

## Modulo per la presentazione delle osservazioni per i piani/programmi/progetti sottoposti a procedimenti di valutazione ambientale di competenza statale

### Presentazione di osservazioni relative alla procedura di:

- Valutazione Ambientale Strategica (VAS) – art.14 co.3 D.Lgs.152/2006 e s.m.i.  
 Valutazione di Impatto Ambientale (VIA) – art.24 co.3 D.Lgs.152/2006 e s.m.i.  
 Verifica di Assoggettabilità alla VIA – art.19 co.4 D.Lgs.152/2006 e s.m.i.

Il Sottoscritto Giovanni Battista Cossu

Il/La Sottoscritto/a \_\_\_\_\_

in qualità di legale rappresentante della Pubblica Amministrazione/Ente/Società/Associazione

*(Nel caso di persona giuridica - società, ente, associazione, altro)*

### PRESENTA

ai sensi del D.Lgs.152/2006, le **seguenti osservazioni** al

- Piano/Programma, sotto indicato  
 Progetto, sotto indicato

ID: [ID12481] \_ [ID 12481] - Progetto di un impianto agrivoltaico, della potenza complessiva pari a 34,769 MWp, da realizzarsi in località Villamuscas - Comune di Uta (CA) (PNIEC-PNRR)

Codice Procedura: 12481

### OGGETTO DELLE OSSERVAZIONI

*(Barrare le caselle di interesse; è possibile selezionare più caselle):*

- Aspetti di carattere generale (es. struttura e contenuti della documentazione, finalità, aspetti procedurali)  
 Aspetti programmatici (coerenza tra piano/programma/progetto e gli atti di pianificazione/programmazione territoriale/settoriale)  
 Aspetti progettuali (proposte progettuali o proposte di azioni del Piano/Programma in funzione delle probabili ricadute ambientali)  
 Aspetti ambientali (relazioni/impatti tra il piano/programma/progetto e fattori/componenti ambientali)  
 Altro (specificare) \_\_\_\_\_

### ASPETTI AMBIENTALI OGGETTO DELLE OSSERVAZIONI

*(Barrare le caselle di interesse; è possibile selezionare più caselle):*

- Atmosfera  
 Ambiente idrico  
 Suolo e sottosuolo

- Rumore, vibrazioni, radiazioni
- Biodiversità (vegetazione, flora, fauna, ecosistemi)
- Salute pubblica
- Beni culturali e paesaggio
- Monitoraggio ambientale
- Altro: **Sottovalutazione nelle analisi sviluppate in relazione ai potenziali impatti sulla popolazione e sulla salute umana nonché sull'ambiente e sulle varie attività economiche presenti, degli effetti cumulativi con quelli di altri impianti già presenti e/o in progetto nella stessa zona.**

## TESTO DELL' OSSERVAZIONE

Si riporta in allegato il testo completo delle osservazioni inclusive degli Allegati che ne fanno PARTE INTEGRANTE E SOSTANZIALE al fine di fornire all'autorità competente nuovi e ulteriori elementi conoscitivi e valutativi in relazione al pianificato progetto presentato da UPV S.r.l., così come previsto dall' art. 24, comma 3 del del D. Lgs.152/2006, così sostituito dall'art. 21, comma 1, lettera b), della legge n. 108 del 2021. \_\_\_\_\_

Il Sottoscritto dichiara di essere consapevole che, ai sensi dell'art. 24, comma 7 e dell'art.19 comma 13, del D.Lgs. 152/2006 e s.m.i., le presenti osservazioni e gli eventuali allegati tecnici saranno pubblicati sul Portale delle valutazioni ambientali VAS-VIA del Ministero dell'Ambiente e della Tutela del Territorio e del Mare ([www.va.minambiente.it](http://www.va.minambiente.it)).

*Tutti i campi del presente modulo devono essere debitamente compilati. In assenza di completa compilazione del modulo l'Amministrazione si riserva la facoltà di verificare se i dati forniti risultano sufficienti al fine di dare seguito alle successive azioni di competenza.*

## ELENCO ALLEGATI

Allegato 1 - Dati personali del soggetto che presenta l'osservazione

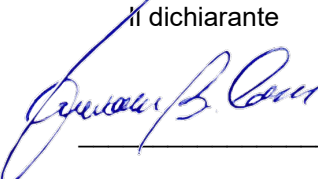
Allegato 2 - Copia del documento di riconoscimento in corso

Allegato 3 - Testo completo delle Osservazioni

*(inserire numero e titolo dell'allegato tecnico se presente e unicamente in formato PDF)*

Luogo e data UTA – li 11.07.2024

Il dichiarante



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Oggetto: [ID 12481] - Progetto di un impianto agrivoltaico, della potenza complessiva pari a 34,769 MWp, da realizzarsi in località Villamuscas - Comune di Uta (CA) . Osservazioni

Con riferimento all'oggetto, obiettivo della presente Nota è quello di rappresentare all'Autorità Competente alcune evidenze desumibili dal quadro documentale che sostanzia il progetto della UPV S.r.L. (*nel seguito indicata come "Proponente"*) ed ulteriori elementi conoscitivi e valutativi su base essenzialmente tecnica così come previsto dall' art. 24, comma 3 del del D. Lgs.152/2006, innovato e sostituito dall'art. 21, comma 1, lettera b), della legge n. 108 del 2021.

Trattasi in estrema sintesi di Osservazioni di carattere generale sulle FER e sull'impatto dei progetti proposti sul sistema di trasmissione dell'energia.

In particolare:

- Produzione da FER - Difformità in relazione alle Direttive Europee e Nazionali in tema di impianti alimentati da fonti rinnovabili;
- Difformità dal Piano Energetico Ambientale Della Regione Autonoma della Sardegna 2015-2030 (PEARS), "*Verso un'Economia condivisa dell'Energia*" approvato con D.G.R. N. 45/40 del 02/08/2016;
- Incoerenza in relazione ai pur proclamati intenti di coniugare "*...in chiave moderna e tecnologica la produzione agricola e quella elettrica, senza che la prima venga sacrificata a vantaggio della seconda...*" ed in relazione ad una del tutto presunta per quanto pretesa "*...ottimizzazione contemporanea dell'ambito agricolo ed energetico...*";
- Sottovalutazione nelle analisi sviluppate in relazione ai potenziali impatti sulla popolazione e sulla salute umana nonché sull'ambiente e sulle varie attività economiche presenti, degli effetti cumulativi con quelli di altri impianti già presenti e/o in progetto nella stessa zona.

I punti suesposti sono sinteticamente illustrati e discussi nel seguito.

## 1) Produzione da FER. Difformità in relazione alle direttive europee e nazionali in tema di impianti alimentati da fonti rinnovabili

Si ritiene utile affrontare preliminarmente il problema del modello della produzione di energia elettrica da F.E.R. in Italia e in Sardegna alla luce dei principi generali e degli obiettivi dettati dal PNIEC, nonché portare all'attenzione la necessità di verificarne la compatibilità con le linee di indirizzo contenute nelle Direttive europee, nel PEARS della Regione Sardegna e, anche in chiave futura, con i piani di sviluppo delle reti elettriche 2023 e segg. elaborati da TERNA S.p.A.

In particolare, si intende analizzare l'inserimento di tale impianto in un contesto territoriale come quello sardo con caratteristiche peculiari, sia con riferimento agli aspetti ambientali che alle problematiche tecniche, queste ultime conseguenti al sistema di trasmissione dell'energia elettrica ed alla specifica natura delle FER, ovvero variabilità e non programmabilità delle stesse.

Un'ipotesi di studio del contesto energetico di cui l'impianto andrebbe a fare rilevante parte è consentito dal supporto analitico dei dati (consolidati) inerenti gli impianti di generazione elettrica in Sardegna nell'anno 2022 (i dati sottoriportati sono di fonte TERNA S.p.A):

- Energia totale lorda prodotta: GWh 13.395,3
- Energia lorda consumata: GWh 8.112,4 pari al 60,56% della totale prodotta, di cui:
  - GWh 2.264,7 domestico, pari al 27,7%
  - GWh 235,9 agricoltura, pari al 2,82%
  - GWh 2.151,1 servizi, pari al 26,51%  
(per un totale parziale di GWh 4.651,7)
  - GWh 3.460,7 industria, pari al 42,67%.
- Produzione lorda impianti fotovoltaici: GWh 1.357,2 pari al 16,73% dell'energia totale consumata;
- Produzione lorda impianti eolici: GWh 1.660,0 pari al 20,46% dell'energia totale consumata
- Potenza lorda impianti fotovoltaici: MW 1.141,0
- Potenza lorda impianti eolici: MW 1.095,7

Totale da rinnovabili di GWh 3.946,7 pari al 46,8% dell'energia totale consumata e all'85% dell'energia consumata per uso domestico, agricoltura e servizi.

Se si sommano a tali produzioni quelle derivanti dagli impianti di generazione elettrica da eolico e fotovoltaico attualmente oggetto di procedura autorizzativa, ne consegue un incremento di una entità tale da portare ad ipotizzare come del tutto possibile il collasso di tutto il sistema infrastrutturale di trasmissione elettrico isolano, tenendo conto del fatto che, come desumibile dai dati TERNA degli ultimi anni, sussiste già un esubero produttivo rispetto ai consumi, con picchi superiori al 40%.

Tali esuberi, in ogni caso, non danno immediata evidenza della reale entità della sovracapacità produttiva (c.d. *"Over Generation"*), dovuta sia ai limiti di capacità dei cavidotti di trasporto dell'energia verso la Penisola Italiana, sia alla grave carenza di impianti di accumulo, dati che lo stesso **D.Lgs. 8 novembre 2021 , n. 199, all'articolo 20 -comma 3 pone come basilari** nel disporre:

*[...] Ai sensi dell'articolo 5, comma 1, lettere a) e b), della legge 22 aprile 2021, n. 53, nella definizione della disciplina inerente le aree idonee, i decreti di cui al comma 1, tengono conto delle esigenze di tutela del patrimonio culturale e del paesaggio, delle aree agricole e forestali, della qualità dell'aria e dei corpi idrici, privilegiando l'utilizzo di superfici di strutture edificate, quali capannoni industriali e parcheggi, nonché di aree a destinazione industriale, artigianale, per servizi e logistica, e verificando l'idoneità di aree non utilizzabili per altri scopi, ivi incluse le superfici agricole non utilizzabili, compatibilmente con le caratteristiche e le disponibilità delle risorse rinnovabili, delle infrastrutture di rete e della domanda elettrica, nonché tenendo in considerazione la dislocazione della domanda, gli eventuali vincoli di rete e il potenziale di sviluppo della rete stessa.*

Già ora, infatti, gli impianti da FER non sono in grado di esprimere compiutamente la propria potenzialità, essendo alquanto spesso costretti a restare fuori-produzione a causa proprio della saturazione della rete.

A riprova si può anche considerare l'incremento della potenza media e dell'efficienza per quanto attiene gli aerogeneratori - ultimamente in forte incremento per numero e "taglia" unitaria - cui però non è corrisposto un equivalente incremento delle ore medie di funzionamento.

Per quanto possa sembrare paradossale, con tali presupposti, un'ulteriore crescita della potenza da generatori a FER installata lascia aperto il campo all'ipotesi di un inevitabile crollo del rendimento complessivo delle diverse tipologie di generatori.

Alquanto irrilevanti appaiono poi i "confidenti" richiami di cui è infarcita la Documentazione progettuale fra cui si segnala, indicativo di un costante "refrain" ampiamente diffuso nei testi a corredo della documentazione progettuale:

*...“Alla base delle motivazioni della presente proposta di intervento vi è la volontà di produrre energia rinnovabile in maniera sostenibile e in armonia con il territorio ed il suo attuale utilizzo. .”... (SIA – pg.8)*

E' infatti allegata alla presente per farne parte integrante e sostanziale (Allegato-1) una Memoria presentata alle Commissioni 4<sup>a</sup>. e 5<sup>a</sup>. Del Consiglio Regionale della Regione Autonoma della Sardegna sotto forma di "Osservazioni in ordine al D.L. N. 15 - Misure urgenti per la salvaguardia del paesaggio, dei beni paesaggistici e ambientali" che, pur in assoluta esiguità di tempi e di mezzi, propone, con il ricorso a dati statistici, Pubblicazioni di Autori di incontestabile Competenza e Attendibilità e Report riferibili ad Agenzie direttamente collegate alla stessa UE due tesi, la cui dimostrazione viene conseguita letteralmente "per tabulas",

1. *Incoerenza/incompatibilità' del sistema di produzione ed esportazione di energia elettrica quale risultante dall'assommarsi dello stato impiantistico corrente e dell'impiantistica di neo-impianto prevista dalle quote di produzione assegnate dall'amministrazione centrale ai fini del conseguimento del c.d. "obiettivo 2030" con la presente (e pianificata nel prossimo futuro) dotazione infrastrutturale della Sardegna e con il suo reale fabbisogno energetico;*

2. *Problematiche di adeguatezza/sostenibilità del modello “Tyrrhenian Link” quale valida infrastruttura ai fini dell’esportazione di energia elettrica secondo le quote di produzione assegnate dall’amministrazione centrale dello stato ai fini del conseguimento del c.d. “obiettivo 2030”.*

Il contenuto, le Fonti utilizzate, la metodologia di Analisi e Discussione dei dati e financo i testi integrali delle Pubblicazioni utilizzate sono contenuti nell’Allegato-1 appena citato e confortano le tesi enunciate.

A titolo di Raffronto viene accluso anche, sotto la denominazione di Allegato-2, un Estratto dall’ *“Analisi costi benefici e approfondimenti del collegamento HVDC Sicilia-Campania (East Link)”* redatto da TERNA S.p.A. il quale, con specifico riferimento al ramo West-Link – Sardegna-Sicilia permette di rendersi edotti, parimenti *“per tabulas”*, che la presunta transizione ecologica da realizzarsi mediante la “decisiva spinta” in Sardegna al processo di decarbonizzazione a seguito di installazione di impianti generatori operanti a FER - fra i quali l’impianto fotovoltaico di cui al progetto “Villamuscas” presentato dal Proponente costituisce (o dovrebbe costituire) elemento di relativa rilevanza - è alquanto carente di razionale, dimostrabile fondamento tecnico-pratico, nello stesso momento in cui, per “ entro il 2030 si renderà necessaria l’installazione di nuovi impianti termo-elettrici a gas (o ad altri combustibili fossili, constatata l’assenza in Sardegna di Reti di approvvigionamento e distribuzione-metano) per potenze variabili da 550 MW fino ai 1250 MW.

A seguito di quanto appena esposto, si possono fare due considerazioni:

1. Già ora, alle attuali condizioni e nonostante le inefficienze, le FER installate consentono di soddisfare l’85% dei fabbisogni dei settori domestico, agricoltura e servizi. Con i doverosi accorgimenti nulla vieta di ipotizzare di poter raggiungere agevolmente il 100%.
2. L’inefficienza del sistema elettrico ha costi di assoluta rilevanza per la Collettività in termini ambientali ed economici. Ad oggi, a causa della carenza di idonei sistemi di accumulo, sono le centrali termoelettriche a fungere da sistema di compensazione per le inevitabili oscillazioni delle FER, pur non avendo le necessarie caratteristiche di flessibilità per svolgere tale compito. Per lavorare in questo regime di “essenzialità” vengono garantiti alle centrali elettriche sostanziosi incentivi; per contro, quando la rete è satura e sono le FER ad essere staccate dalla rete, malgrado i meccanismi di priorità d’accesso previsti dal D.Lgs. 199/2021, queste ultime trovano remunerazioni equivalenti a quelle della loro effettiva produzione proprio per il loro diritto di priorità nell’immissione in rete. I costi sono, ovviamente, a carico della Collettività e scaricati sulle utenze elettriche tramite le “opportune” voci in bolletta. Il proliferare di progetti, apparentemente senza una logica distributiva sulla base di consumi di prossimità, e la situazione attuale della rete di trasmissione, risulta incompatibile con una generazione da FER, che avrebbe necessità di una rete interconnessa e magliata, con adeguati nodi di conferimento ed idonei sistemi di accumulo, attualmente non esistenti e/o comunque previsti per coperture del tutto marginali rispetto al prevedibile fabbisogno.

Progettare e proporre un impianto fotovoltaico di dimensioni quali quelle ipotizzate (un impianto peraltro di taglia e caratteristiche generali chiaramente industriale) richiede anche di calarsi nelle logiche e nelle scelte puntuali di programmazione e pianificazione; in difetto di tale

logica progettuale, come si sta peraltro verificando nell'attualità, il possibile anzi (il più-che) probabile risultato potrebbe essere il moltiplicarsi di mega-impianti da rinnovabili il cui principale obiettivo pare quello di soddisfare esclusivamente interessi speculativi, risultando piuttosto opportunistico trincerarsi dietro un generico ed autoreferenziale *“L'opera progettata si integra nel territorio rispettando tutte le realtà esistenti. Essa rafforza le azioni intraprese a livello europeo e nazionale di aumento di fornitura di energia tramite fonti rinnovabili.”* (R01 - Relazione Illustrativa – pg. 58)

Se l'analisi si dovesse fermare a tale considerazione, il risultato più probabile appare quello di rendere ancor più precarie le condizioni di funzionamento della rete di trasmissione. Per questo motivo, qualsiasi progetto di nuovi impianti di produzione energetica dovrebbe tener conto anche delle condizioni attuali e future delle reti di trasmissione dell'energia, “argomento” evidentemente “alieno” per il Proponente, dal momento in cui anche da un'accurata analisi, non si rilevano considerazioni in merito nella pur “articolata”, “corposa”, “poderosa” (ma soprattutto... “ponderosa”) documentazione presentata a corredo dei progetti per la località “Villamuscas” al momento di asseverare le presunte per quanto pretese “motivazioni progettuali”.

Scontata l'autoreferenzialità, la documentazione di progetto non fornisce in realtà elementi obiettivi atti a dimostrare l'inderogabilità/indifferibilità dell'opera, se non estrapolando e decontestualizzando alcune norme generali.

Nei fatti, le recenti Direttive europee sollecitano l'adozione di sistemi di produzione energetica diffusi sul territorio, sollecitano l'autoconsumo e disegnano modelli di energy community. In particolare, il documento *“Green-New Deal”* della Commissione Europea e la Direttiva (UE) 2018/2001 sulla “Promozione dell'uso dell'energia da fonti rinnovabili” fanno specifico riferimento a produzioni e consumi energetici di tipo distrettuale e dettano specifici indirizzi normativi sulle Comunità energetiche (CER) e sull'autoconsumo collettivo (AC), scenari alternativi a quelli delle concentrazioni produttive.

Nel SIA in parola (ma in tutta la documentazione progettuale) in tema solo scarse (e vaghe) argomentazioni di “sapore” vagamente tecnico quando invece costituisce argomento alquanto noto la massima giurisprudenziale:

*“è ben noto che la valutazione di impatto ambientale non si sostanzia in una mera verifica di natura tecnica circa la astratta compatibilità ambientale dell'opera, ma implica una complessa e approfondita analisi comparativa tesa a valutare il sacrificio ambientale imposto rispetto all'utilità socio-economica, tenuto conto anche delle alternative possibili e dei riflessi sulla stessa c.d. opzione - zero; in particolare, la natura schiettamente discrezionale della decisione finale, sul versante tecnico ed anche amministrativo, rende allora fisiologico ed obbediente alla ratio su evidenziata che si pervenga ad una soluzione negativa ove l'intervento proposto cagioni un sacrificio ambientale superiore a quello necessario per il soddisfacimento dell'interesse diverso sotteso all'iniziativa; da qui la possibilità di bocciare progetti che arrechino vulnus non giustificato da esigenze produttive”* (T.A.R. PUGLIA, SENT. N. 140/2021; CONS. DI STATO, SEZ. V, SENT. N. 4928/2014)

E il PEAR-Sardegna?...

E la produzione energetica come perno di tutte le programmazioni territoriali?...

E la coerenza con le reti di trasmissione?...

E il sistematico richiamo all'esigenza di dotare i nuovi impianti (ma non solo) di adeguati sistemi di storages, accumuli, produzione di vettori energetici alternativi, ecc. per il superamento delle criticità imposte dalle FER.?...

Contrariamente a quanto sostenuto, si devono evidenziare anche su questi aspetti le "anomalie" rispetto alla programmazione Comunitaria, Nazionale, Regionale e al contesto locale.

In definitiva, il quadro complessivo che emerge dalla proposta progettuale non appare tenere affatto conto delle descritte criticità, elude le direttive europee, italiane e regionali, non contempla la programmazione sulle reti di trasporto dell'energia, mentre punta a massimizzare i profitti derivanti da incentivi non condizionati dal mercato, da incertezze di consumi, dallo stesso "rischio di investimento" che connota, anzi "deve connotare" per definizione qualsivoglia iniziativa e/o intrapresa che si voglia definire economica.

Perseguendo una tale linea si favoriscono invece le produzioni di energia concentrate, penalizzando la generazione diffusa in palese contrasto con gli orientamenti Comunitari.

