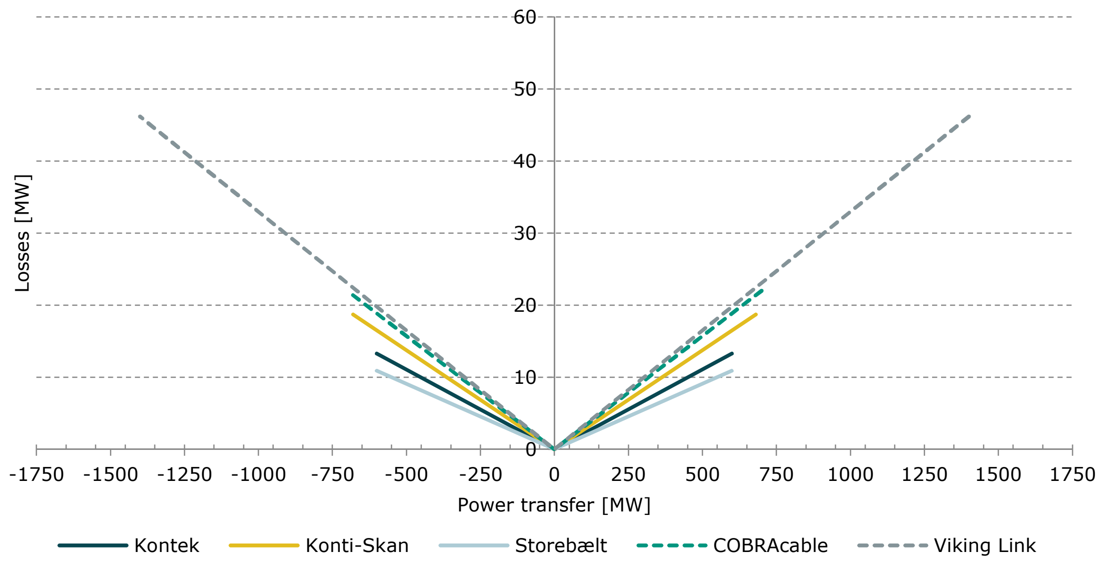


Figure 5 Loss factor on existing (solid lines) and future (dashed line) HVDC lines for "normal" capacity HVDC borders.

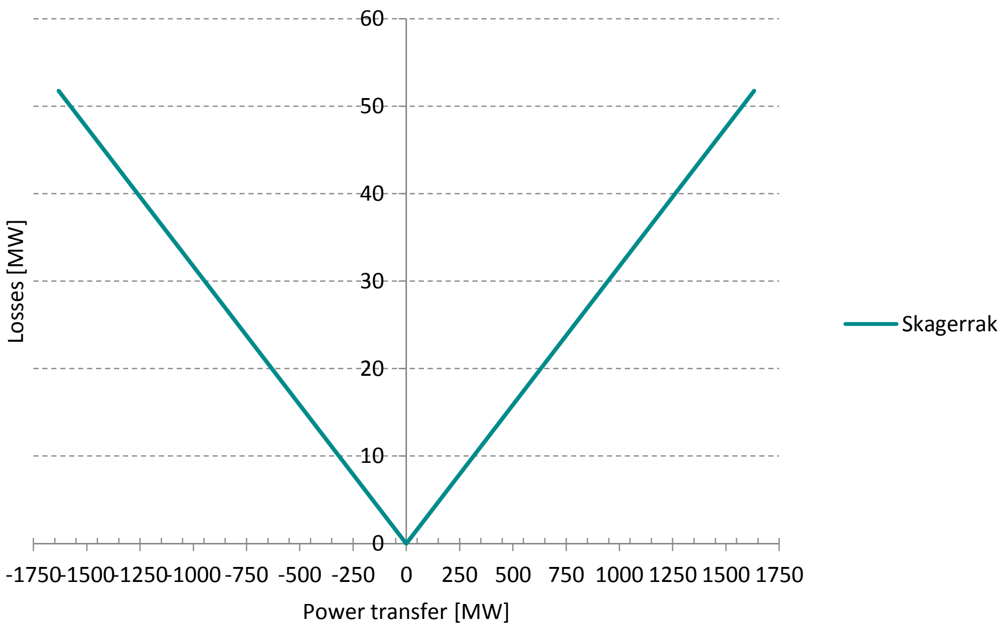


Figure 6 Loss factor on existing (solid lines) and future (dashed line) HVDC lines for "large" capacity HVDC borders.