Il quadro complessivo che emerge dalle proposte progettuali appare pertanto disapplicare se non direttamente violare le linee programmatiche sulla transizione energetica dettate in ogni Sede, con il duplice risultato di contribuire ad aumentare i problemi di approvvigionamento energetico da FER pianificato razionalmente e di creare nuovi e rilevanti impatti su ambiente, paesaggio, beni archeologici ed identitari e questo si ritiene patentemente inaccettabile.

Ovvero non sono accettabili progetti con tali impatti e tali dimensioni se non tiene in alcun conto un'attenta strategia energetica ambientale che permetta di centrare sia i target energetici e di sostenibilità ambientale fissati dalle nuove politiche energetiche comunitaria, nazionale e regionale (PNIEC, PEARS), sia... ricordando anche l'Art. 41 della Costituzione Italiana, in particolare il Comma 2, gli obiettivi di sostenibilità economica, ambientale e sociale necessari per il Territorio.

Si sta peraltro affermando in questi ultimi anni un modello innovativo di produzione e consumo dell'energia, antitetico rispetto a quello accentrato e oligopolistico, strettamente legato all'utilizzo delle fonti fossili, che ha prevalso in passato. Questa conversione, recepita nelle direttive europee e che potremmo definire storica con riferimento per l'ampiezza degli scenari in gioco, riguarda direttamente la taglia degli impianti, la loro localizzazione e la modalità di utilizzo dell'energia prodotta, nonché i processi decisionali che determinano tali insediamenti.

La UE punta ora con decisione, sia pure con la opportuna gradualità, sulla "generazione diffusa", basata prevalentemente su impianti localizzati presso le utenze, grazie all'ampia disponibilità delle fonti rinnovabili ed alla maturazione delle tecnologie che ne consentono l'utilizzo.

Questo processo ha origine, oltre che da svariati fattori socioeconomici ed ambientali, da elementari principi di corretto uso dell'energia, che tendono a minimizzare le perdite di trasmissione e gli impatti ambientali connessi, localizzando la produzione di energia il più vicino possibile ai singoli centri di consumo.

In aggiunta le sempre più impellenti emergenze legate al consumo e all'uso improprio del suolo stanno evidentemente orientando i decisori politici a privilegiare nella collocazione degli impianti le superfici edificate esistenti, evitando di consumare suolo, pertanto, in tale contesto, i grandi impianti fotovoltaici non vengono tassativamente esclusi, al fine di conseguire gli obiettivi previsti dalle politiche nazionali ed europee, ma è da notare che il loro insediamento viene sempre viepiù limitato ad aree già antropizzate, come ad esempio cave e/o discariche dismesse, aree inquinate e bonificate, zone degradate, tetti di edifici industriali e non.



In tale quadro generale, la normativa europea e nazionale ha introdotto la figura del “prosumer”, cioè quel soggetto che è allo stesso tempo produttore e consumatore di energia, e sta attuando un quadro normativo che facilita l’autoconsumo e lo scambio dell’energia tra utenti-produttori, anche attraverso le “Comunità Energetiche Rinnovabili”.

Rispetto al vecchio modello accentrato, in cui pochi oligopolisti producono l’energia e tutti gli altri la consumano, il nuovo modello trasforma il consumatore in un produttore-consumatore, che partecipa in prima persona alle opportunità offerte dal mercato, e coinvolge una platea di soggetti enormemente più ampia, con uno straordinario processo di responsabilizzazione e di democratizzazione della produzione energetica.

E d’altra parte quanto appena sopra espresso appare trovare formale riconoscimento nella stessa Direttiva UE 2018/2001 dell’11.12.2018 sulla promozione dell’uso dell’energia da fonti rinnovabili

*(premessa, Par. 65): «È opportuno consentire lo sviluppo delle tecnologie decentrate per la produzione e lo stoccaggio di energia da fonti rinnovabili a condizioni non discriminatorie e senza ostacolare il finanziamento degli investimenti nelle infrastrutture. Il passaggio a una produzione energetica decentrata presenta molti vantaggi, compreso l'utilizzo delle fonti di energia locali, maggiore sicurezza locale degli approvvigionamenti energetici, minori distanze di trasporto e ridotta dispersione energetica. Tale passaggio favorisce, inoltre, lo sviluppo e la coesione delle comunità grazie alla disponibilità di fonti di reddito e alla creazione di posti di lavoro a livello locale.» (21.12.2018 L 328/91 GAZZETTA UFFICIALE DELL'UNIONE EUROPEA).*

In precedenza anche la Risoluzione del Parlamento Europeo del 23 giugno 2016 (2016/2041(INI) al punto 45 aveva sottolineato:

*«la produzione di energia elettrica da fonti rinnovabili dovrebbe essere integrata nei sistemi di distribuzione a tutti i livelli, come pure nei sistemi di trasmissione, visti i cambiamenti orientati verso un modello di produzione energetica più flessibile e decentrato che tiene conto del mercato».*

**Alla luce di quanto esposto, il grado di coerenza e sostenibilità di progetti come quello di un impianto “agrivoltaico” da 34,769 MWp, da realizzarsi in località “Villamuscas” presentato dal Proponente, valutato in relazione alle Direttive europee in tema di impianti alimentati da fonti rinnovabili, ai citati orientamenti del Parlamento Europeo - tutt’ora validi e immutati – ed agli stessi indirizzi di Pianificazione Nazionale si ritiene sia pratica facilmente ed oggettivamente implementabile da qualsivoglia lettore.**

**Ci si limita solo a puntualizzare che, sempre in relazione a quanto esposto appare del tutto legittima/comprovata l’asserzione per cui lo stesso Proponente, in relazione al progetto in parola appare aver svolto analisi, considerazioni e sviluppi che appaiono alquanto inadeguati in merito alle alternative, in disapplicazione se non direttamente contrasto, oltre che con le citate direttive europee in tema di impianti alimentati da fonti rinnovabili, anche con il dettato dell’art. 22, comma 3°, lettera d, del decreto legislativo n. 152/2006 e s.m.i.**

**2) Difformità dal Piano Energetico Ambientale Della Regione Autonoma della Sardegna 2015-2030 (PEARS), “Verso un’Economia condivisa dell’Energia” approvato con D.G.R. N. 45/40 del 02/08/2016;**

Il Piano in parola, adottato con Delibera di G.R. N. 45/40 DEL 02/08/2016, e pur probabilmente superato per quanto riguarda gli obiettivi di produzione rinnovabile rispetto agli attuali target nazionali, rimane comunque lo strumento attraverso il quale la Regione Autonoma della Sardegna esprime il proprio Potere Concorrente, ai sensi dello Statuto Sardo (Legge di rango Costituzionale) in materia di produzione energetica sul proprio Territorio.

L'impostazione dello stesso PEAR-Sardegna, già in premessa (pag. 4) definisce uno scenario che ricorda da vicino anche il territorio in cui si propone l'intervento: «La separazione fra produzione e consumo non ha più ragion d'essere: offerta e domanda devono muoversi insieme e i territori, definiti nel Piano come distretti energetici, sono i luoghi nei quali questa coesistenza deve realizzarsi».

L'orientamento alla base delle azioni previste dal PEARS è il raggiungimento dei target europei attraverso un intervento primario e complessivo di efficienza e risparmio da attuarsi anche attraverso la massimizzazione dell'utilizzo locale dell'energia attualmente prodotta da fonte rinnovabile.

Tale azione è considerata propedeutica per lo sviluppo armonico di nuova capacità di generazione da rinnovabile e funzionale al raggiungimento dell'obiettivo del 2030. In tale visione si prevede una mitigazione degli impatti causati sino ad oggi dalla realizzazione delle FER grazie ad un loro condizionamento alla strategia energetica regionale, indirizzando la vecchia e la nuova generazione da fonti rinnovabili rispetto al passato, nel paradigma della generazione distribuita asservita all'autoconsumo e integrata nel modello gestionale delle “smart grids” e delle “smart communities” nel quadro di un sistema di mercato adeguatamente regolato dallo strumento di pianificazione pubblica.

Il PEAR-Sardegna, come si è detto pur probabilmente superato per quanto riguarda gli obiettivi di produzione rinnovabile rispetto agli attuali target nazionali, riflette pertanto la volontà di promuovere un nuovo modello di economia circolare e “realmente ecosostenibile” che minimizzi il consumo di suolo, di paesaggio e di risorse naturali e che trova il suo elemento fondante nel primato riservato all'uso della generazione diffusa esistente con installazione di impianti di taglia medio-piccola calibrati sui profili di consumo delle utenze, la promozione dell'accumulo distribuito, l'aggiornamento tecnologico e il conseguente efficientamento degli impianti esistenti alimentati da fonti rinnovabili (e non) considerando tali azioni prioritarie rispetto alla realizzazione di nuovi impianti.

L'idea di fondo è chiaramente quella di accompagnare la transizione energetica facendo emergere i vantaggi economici ed ambientali insiti nella transizione da un modello di produzione e consumo di energia da fonti fossili e rinnovabili accentrati e per grossi poli ad un modello distribuito e dimensionato sui fabbisogni di prossimità.

Come già scritto, non vi è traccia concreta di tali concetti nel progetto di “agrivoltaico” presentato da UPV S.r.l., si tende anzi a “superare” (quantunque “obnubilare” o “nascondere”

sembrano termini alquanto più... adatti) il contesto di produzione energetica preesistente nel territorio circumvicino.

**Pertanto ancora una volta si ritiene doveroso osservare lo sviluppo decisamente NON adeguato delle considerazioni in relazione alle disposizioni del VIGENTE Piano Energetico Ambientale Della Regione Autonoma della Sardegna 2015-2030, con particolare riferimento alle alternative di progetto, ancora una volta in disapplicazione dell'art. 22, comma 3°, lettera d, del decreto legislativo n. 152/2006 e s.m.i**

**3) Incoerenza in relazione ai pur proclamati intenti di coniugare “...in chiave moderna e tecnologica la produzione agricola e quella elettrica, senza che la prima venga sacrificata a vantaggio della seconda...” ed in relazione ad una del tutto presunta per quanto pretesa “...ottimizzazione contemporanea dell'ambito agricolo ed energetico...”;**

Come già precedentemente esposto, appare d'uopo richiamare che il progetto presentato risulta in netto contrasto con numerose norme e principi a più livelli e relative a vari ambiti, e presenta vantaggi alquanto opinabili per la popolazione residente nei Comuni interessati e per la Comunità Nazionale tutta. Al contrario, il suo effetto sul paesaggio, sull'ambiente, sul patrimonio immateriale/culturale e sulle attività economiche dell'area sembra apparire piuttosto negativo.

L'uso del corsivo già nell'enunciato suesposto non si deve ritenere un errore grafico. Si tratta infatti di un passo riportato con l'enfasi del grassetto già alla pagina 6 – righe 14 e 15 del “SIA – Studio d'Impatto Ambientale”.

L'appassionata “dichiarazione d'intenti” prosegue anche con:

*“...l'impianto in progetto consentirà di preservare la continuità delle attuali attività di coltivazione agricola e di pascolo sul sito di installazione, garantendo al contempo, una buona produzione energetica da fonti rinnovabili.”*

Non si ritiene in questa sezione di dover mettere in discussione la “bontà” o meno della produzione energetica; si ritiene invece doveroso richiamare l'attenzione su alcuni dati che suggeriscono valutazioni alquanto diverse, contenuti in una Memoria facilmente rintracciabile in quanto di Dominio Pubblico, pubblicata in cartaceo e sul proprio website ([www.nature.com/scientificreports](http://www.nature.com/scientificreports)) dalla rivista “**Nature**” il 13 Ottobre 2016:

**“The Photovoltaic Heat Island Effect: Larger solar power plants increase local temperatures.”**

(Auct. cit.: *Barron-Gafford, G. A. et al. : The Photovoltaic Heat Island Effect: Larger solar power plants increase local temperatures. - Sci. Rep. 6, 35070; doi: 10.1038/srep35070 (2016)*)

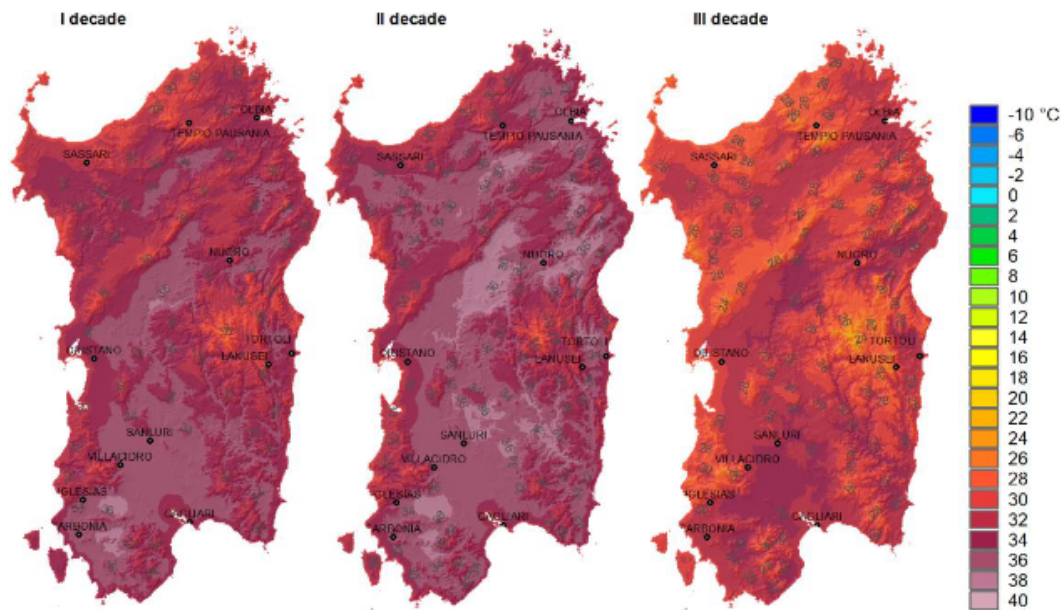
Come immediatamente arguibile dalla titolazione, si tratta di un report sui risultati di un esperimento scientifico appositamente concepito ed incentrato sull'ancora poco studiata tematica degli effetti connessi alla realizzazione di impianti fotovoltaici di dimensioni superiori a quelli classificabili come “domestici”. In particolare si è incentrata l'attenzione sulla possibilità o meno che tali impianti causino o meno un effetto "Isola di calore" tale da causare il riscaldamento anche le aree circostanti, influenzando così potenzialmente la funzione dell'ecosistema nelle zone naturali, la Salute umana, l'habitat della fauna selvatica, e financo il valore delle abitazioni presenti nelle aree più o meno circoscrutte.

Non appare certo questa la Sede appropriata per avviare un Tavolo di discussione sistematica sulle procedure e sui dati recuperati ed elaborati nella Memoria in parola **(che in ogni caso si riporta in versione integrale in coda alla presente Nota come Allegato-3)** ci si limita di necessità ad alcuni passi reputati particolarmente salienti:

- a) I dati sperimentali sono stati acquisiti monitorando simultaneamente tre siti che rappresentano un ecosistema naturale semiarido/desertico, un ambiente urbano tradizionale (parcheeggio circondato da edifici commerciali) ed una centrale fotovoltaica di produzione;
- b) gli effetti “di disturbo” della variabilità dell'energia localmente in entrata, della temperatura e delle precipitazioni sono stati contenuti utilizzando siti distribuiti in un raggio di c.a. 1 km.
- c) In ogni sito, la temperatura dell'aria è stata monitorata in modo continuo per oltre un anno, utilizzando sonde di temperatura aspirate posizionate 2,5 m sopra la superficie del suolo. La temperatura media annua è risultata di  $22,7 + 0,5$  °C nell'impianto fotovoltaico, mentre nel vicino ecosistema naturale semiarido/desertico era di soli  $20,3 + 0,5$  °C, il che indica la realtà del manifestarsi di un effetto “Isola di Calore”.
- d) Le differenze di temperatura tra le aree oggetto di rilevazione sono risultate significativamente variabili a seconda dell'ora del giorno e del mese dell'anno ma l'impianto FV aveva sempre una temperatura superiore o uguale a quella degli altri siti. Come nel caso dell'effetto “Isola di Calore”-aree urbane, nella zona naturale/semiarida l'effetto “Isola di Calore-fotovoltaica ha prodotto il ritardato raffreddamento delle temperature ambientali la sera, producendo la differenza più significativa nelle temperature notturne in tutte le stagioni. Le temperature medie annuali alla mezzanotte sono risultate erano di  $19,3 + 0,6$  °C nell'impianto fotovoltaico, mentre nel vicino ecosistema naturale semiarido/desertico erano di soli  $15,8 + 0,6$  °C. **Questo effetto “Isola di Calore”-fotovoltaica è stato particolarmente significativo in termini effettivi di riscaldamento (+3,5 °C) nei mesi estivi.**

Sulla scorta di tali punti e dei risultati illustrati sembra alquanto pleonastico proseguire ulteriormente. Appare solo doveroso rimarcare che nella pur corposa, poderosa (ma soprattutto “ponderosa”) documentazione progettuale, il Tema in questione, pur facendosi ampio uso, nelle Tavole grafiche di Ortofoto AGEA che evidenziano chiaramente la più che considerevole presenza di strutture afferenti attività economiche in ambito agricolo, di allevamento e financo di edifici d'abitazione a breve distanza dal sito d'intervento, stranamente, non sembra trovare alcuno spazio e/o interesse.

Interesse che dovrebbe altresì risultare ineludibile anche da un semplice raffronto con l'immagine alla pag. successiva, riprodotta dalla documentazione relativa al mese di Agosto resa disponibile come “*Riepilogo mensile meteorologico e agrometeorologico*” dal Dipartimento Meteorologico - Servizio Meteorologico, Agrometeorologico ed Ecosistemi di ARPA-Sardegna relativi al mese di Agosto **(al fine di non appesantire la trattazione, la serie quinquennale completa relativa all'intervallo 2019-2023 è allegata in coda alla presente Nota con la denominazione Allegato-4)**



**Figura 3: Valori medi decadali delle temperature massime registrate nel mese di Agosto 2021**

E' appena il caso di notare che dai dati desumibili dalla precedente immagine, l'area di intervento e lo stesso Territorio Comunale di Uta sono chiaramente assoggettati, nel mese di Agosto (statisticamente il più' caldo dell'anno) per più' decenni a **valori medi di temperatura di 38 °C** (con **punte diurne che in talune giornate caratterizzate da "deprecabili circostanze avverse" hanno agevolmente raggiunto i 42 °C**).

Si ritiene anche pratica alquanto facilmente implementabile quella di ipotizzare "quali" possono essere i "risultati" di un incremento medio di **+ 3,5 °C** (dato medio rilevato alla c.d. "mezzanotte" – durante le ore diurne ed al variare delle stagioni gli incrementi possono agevolmente raggiungere valori decisamente superiori) sulla falsariga dei risultati esposti nella succitata Memoria.

"Risultati" che appaiono oggettivamente alquanto "agevoli" da raggiungere qualora si tenga conto che la superficie "radiante" dei pannelli installandi risulta di **154.860,79 mq**.

"Risultati" che appaiono contraddire in radice l'impegnativa, categorica affermazione che si può leggere alla pag. 84 del SIA – Studio d'Impatto Ambientale

*"Il progetto proposto intende sviluppare una migliore gestione agronomica dei terreni al fine di contribuire nel tempo ad un miglioramento deciso della fertilità del suolo agrario, con lo scopo di restituire alla fine della vita utile dell'impianto agrivoltaico un terreno migliorato e pronto ad essere reimmesso nel ciclo produttivo agro-zootecnico."*

- Perché appare tutt'altro che irragionevole l'ipotesi che l'esposizione diretta dei terreni interessati dall'impianto ad anomalie termiche dell'ordine e delle tempistiche di quelle

suesposte possa portare alquanto scontatamente alla rapida sterilizzazione degli stessi, non certo ad un “miglioramento della fertilità”;

- Perché anomalie termiche del tipo e sulla scala di quelle evidenziate non si possono certo ritenere “passibili di mitigazione” con l’impianto di uno o più filari di giovani piante (in fitocella) che appaiono peraltro destinate a rapido annientamento;

- Perché non esiste alcuna oggettiva garanzia che gli stessi fenomeni termici non abbiano ad estendersi alle aree circoscrutte – sia facenti parte delle superfici direttamente interessate dalla proposta d’investimento del Proponente, sia ad esse aliene - stravolgendo le funzioni dell’ecosistema nelle zone naturali, l’habitat della fauna selvatica e financo la Salute umana, essendo numerose le attività economiche di tipo agricolo, agri-faunistico ed allevamento, e considerando anche l’alterazione delle condizioni di vivibilità e del valore stesso degli edifici d’abitazione esterni al perimetro del sito d’intervento ed alla stesse superfici direttamente interessate dall’investimento della UPV S.r.L. ma che risulta chiaramente impensabile trascurare;

- Perché non compare fra i Documenti di progetto alcuno studio specifico sulle problematiche evidenziate, limitandosi quelli presenti ad avvalorare la tesi di fondo dell’enunciato del Proponente sopra-riportato, una tesi che, si è visto, con estrema facilità si dimostra incongruente con la realtà dei fatti, soprattutto quando essa risulta suffragata dagli indispensabili riscontri sperimentali.

Confrontando quanto suesposto con quanto affermato alla pagina 111 del SIA – Studio di Impatto Ambientale nella fase di una quantomeno “curiosa” valutazione” della c.d. “alternativa zero” – ovvero, in combinato-disposto:

*“L’altezza da terra dei moduli fotovoltaici permetterà di proseguire l’attività di pascolo attualmente presente. Inoltre a bordo lotto la recinzione perimetrale sarà provvista di passaggi per la piccola fauna per creare continuità agli attuali corridoi ecologici presenti.”*

*“L’area, che risulta antropizzata dall’uso combinato di seminativo semplice e pascolo, non subirà mutamenti, pertanto non sono previste modifiche della biodiversità nell’area interessata”*

*“L’opera non ha effetti negativi sul microclima, al contrario, come descritto nello studio agronomico effettuato, le colture previste tra i filari e sotto di essi ne gioveranno dal punto di vista produttivo”*

risulta alquanto “in salita” non cogliere le (evidenti) contraddizioni. Si può altresì affermare che l’analisi acritica dell’intero “corpus” dei documenti progettuali relativi alla realizzazione di un impianto agrivoltaico, della potenza complessiva pari a 34,769 MWp, in località Villamuscas – Uta mostra con sconcertante (e sconcertante) chiarezza la lontananza rispetto a qualsivoglia possibilità di coniugare “...in chiave moderna e tecnologica la produzione agricola e quella elettrica, senza che la prima venga sacrificata a vantaggio della seconda...”.

**Con onestà intellettuale si deve (purtroppo) riconoscere che, nel suo complesso, il progetto appare piuttosto maggiormente funzionale alla trasformazione di una superficie**

agricola, pur di qualità non eccelsa, deliberatamente in un lembo del deserto del Sahara trapiantato al di qua del Mediterraneo.

- 4) **Sottovalutazione nelle analisi sviluppate in relazione ai potenziali impatti sulla popolazione e sulla salute umana nonché sull'ambiente e sulle varie attività economiche presenti, degli effetti cumulativi con quelli di altri impianti già presenti e/o in progetto nella stessa zona.**

Fatto doveroso cenno all'evidenza che, nel "corpus" dei documenti progettuali, il più approfondito momento di "analisi" in relazione ai potenziali impatti sulla popolazione e sulla salute umana appare doversi individuare in quanto dichiarato ancora alla pagina 111 del SIA – Studio di Impatto Ambientale, sempre nella fase di una quantomeno "curiosa" valutazione" della c.d. "alternativa zero" , ovvero:

*"Alla luce dei valori elettromagnetici dichiarati, dal mancato utilizzo di prodotti chimici e, soprattutto, alla luce delle emissioni in atmosfera evitate, si considera un impatto assolutamente positivo dell'impianto agrivoltaico in oggetto."*

Richiamato quanto esposto precedente punto 3) - che si riconferma fino all'ultimo segno grafico – **NON si ritiene di dover aggiungere nient'altro...**

## **Conclusioni**

Anche e soprattutto per ciò che riguarda gli obiettivi della transizione energetica ed il passaggio alle energie rinnovabili è giusto tenere in considerazione il fatto che le richieste fatte nel territorio sardo sono di gran lunga superiori agli obiettivi proposti originariamente nel decreto legislativo 199/2021 e anche quelli vigenti di 6,2 GW (su 80 GW per l'intero stato italiano) a seguito delle nuove disposizioni previste per il 2024.

Al 30 marzo 2024 le ben 809 istanze di connessione di nuovi impianti presentate a Terna s.p.a. risultavano complessivamente pari a 57,67 GW di potenza, per una quantità di energia talmente elevata da essere verosimilmente non assorbibile dalla richiesta interna (essendo da svariati anni la produzione di energia in Sardegna superiore al fabbisogno, non conservabile e non trasportabile altrove per le oggettive carenze infrastrutturali e per le insostenibili perdite connesse al trasporto su cavidotti subacquei pur utilizzando la tecnologia HVDC .

L'assalto al territorio sardo, di cui il progetto pare far parte, si prefigura dunque come un inutile danno che potrebbe solo arricchire le aziende "intraprendenti" tramite una speculazione fatta sulla pelle delle popolazioni locali, in contrasto con un'idea di transizione energetica che favorisca invece l'autoconsumo e le comunità energetiche rinnovabili (C.E.R.).

La vocazione agricola, nella sua ricaduta paesaggistica, sociale e culturale costituisce il carattere peculiare dell'area oggetto di intervento, e ne definisce anche la prospettiva di sviluppo in riferimento alle produzioni agro-alimentari di pregio e alle attività che da tale settore deriverebbero come indotto diretto o indiretto: produzione alimentare, servizi, turismo etc.

Concretizzare in Sardegna l'attuazione della transizione energetica richiede una politica in grado di valorizzare e supportare le iniziative delle comunità e dei cittadini autoproduttori, accompagnare e incentivare la loro azione di "prosumers" e di imprenditori responsabili, favorendo lo sviluppo di un ecosistema dell'innovazione rispettoso delle comunità locali.

Impianti industriali come quello proposto rappresentano un freno a tale auspicato percorso, per cui risulta paradossale il fatto che si possano autorizzare in spregio a tutte le necessità di preservazione dell'ambiente, del paesaggio, e dello sviluppo che solo con un rapporto di co-pianificazione e rispetto delle comunità locali e dei loro diritti può dirsi davvero sostenibile.

In sovrammarchato, il presunto per quanto preteso "impianto agrivoltaico" di Villamuscas non possiede alcuna delle dichiarate caratteristiche di compatibilità con le produzioni agricole allo stato attuale praticate nel sito proposto per l'installazione e risulta viceversa altamente nocivo

- per l'ecosistema nelle zone naturali, delle aree agricole e financo delle attività agricole che insistono sulle aree circosvicine (facciano esse parte delle superfici oggetto e/o aggregate a quelle facenti parte dell'investimento del Proponente o altresì del tutto aliene alle stesse);
- per la Salute umana degli addetti all'impianto e di quelli impiegati nelle attività agricole che insistono nelle aree circosvicine indipendenti rispetto allo stesso;
- per l'habitat della fauna selvatica;
- financo per il valore delle abitazioni presenti nelle aree più o meno circosvicine e regolarmente utilizzate come residenza da un indefinito numero di addetti impiegati nelle attività agricole che insistono nelle aree circosvicine ma indipendenti rispetto allo stesso e rispettive famiglie

**Per tali motivazioni SI CHIEDE ED AUSPICA che le osservazioni formulate in questo documento siano considerate nell'ambito del presente procedimento di Valutazione d'Impatto Ambientale da parte delle Autorità Competenti, ai sensi degli artt. 9 e ss. della legge n. 241/1990 e s.m.i. e artt. 24 del decreto legislativo n. 152/2006 e s.m.i., e che le stesse vogliano esprimersi con una SERENA, MOTIVATA VALUTAZIONE DI NON COMPATIBILITÀ AMBIENTALE, ai sensi degli artt. 25 e ss. del decreto legislativo n. 152/2006 e s.m.i.**

Uta – li 10.07.2024





***[ID 12481]***

***Progetto di un impianto agrivoltaico, della potenza complessiva pari a 34,769 MWp, da realizzarsi in località Villamuscas - Comune di Uta (CA)***

***Osservazioni***

***Allegato-1***

**Oggetto: Memoria – osservazioni in ordine al D.L. 15 - Misure urgenti per la salvaguardia del paesaggio, dei beni paesaggistici e ambientali**

## **Premessa**

Secondo la definizione data da “L’Enciclopedia Italiana di scienze, lettere ed arti” - comunemente nota come “La Treccani” - **la transizione ecologica è la ricerca di un equilibrio tra la società umana e l’ambiente fisico.**

In senso pratico si tratta di una **“riconversione tecnologica finalizzata a produrre meno sostanze inquinanti”**.

Transizione ecologica e interessi economici sono stati a lungo su sponde opposte ma attraverso piani ecologici e sostenibili, come quelli presentati in seno all’Europa, le Istituzioni Nazionali e non hanno avuto il potere di brandire la bandiera della sostenibilità senza venir meno alle necessità di sviluppo e produzione. Tra questi, per esempio, troviamo il ministero della Transizione ecologica, oggi MASE - Ministero dell’ambiente e della sicurezza energetica - il cui obiettivo è quello di perseguire lo sviluppo economico pianificando la salute del pianeta e una società giusta.

Transizione ecologica è quindi un termine che racchiude le necessità economiche e il tema più ampio che vede la relazione tra esseri umani e ambiente, l’impatto antropico su questo e il tentativo di limare le conseguenze del cambiamento su ambiente, cose e persone.

È in questa formula che si inserisce il concetto di “sostenibilità” o, ancor meglio, sviluppo sostenibile che tiene conto non soltanto dello sviluppo volto a soddisfare i bisogni antropici, ma anche quelli ambientali.

Ed ecco pertanto una possibile spiegazione al “fiorire” sui mezzi di comunicazione di massa *“mainstream”* - ma anche su svariate decine di Relazioni-SIA – Studio di Impatto Ambientale (o pretesi tali) che accompagnano svariate decine di “progetti” di installazione di nuovi impianti di elettrogenazione alimentati da F.E.R. presentati in Sardegna per l’avvio dei procedimenti autorizzativi (accuratamente ed a-pregiudizialmente consultati oltre che metodicamente confrontati) autentici “peana” alla transizione ecologica come quello esemplificativamente sotto-risportato, estratto proprio dalla Relazione-SIA che accompagna e correda uno dei pretesi “progetti” in parola, del quale peraltro non appare certo questa la sede opportuna per riportare gli estremi di denominazione/identificazione:

*“... In un contesto in cui il fabbisogno energetico continua a crescere, la produzione di energia da fonti rinnovabili rappresenta una valida risposta alle problematiche riguardanti lo sviluppo economico sostenibile e il cambiamento climatico. La transizione verso l’energia verde è necessaria per ridurre le emissioni di CO2 legate all’energia prodotte dai combustibili fossili, che la ricerca scientifica conferma essere un fattore chiave del cambiamento climatico, e quindi mitigare gli impatti dirompenti. L’intento condiviso, in Italia e in Europa, è quello di portare avanti un processo di decarbonizzazione energetica, che preveda il passaggio dall’utilizzo di fonti fossili tradizionali (carbone, olio, gas) a quelle più ecosostenibili, per raggiungere la neutralità carbonica entro il 2050. Il fotovoltaico fa parte delle alternative green su cui si sta investendo di più negli ultimi anni dal momento che presenta numerosi vantaggi: la fonte energetica solare è inesauribile, è immediatamente reperibile ed è pulita. Oltre a ciò, la realizzazione di nuovi impianti*

*fotovoltaici costituisce una possibilità concreta di riqualifica e di riutilizzo di aree industriali dismesse o di terreni agricoli abbandonati.[...]  
...nell'attuale contesto di deciso sviluppo del settore fotovoltaico, al quale è ormai diffusamente riconosciuta una rilevante importanza tra le tecnologie che sfruttano le fonti di energia rinnovabili. La proposta di installazione di un impianto solare fotovoltaico è coerente sia con gli obiettivi del PNIEC, sia con l'esigenza, auspicata dal PEAR, di realizzare le condizioni per uno sviluppo armonico degli impianti di produzione di energia elettrica da fonti rinnovabili assicurando, allo stesso tempo, la salvaguardia dei valori ambientali e paesaggistici...."*

Concetti del tutto analoghi sembrano peraltro (incredibilmente) ripetersi - con scarse variazioni di sintassi e vocabolario tanto da indurre più di qualche (si ritiene) ragionevole dubbio in merito ad "originalità", "autenticità" e "genuinità" della/e fonte/i - sono riscontrabili anche nell'ambito e documentazione di molteplici "progetti" di installazione di sistemi basati su aerogeneratori (o pale eoliche che dir si voglia).

Tutto (apparentemente) molto condivisibile se non direttamente apprezzabile ma con un problema innato quanto profondo... perché in tema di "sostenibilità", nella corsa alla transizione ecologica in atto, corre l'obbligo di segnalare il rischio di dimenticare che "sostenibile" deve includere non solo la sostenibilità ambientale e quella umana - un valore aggiunto rispetto a quello puramente economico.

Appare infatti alquanto ragionevole rimarcare che sostenibilità ambientale, umana ed economica devono **INDEROGABILMENTE** essere confrontate con la sostenibilità **TECNICA**, pratica che non appare essere invalsa nella redazione dei progetti in parola e che, applicata con un leale coerenza metodologica scevra da qualsivogli pregiudizio ideologico ha (purtroppo) evidenziato alcune **CRITICITA' DI SISTEMA** che si ritiene di estrema rilevanza e sono sommariamente esposte e discusse nel seguito.

- 1) INCOERENZA/INCOMPATIBILITA' DEL SISTEMA DI PRODUZIONE ED ESPORTAZIONE DI ENERGIA ELETTRICA QUALE RISULTANTE DALL'ASSOMMARSÌ DELLO STATO IMPIANTISTICO CORRENTE E DELL'IMPIANTISTICA DI NEO-IMPIANTO PREVISTA DALLE QUOTE DI PRODUZIONE ASSEGNATE DALL'AMMINISTRAZIONE CENTRALE AI FINI DEL CONSEGUIMENTO DEL C.D. "OBIETTIVO 2030" CON LA PRESENTE (E PIANIFICATA NEL PROSSIMO FUTURO) DOTAZIONE INFRASTRUTTURALE DELLA SARDEGNA E CON IL SUO REALE FABBISOGNO ENERGETICO

Alla base della questione, il c.d. decreto "*Burden Sharing*", che non è altro che il D.M. 15 marzo 2012, emanato in attuazione dell'art. 2, comma 167 della L. Finanziaria Italiana per il 2008, che recepiva le indicazioni provenienti dalla Direttiva Europea n. 28 del 2009 (e l'allora PAN, Piano di Azione Nazionale per le energie rinnovabili).

Tale decreto ministeriale fissava le quote di produzione da fonti rinnovabili per la Sardegna (e per le altre Regioni Italiane) con riferimento alla normativa europea vigente in quel momento, come recepita dall'Italia.

Si reputa alquanto interessante delineare sommariamente l'iter normativo che si è dipanato nel periodo intercorrente tra il DM *Burden Sharing* del 2012 e l'ultimo intervento in tema, il c.d. D.M.-Pichetto Fratin peraltro ancora non emanato alla data di stesura della presente Memoria.

Nel 2018, infatti, l'UE ha emanato una nuova direttiva (la numero 2001/2018) la quale prevede che gli Stati membri provvedano collettivamente a far sì che, nel 2030, la quota di energia da fonti rinnovabili nel consumo finale lordo di energia dell'Unione arrivi ad una quota pari almeno al **32%** (articolo 1 e articolo 3, comma 1). Quasi contestualmente alla Direttiva, l'UE ha emanato il Regolamento 1999/2018.

Di fronte al mutato quadro normativo europeo, l'Amministrazione Centrale Italiana è dovuta intervenire per recepire le novità introdotte:

- nel dicembre del 2019 è stato predisposto il PNIEC - Piano Nazionale Integrato per l'Energia e il Clima, che prevede per l'Italia una percentuale di energia da fonti rinnovabili nei Consumi Finali Lordi di energia pari al 30%;
- la trasposizione completa nell'ordinamento nazionale di tali indicazioni è avvenuta in attuazione della legge delega n. 53/2021, approvata il 22 aprile 2021, in base alla quale l'Esecutivo a Presidenza-Draghi ha predisposto ed emanato il D.lgs. n. 199/2021.
- Un ulteriore Provvedimento emanato dall'Esecutivo -Draghi, il Dpcm 29 marzo 2022 (*Energia Sardegna*), che non casualmente richiama i decreti legge 76/2020 e 77/2021 ha fissato (art. 2, comma 3) un limite più basso di produzione da rinnovabili per la Sardegna ma con riferimento ad un'altra questione: ossia, l'individuazione delle opere e delle infrastrutture necessarie alla dismissione dell'utilizzo del carbone in Sardegna e alla decarbonizzazione dei settori industriali.
- In ultimo, cronologicamente, il D.M. Pichetto Fratin - c.d. "Aree Idonee" - nell'ultima bozza disponibile, quella del 30 maggio u.s. - all'Art. 1 – comma 1 - lettera "a" riporta:

*“il presente decreto, in attuazione dell'articolo 20, commi 1 e 2, del decreto legislativo n.199 del 2021, ha la finalità di: a) individuare la ripartizione fra le Regioni e le Province autonome dell'obiettivo nazionale al 2030 di una potenza aggiuntiva pari a 80 GW da fonti rinnovabili, necessaria per raggiungere gli obiettivi fissati dal PNIEC e rispondere ai nuovi obiettivi derivanti dall'attuazione del pacchetto “Fit for 55”, anche alla luce del pacchetto “Repower UE*

nello stesso momento in cui all'Art. 2 – comma 1 – Tabella “A” delinea la “*traiettoria di conseguimento dell'obiettivo di potenza complessiva da tra guardare al 2030*” che per la Sardegna indica come obiettivo minimo di potenza installata per impianti alimentati da F.E.R. la soglia di **6.264 MW**

E' da quest'ultimo dato che si è ritenuto inderogabile partire nell'Analisi che ha condotto alla conclusione di cui all'asserzione di apertura.

Allo stato attuale, dai dati resi disponibili da TERNA S.p.A., in Sardegna risultano installati elettro-generatori per una potenza elettrica efficiente lorda pari a **4.744 MW**, a fronte dei quali la componente termoelettrica è pari a **2.501 MW**.

Diversamente dal resto d'Italia, dove l'energia termoelettrica è prodotta da combustione di gas metano, nell'Isola la produzione di energia termoelettrica avviene mediante combustibili quali carbone, gasolio, olio combustibile, syngas e biomasse.

In diretta conseguenza di ciò, per semplice somma algebrica appare legittimo affermare che già allo stato attuale, in Sardegna **risultano già installati elettro-generatori alimentati da F.E.R. per una potenza elettrica efficiente lorda pari a 2.243 MW**.

Passando ora al versante “fabbisogno energetico”, dai report statistici di TERNA e GSE la potenza istantanea mediamente richiesta dalle utenze sarde é alquanto inferiore ai **1.300 MW** (con **punte prossime ai 1.500 MW in casi del tutto eccezionali** che si verificano essenzialmente nel mese di Agosto) e tendenzialmente in calo nell'ultimo decennio (non appare qui il caso di disquisire sulle peraltro “note” motivazioni, che spaziano dal progressivo spopolamento per emigrazione alla desertificazione industriale in atto ormai da decenni).

Tenuto conto che l'accumulo di energia è essenzialmente legato:

- alla pratica del “pompaggio inverso” è possibile solo in una parte dei **18 invasi dotati di impianti idro-elettrici**;
- l'accumulo mediante sistemi a batterie ricaricabili equivale ad una **quota assolutamente marginale** della produzione di energia elettrica che già attualmente si realizza.

senza trascurare che gli impianti termo-elettrici di Fiumesanto, Portovesme, Assemini e Sarroch operano in regime di “*essenzialità per la sicurezza del sistema elettrico ai sensi dell'articolo 63, comma 63.1, dell'Allegato A alla delibera n. 111/06 dell'AUTORITÀ PER L'ENERGIA ELETTRICA E IL GAS (ora ARERA)*” ed in quanto tali sono soggetti, al fine di limitare gli squilibri nella Rete di Distribuzione ad un regime di fermo programmato (peraltro ampiamente compensato dagli indenizzi stabiliti da ARERA), appare del tutto evidente che già allo stato attuale, in Sardegna risulta mediamente generata una **potenza elettrica “esportabile” di oltre 2500 MW**, una quantità che rischia di andare **in rilevantissima quota sprecata**, in quanto non utilizzata in Sardegna... di certo “non imbottigliabile” e/o “conservabile” secondo canoni tradizionali... e tantomeno... “trasferibile” ad altre regioni attraverso il sistema che connette la Rete Elettrica della Sardegna con la Rete Elettrica della Penisola Italiana, servito al momento dai due collegamenti via cavo:

- **SA.PE.I. - con capacità di trasporto di 1000 MW;**
- **SA.CO.I. - avente capacità teorica di trasporto di 300 MW.**

(N.d.r. - per non sovraccaricare il testo, i dati completi dei due citati sistemi – e non solo - sono stati raccolti in una prima appendice in coda alla presente, denominata “Allegato-1”)

A tutti gli effetti, allo stato attuale la **capacità teorica di esportazione/trasporto** di corrente elettrica all'esterno dell'Isola equivale pertanto ad una potenza di **1300 MW**, quantunque tale cifra debba essere presa con assoluta cautela in quanto, soprattutto il SA.CO.I. - la cui costruzione risale al 1967 - è da considerarsi alquanto vetusto per poter forse sostenere con sufficienti condizioni di stabilità e sicurezza i carichi di servizio “di targa”.