Reporting

Annual report to the NRA could be good. In order to make the assessment and following adjustment of the loss factor more precise and efficient it is suggested to start a collection of data for the below Table 2.

HVDC border	Capacity A-B [MW]	Capacity B-A [MW]	Transferred power [GWh]	Physical losses [MWh]	Implict losses [GWh]
..	..	..	..	..	..

Table 2 Example of data collection fo rthe assessment and adjustment of loss factor

Process for update of loss factors

If modifications of the HVDC line configuration lead to a change of the loss factor by more than e.g. 20 % (for instance due to a cable failure or adding a new pole) and the situation is expected to persist for more than one month the TSOs should be able to request NEMOs to update the factors with a one week notice after notifying the NEMOs and NRAs.

Allocation of reserves on an HVDC border could affect the capacity made available to the market. This may also lead to an updated calculation of the loss factors. The update should follow the principles in this methodology.

ENERGINET Statnett

Appendix 2: Bottom-Up Approach

INNHOLD

INNLEDNING

Dette dokumentet er en beskrivelse av et forsøk på å implementere en makro i Excel som utfører tapsberegninger i de fire Skagerrak-kablene og tilhørende omformeranlegg. Datagrunnlaget for implementasjonen er et utvalg tekniske rapporter fra ABB/ASEA, som har levert omformeranleggene, og tilsvarende fra Nexans/Alcatel/Prysmian, som har levert kablene.

DATAGRUNNLAG

Datagrunnlaget for beregningene er hentet fra en rekke tekniske rapporter. For omformerne er disse Skagerrak "HVDC Overføring Tapsberegning" fra ASEA for SK1 og SK2, og "Determination of losses" fra ABB for SK3 og SK4 (to forskjellige rapporter). For motstand i sjøkablene er "Kontrakt av 27. september 1973 mellom Norges vassdrags- og elektrisitetsvesen og Standard Telefon og Kabelfabrik A/S for levering av 2 sjøkabler for likestrømsoverføring mellom Norge og Danmark" brukt for SK1 og SK2, "Skagerrak 3 Dokumentasjon" for SK3, og "Design Description, Submarine Cable Shallow Water" fra Nexans for SK4. Mostand for luftlinjer og elektroder er hentet fra et regneark med detaljerte beregninger av resistanser for ulike linjer. Se vedleggene for oversikt over komponentene i omformeranleggene som er tatt med i beregningene.