Nell'evidente tentativo di porre rimedio alla situazione appena descritta, la soluzione proposta da TERNA S.p.A. è quella che è stata definita “*il più importante progetto al mondo per la trasmissione di energia elettrica sotto il mare e soprattutto una grande opera industriale...*”: il

**Tyrrhenian Link**, con **capacità di trasporto di 1000 MW** ripartiti su due cavi, che TERNA S.p.A., gestore della rete elettrica nazionale, ha in programma di realizzare nei prossimi anni (con entrata in servizio del c.d. “Ramo-Ovest” che collegherà la Sardegna alla Sicilia **programmata per il 2028**).

Le caratteristiche generali dell’opera sono alquanto note (*anche in questo caso sono state compendiate nell’Allegato-1 alla presente Nota*).

Per quanto riguarda il Ramo-Ovest (Sardegna-Sicilia) sommariamente si tratta di:

- un elettrodotto con n.2 collegamenti bipolari di potenza in cavo sottomarino di lunghezza di circa 471 km che collegheranno l’approdo siciliano di Fiumetorto all’approdo sardo di Terra Mala, da installare considerando una massima profondità di posa ad oggi prevista pari a circa 2150 m;
- n.2 collegamenti di circa 31 km di cavo terrestre di polo e di elettrodo che collegheranno l’approdo sardo di Terra Mala, nel comune di Quartu Sant’Elena, alla stazione di conversione di Selargius.

Tenendo conto delle analoghe opere da realizzarsi in Sicilia fra il punto di approdo di Fiumetorto e la stazione di conversione di Termini Imerese (per una lunghezza di 9 km), la lunghezza complessiva del Ramo-Ovest del Tyrrhenian Link è di 511 km.

Qualora invece si voglia tenere conto anche del Ramo-Est (Sicilia – Torre Tuscia Magazzino – Battipaglia - Campania), la lunghezza complessiva dell’elettrodotto sottomarino porta ad una sommatoria di ben 970 km

Gli oneri per la realizzazione in quota-investimenti di TERNA S.p.A. sono stati quantificati complessivamente in **3,7 miliardi di euro**, di cui 1,9 miliardi finanziati da B.E.I. con un prestito a lungo termine, andranno a gravare direttamente come Debito nel Bilancio di una Società a maggioranza azionaria Pubblica caratterizzata peraltro da un indebitamento netto di oltre 10 miliardi di euro, ovvero circa 3 volte e mezzo il proprio fatturato che pure si presenta stabile nell’ultimo decennio.

In mezzo alla cospicua mole di dati tecnico-progettuali non si è ritenuto di dover trascurare nemmeno il rilevante accompagnamento di “fanfare e proclami” (per quanto non sempre chiaramente “intonati”), che hanno accompagnato progetto fin dalla sua presentazione.

Di particolare interesse benché anche abbastanza inquietante in alcuni passaggi, in quanto esplicitativa di una mentalità imprenditorial-aziendalista alquanto “predatoria” la posizione espressa da Giacomo Donnini - Direttore Grandi Progetti e Sviluppo Internazionale di TERNA S.p.A in una intervista rilasciata alla Rivista “L’Industria Italiana” e dalla stessa pubblicata il 17 gennaio 2023:

*«L’obiettivo principale del Tyrrhenian Link è quello di stabilizzazione e messa in sicurezza della rete, assicurando lo scambio efficiente tra le due isole e tra queste e il Continente.*

*Collegato a questo, c’è il tema dell’integrazione nella rete nazionale delle fonti rinnovabili.*

***Le aree di approdo dell’opera non sono casuali: sono luoghi dove c’è molta disponibilità di sole e vento.***

***L’energia delle fonti rinnovabili è per sua natura intermittente e pertanto dobbiamo prevedere un’importante capacità di trasporto:***

*una rete che consenta di prelevarla dove viene prodotta e di portarla dove viene consumata, sostanzialmente quindi da Sud verso Nord, dove si concentra la maggior parte dei consumi civili e industriali. Questo vale in un contesto italiano, ma se allarghiamo lo sguardo all'Europa, i due maggiori bacini di rinnovabili sono l'eolico nel mare del Nord e il fotovoltaico nel Mediterraneo. Dobbiamo avere la possibilità di trasferire quest'energia da un'area all'altra in base a disponibilità ed esigenze di consumo...»*

(<https://www.industriaitaliana.it/terna-tyrrhenian-link-energia/> )

Acquisiti i dati suesposti, la questione conseguente che è stata affrontata è:

1. *“prescindendo completamente dai teorici benefici che si sostiene connessi al possibile funzionamento in “reverse-mode” (possibile solo per il Tyrrhenian Link peraltro) il sistema di trasmissione realizzato dalla sommatoria delle capacità di trasporto di SA.PE.I. SA.CO.I. e Tyrrhenian Link... è in grado di sostenere l'esportazione verso la Penisola dell'energia elettrica prodotta in Sardegna con l'attuale configurazione impiantistica?*
2. *...e con la configurazione prevista per il 2030 dal D.M. Pichetto Fratin - c.d. “Aree Idonee” ?...*
3. *...e con l'eventuale via libera all'installazione di elettro-generatori Fotovoltaici, Eolici a Terra ed Eolici a mare per ulteriori **57.670 MW** di potenza che fanno capo alle 809 richieste di avvio-pratiche di connessione presentate a TERNA alla data del 31.03.2024 come si desume dal sistema “econnexion” della stessa Società?...*

L'unica risposta razionalmente e ragionevolmente sostenibile, tenuto anche conto che dai dati del Cronoprogramma dei Lavori presentato da TERNA S.p.A il Tyrrhenian Link non sarà comunque in servizio prima del 2028 sono **tre consecutive, documentate e argomentate NEGAZIONI.**

Il sistema infrastrutturale di collegamento fra la Sardegna e la R.T.N. come dimostrano inequivocabilmente i dati suesposti confrontati con la capacità di trasmissione delle infrastrutture di collegamento è **già oggi intrinsecamente e strutturalmente inidoneo** a supportare l'attuale livello di interscambio fra Sardegna e Penisola Italiana ipotizzabile in base alla potenza del parco di elettro-generazione installato e può essere ancora attualmente “gestito” unicamente grazie al sistematico ricorso al regime di fermo programmato, che remunera a fondo perduto il Produttore proprietario dell'impianto “fermato” con oneri che si scaricano direttamente sulla Comunità dei Cittadini-Utenti gonfiando le bollette con le voci afferenti gli “Oneri di Sistema”. .

**Lo sarà in misura addirittura maggiore nel 2028**, quando entrerà in servizio il Tyrrhenian Link ma... secondo la Tabella “A” di cui all'Art. 2 – comma 1 – della bozza 31.05.24 del D.M. Pichetto Fratin - c.d. “Aree Idonee” dovranno risultare installati in Sardegna, entro il 31.12.2028 , ulteriori **3.892 MW** di potenza sotto forma di elettro-generatori alimentati a F.E.R. rispetto a quanto già presente al 31.12.2020, **chiaramente inadeguato/insufficiente - anche al più considerando un irragionevole coefficiente di contemporaneità del parco di neo-generazione de solo 50%** - a fronte di un incremento della capacità di trasporto rispetto a quella attuale di “soli” **1000 MW**.

**Lo sarà in misura drammaticamente maggiore nel 2030**, quando, a fronte di un Tyrrhenian Link in pieno esercizio, secondo la Tabella “A” di cui all’Art. 2 – comma 1 – della bozza 31.05.24 del D.M. Pichetto Fratin - c.d. “Aree Idonee” dovranno risultare installati in Sardegna, entro il 31.12.2028 , ulteriori **6.264 MW** di potenza sotto forma di elettro-generatori alimentati a F.E.R. rispetto a quanto già presente al 31.12.2020. e con nessun incremento della capacità di trasporto in programma rispetto a quella teoricamente resa disponibile nel 2028.

**Lo sarà in misura follemente maggiore** in qualsivoglia momento dovesse trovare concreto via libera l’installazione dei succitati elettro-generatori Fotovoltaici, Eolici a Terra ed Eolici a mare per ulteriori **57.670 MW** di potenza che fanno capo alle 809 richieste di avvio-pratiche di connessione presentate a TERNA alla data del 31.03.2024

( Cfr. Allegato-1 o direttamente: <https://www.terna.it/it/sistema-elettrico/programmazione-territoriale-efficiente/econnection> )

Rimarcata una volta di più l’assoluta (e sconcertante) chiarezza delle indicazioni che emergono dall’analisi dei dati numerici, non si ritiene ci sia molto altro da aggiungere per avvalorare la fondatezza dell’asserto iniziale.

Solo osservare che la Regione Sardegna, come da orientamenti Istituzionali pubblicamente espressi e in armonia con il contesto dell’Europa e dell’Italia, sostiene di riservare particolare importanza alla tutela ambientale, territoriale e paesaggistica dell’Isola.

Pertanto, si ritiene che gli interventi e le azioni “del” e “sul” Sistema Energetico Regionale devono di necessità essere concepiti in modo da minimizzare l’alterazione ambientale.

In coerenza con questa impostazione si ritiene pertanto di sommessamente suggerire che tutti gli impianti di captazione di energia, sia essa eolica, fotovoltaica e/o solare aventi estensione fisica considerevole per la produzione di potenza elettrica su scala industriale, dovrebbero essere localizzati in siti compromessi, preferibilmente in aree industriali esistenti e comunque in assoluta coerenza con il Piano Paesaggistico Regionale e con gli Strumenti di Governo del Territorio degli Enti Territorialmente competenti.

Si ritiene anche di poter suggerire l’adozione urgente di Provvedimenti idonei ad incrementare il più possibile il sistema di generazione fotovoltaico con l’utilizzo dei tetti degli edifici residenziali interni ai centri abitati, prendendo per estremo in considerazione anche le aree cimiteriali (naturalmente ove possibile).

Per quanto invece attiene gli impianti già autorizzati, un possibile, ragionevole suggerimento che si ritiene di sottoporre è l’introduzione d’urgenza di un’innovazione Normativa che preveda l’introduzione di una cauzione (sostitutiva o collegata a fideiussione, in ogni caso garantita e rivalutabile) che copra completamente i futuri costi di smaltimento sia dei parchi eolici sia di quelli fotovoltaici oltre che dei relativi cavidotti, stazioni elettriche e di accumulo.

Cauzione e fideiussione obbligatorie pena il non rilascio del nulla-osta all’avvio dei lavori.



- 2) PROBLEMATICHE DI INADEGUATEZZA/SOSTENIBILITÀ DEL MODELLO “TYRRHENIAN LINK” QUALE VALIDA INFRASTRUTTURA AI FINI DELL’ESPORTAZIONE DI ENERGIA ELETTRICA SECONDO LE QUOTE DI PRODUZIONE ASSEGNATE DALL’AMMINISTRAZIONE CENTRALE DELLO STATO AI FINI DEL CONSEGUIMENTO DEL C.D. “OBIETTIVO 2030”.

Come accennato in precedenza, insieme ad una cospicua messe di Informazioni in relazione al Tyrrhenian Link, redatte in termini e contenuti piu’ o meno tecnici e con evidenti diversi gradi di imparzialità, è stata resa disponibile al Pubblico anche una rilevante produzione di “opinioni” piu’ o meno tecniche e/o interessate, “proclami” *et similia*.

Nell’ambito di tale produzione ha suscitato particolare interesse e curiosità nello Scrivente la già citata posizione pubblicamente espressa da Giacomo Donnini - Direttore Grandi Progetti e Sviluppo Internazionale di TERNA S.p.A. - nello specifico in una dichiarazione dello scorso 17 gennaio 2023 alla rivista “Industria Italiana” (<https://www.industriaitaliana.it/terna-tyrrhenian-link-energia/> )

Nello specifico quella sintetizzata da:

*«L’obiettivo principale del Tyrrhenian Link è quello di stabilizzazione e messa in sicurezza della rete, assicurando lo scambio efficiente tra le due isole e tra queste e il Continente. [...]*

Tali interesse e curiosità hanno stimolato a considerare alquanto utile un approfondimento sullo specifico tema.

Corrisponde al vero la sostenuta stabilizzazione e messa in sicurezza della rete (di distribuzione, interconnessione con la R.T.N. e trasporto) conseguibile con infrastrutture sul “Modello Tyrrhenian Link”?

E’ davvero in grado tale tipo di infrastruttura ad assicurare lo scambio efficiente tra le due Isole e tra queste e il Continente ?

La questione è stata trattata da due diversi punti di vista:

- un primo approccio basato sull’acquisizione e discussione di elementi di tipo eminentemente geostrategico;
- un secondo approccio di tipo esclusivamente Tecnico-Scientifico, basato su considerazioni successive ad approfondimenti di carattere tecnico, statistico e bibliografico sui temi afferenti lo specifico argomento

Si anticipa che i risultati conseguiti non sono (purtroppo) del tutto in linea con le asserzioni in verifica:

## **2-a) Approccio di tipo geostrategico**

Approfondendo l’Analisi e la conseguente Discussione dal punto di vista geostrategico si è pervenuti alla (sconfortante) conclusione che lungi dal fungere da elemento di stabilizzazione e messa in sicurezza della Rete (della Sardegna, della

Sicilia e della Penisola Italiana in generale) esso in realtà introduce un più che rilevante contenuto di **aleatorietà e vulnerabilità** stante l'attuale Situazione Internazionale e i possibili sviluppi a breve/medio termine.

Nessuno infatti può dimenticare quanto accaduto nel 2023 Nel Mar Baltico al gasdotto North-Stream... e che il “socio di maggioranza” di tale Opera è ancora saldamente ed indefinitamente “sulla cresta dell'onda”.

Considerando il lunghissimo tragitto in acque internazionali battute da un intenso traffico marittimo e parlando “fuori-di-metafore... si ritiene alquanto evidente che un sistema di interconnessione via cavo “Modello “Tyrrhenian-Link” risulta altamente vulnerabile a possibili azioni di “disturbo” o di “guerra ibrida” o di... sabotaggio che dir si voglia, le quali avrebbero tra l'alto il dubbio pregio di risultare alquanto “economiche” da realizzarsi oltre che praticamente... “definitive” (nel senso che si ha il ragionato e si ritiene ragionevole dubbio che - senza nemmeno ipotizzare l'intervento di mezzi sottomarini specializzati - potrebbe risultare sufficiente un "innocuo battello" che, raggiunta una “opportuna posizione” in acque internazionali fila in mare alcune cariche di profondità “sapientemente” distanziate e con spolette ritardate per... eliminare “in radice” il problema-connessione con (purtroppo) “saluti & auguri” a chi si troverebbe ad ipotizzarne il recupero e la riparazione (che a 2100 metri di profondità appare come strada alquanto “in salita” se non direttamente improbabile).

Appare inoltre doveroso rimarcare come l'eventuale infausto concretarsi di uno scenario del tipo analizzato appare in condizione di esplicitare i suoi nefasti effetti soprattutto sulla Sardegna che, rispetto alla Sicilia ha un numero molto più ristretto di alternative per l'interconnessione con la R.T.N. oltre che un posizionamento geografico nettamente più sfavorevole.

Avrebbe invece effetti alquanto trascurabili in relazione alla R.T.N. ed all'approvvigionamento energetico della Penisola Italiana, stante che (come viene dimostrato nel seguito della presente nota basandosi sui dati contenuti negli Allegati indicati) **nella malaugurata ipotesi di utilizzo dei 970 Km del Tyrrhenian Link** per la trasmissione – via interposto approdo in Sicilia – di energia elettrica dalla Sardegna alla Penisola, le **perdite di potenza** per il processo di

**[conversione-AC-DC]-[trasporto sottomarino]-[ricomversione-DC-AC]** sfiorano statisticamente il raccapricciante valore del **56,5%, ovvero, ragionando in termini meramente energetici... di 565 MWh per ogni 1000 MWh** eventualmente immessi nel sistema dall'eventuale futura stazione di conversione prevista in Agro del Comune di Selargius (CA).

## 2-b) Approccio di tipo meramente Tecnico

Come suesposto, l'Analisi e Discussione in relazione al tema è stata sviluppata anche dal punto di vista meramente Tecnico, basandosi su Pubblicazioni e Lavori Scientifico-Statistici di Autori di adeguate caratteristiche di Competenza, Attendibilità e Rigore Scientifico-metodologico Internazionalmente riconosciute oltre che su Report prodotti negli ultimi anni da Agenzie e/o da Consulenti Tecnici collegabili alla stessa Unione Europea.

L'attenzione si è focalizzata in particolare sull'argomento delle **perdite statistiche per conversione e trasporto di energia** per sistemi basati sulla tecnologia HVDC e sulla puntuale verifica dei dati esposti in via statistico-teorica con quelli rilevati da alcuni dei principali sistemi di trasporto utilizzando la stessa tecnologia e realmente operativi, asserviti ad impianti di produzione di Energia basati su campi di aerogeneratori non a caso localizzati fra Mare del Nord e Baltico.

Fra le Pubblicazioni e Lavori analizzati, due si sono rivelati alquanto interessanti:

- ***“Economic comparison of VSC HVDC and HVAC as transmission system for a 300 MW offshore wind farm” di B. Van Eeckhout, D. Van Hertem et alii, pubblicato nella collana EUROPEAN TRANSACTIONS ON ELECTRICAL POWER - Wiley InterScience - John Wiley & Sons, Ltd – 2009;***
- ***ENTSO-E - European Network of Transmission System Operators for Electricity - HVDC Utilisation and Unavailability Statistics 2021 - Report rendered 16 August 2022***

Come in precedenza, dalle Pubblicazioni citate sono stati estratti alcuni passaggi che si reputano alquanto salienti, raccolti in forma prevalentemente grafica ma anche tabellare in una appendice alla presente denominata **Allegato-2**.

Le Pubblicazioni citate si allegano in ogni caso ed anche al fine di consentire le opportune verifiche al lettore “dubbioso”, in versione integrale come **Allegato-3** ed **Allegato-4** alla presente.

Nell'ampia messe di dati acquisiti, di assoluta rilevanza appaiono quelli condensati nell'immagine indicata come **Img 1 dell'Allegato-2**.

Si tratta di abaco-calcolatore generato da un'indagine statistica condotta a partire da un impianto di trasmissione di energia elettrica asservito ad un campo di generatori eolici off-shore della potenza complessiva di 300 MW, ove la trasmissione verso la Rete di distribuzione a terra è realizzata tramite connessione via cavo che si avvale della tecnologia HVDC, la stessa implementata - a parte la potenza – nelle due connessioni Sardegna-Italia attualmente in esercizio e che sarà utilizzata, da progetto per lo stesso Tyrrhenian Link.

In conseguenza di ciò, anche al fine di rispondere alle possibili obiezioni relative al dato di fatto che trattasi di una Pubblicazione edita nel 2009, i dati desumibili da tale abaco-calcolatore grafico sono stati metodicamente e puntigliosamente confrontati e correlati con quelli desumibili dal citato Report **Entso-E** - edito nel 2022 e relativo ad una serie di impianti reali e consimili realmente operativi nell'anno solare 2021, con esigenze di trasporto comparabili, se non superiori a quelle che vengono realizzate nelle due connessioni Sardegna-Italia attualmente in esercizio e nel futuro dallo stesso Tyrrhenian Link. Si tratta dei dati desumibili dal confronto fra le immagini indicate con **Img 2, Img 4 ed Img 5** nell'**Allegato 2**.

In particolare, a parte lievi scostamenti, da riferire con alta probabilità a meccanismi di casualità statistica, i dati desumibili soprattutto dall'**Img\_5** confermano la validità di quanto condensato nell'abaco-calcolatore di cui all'**Img\_1** dell'**Allegato-2** e... non si possono di certo definire soddisfacenti.

Con l'utilizzo dell'abaco-calcolatore in parola è stato infatti impostato, a titolo esemplificativo il calcolo delle perdite energetiche statisticamente riferibili, in percentuale sull'energia trasmessa, alla trasmissione di energia tramite cavo in Alta tensione alimentato in Corrente Continua (HVDC), limitando - deliberatamente e sempre ai fini di comodità di lettura - la distanza di trasporto a soli 100 km.

I risultati ottenuti sono riportati nell'immagine in coda all'Allegato-2 e possono essere così sintetizzati:

1. A fronte di una **distanza di trasporto (lunghezza del cavo) di 100 Km, le perdite** nel caso di utilizzo della tecnologia HVDC **si posizionano in un intorno del 5%** ;
2. Statisticamente le **perdite di conversione AC/DC nella stazione di immissione si possono valutare nell'ordine del 4%** ;
3. **Perdite del tutto analoghe si possono legittimamente ipotizzare nella stazione di conversione inversa DC/AC al punto di recapito, ovvero di ulteriori 4%.**

Tali risultati, stante l'assoluta coincidenza della tecnologia utilizzata ed in assenza di notizie circa possibili "stravolgimenti epocali" intervenuti in relazione alla realizzazione dei cavi sottomarini, si ritiene siano assolutamente e perfettamente correlabili ai cavi che uniscono (o uniranno) la Sardegna, la Penisola Italiana e la Sicilia. In particolare si ritiene siano alquanto correlabili al **Tyrrhenian Link** in progetto, con l'aspettativa di risultati di questo genere:

- A fronte di una **distanza di trasporto (lunghezza del cavo) di 511 Km, le perdite sono da ritenersi in un intorno del 25,6%** ;
- le **perdite di conversione AC/DC nella stazione di immissione (Selargius o Fiumetorto, essendo il sistema reversibile) si possono ancora valutare nell'ordine del 4%** ;
- **Il valore precedente deve essere replicato per tenere conto della conversione inversa DC/AC al punto di recapito, il che porta a stimare un ulteriore 4% di perdite:**
- La **perdita complessiva nel tratto Sardegna-Sicilia assurge pertanto statisticamente ad un valore del 33,6 %** ovvero, in termini energetici... c.a. 336 MWh per ogni 1000 Mwh immessi alla stazione di conversione.

**Considerazioni del tutto simili valgono nel caso degli altri due "link" attualmente già in esercizio. Si tratta di valori alquanto sconcertanti ma che come già accennato in precedenza potrebbero anche "drammaticamente"**

**peggiore nella malaugurata ipotesi di utilizzo dei 970 Km del Tyrrhenian Link per la trasmissione – via interposto approdo in Sicilia – di energia elettrica dalla Sardegna alla Penisola, in quanto, con lo stesso meccanismo appena illustrato, si dimostra all’istante che le perdite andrebbero statisticamente ad assurgere all’insostenibile valore del 56,5%, ovvero 565 MWh per ogni 1000 MWh eventualmente immessi nel sistema dalla futura stazione di conversione di Selargius, con in aggiunta il “sovramercato” che in ogni caso, l’energia ritirata dall’Acquirente Unico ed avviata verso la Stazione di conversione di Selargius dovrà essere remunerata al 100% della sua entità misurata al punto di prelievo, ai valori stabiliti dal D.Lgs. 199/2021 in relazione alle quotazioni d’Asta della Borsa Elettrica di riferimento (c.d. “asta del giorno precedente”) quantunque lo stesso Acquirente Unico si ritroverà a disporre, al punto di approdo ed all’atto di immissione nella R.T.N. di un quantitativo di energia da distribuire ai suoi Clienti decurtato come minimo di oltre 1/3 da un semplice **fenomeno Fisico** e quantunque... per una semplice **legge economica**, lo stesso potrà comunque (ampiamente) rivalersi sui portafogli dei Clienti computando le perdite sostenute fra gli **Oneri di Sistema** addebitati in bolletta. Il Risultato, per quanto paradossale potrebbe concretarsi in un aumento indiscriminato degli importi addebitati pur in presenza di una crescente disponibilità della materia-prima ENERGIA e ad un conseguente, possibile calo delle quotazioni.**

Quanto poi, alla luce di quanto appena esposto, rimanga ancora di sostenibile e/o condivisibile delle già riportate parole del Direttore Grandi Progetti e Sviluppo Internazionale di TERN A S.p.A, Giacomo Donnini, con particolare riferimento alla “tonante” affermazione:

*“...L’energia delle fonti rinnovabili è per sua natura intermittente e pertanto dobbiamo prevedere un’importante capacità di trasporto: una rete che consenta di prelevarla dove viene prodotta e di portarla dove viene consumata, sostanzialmente quindi da Sud verso Nord, dove si concentra la maggior parte dei consumi civili e industriali...”*

non si ritiene rientri fra le finalità della presente Nota.

Ci si limita ad osservare che risulta alquanto arduo sostenere la bontà e praticabilità di una presunta per quanto pretesa “Iniziativa Industriale Epocale” che anziché su fatti reali, tangibili ed economicamente solidi si dimostra poggiare su scelte ideologiche, teoremi indimostrati ed indimostrabili e/o reboanti proclami (ogni riferimento ad un presunto futuro “Hub energetico Italiano” chiamato Sardegna è da ritenersi puramente... casuale).

## **Conclusioni Sintetiche**

Si ritiene appaia alquanto scontata l’evidenza, anche da quanto esposto in precedenza, che il Decreto in fase di conversione, che contempla la moratoria di 18 mesi in relazione all’installazione di nuovi impianti alimentati da F.E.R. risulti purtroppo insufficiente a conseguire l’obiettivo di

tutelare l'isola dal vero e proprio assalto che sta subendo da multinazionali energetiche di varia taglia ma il cui "peso" e la cui relativa capacità di influenzare la Vita Pubblica e Sociale anche attraverso interventi di "lobbyng & influencing" non sempre del tutto cristallini appare in rapida crescita.

Si reputa di estrema necessità ed urgenza un provvedimento idoneo ad istituire, in attesa della definizione delle "condizioni al contorno" anche una moratoria dei processi autorizzativi che possa eventualmente vedere coinvolta anche TERNA, che non può ragionevolmente operare come un "pusher" mandando avanti indistintamente sia richieste da parte di legali e fondate iniziative industriali sia altre iniziative, riferibili a presunti progetti che talvolta risultano piu' assimilabili a scorribande piratesche che ad iniziative industriali, creando i presupposti per operazioni di tipo rivendicativo e naturalmente... senza tenere conto dei limiti che i normali processi fisici impongono alle sue stesse infrastrutture di trasporto, evidenziati anche in queste pagine e che con certezza non possono essergli ignoti.

Si reputa opportuno suggerire inoltre tutta l'opportunità della riapertura di una interlocuzione urgente con il Governo Centrale ed il MASE in particolare, durante la quale illustrare con l'adeguata chiarezza, non scevra dalle Arti della Diplomazia e della Politica, i limiti Fisici (non di ideologie o di qualsivoglia velleitarismo) che rendono e renderanno impraticabile a tempo indeterminato l'attuazione di buona parte delle disposizioni pregresse ed in particolare di quanto viene ipotizzato nella bozza del 31.05.2024 del D.M. Pichetto Fratin - c.d. "Aree Idonee" - Tabella "A" di cui all'Art. 2 – comma 1.

La stessa citata sede di interlocuzione appare peraltro come occasione di massima opportunità soprattutto per Rappresentare al Ministro in parola le specificità dello Statuto di Autonomia della Regione Sardegna, il loro rango Costituzionale e la irrinunciabilità delle stesse

Al tempo stesso si reputa necessario un intervento urgente in materia di Urbanistica che possa garantire che tutti gli impianti di captazione di energia, sia essa eolica, fotovoltaica e/o solare aventi estensione fisica da poter essere assimilati a meri impianti di produzione elettrica su scala industriale, debbano essere senza possibilità di compromesso localizzati nelle aree industriali già esistenti e comunque in assoluta coerenza con il Piano Paesaggistico Regionale e con gli Strumenti di Governo del Territorio degli Enti Territorialmente competenti.

Si ritiene anche di poter suggerire l'adozione urgente di Provvedimenti idonei ad incrementare il più possibile il sistema di generazione fotovoltaico con l'utilizzo dei tetti degli edifici residenziali localizzati nei centri abitati, prendendo in considerazione pure le aree cimiteriali (naturalmente ove possibile).

Infine, per quanto invece attiene gli impianti già autorizzati, un possibile, ragionevole suggerimento che si ritiene di sottoporre è l'introduzione d'urgenza di una novellazione di tipo normativo che preveda l'introduzione di una cauzione (sostitutiva o collegata a fideiussione, in ogni caso garantita e rivalutabile) che copra completamente i futuri costi di smaltimento sia dei parchi eolici sia di quelli fotovoltaici oltre che dei relativiavidotti, stazioni elettriche e di accumulo.

Cauzione e fideiussione obbligatorie pena il non rilascio del nulla-osta all'avvio dei lavori.

**Uta-Cagliari li 05.06.2024**



***Memoria***  
***Osservazioni in ordine al D.L. 15 - Misure urgenti per la salvaguardia del***  
***paesaggio, dei beni paesaggistici e ambientali***

***Allegato-1***

**Img\_ 1 – Principali caratteristiche fisiche e prestazionali SA.PE.I - (fonte: SA.PE.I - Terna S.p.A)**

<a href="#">Il SAPEI</a>	2	cavi marini, cavi terrestri, stazioni di conversione
<a href="#">Avanzamento dell'opera</a>	12	centimetri il diametro del cavo
<a href="#">Benefici del SAPEI</a>	22	metri di altezza degli edifici delle stazioni di conversione
<a href="#">Tutti i numeri del SAPEI</a>	50	tonnellate del tiro della nave posa-cavi
	70	prescrizioni tecniche e ambientali
	90	risorse coinvolte complessivamente nel progetto
	420	km di lunghezza
	500	kV di tensione
	1.000	MW di potenza
	1.600	profondità max. di posa
	5.000	elaborati di progetto
	7.000	tonnellate di capacità della nave posa-cavi
	35.000	m <sup>2</sup> l'area della stazione di Latina
	48.000	m <sup>2</sup> l'area della stazione di Fiumesanto (SS)
	50.000	m <sup>3</sup> di terreno movimentato
	700.000.000	investimenti in euro previsti





Img\_2 - Principali caratteristiche fisiche e prestazionali SA.CO.I (fonte: Terna S.p.A)

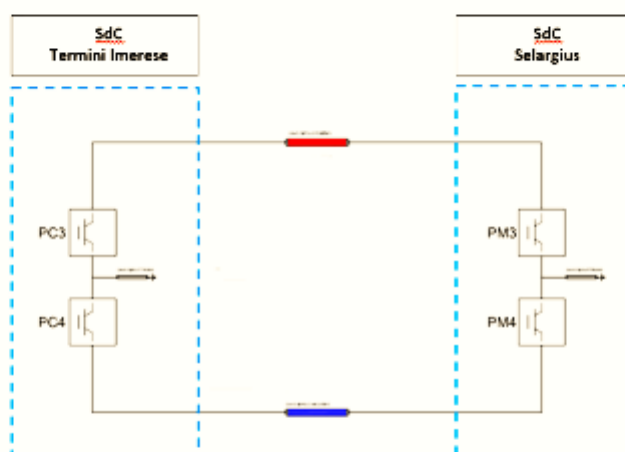
HVDC Italy–Corsica–Sardinia	
<b>Location</b>	
Country	Italy France
From	Suvereto  43°03'10"N 10°41'42"E
Passes through	Lucciana, Corsica  42°31'40"N 9°26'59"E
To	Codrongianos, Sardinia  40°39'07"N 8°42'48"E
<b>Ownership information</b>	
Operator	Terna
<b>Construction information</b>	
Manufacturer of substations	Ansaldo English Electric Alstom
Commissioned	1967, 1988, 1992
<b>Technical information</b>	
Type	overhead lines submarine cables
Type of current	HVDC
Total length	385 km (239 mi)
Power rating	300 MW
DC voltage	200 kV
No. of poles	1

**Img\_3 – Principali caratteristiche fisiche e prestazionali “Tyrrhenian Link” (in costruzione)**  
(fonte: Terna S.p.A)

Da un punto di vista elettrico, il collegamento ovest del “Tyrrhenian Link” consentirà l’interconnessione tra le isole della Sicilia e della Sardegna sarà realizzato con uno schema bipolare con elettrodi di tipo “bidirezionale”.

Tale configurazione permette, in condizioni di guasto su uno dei due cavi di polo, il funzionamento monopolare con ritorno di corrente in mare tramite gli elettrodi marini, opportunamente dimensionati per garantire identico transito di potenza. Sarà inoltre prevista la possibilità di funzionamento monopolare con ritorno metallico su uno dei due cavi di polo con passaggio da una configurazione all’altra in modo automatico, senza richiedere il fuori servizio bipolare.

Di seguito lo schema di principio del collegamento tra le due SdC a Termini Imerese e a Selargius:



La tensione di esercizio sarà di  $\pm 500$  kV e la potenza nominale sarà di 1000 MW in configurazione bipolare (ovvero 500 MW per ciascun polo).

Ulteriori caratteristiche elettriche del collegamento sono indicate nella tabella sottostante.

Caratteristiche del collegamento	
Tensione nominale	$\pm 500$ kV
Corrente nominale per ciascun polo	1000 A
Potenza nominale per ciascun polo	500 MW
Potenza massima in configurazione bipolare	1000 MW
Flusso di potenza	bidirezionale

***Memoria***  
***Osservazioni in ordine al D.L. 15 - Misure urgenti per la salvaguardia del***  
***paesaggio, dei beni paesaggistici e ambientali***

***Allegato-2***

**Img\_1 - Perdite di Trasmissione su Reti SUBACQUEE** - fonte: EUROPEAN TRANSACTIONS ON ELECTRICAL POWER - B. Van Eeckhout, D. Van Hertem et alii - Wiley InterScience - 2009)

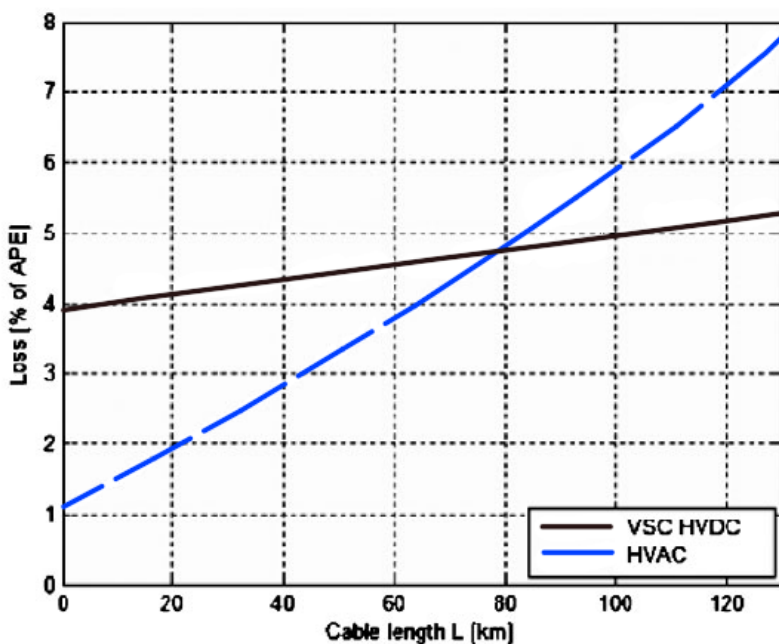


Figure 5. Loss percentage  $I_{\%}$  for VSC HVDC and HVAC as a function of cable length ( $P_{wind\ farm, nom} = 300\ MW$ ).

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*Euro. Trans. Electr. Power* (2009)  
DOI: 10.1002/etep

**Img\_2 Principali RETI SUBACQUEE di COLLAUDATA OPERATIVITA'** - (fonte: ENTSO-E - European Network of Transmission System Operators for Electricity - HVDC Utilisation and Unavailability Statistics 2021)

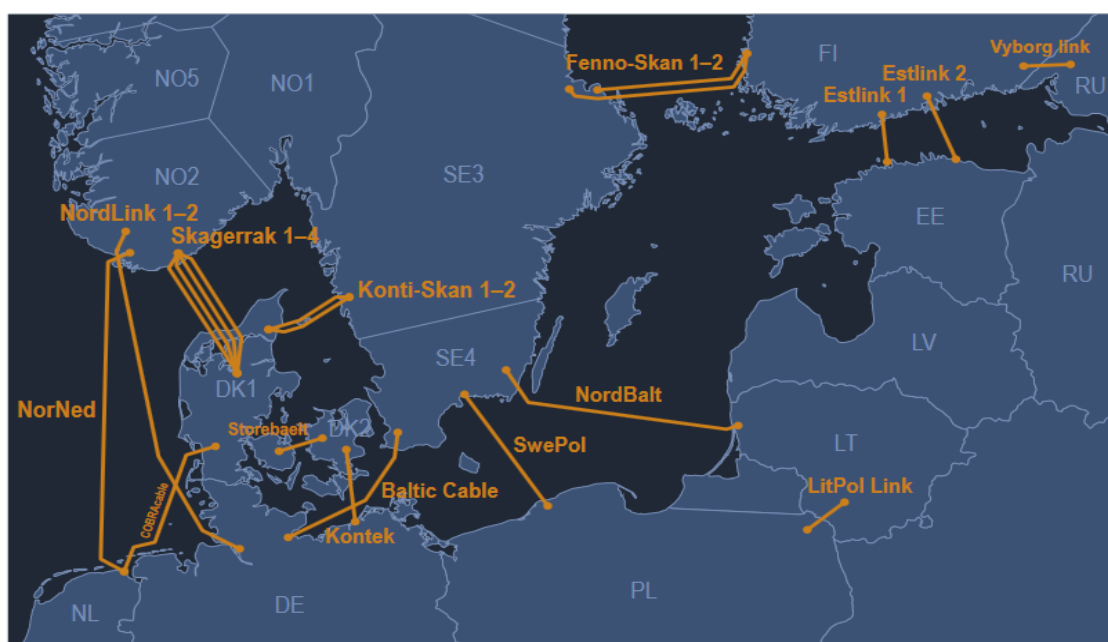


Figure 1.1: A map of the 20 HVDC links included in this report and the bidding zones in the area.

**Img 3 Criteri di valutazione delle Prestazioni utilizzati** - fonte: ENTSO-E - European Network of Transmission System Operators for Electricity - HVDC Utilisation and Unavailability Statistics to 2021)

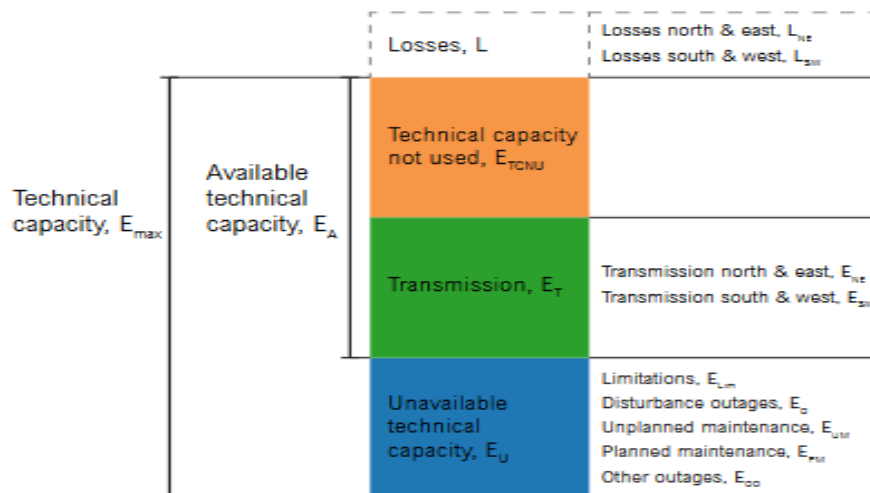


Figure 3.1: The hierarchy of the availability and utilisation categories used in the HVDC statistics.

**Img 4 – Dati operativi RETI SUBACQUEE in esame** - fonte: ENTSO-E - European Network of Transmission System Operators for Electricity - HVDC Utilisation and Unavailability Statistics to 2021)

Table 4.1: Main properties of the HVDC links.

Link	Commissioning year	Market connection	HVDC converter type	Rated power, monopolar (MW)	Parallel monopolar capacity (MW)	Bipolar capacity
Baltic Cable	1994	Yes	LCC	600		
COBRACable	2019	Yes	VSC	700		
EstLink 1	2006	Yes	VSC	350	1000	
EstLink 2	2014	Yes	LCC	650		
Fenno-Skan 1	1989	Yes	LCC	400	1200	1200
Fenno-Skan 2	2011	Yes	LCC	800		
Kontek	1995	Yes	LCC	600		
Konti-Skan 1 <sup>1</sup>	2008	Yes	LCC	357.5		715
Konti-Skan 2 <sup>1</sup>	1988	Yes	LCC	357.5		
LitPol Link	2015	Yes	LCC	500		
NordBalt	2016	Yes	VSC	700		
NordLink 1-2	2020	Yes	VSC	700×2		1400
NorNed	2008	Yes	LCC	700		
Skagerrak 1	1977	Yes	LCC	236		
Skagerrak 2	1977	Yes	LCC	236	1000	1000
Skagerrak 3	1993	Yes	LCC	478		
Skagerrak 4	2014	Yes	VSC	682		
Storebaelt	2010	Yes	LCC	600		
SwePol	2000	Yes	LCC	600		
Vyborg Link <sup>2</sup>	1981, 1982, 1984, 2000	Partly	LCC	1400		
<b>Total</b>				<b>10972</b>	<b>3940</b>	<b>2200</b>

<sup>1</sup> Konti-Skan bipole can export 740 MW and the import capacity is 715 MW. This counts in both directions since the reference point is now on the importing side.

<sup>2</sup> Each commissioning increased capacity by 350 MW. However, the total commercial capacity of Vyborg Link is 1300 MW. Fingrid Oyj, the Finnish transmission system operator, allocates 100 MW for reserves.