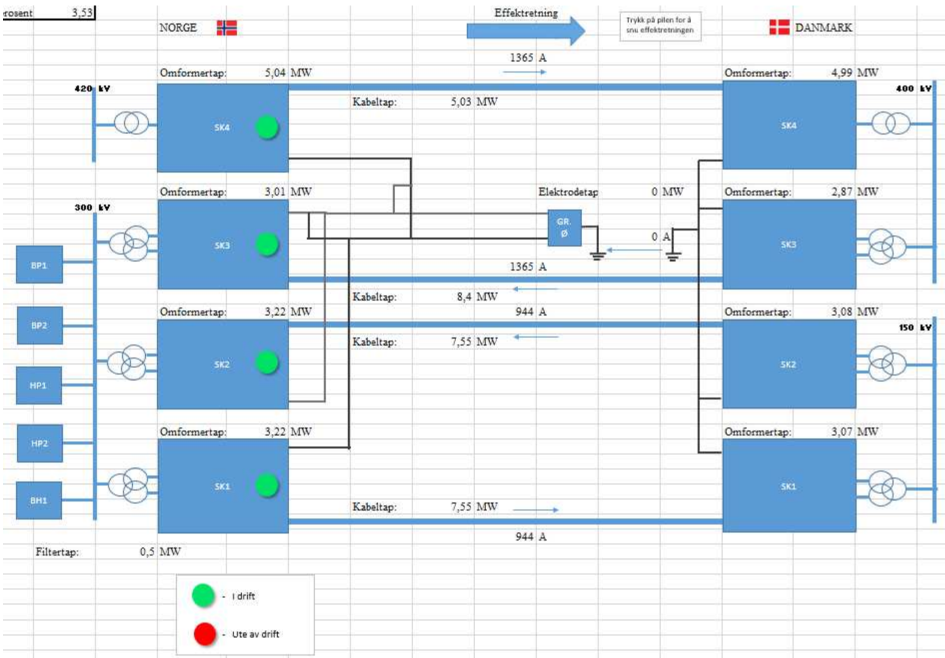
ANTAGELSER

For å muliggjøre beregningene i Excel, har en rekke antagelser og forenklinger blitt gjort. Det har blitt antatt (med unntak av luftlinjene til SK1-3 hvor man kan velge ledertemperatur på enten 20 eller 75 grader) en ledertemperatur på 20 grader, siden det hovedsakelig er resistans for denne temperaturen som er oppgitt i rapportene beregningene er basert på. Videre har det ikke blitt tatt høyde for systemtjenestekapasitet. Det tas ikke hensyn til reaktiv effekt, noe som vil si at tapene som regnes ut vil være et underestimat, da omformerne i SK1-3 i realiteten absorberer reaktiv effekt (det bør også nevnes at det i rapportene antas en effektfaktor på 1). Tapene i de kompenserende filtrene er tatt med, men har utregningene her har blitt noe forenklet. Istedenfor å laste opp filtrene i steg, regnes tapene ut ved å interpolere mellom null last og full last (for SK1-3). Data for filtertap er hentet fra de samme rapportene som omformertapene, mens antall filter ble funnet i en annen rapport fra ABB om harmoniske forstyrrelser [1].

Det bør presiseres at data for omformeranlegg i SK4 er av vesentlig mer detalj enn de øvrige. Her har man oppgitt tap for 0 (no-load), 10, 35, 50, 75 og 100 prosent belastning i rapporten, mens det for SK1-3 kun er oppgitt tall for no-load og full last. Dette medfører at nøyaktigheten for beregningene i disse omformerstasjonene vil være noe lavere enn for SK4 (her må det utdypes hvordan 10, 35, 50, 75-punktene ble regnet ut for SK1-3). Sammenligner man tapskurvene til SK4 med SK1-3 ser man at den er mindre konkav, noe som betyr at man muligens underestimerer tapene i SK1-3 mellom no-load og full last.

BRUKERGRENSESNITT

For å gjøre det enklest mulig for den som skal bruke modellen for tapsestimering, er dataene lagt i egne regneark for hver pol, med en enkel tegning av HVDC systemet som første ark:



Figur 4: Skisse av SK1-4 brukt som brukergrensesnitt i regnearket

Da er det bare velge hvilke poler som er i drift (grønn angir i drift/rød angir ute av drift), effektretning (angis og kan endres ved å krykke på blå pil) og samlet overføring på de polene som er i drift. Deretter startes tapsberegningen ved å trykke på knappen **Kjør**.

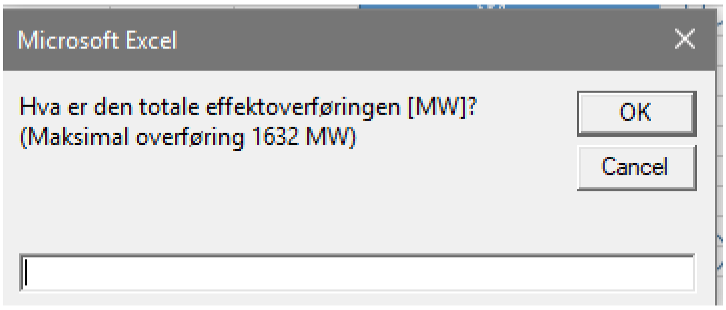
Informasjon om tapene i hver pol vises i nærliggende celler, som man kan se av bildet. Dette inkluderer omformertap, strøm (med retning), tap i DC kabel/ledning og elektrodestrøm.

Øverst i høyre hjørne presenteres de beregnede tapene ved den spesifiserte effektoverføringen på de ulike polene:

Total effekt	1632	MW	Tap i prosent	3,53
Totale tap	57,53	MW		
Effektfordeling				
SK1	236	MW		
SK2	236	MW		420
SK3	478	MW		
SK4	682	MW		
Tap				
SK1	13,84	MW		
SK2	13,85	MW		
SK3	14,28	MW		
SK4	15,06	MW		300

Figur 5: Hovedinformasjon tap med gitt effektoverføring på de ulike polene.

Her vises total effektoverføring, totale tap, effektfordeling i de ulike kablene, og tap som prosentandel av total overført effekt. Videre har man en "kjør"-knapp, som trykkes for utføre beregningene. Trykker man på den, fås dette vinduet opp midt på skjermen:



Figur 6: Vindu for valg av effektoverføring, alle poler i drift

I dette vinduet skriver man inn total effektoverføring, trykker OK, så kjøres makroen, og alle cellene oppdateres med nye verdier. Dersom man skylle krysse ut vinduet, eller skriver inn en effekt som er høyere enn overføringskapasiteten, settes alle cellene til null. Overføringskapasiteter er referert til sendende ende.

Temperatur i luftlinjer

Nede i høyre hjørne av modellen finner man denne:

Figur 7: Knapper for valg av temperatur DC luftlinjer SK1-3

Her velges temperaturen i luftlinjene for SK1-3 før kjøring. Økende temperatur i en leder gir høyere resistans, og i dette tilfellet vil 75 grader gi ca. 20 % større resistans enn 20 grader (det kan legges inn interpoleringsmuligheter her dersom dette er ønskelig, slik at man kan velge en temperatur mellom 20 og 75 grader). Det at man kan velge temperaturen her er egentlig uriktig, da man kan velge temperatur i lederne uavhengig av strømmen. I virkeligheten gir større strøm høyere ledetemperatur. Man kan heller se på det som oppveiende for mulige underestimater andre steder i beregningene, eller simpelthen sette temperaturen til 20 grader slik at det er konsistens med antagelsene i resten av beregningene.

Driftsmodi

Nede i høyre hjørne av modellen finner man denne knappen:

Figur 8: Mulighet for å endre tabell for driftsmønster.

Ved å trykke på **Endre tabell for driftsmønster**, kommer det opp en tabell med 16 ulike driftsmodi, vist i Tabell 1. Den inneholder 16 ulike kombinasjoner med Pol 1, 2, 3 og 4 i drift.

Driftmønster

DRIFTSMØNSTER

NR	Kabel kon	Rekkf	NTC SM	NTC 12	NTC 34	FRR	FCR	ATC 12	ATC 34
1	1+2+3+4	34+12	1632	472	1160	100	10	472	1160
2	1+2+3	3+12	802	472	330	100	10	472	230
3	1+2+4	4+12	953	472	481	100	10	472	381
4	1+3+4	34+1	1387	227	1160	100	10	227	1060
5	2+3+4	34+2	1387	227	1160	100	10	227	1060
6	1+2	12	472	472	0	0-100	0-5	372-47	0
7	2+3	3+2	330	0	330	0-100	0	0	230-33
8	1+4	4+1	915	233	682	0-100	0-10	233	582-68
9	3+4	34	1160	0	1160	100	10	0	1060
10	1+3	3+1	710	233	477	0-100	0	233	377-47
11	2+4	4+2	915	233	682	0-100	0-10	233	582-68
12	1	1	227	227	0	0	0	227	0
13	2	2	227	227	0	0	0	227	0
14	3	3	330	0	330	0-100	0	0	230-33
15	4	4	481	0	481	0-100	0-10	0	381-48
16	0	0	0	0	0	0	0	0	0

Hent siste innstillinger | Hent standardinnstillinger | Lukk

Endre verdier i tabell:

SK1 Pmaks, ikke i bipol | SK1 Pmaks, i bipol | SK34 Pmaks

SK2 Pmaks, ikke i bipol | SK2 Pmaks, i bipol | SK12 Pmaks

SK3 Pmaks, ikke i bipol | SK3 Pmaks, i bipol

SK4 Pmaks, ikke i bipol | SK4 Pmaks, i bipol

Oppdater tabell

Tabell 1: Oversikt over 16 ulike tilgjengelige driftsmodi for Skagerrak forbindelsene.

Det er ikke nødvendig å gå inn her med mindre man skal endre på kapasitetene for noen av de 16 driftsmodiene. Kapasitetene for de 16 driftsmodiene er hardkodet i modellen og kan alltid hentes fram ved å trykke **Hent standardinnstillinger**.