**Img\_ 5 - Statistiche prestazioni ANNUALI - anno 2021** - fonte: ENTSO-E - European Network of Transmission System Operators for Electricity - HVDC Utilisation and Unavailability Statistics to 2021)

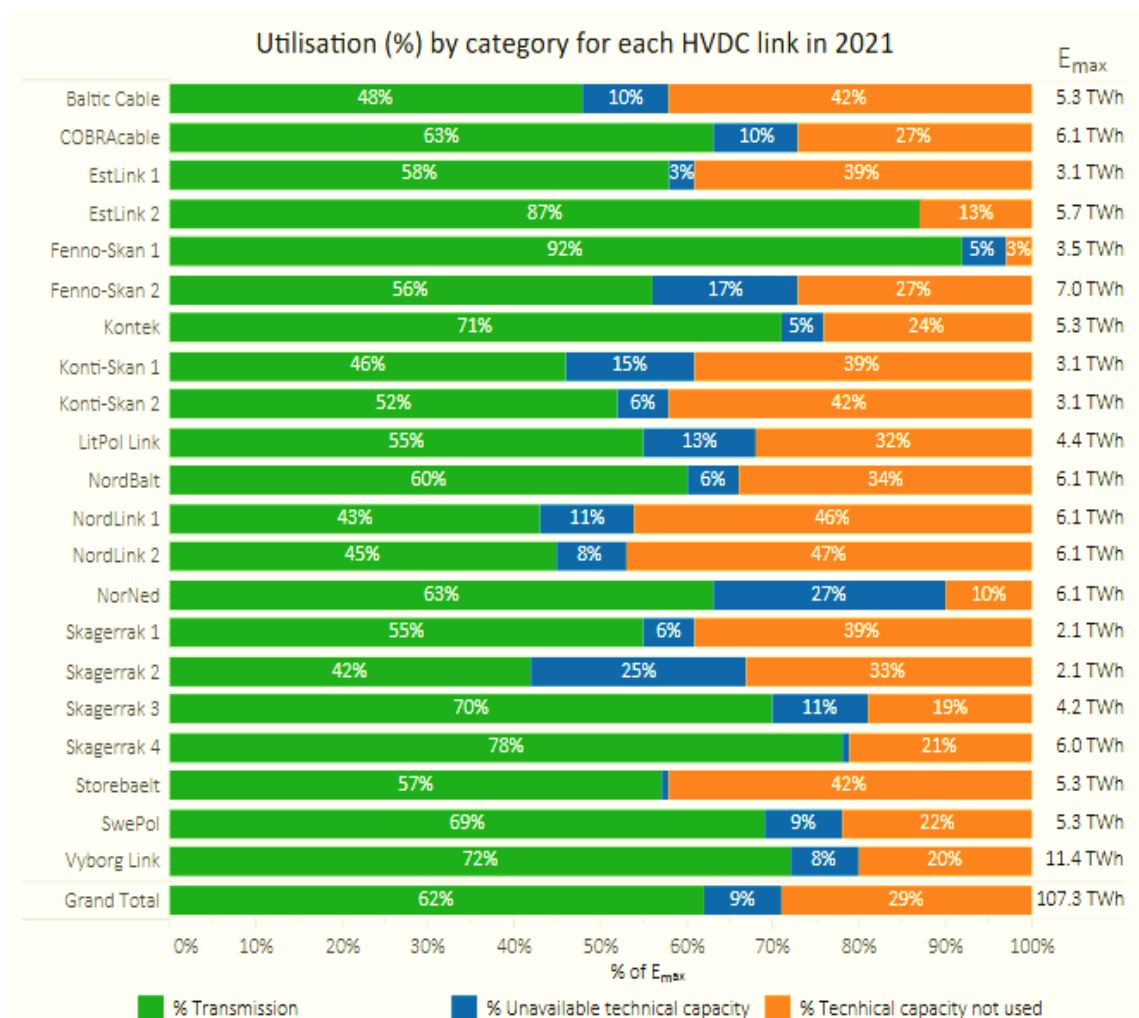


Figure 5.1: Utilisation (%) by category for each HVDC link in 2021. The unavailable technical capacity ( $E_U$ ) is the amount of technical capacity ( $E_{max}$ ) not available due to limitations or outages. Transmission ( $E_T$ ) is the amount of technical capacity ( $E_{max}$ ) transmitted through the HVDC link. Technical capacity not used ( $E_{TCNU}$ ) is the amount of energy that has not been transmitted or been unavailable due to limitations or outages. More detailed explanations can be read in Chapter 3.

**Esempio Calcolo perdite % per cavi subacquei in corrente continua (HVDC) e in corrente alternata (HVAC) in funzione della lunghezza-cavo**

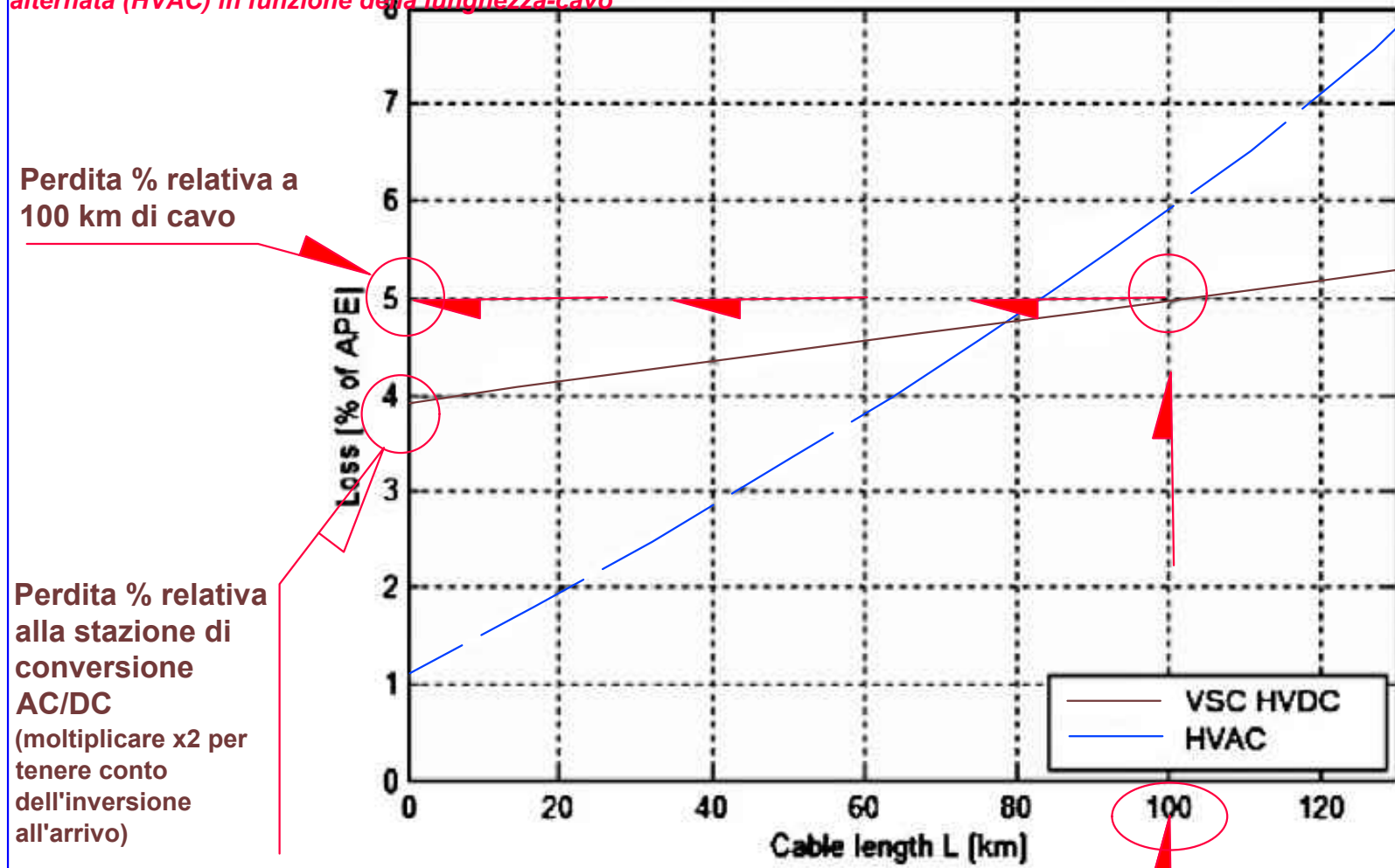


Figure 5. Loss percentage  $l_{\%}$  for VSC HVDC and HVAC as a function of cable length ( $P_{\text{wind farm, nom}} = 300 \text{ MW}$ ).

***Memoria***  
***Osservazioni in ordine al D.L. 15 - Misure urgenti per la salvaguardia del***  
***paesaggio, dei beni paesaggistici e ambientali***

***Allegato-3***



## Economic comparison of VSC HVDC and HVAC as transmission system for a 300 MW offshore wind farm

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### SUMMARY

Voltage source converter high voltage direct current (VSC HVDC) is a relatively new technology which allows the connection of islanded power systems. As such, it can form a connection between large-scale future offshore wind farms and the onshore transmission grid. In this paper, the VSC HVDC solution is proposed as a promising alternative for high voltage alternating current (HVAC). The choice for a transmission technology is primarily based on economic considerations. Therefore, the economic value of VSC HVDC is investigated in this paper. VSC HVDC has important technical advantages for submarine installation compared to HVAC. The aim is to monetize these advantages in an economic comparison. Possible wind farm topology simplifications and optimizations due to the use of VSC HVDC are taken into account. Depending on the ownership of the transmission cable, the break-even cable length, above which the HVDC option is chosen, varies. A sensitivity analysis is included in this paper. Copyright © 2009 John Wiley & Sons, Ltd.

KEY WORDS: HVAC; offshore wind farms; renewable energy sources; VSC HVDC

### 1. INTRODUCTION

Mankind faces an increasing demand of electricity for the future. The prices of fossil fuels are higher than ever before (July 2008). Their use, amongst others, for electricity generation is harming the environment and affecting the climate [1]. The use of wind energy is seen as a valuable alternative for clean electricity generation. Wind turbines are installed in increasing numbers, even offshore. The latter development is pushed by better wind conditions [2], onshore space restrictions [3], scaling advantages for large wind turbines and farms [4], and governmental support for offshore wind farms [5].

Offshore wind farms are nowadays planned further from shore than in the early stages of offshore wind development. Reasons for this trend are better wind conditions, legislation to move wind farms out of sight, and the limited number of suitable nearshore sites (<10 km from shore) to build offshore wind farms (nearshore waters often frequented by ships e.g., to access ports, for military purposes, or fishing) [6]. For longer transmission distances, increase in the power rating of the wind farm is economically seen as more interesting. For farshore wind farms (>10 km from shore), a high voltage transmission system is set up between the wind farm and the onshore grid. The cost of this transmission system is expressed as cost/MW<sub>installed</sub>. A higher power rating of the wind farm is thus preferable for a long transmission cable, to keep the installation costs within acceptable limits. Typical wind farms for the near future are expected to be 20–60 km from the Point of Common Connection (PCC) onshore and in power ratings of 200–500 MW. As a relevant example, a 300 MW wind farm is studied as it fits well in the range of the expected capacities of future offshore wind farms. Voltage source converter high voltage direct current (VSC HVDC) is available in standard modules, with 300 MW a readily available VSC HVDC module. This shows that data are available in the public domain and as such used for this study.

Presently, high voltage alternating current (HVAC) is chosen as transmission technology for the majority of offshore wind farms [7–9]. The transformation stations at the ends of the cables are rather simple compared to DC connections and overall losses are

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lower for short distances [10]. The use of VSC HVDC is proposed here as an alternative. VSC HVDC has several important technical advantages compared to the classic HVAC approach, especially in the context of offshore wind farms [11]:

- Control of active power through the link,
- Independent control of reactive power at both converter stations,
- Variable frequency operation of the offshore wind farm grid,
- Decoupling of offshore wind farm grid and onshore transmission grid (e.g., faults), and
- Black start capability.

Line commutated converter (LCC) or classic HVDC is not an option as it would require an independent rotating magnetic field offshore to ensure the commutation of the thyristors to take place.

However, the choice for a certain transmission technology is based on the economic considerations. The extra costs for the AC/DC converters at both terminals of the link in the case of VSC HVDC make this technology unsuitable for short transmission distances. The converter stations also introduce important extra losses not present in the AC case. The cable cost (investment and installation) and cable losses per km are lower for the DC option resulting in a break-even cable length [12].

Although each wind farm has case-specific aspects, the purpose of this paper is to draw useful conclusions based on the choice for a transmission technology for a 300 MW wind farm. The length of the cable is varied, to find the break-even distances. It is shown that the transmission cable ownership (either government or wind farm developer) has a significant influence on choice of the technology. A sensitivity analysis is performed for variations of electricity price and converter losses.

## 2. METHODOLOGY

### 2.1. Discounted cash flow

The economic comparison of HVAC and VSC HVDC for the connection of an offshore wind farm with the onshore grid is performed, using a discounted cash flow (DCF) method. Only the differences in revenues and costs are required to compare both technologies. The result is the net present value (NPV) of the monetary difference between the investment in VSC HVDC and HVAC as transmission technology.

The inputs for the calculation are the initial investment costs and the annual costs and revenues. The annual costs and revenues are then yearly discounted, resulting in the NPV they represent. The assumed discount factor is 5%. The difference in investment cost linearly depreciates over the lifetime of the wind farm. The lifetime of an offshore wind farm is taken to be 20 years. A taxation rate of 40% is assumed.

### 2.2. Transmission cable ownership

The objectives of the investor are decisive for the choice of a transmission technology. Two cases are used in this paper and represented in Figure 1. In case the investor of the transmission system is not the investor of the wind farm (Scenario 1), the wind farm is seen as a black box. This is, for example, the case in Germany, where the transmission system operator is responsible for the grid connection of offshore wind farms and not the wind farm developer. The objectives of the cable investor are the reduction of the initial investment and the annual costs of the transmission link. When the developer of a wind farm is responsible for the connection to shore, the wind farm and transmission system are seen as one project and optimized as such (Scenario 2). The technical advantages of VSC HVDC then have an influence on the wind farm configuration and an economic optimum for the total project is aimed at. Both situations are discussed in Sections 3 and 4, respectively.

### 2.3. Input parameters

In order to perform a detailed economic comparison, a lot of financial data and technical aspects are combined. Data are found in numerous reports and publications available in the public domain [13–15]. Uncertainty nevertheless exists due to the fluctuations in currency rates, copper price, price of components, etc. The prices and costs given in this paper should therefore be taken as indicative estimates of the real prices.

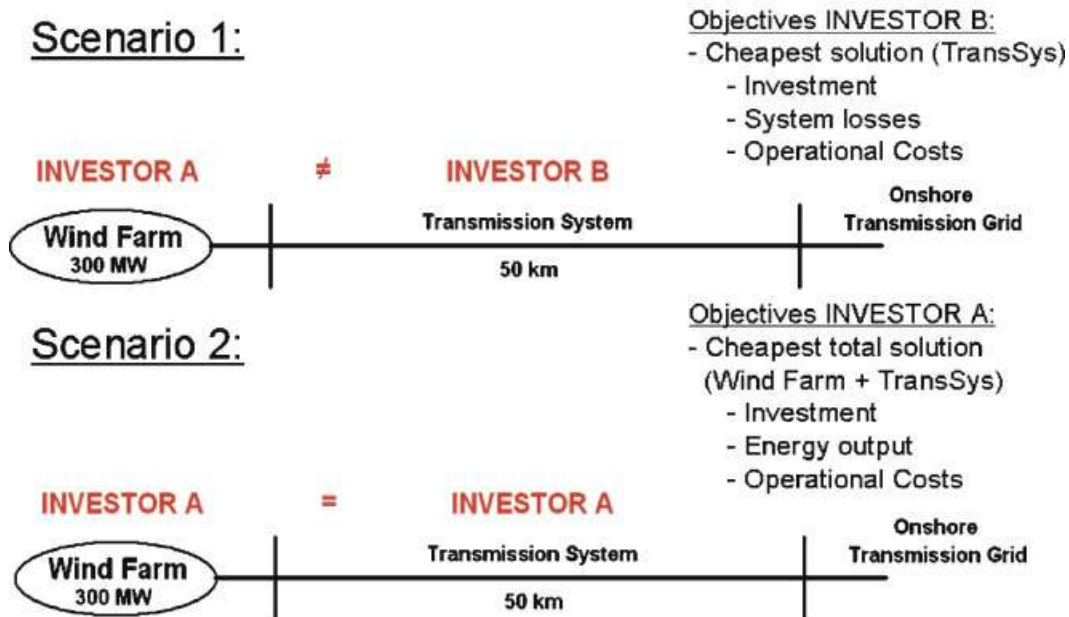
**FIGURES**

Figure 1. Impact of owners relations on investment objectives.

The prices for the transmission system refer to appropriate systems for a 300 MW wind farm. For the VSC HVDC option, a 376 MVA converter module is chosen with  $\pm 150$  kV DC cables [16]. The HVAC option is dimensioned to two parallel copper 3-core cables with a 500 mm<sup>2</sup> cross section per conductor each carrying half of the power produced [17,18]. The choices are made on basis of best practices in industry, weighing the different advantages and disadvantages for each technology separately.

### 3. SCENARIO 1—LINK INVESTOR DIFFERENT FROM WIND FARM INVESTOR

#### 3.1. Transmission system investment costs

The cost of a transmission system is broken down into several components for both VSC HVDC and HVAC options: substation, cable, cable installation, offshore rig, and land use cost. The values used for both technologies are shown in Table I [13].

The substation cost is higher for the HVDC option due to the IGBT-based AC/DC converters (power electronics, phase reactors, filters, transformers, enclosed valves, etc.). The substation for an HVAC station only comprises transformers, switchgear, and control equipment. A substation is needed at both ends of the transmission cable for both technologies.

The purchase price for the bipolar HVDC cable pair to transport the same amount of active power is lower than the cost for the two parallel 3-core HVAC cables. The DC cables are less complex (no need for three phases in one cable), have lower symmetry and insulation requirements, and need less conductor (copper or aluminum) surface per unit of transported power. The price of cables depends strongly on the price of copper, which was volatile during the last few years.

Table I. Prices of HVAC and VSC HVDC transmission system for 300 MW offshore wind farm.

Item	HVAC	VSC HVDC
Substation (M€)	10	45
Cable (k€/km)	1 500	600
Cable installation (k€/km)	340	215
Offshore substation rig (M€)	13	24
Onshore land use (k€)	50	125

The installation of DC cables is less difficult than the installation of AC cables, leading to a lower installation cost. The technical reasons for the easier cable laying process are the flexibility of the cables (single core versus 3-core) and the simpler (and thinner) construction of the cable insulation. The cables of both technologies are buried in the seabed, 1 m deep, to protect them from the submarine environment. This is common standard for undersea transmission systems.

The substation at the wind farm end of the cable is installed on an offshore top-site structure. The cost of such a platform structure depends on the volume of the substation. A cost of 1000 €/m<sup>3</sup> is assumed for the offshore rig. The installation of an AC/DC converter requires more space than an AC station, leading to an elevated rig cost for the VSC HVDC option. The onshore land use is a minor cost in the transmission system cost and depends on the required surface.

Long AC cables generate reactive power (large shunt capacitance) at both cable ends. To ensure stable operation of the transmission grid, reactive power is controlled at both nodes. Therefore, compensation equipment (shunt inductances) needs to be installed at both cable ends when the AC cable exceeds a certain length ( $\pm 130$  km for 150 kV,  $\pm 20$  km for 380 kV). The limits on reactive power variations are stated in the grid code requirements of the transmission grid. More stringent grid code requirements are in force in countries with a considerable amount of electricity generation from wind energy due to the impact of variable wind output on the transmission grid. One of the requirements, also applicable for offshore wind farms, is the controllability of the power factor. Power factor control is possible with VSC HVDC without any additional equipment (control of reactive power at onshore substation). To achieve this with HVAC, an additional dynamic compensator such as a SVC (Static VAR Compensator) or STATCOM (Static Synchronous Compensator) is needed [19]. The need for extra compensation equipment increases the cost of the HVAC option. This extra cost depends on the cable length. The investment costs for a 50 km cable are shown in Figure 2 for both technologies. The possibility of using an SVC or a STATCOM is considered during the evaluation process as it adds to the cost of the AC connection.

### 3.2. Annual operating costs

Two operating cost elements are incorporated in the economic comparison: maintenance and losses. The differences in reliability for both transmission technologies are not taken into account. Also, the differences in insurance costs are omitted.

The annual maintenance cost of a VSC HVDC link is taken to be 0.5% of the capital cost of the components. The lifetime maintenance cost for HVAC equipment is assumed to be 15% of the investment costs. The SVC or STATCOM used for power factor correction are equipped with an AC/DC converter and require maintenance as well. For a 300 MW wind farm with a cable length of 50 km, the annual maintenance cost for VSC HVDC is taken at 650 000 € and for HVAC at 200 000 € [13].

The annual cost due to losses depends on the transported electric power throughout the year. The actual amount of electric power transported through the link, either DC or AC, depends on the wind conditions at the wind farm. In the model used, the wind is assumed to be Weibull distributed with shape factor  $C = 2.1$  and scale factor  $A = 9.8$  m/s [20]. The Weibull distribution of the wind speed is used to find the probability distribution of the power through the transmission link using the power–speed characteristic of a

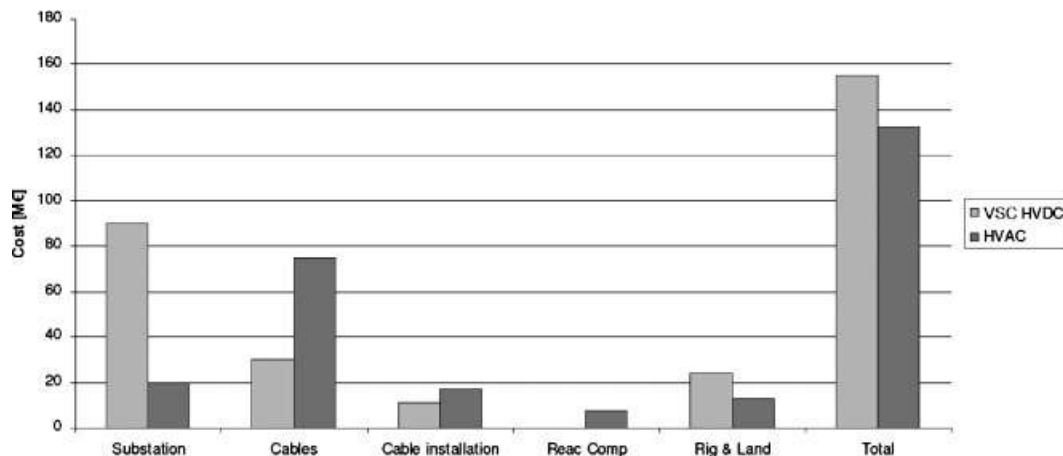


Figure 2. Investment cost breakdown for VSC HVDC and HVAC (cable length = 50 km).

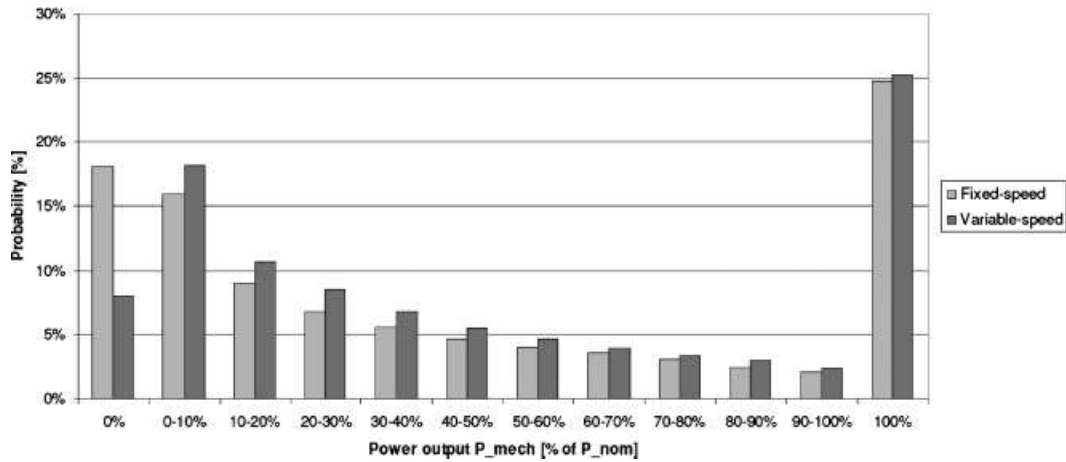


Figure 3. Probability distribution of power through transmission link for wind farm ( $A = 9.8$  m/s;  $C = 2.1$ ;  $V_{cut-in} = 3$  m/s;  $V_{cut-out} = 30$  m/s).

typical wind turbine. The result is shown in Figure 3 for a wind farm based on fixed and variable rotational speed of the turbine blades. The increase in energy output due to the use of variable-speed wind turbines is clear. Given the high investment costs encountered in offshore wind, variable speed wind turbines are therefore used.

A loss model for VSC HVDC is used, based on data from the Cross Sound Cable Project (USA) [21]. For the HVAC case, a loss model is developed taking into account conductor losses (with skin, proximity, and temperature effect), shield and armor losses in the cables and losses in transformers, and shunt compensators [9]. The power loss depends on the amount of power flowing through the link. The result for both transmission technologies for a 50 km cable is shown in Figure 4.

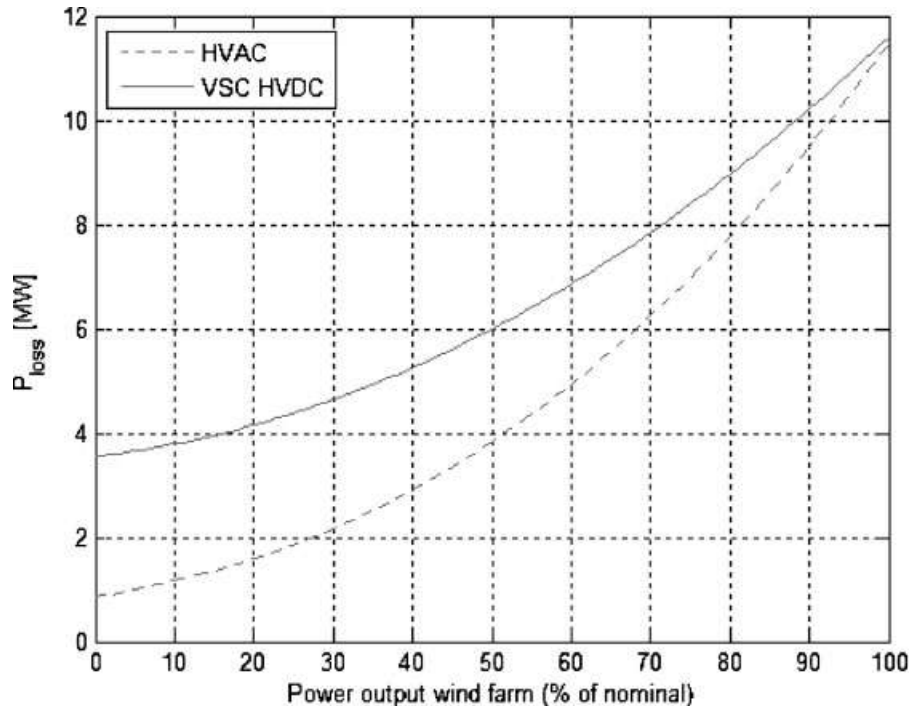


Figure 4. Transmission losses [MW] for VSC HVDC and HVAC (cable length = 50 km;  $P_{wind\ farm, nom} = 300$  MW).

The losses in the transmission link are presented as a percentage of the annually produced energy (APE) in the following:

$$l_{\%} = \frac{\text{losses}}{\text{production}} \times 100 = \frac{(\sum P_{\text{loss},i} \times p_i) \times h}{(\sum P_{\text{gen},i} \times p_i) \times h} \times 100 \quad (1)$$

where  $l_{\%}$  represents the loss percentage. The power range (0–100%) of the wind farm is divided into  $N$  pieces  $i$ , each representing a generated electric power  $P_{\text{gen},i}$ .  $P_{\text{loss},i}$  is the power lost in the transmission link when  $P_{\text{gen},i}$  is produced by the wind farm and transported through the link.  $p_i$  is the probability of  $P_{\text{gen},i}$  (based on Figure 3) and  $h$  is the number of hours in a year. The result is shown in Figure 5 for cable lengths up to 130 km (critical length for AC transmission system at 150 kV) for both transmission technologies. The energy lost along the transmission system (50 km) for a VSC HVDC link is 4.45% of the annual produced energy, whereas only 3.31% for an HVAC link. Energy losses are rated at the price of the unsold electricity. The cost of electric energy is variable from country to country, from day to day and varies during the day as well. A value of 40 €/MWh is used as a base value in the financial analysis. No account is given to possible extra subsidies for renewable energy sources that can be in effect, and add considerably to the profitability of the wind farm.

### 3.3. Discounted cash flow result

The data for the transmission cable investment cost and the annual costs due to maintenance and losses are combined in a DCF calculation to compare VSC HVDC with HVAC on an economic basis. Figure 6 shows the results for three different cable lengths (25, 50, and 75 km). The investment costs for VSC HVDC and HVAC are shown in a line graph. The difference between the investment costs and the discounted cash flow results for a wind farm lifetime of 20 years is shown in bars. Due to the extra losses and the higher maintenance costs, the discounted cash flow result is lower than the difference in investment costs. Although the investment cost for a 75 km cable is higher for the HVAC option, the DCF result of the comparison of VSC HVDC and HVAC is still negative. The use of HVAC is therefore more favorable for cable lengths up to 75 km. The economic break-even distance is found around 80 km. This result is consistent with the decision of the German transmission grid company to use VSC HVDC for the connection of the Borkum 2 wind farm, situated over 120 km from shore [22].

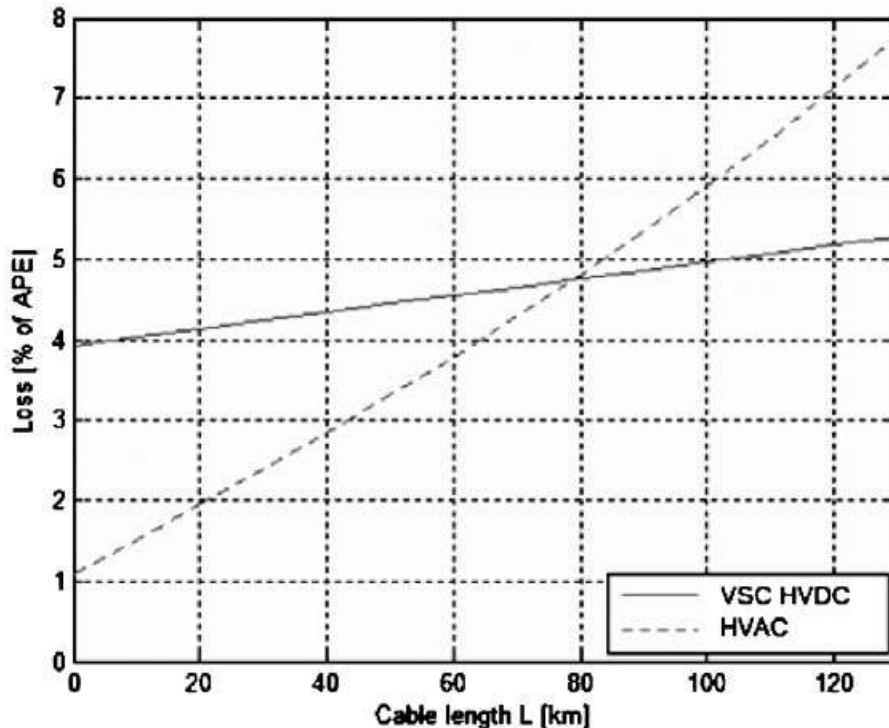


Figure 5. Loss percentage  $l_{\%}$  for VSC HVDC and HVAC as a function of cable length ( $P_{\text{wind farm, nom}} = 300$  MW).



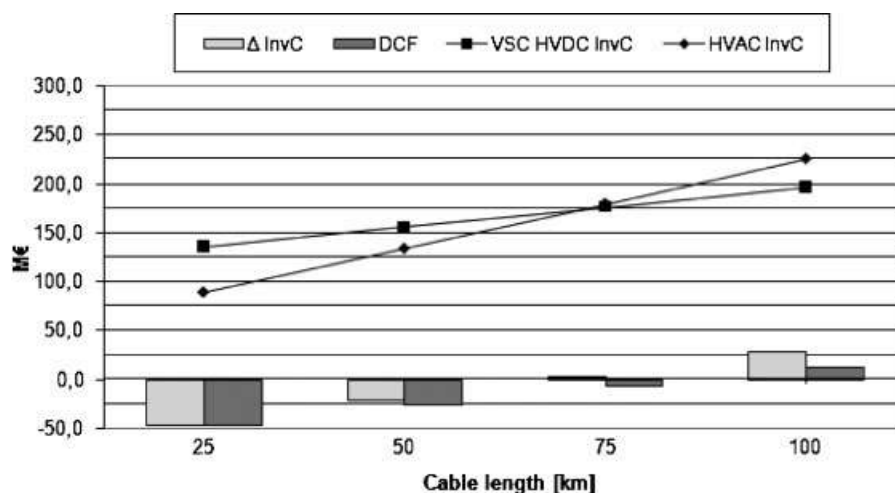


Figure 6. Comparison of investment costs and discounted cash flow of VSC HVDC and HVAC (InvC = Investment Cost as in Figure 2; DCF = discounted cash flow result).

#### 4. SCENARIO 2—LINK INVESTOR SAME AS WIND FARM INVESTOR

##### 4.1. Wind farm investment costs

Transmission cables for offshore wind farms traditionally have AC technology. Hence, the offshore wind farm grid frequency is fixed to 50 Hz (Europe). In order to implement variable rotational speed operation of the wind turbines, a power electronic converter is installed in each nacelle. The state-of-the-art technology for offshore wind farms is the doubly-fed induction generator (DFIG). The use of VSC HVDC, however, may allow the wind farm developer to optimize and simplify the generating turbines in the wind farm. As the VSC HVDC technology does not impose a fixed frequency on the offshore grid, there is a new degree of freedom for the optimization of the wind farm. The use of directly connected induction generators is proposed here. The individual converters can be reduced in size or even omitted, by operating the offshore wind farm grid (isolated grid) at a varying frequency, controlled by the offshore VSC HVDC converter station, hereby allowing the variable speed operation of the turbines according to the present wind conditions.

Next to the lower investment costs due to the avoidance of converters, the electricity generators are cheaper. There is no need for slip rings to connect the converter to the rotor and simple, robust squirrel cage induction generators (SCIG) can be used. Avoiding converters and slip rings also increases the efficiency of the wind turbine drive train, allowing for a higher energy yield of the wind farm and a reduced maintenance. The maintenance costs of the turbines are assumed to be 30% lower than for the DFIG topology [13]. A summary of these economic benefits is given in Table II. The data from Table II together with the results of Scenario 1 allow to compare a system with VSC HVDC and SCIG with HVAC and DFIG. For a 300 MW wind farm (60 turbines of 5 MW), the investment costs for the wind farm development are 12 600 000 € lower due to the proposed simplifications. Due to the difference in drive train efficiency, the energy yield at the offshore wind farm node is more than 2% higher in the SCIG case.

Table II. Differences in wind farm investment costs, efficiency, and operating and maintenance costs.

	HVAC + DFIG	VSC HVDC + SCIG
Generator InvC (k€)	250	400
Converter InvC (k€)	—	60
Generator efficiency (%)	98,4	98,0
Converter efficiency (%)	—	98,33
Turbine annual maintenance (k€) (50 km from shore)	120	170

#### 4.2. Discounted cash flow result

The result of the discounted cash flow calculation is shown in Figure 7 together with the difference in investment costs for the total project (wind farm + transmission cable). The zero-crossing of the DCF curve shows the break-even cable length between VSC HVDC + SCIG and HVAC + DFIG. The lower investment costs and the annual economic benefits due to the higher energy yield and lower maintenance costs justify the use of a more expensive transmission system with higher losses for cable lengths higher than 35 km. This result differs considerably from the result of Scenario 1 (Section 3.3).

### 5. COMPARISON OF SCENARIO RESULTS

In several countries (e.g., Germany) Scenario 1 is in effect. The transmission system operator is then held responsible for the installation of the transmission cable. The main reason for this choice is to relieve wind farm developers from this considerable cost. In this case, HVAC is chosen for cable lengths shorter than 80 km and VSC HVDC is used for longer cables. As shown in this paper, Scenario 1 leads to an inefficient use of resources. When the investor for the transmission cable and the offshore wind turbines is the same party (Scenario 2), VSC HVDC is already economically preferable for cable lengths of 35 km and higher.

From a macro-economic point of view, Scenario 2 optimizes welfare more than Scenario 1 since the investments for wind farm and transmission cable are simultaneously optimized. Although governments opt for Scenario 1, in order to incentivize investors to install offshore wind farms, Scenario 2 is macro-economically more optimal i.e., a maximum of electric energy produced from offshore wind for a given societal cost.

### 6. SENSITIVITY ANALYSIS

The parameters used in the economic calculations are uncertain. It is therefore useful to investigate how the results change when a parameter changes. The cost of electric energy is taken at 40 €/MWh throughout this paper. Due to governmental support mechanisms, the experienced electricity price is much higher for the wind farm developer. The discounted cash flow result is therefore recalculated for a cost of 80, 120 and 160 €/MWh as well. The result for Scenario 2 is shown in Figure 8. For higher transmission lengths, the system with VSC HVDC and SCIG becomes more efficient than the combination of HVAC and DFIG. Therefore, a higher electricity price has a positive effect on the DCF result, encouraging the use of VSC HVDC for shorter cable lengths (break-even lengths become shorter).

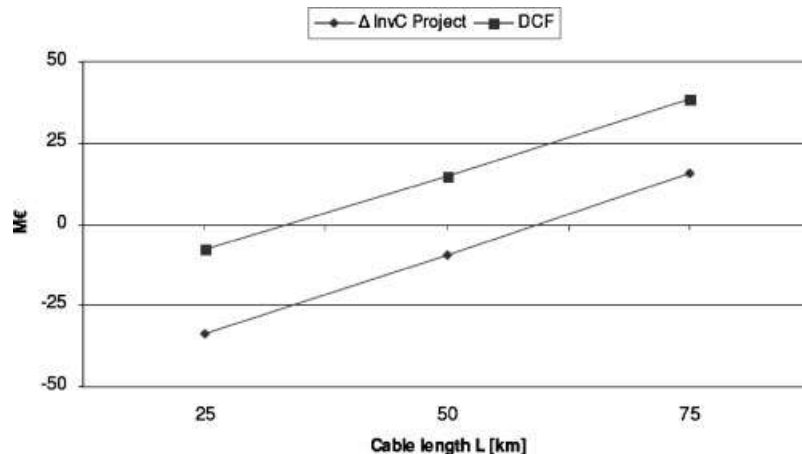


Figure 7. Comparison of investment costs and discounted cash flow of VSC HVDC + SCIG and HVAC + DFIG.



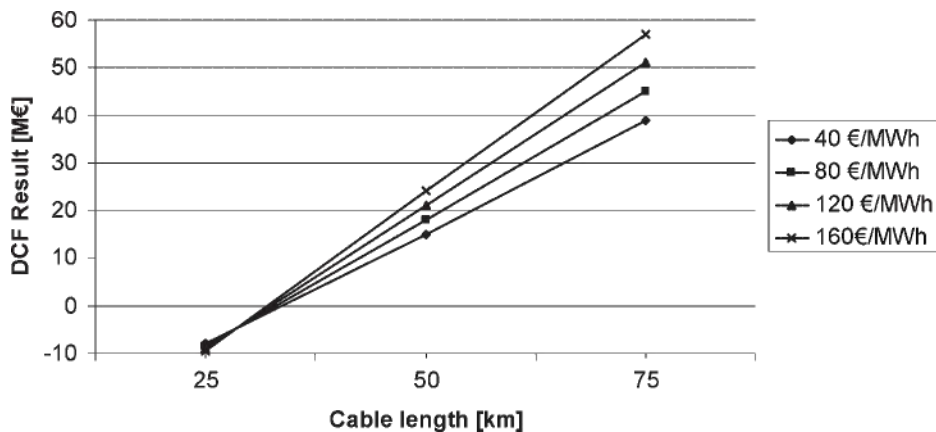


Figure 8. Sensitivity analysis on impact of cost of electricity on DCF result for Scenario 2.

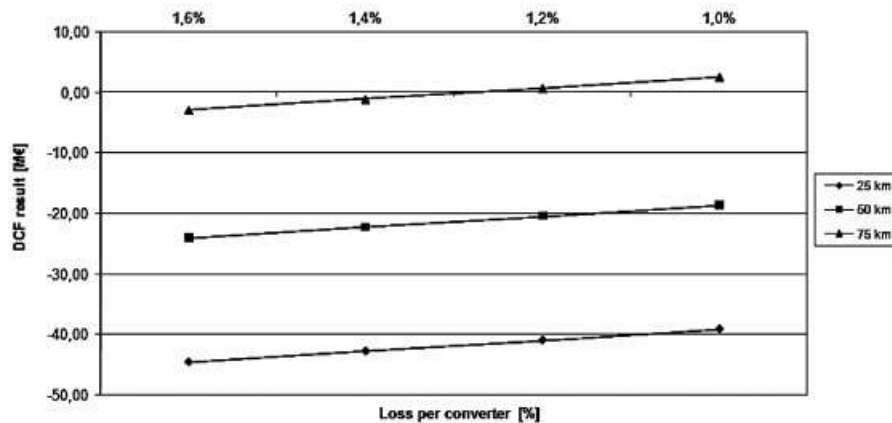


Figure 9. Sensitivity of DCF result to reduction of converter losses for Scenario 1.