Det er mulig å endre kapasitetene ved å legge inn nye kapasiteter nederst og deretter trykke **Oppdater tabell**. Her kan man angi 10 nye kapasiteter, f.eks. **SK1 Pmaks, ikke i bipol**. Når man trykker **Oppdater Tabell**, så brukes denne kapasiteten i driftsmodi hvor SK1 driftes uten SK2, dvs. kapasitetene for driftsmodi 4, 8, 10 og 12 blir oppdatert.

For å gå ut av vinduet trykker man **Lukk**.

DRIFTSMØNSTER

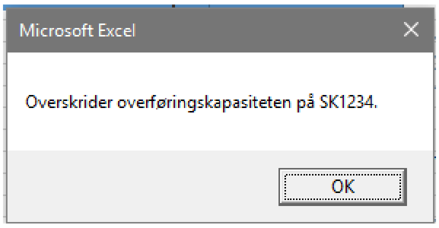
Oppdatert driftsinstruks med kapasiteter med 16 ulike driftsmodi, vist i tabellen nedenfor, ble mottatt av D&M ved Trond A. Jensen på e-post den 14. mars 2018.

Normalsituationer som ikke krever omkobling i HVDC-anleggene											
NR	Kabel kombi-nasjoner	Rekkefølge opplasting	NTC Sum korridor (MW)	NTC bipol 12 (MW)	NTC bipol 34 (MW)	FRR (MW)	FCR (MW)	ATC bipol 12 (MW)	ATC bipol 34 (MW)	Kommentar	Alternativt DM for drift med unntak for høy elektrodestrøm (inntil 40 timer)
1	1+2+3+4	34+12	1632	472	1160	100	10	472	1060		
2	1+2+3	3+12	802	472	330*	100	10	472	230	* NTC kun 330 MW på pol 3, hensynta elektrodestrøm.	20
3	1+2+4	4+12	953	472	481*	100	10	472	381	* NTC kun 481 MW på pol 4, hensynta elektrodestrøm.	18
4	1+3+4	34+1	1387	227	1160	100	10	227	1060		
5	2+3+4	34+2	1387	227	1160	100	10	227	1060		
6	1+2	12	472	472	0	0-100	(0-5)**	372-472	0	Leveranse av systemtjenester vil kun være aktuelt når ENDK er ledende. Begrensninger i FRR leveransen.	
7	2+3	3+2	330	0*	330*	0-100	0	0	230-330	* NTC kun 330 MW på pol 3, hensyntatt elektrodestrøm. Begrensninger i FRR leveransen.	19
8	1+4	4+1	915 NO2>DK1 481 DK1>NO2	233	682	0-100	(0-10)	233	582-682	Reduksjon retning nord pga. elektrodestrøm da polaritet på SK4 må endres manuelt ved endring av retning	
9	3+4	34	1160	0	1160	100	10	0	1060		
10	1+3	3+1	710	233	477	0-100	0	233	377-477	Begrensninger i FRR leveransen.	
11	2+4	4+2	915 NO2>DK1 481 DK1>NO2	233	682	0-100	0-10	233	582-682	Reduksjon retning syd pga. elektrodestrøm da polaritet på SK4 må endres manuelt ved endring av retning	
12	1	1	227	227	0	0	0	227	0	Ikke teknisk mulig å levere systemtjenester.	
13	2	2	227	227	0	0	0	227	0	Ikke teknisk mulig å levere systemtjenester.	
14	3	3	330	0	330*	0-100	0	0	230-330	NTC reduksjon pga elektrodestrøm. Begrensninger i FRR leveransen.	22
15	4	4	481	0	481*	0-100	0-10	0	381-481	NTC reduksjon pga elektrodestrøm.	25
16	0	34+12	0	0	0	0	0	0	0	Plan må lages i planverktøy.	

Figur 9: Tabell for driftsmønster SK1-4

Kort oppsummert er opplastningsrekkefølgen slik: Polene SK3 og SK4 lastes opp først, deretter SK1 og SK2. Hvis noen av polene er utilgjengelige, f. eks SK3, vil SK4 lastes opp til maksgrense for elektrodestrømmen nås (1000 A). Det kan nevnes at dersom alle kabler er tilgjengelige for overføring, vil man få noe mindre tap ved å laste de siste ca. 200 MW på SK1/2, men tabellen ble fulgt slavisk for enkelhets skyld. Det bemerkes at SK1 har strømretning sørover (dvs. fra Norge til Danmark), SK2 og SK3 nordover (dvs. fra Danmark til Norge). Dette innebærer at SK2 og SK3 driftes sammen (driftsmønster 7) gir begrensing i samlet overføringskapasitet på 330 MW på grunn av maksgrense på elektrodestrøm.

Dersom man skulle velge en effektoverføring som er høyere enn kapasiteten til polene som er i drift, vil alle cellene settes til null, og dette vinduet kommer opp:



Figur 10: Advarselsvindu, maksgrense for effektoverføring

IMPLEMENTASJON I EXCEL

For å regne ut tapene har det blitt skrevet funksjoner i Excels innebygde programmeringsspråk, Visual Basic for Applications. For å interpolere mellom de ulike datapunktene, brukes if-elseif setninger:

```
ElseIf (x >= 10 And x < 35) Then
    tap_likeretter = Range("B14").Value + ((Range("B15").Value - Range("B14").Value) / (Range("A15").Value - Range("A14").Value)) * (x - Range("A14").Value)
```

Figur 11: Utdrag fra VBA-kode, Tap_SK4_sør

	A	B	C
1	Data SK4 omformer		
2	Kristiansand:		
3			
4	Grunndata Omrformer		
5	Nominell effekt [MW]	715	
6	Nominell reaktiv effekt [Mvar]	85	
7	Nominell DC spenning [kV]	500	
8	Nominell Strøm [A]	1430	
9			
10	Tapsdata er tatt fra rapport 1JNL100182-648		
11			
12	Effektoverføring %	Likeretter [kW]	Inverter [kW]
13	0	360,4	360,4
14	10	950	926,4
15	35	1898	1850,1
16	50	2550,9	2417,4
17	75	3813,7	3793
18	100	5308,9	5360

Figur 11: Utklipp fra regneark "Tap SK4 omf"

Her ser man altså (med utgangspunkt i formelen for lineær interpolasjon) at setningen i Visual Basic svarer til å interpolere mellom 10 og 35 % belastning. Det er skrevet 8 funksjoner som regner ut tapene, en for hver kabel og retning (det er litt forskjell i tapene avhengig av om man kjører en bestemt omformer som inverter eller likeretter, i tillegg tas det hensyn til at noe av effekten går tapt i ledere. Eksempelvis med SK4: 100 % belastning i likeretteren gir ca. 99 % belastning i inverteren). I hver tapsfunksjon er det også lagt inn setninger som regner ut ledertap ut i fra strøm (regnes ut fra nominell spenning og overført effekt) og resistans.

"Hovedmakroen" baserer seg en representasjon av driftstilstanden av de ulike kablene som boolske variabler, hvor True representerer "I drift" og False "Ute av drift". Brukeren velger hvilke kabler som er i drift, skriver inn effektoverføring, og så evalueres den gitte driftssituasjonen og opplastningsrekkefølgen ut i fra hvilke kabler man har i drift og overført effekt, i tillegg til effektretning og temperatur for luftlinjer SK1-3. Egentlig er denne makroen bare en stor nøstet if-setning (se kommentarer i VBA-kode for mer informasjon).

VEDLEGG

Omformertap SK1-2

Kristiansand:

Objekt	Tomgångs förluster kW	Belastnings-förluster kW
Tyristorventiler	54	2 196
Strömriktartransformatorer	426	2 770
Fasreaktorer	-	17
Linjereaktor	-	37
Glättningsreaktor	2	263
Övertonsfilter	137	12
Källspänningstransf. Mätspänningsdelare Strömtransformatorer och mättransduktorer	1	5
Totalt hjälpkraftbehov till kylutrustning och kontrollutr.	765	-
SUMMA	1385	5300

Tjele:

Objekt	Tomgångs förluster kW	Belastnings-förluster kW
Tyristorventiler	54	2 196
Strömriktartransformatorer	398	2 937
Fasreaktorer	-	17
Linjereaktor	-	37
Glättningsreaktor	2	265
Övertonsfilter	141	16
Källspänningstransf. Mätspänningsdelare Strömtransformatorer och mättransduktorer	1	5
Totalt hjälpkraftbehov för kylutrustn. och kontrollutrustn.	765	-
SUMMA	1361	5473

[2]

Omformertap SK3

	No-load losses	Load losses Rectifier	Load losses Inverter	
Kristiansand				
Converter Transformers	301.5	1613.2	1613.2	kW
Thyristor Valves	14.4	753.1	758.3	kW
Smoothing Reactors	0	119.8	119.8	kW
AC Filters	0	123.4	127.3	kW
DC Filters	0	9.4	9.6	kW
Converter transformer coolers	5.2	15.7	15.7	kW
Thyristor valve coolers	5	76	76	kW
Other aux. consumption	13.2	13.2	13.2	kW
Total losses	339.3	2724	2733	kW

	No-load losses	Load losses Rectifier	Load losses Inverter	
Tjele				
Converter Transformers	307.9	1587	1587	kW
Thyristor Valves	14.4	753.1	758.4	kW
Smoothing Reactors	0	119.8	119.8	kW
AC Filters	0	223.1	244.8	kW
DC Filters	0	14.2	14.2	kW
Converter transformer coolers	4	16	16	kW
Thyristor valve coolers	5	76	76	kW
Other aux. consumption	13.2	13.2	13.2	kW
Total losses	344.5	2802	2829	kW

[3]

Omformertap SK4

	LOAD LOSSES. KRISTIANSAND [kW]					
	Rectifier					
P [%]	**0%**	**10%**	**35%**	**50%**	**75%**	**100%**
IGBT valves [kW]	60,6	358,3	1106,3	1547,3	2294,8	3081,5
Valve cooling [kW]	35,5	84,5	97,0	104,5	117,0	132,0
Cell capacitors [kW]	2,9	2,0	7,7	14,3	30,9	50,8
HF dampers [kW]	0,0	7,1	8,3	9,7	13,2	18,0
Power transformers [kW]	213,0	103,2	243,6	393,9	750,9	1261,2
Cooling of power transformers [kW]	13,5	0,0	0,0	0,0	13,5	13,5
Converter reactors [kW]	0,0	2,2	26,5	54,2	122,4	218,9
Smoothing reactors [kW]	0,0	0,8	9,2	18,8	42,2	74,8
AC PLC/RI reactors [kW]	0,0	0,3	3,2	6,6	14,9	26,9
DC PLC/RI reactors [kW]	0,0	0,3	3,7	7,5	16,9	30,0
Auxiliary losses [kW]	34,9	20,2	20,3	20,3	20,5	20,6
BR2 Capacitors [kW]	0,0	0,1	1,2	2,4	5,5	9,7
HF Filter Capacitor [kW]	0,0	0,8	0,8	0,8	0,8	0,8
DC Capacitor [kW]	0,0	9,8	9,8	9,8	9,8	9,8
Total Load Losses [kW]	**360**	**589**	**1538**	**2190**	**3453**	**4948**
Total Operating Losses [kW]	**360**	**950**	**1898**	**2551**	**3814**	**5309**

	LOAD LOSSES. KRISTIANSAND [kW]					
	Inverter					
P [%]	**0%**	**10%**	**35%**	**50%**	**75%**	**100%**
IGBT valves [kW]	60,6	338,6	1068,3	1518,4	2316,2	3173,6
Valve cooling [kW]	35,5	82,0	97,0	104,5	119,5	134,5
Cell capacitors [kW]	2,9	2,0	7,6	14,0	30,5	47,0
HF dampers [kW]	0,0	7,1	8,3	9,7	13,1	18,0
Power transformers [kW]	213,0	102,0	234,9	372,9	709,5	1222,5
Cooling of power transformers [kW]	13,5	0,0	0,0	0,0	13,5	13,5
Converter reactors [kW]	0,0	2,1	25,8	53,0	120,6	218,1
Smoothing reactors [kW]	0,0	0,7	9,0	18,4	41,7	74,8
AC PLC/RI reactors [kW]	0,0	0,3	3,1	6,4	14,7	26,7
DC PLC/RI reactors [kW]	0,0	0,3	3,6	7,4	16,7	30,0
Auxiliary losses [kW]	34,9	20,2	20,3	20,3	20,5	20,6
BR2 Capacitors [kW]	0,0	0,1	1,2	2,4	5,5	9,7
HF Filter Capacitor [kW]	0,0	0,8	0,8	0,8	0,8	0,8
DC Capacitor [kW]	0,0	9,8	9,8	9,8	9,8	9,8
Total Load Losses [kW]	**360**	**566**	**1490**	**2138**	**3433**	**5000**
Total Operating Losses [kW]	**360**	**926**	**1850**	**2499**	**3793**	**5360**

	LOAD LOSSES, TJELE [kW]					
	Rectifier					
P [%]	**0%**	**10%**	**35%**	**50%**	**75%**	**100%**
IGBT valves [kW]	60,6	358,3	1106,3	1547,3	2294,8	3087,4
Valve cooling [kW]	34,5	81,5	93,5	99,5	110,0	120,5
Cell capacitors [kW]	2,9	2,0	7,7	14,3	30,9	51,6
HF dampers [kW]	0,0	7,1	8,3	9,7	13,2	18,0
Power transformers [kW]	213,0	103,2	243,6	393,9	750,9	1267,8
Cooling of power transformers [kW]	13,5	0,0	0,0	0,0	13,5	13,5
Converter reactors [kW]	0,0	2,2	26,7	54,6	123,3	220,6
Smoothing reactors [kW]	0,0	0,7	9,2	18,7	42,0	74,5
AC PLC/RI reactors [kW]	0,0	0,3	3,2	6,6	14,9	26,9
DC PLC/RI reactor [kW]	0,0	0,3	3,7	7,5	16,9	30,0
Auxiliary losses [kW]	21,2	5,3	2,3	2,3	2,4	5,4
BR2 Capacitors [kW]	0,0	0,1	1,2	2,4	5,5	9,7
HF Filter Capacitor [kW]	0,0	0,8	0,8	0,8	0,8	0,8
DC Capacitor [kW]	0,0	9,8	9,8	9,8	9,8	9,8
Total Load Losses [kW]	**346**	**572**	**1516**	**2168**	**3429**	**4937**
Total Operating Losses [kW]	**346**	**917**	**1862**	**2513**	**3775**	**5282**

	LOAD LOSSES, TJELE [kW]					
	Inverter					
P [%]	**0%**	**10%**	**35%**	**50%**	**75%**	**100%**
IGBT valves [kW]	60,6	338,6	1068,3	1518,4	2316,2	3180,2
Valve cooling [kW]	34,5	81,5	92,0	98,0	110,0	122,0
Cell capacitors [kW]	2,9	2,0	7,6	14,0	30,5	47,7
HF dampers [kW]	0,0	7,1	8,3	9,7	13,1	18,0
Power transformers [kW]	213,0	102,0	234,9	372,9	709,5	1222,5
Cooling of power transformers [kW]	13,5	0,0	0,0	0,0	13,5	13,5
Converter reactors [kW]	0,0	2,1	26,0	53,4	121,5	219,7
Smoothing reactors [kW]	0,0	0,7	9,0	18,4	41,6	74,5
AC PLC/RI reactors [kW]	0,0	0,3	3,1	6,4	14,7	26,7
DC PLC/RI reactors [kW]	0,0	0,3	3,6	7,4	16,7	30,0
Auxiliary losses [kW]	21,2	5,3	2,3	2,3	2,4	5,4
BR2 Capacitors [kW]	0,0	0,1	1,2	2,4	5,5	9,7
HF Filter Capacitor [kW]	0,0	0,8	0,8	0,8	0,8	0,8
DC Capacitor [kW]	0,0	9,8	9,8	9,8	9,8	9,8
Total Load Losses [kW]	**346**	**551**	**1467**	**2114**	**3406**	**4981**
Total Operating Losses [kW]	**346**	**896**	**1813**	**2460**	**3751**	**5326**

[4]

REFERANSER

[1] "Skagerrak 4 - Harmonic Performance Study", ABB

[2] "Skagerrak HVDC tapsberegning" (SK1-2), ASEA

[3] "Determination of losses" (SK3), ABB

[4] "Determination of losses" (SK4), ABB