Reducing the converter losses is an important aspect of current developments within VSC HVDC research, and significant progress in that direction is anticipated within the near future. Therefore, the sensitivity towards loss reduction is investigated. Values varying from 1.6% full load converter losses to as low as 1% are considered. The results are shown in Figure 9. Improving the efficiency of the converters has a positive influence on the DCF and the break-even distance.

## 7. CONCLUSIONS

This paper investigates the economic value of VSC HVDC compared to HVAC, taking into account the economic benefits related to the technical advantages VSC HVDC has. Although each wind farm development project has case-specific boundary conditions, this paper uses a generic approach allowing to draw conclusions on the break-even distances between both technologies. The influence of the ownership of the wind farm and transmission cable is shown for two scenarios. If two unrelated parties are responsible for the investment (Scenario 1), a break-even distance of 80 km is found. If the investment decision for wind farm and cable is taken by related parties (Scenario 2), the break-even distance is 35 km. The results of both scenarios differ considerably. Although Scenario 1 is in effect in most of the countries, Scenario 2 optimizes macro-economic welfare. A sensitivity analysis on the DCF result for variations of the electricity price shows that a higher electricity price is in favor of VSC HVDC, resulting in lower break-even cable lengths. Also, the future reduction of the converter losses is clearly beneficial for the VSC HVDC technology.

## 8. LISTS OF SYMBOLS AND ABBREVIATIONS

DCF	Discounted Cash Flow
DFIG	Doubly-Fed Induction Generator
HVAC	High Voltage Alternating Current
InvC	Investment Cost
L	cable length
LCC HVDC	Line Commutated Converter High Voltage Direct Current
NPV	Net Present Value
P <sub>mech</sub>	Mechanical Power
P <sub>nom</sub>	Nominal Power
P <sub>loss</sub>	Power Losses
P <sub>gen</sub>	Generated Power
SVC	Static VAR Compensator
STATCOM	Static Synchronous Compensator
SCIG	Squirrel Cage Induction Generator
Symbols	
VSC HVDC	Voltage Source Converter High Voltage Direct Current
1%	Loss Percentage

\*[note that the % sign of 1%, “loss” in P<sub>loss</sub> and “gen” in P<sub>gen</sub> must be in subscript]\*

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***Memoria***  
***Osservazioni in ordine al D.L. 15 - Misure urgenti per la salvaguardia del***  
***paesaggio, dei beni paesaggistici e ambientali***

***Allegato-4***

# ENTSO-E HVDC UTILISATION AND UNAVAILABILITY STATISTICS 2021

FOR PUBLISHING | 16 August 2022

From: DISTAC Subgroup

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ENTSO-E HVDC Utilisation and Unavailability Statistics 2021

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Report rendered 16 August 2022

## ENTSO-E Mission Statement

### Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association for the cooperation of the European transmission system operators (TSOs). The 42 member TSOs, representing 35 countries, are responsible for the secure and coordinated operation of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E brings together the unique expertise of TSOs for the benefit of European citizens by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

### Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the security of the inter-connected power system in all time frames at pan-European level and the optimal functioning and development of the European inter-connected electricity markets, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

### Our vision

ENTSO-E plays a central role in enabling Europe to become the first climate-neutral continent by 2050 by creating a system that is secure, sustainable and affordable, and that integrates the expected amount of renewable energy, thereby offering an essential contribution to the European Green Deal. This endeavour requires sector integration and close cooperation among all actors.

Europe is moving towards a sustainable, digitalised, integrated and electrified energy system with a combination of centralised and distributed resources. ENTSO-E acts to ensure that this energy system keeps consumers at its centre and is operated and developed with climate objectives and social welfare in mind.

ENTSO-E is committed to use its unique expertise and system-wide view – supported by a responsibility to maintain the system's security – to deliver a comprehensive roadmap of how a climate-neutral Europe looks.

### Our values

ENTSO-E acts in solidarity as a community of TSOs united by a shared responsibility.

As the professional association of independent and neutral regulated entities acting under a clear legal mandate, ENTSO-E serves the interests of society by optimising social welfare in its dimensions of safety, economy, environment, and performance.

ENTSO-E is committed to working with the highest technical rigour as well as developing sustainable and innovative responses to prepare for the future and overcoming the challenges of keeping the power system secure in a climate-neutral Europe. In all its activities, ENTSO-E acts with transparency and in a trustworthy dialogue with legislative and regulatory decision makers and stakeholders.

### Our contributions

ENTSO-E supports the cooperation among its members at European and regional levels. Over the past decades, TSOs have undertaken initiatives to increase their cooperation in network planning, operation and market integration, thereby successfully contributing to meeting EU climate and energy targets.

To carry out its legally mandated tasks, ENTSO-E's key responsibilities include the following:

- › Development and implementation of standards, network codes, platforms and tools to ensure secure system and market operation as well as integration of renewable energy; › Assessment of the adequacy of the system in different timeframes;
- › Coordination of the planning and development of infrastructures at the European level (Ten-Year Network Development Plans, TYNDPs);
- › Coordination of research, development and innovation activities of TSOs;
- › Development of platforms to enable the transparent sharing of data with market participants.

ENTSO-E supports its members in the implementation and monitoring of the agreed common rules.

ENTSO-E is the common voice of European TSOs and provides expert contributions and a constructive view to energy debates to support policymakers in making informed decisions.

# Executive Summary

The HVDC links are important components for a stable operation of the Nordic and Baltic power system while supporting the commercial power trade in the European energy markets. Furthermore, the HVDC links can provide other important functions like voltage and emergency power support to the HVAC grid. Hence, the advantages of keeping the HVDC links in operation as much as possible are indisputable. The ENTSO-E HVDC Utilisation and Unavailability Statistics 2021 report aims to provide an overview of the Nordic and Baltic HVDC links as well as a detailed view of each individual link.

In 2021, 66.9 TWh of electric energy was transmitted through the Nordic and Baltic HVDC links, as seen in Figure 1. The total number of disturbance outages registered was 81, preventing 2.4 TWh of potential energy transmission, or 2.2 % of the total technical capacity ( $E_{max}$ ).

Maintenance outages amounted to 3.5 TWh, or 3.2 % of the total technical capacity ( $E_{max}$ ), and limitations reduced the transmission capacity by 4.0 TWh (3.7 % of the total technical HVDC transmission capacity).

The most utilised market connections in 2021 were FI-EE (76.9 %) and DK2-DE (71.4 %). Six other market connections reached a utilisation rate of 60–70 % while the five remaining market connections were utilised between 44–57 % of the maximum technical capacity ( $E_{max}$ ).

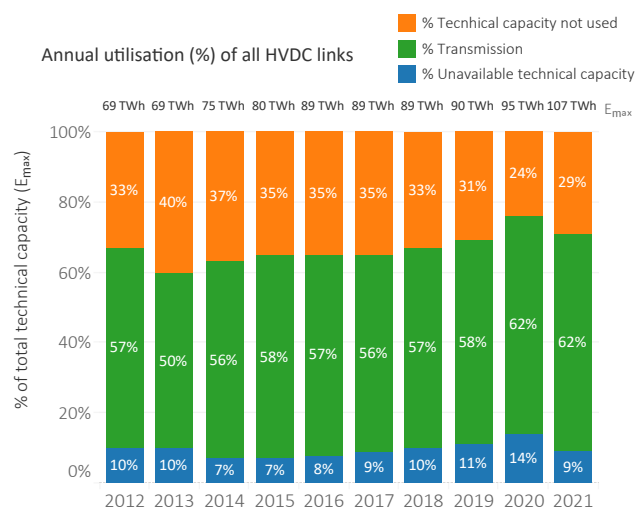


Figure 1: The annual utilisation of all HVDC links since 2012. Technical capacity not used is the amount of energy that has neither been transmitted nor been unavailable due to limitations or outages.

The percentage of unavailable technical capacity ( $E_U$ ) in 2021 dropped to the same levels as in 2017 (9 %), while the percentage of transmission ( $E_T$ ) was high compared to pre-

vious years. Table 1 shows that many of the HVDC links that have had a high share of unavailable capacity performed well in 2021, which is a good sign for the future.

The higher availability did not have a high impact on the utilisation rate, which increased from 61.6 % in 2020 to 62.3 % in 2021. On the other hand, the recently commissioned HVDC links have increased the total technical capacity ( $E_{max}$ ) available to the markets. Compared to 2020 when 58.8 TWh of electricity was transmitted through the HVDC links, 8.1 TWh or almost 14 % more was transmitted in 2021. The amount of transmitted energy has increased by almost 70 % since 2012–2014 when around 40 TWh was transmitted annually.

Table 1: Annual unavailability (%) per bidding zone.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
DK1-NL								5%	29%	10%
DK2-DE	6%	4%	3%	5%	10%	14%	26%	4%	30%	5%
DK2-DK1	3%	10%	5%	2%	3%	2%	2%	2%	0%	1%
FI-EE	3%	5%	15%	6%	4%	1%	4%	2%	3%	1%
FI-SE3	27%	17%	5%	9%	2%	1%	1%	5%	1%	13%
LT-PL					14%	10%	6%	4%	9%	13%
NO2-DE										10%
NO2-DK1	2%	8%	11%	6%	5%	18%	13%	27%	24%	8%
NO2-NL	3%	19%	5%	4%	8%	8%	14%	13%	17%	27%
RU-FI	10%	1%	0%	0%	1%	2%	5%	5%	12%	8%
SE3-DK1	5%	11%	16%	17%	5%	7%	4%	16%	17%	11%
SE4-DE	22%	18%	7%	12%	20%	27%	36%	26%	19%	10%
SE4-LT					26%	16%	22%	8%	5%	6%
SE4-PL	0%	3%	7%	7%	15%	6%	4%	14%	13%	9%
Grand Total	10%	10%	7%	7%	8%	9%	10%	11%	14%	9%

The HVDC links with most unavailable technical capacity due to outages were, in descending order, NorNed, LitPol Link, Konti-Skan 1 and COBRACable. NorNed had a major cable fault on the Dutch side in mid-January until March. Most of LitPol Link’s unavailable capacity was due to longer than expected maintenances due to unplanned replacement of a converter transformer’s bushing. The unavailable capacity of Konti-Skan 1 was due to a cable fault on land cable, and the unavailable capacity of COBRACable was due to the submarine cable fault from 2020 that also covered some of 2021 and planned maintenance to cover some exposed offshore cable. Fenno-Skan 1 had more than usual unavailability due to disturbance outages.

The unavailability of NordLink 1 and 2 is due testing and repairs during the first year after commissioning

Limitations were prominent on Skagerrak 2 (22 % of the technical capacity), Fenno-Skan 2 (16 %), Skagerrak 3 (9 %) and Baltic Cable (8 %). Skagerrak 2 and 3 were limited in the north direction because of the multiple cable faults on Skagerrak 4 in the recent years.



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# 1 Introduction and background

The ENTSO-E HVDC Utilisation and Unavailability Statistics 2021 presents the availability and utilisation of HVDC links connected to the Nordic and Baltic power system in 2021. This includes an overview of availability and utilisation for the HVDC links, information about disturbances and unavailability and individual presentations of the performance of each HVDC link.

The first version of the HVDC statistics for utilisation and unavailability was published in 2011 as an addition to the Nordic Grid Disturbance and Fault Statistics 2010 [1]. At that time, the report covered only the Nordic power systems

and presented 8 HVDC links. For the statistical year 2012, the HVAC Grid Disturbance Report and HVDC statistics were separated into two reports, which is the format of the reports today. In present time, this report includes 20 HVDC links connected to the Nordic and Baltic countries.

The total HVDC transmission capacity connected to the Nordic and Baltic power systems in 2021 is 13.9 GW, which makes the annual transmission capacity 121.6 TWh. Most of the HVDC links connect the Nordic synchronous system to other systems. A map of the bidding zones and each HVDC link is presented in Figure 1.1.

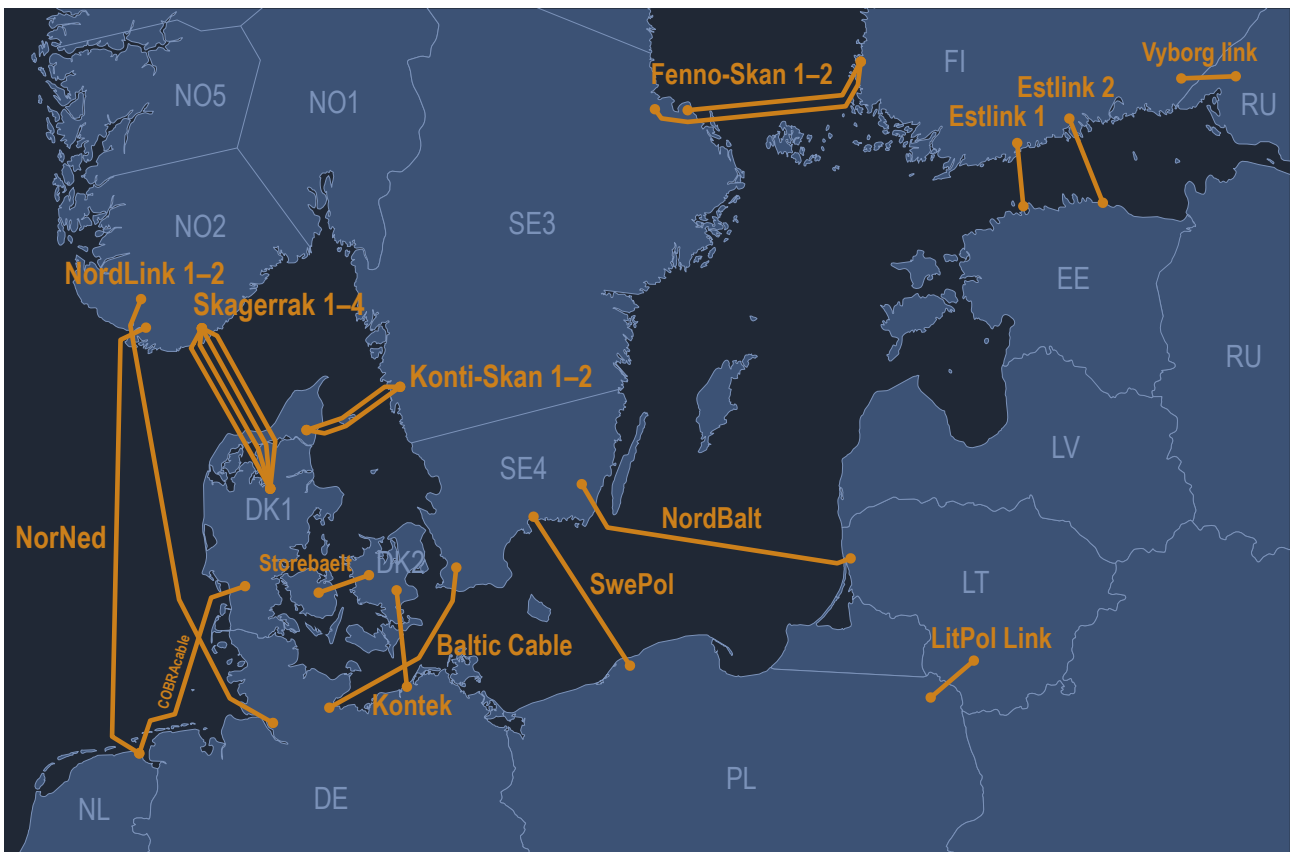


Figure 1.1: A map of the 20 HVDC links included in this report and the bidding zones in the area.

## 2 Scope

The ENTSO-E HVDC Utilisation and Unavailability Statistics 2021 presents a macro view of the availability and utilisation of each HVDC link, including disturbance, maintenance and other outage events as well as limitations. Limitations originating from maintenance work done in the AC grid are also included if they affect the power transfer of an HVDC connection. Furthermore, disturbance outages are more thoroughly examined than other events.

The scope of the Report is different from the CIGRE performance survey data [2], which focuses mainly on outages, faults and disturbances of the HVDC systems. CIGRE statistics give more details about the condition and performance of the HVDC assets themselves, including forced and scheduled outages, thyristor and transistor failure rates, commutation failures, and so on. On the other hand, DISTAC HVDC statistics cover more divergent performance and availability data and partly going deeper into classifi-

cation, consequences and outage reasons.

The HVDC WG of NordAM<sup>1</sup> and the DISTAC group have together developed the DISTAC HVDC outage and utilization data collection so that more detailed HVDC performance data analysis will be enabled in future. Together they also updated the HVDC performance data collection guidelines according to the new features.

### 2.1 Contact persons

Each country is represented by at least one contact person who is responsible for the statistical information of the corresponding country. The contact person can provide additional information concerning the HVDC availability and utilisation statistics. The relevant contact information is given in Appendix C.

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<sup>1</sup>The five Nordic Transmission System Operators (TSOs) founded a Nordic Asset Management Forum (NordAM) in 2009 with the main goal to increase cooperation, jointly influence, build up knowledge, create networks as well as carry out agreed surveys and development tasks within the field of Asset Management. The HVDC working group was established after a very successful task force work done in 2017.

### 3 Methods and definitions

To compare the utilisation and availability between HVDC links, different ways of using them must be discerned and understood. This chapter explains the availability and utilisation categories used to differentiate between means of utilising HVDC links. The hierarchy of the categories is illustrated in Figure 3.1.

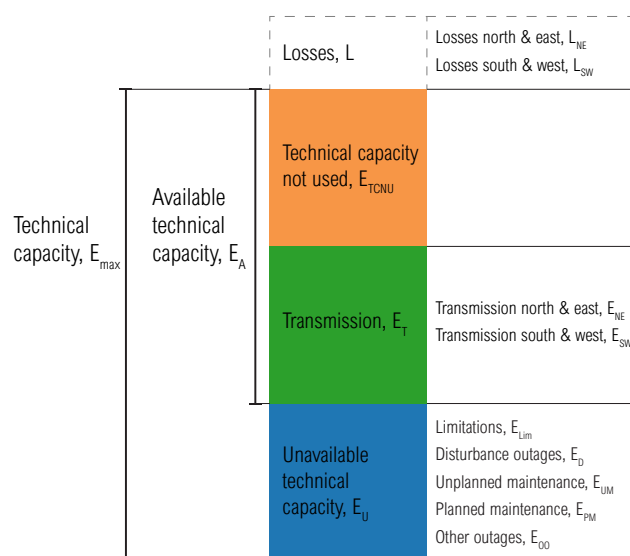


Figure 3.1: The hierarchy of the availability and utilisation categories used in the HVDC statistics.

The *technical capacity* ( $E_{max}$ ) of an HVDC link is the maximum energy that can be physically received through the HVDC link to the converter station, excluding all HVDC link losses, during a year. The technical capacity is divided into two categories: *available technical capacity* ( $E_A$ ) and *unavailable technical capacity* ( $E_U$ ).

The *available technical capacity* ( $E_A$ ) is divided into technical capacity that has been *transmitted* ( $E_T$ ) and into technical capacity that could have been transmitted/utilised that is, *technical capacity not used* ( $E_{TCNU}$ ).

*Transmitted energy* ( $E_T$ ) is the sum of transmitted energy in both directions of the HVDC link. Energy transferred to the north or east side of the HVDC link is called *transmission north and east* ( $E_{NE}$ ) (previously export), and energy transferred to the south or west side of the HVDC link is called *transmission south and west* ( $E_{SW}$ ) (previously import). It does not include *losses* ( $L$ ) that is, the energy losses in any of the HVDC link components during transmission. It should be noted that these values are measurements and therefore considered factual.

*Technical capacity not used* ( $E_{TCNU}$ ) is the residual energy after transmission, outages and limitations have been accounted for. The electricity market does not need the added transfer in most of these cases.

The *unavailable technical capacity* ( $E_U$ ) is the part of the *technical capacity* ( $E_{max}$ ) that could not be utilised. It has five subcategories: *limitations* ( $E_{Lim}$ ), *disturbance outages* ( $E_D$ ), *unplanned maintenance* ( $E_{UM}$ ), *planned maintenance* ( $E_{PM}$ ) and *other outages* ( $E_{OO}$ ). An outage occurs when the HVDC link is fully disconnected from the system and the transfer capacity is reduced to zero. A limitation occurs when the capacity of the link has been reduced by between 0–100%. Limitations and the outages are described in more detail below.

A *limitation* ( $E_{Lim}$ ) is a condition when the transmission capacity of an HVDC link is limited that is, the power transmission capacity of the link is less than the rated power. The limitation is always motivated from a technical perspective, but not always concerning the link itself. The most common causes of limitations are:

- faults on any HVDC link component that do not cause a total outage;
- faults, congestions or outages in the AC grid causing a limitation in the transmission capacity of the link;
- seasonal variations on the transmission capacity of the HVDC link.

Note that a limitation is counted for an hour only if there was transmission in the direction of the limitation and the sum of transmission and unavailable technical capacity is more than 90% of the rated capacity. The reason to this is to only include limitations that have truly impacted the transmission of a HVDC link. Limitations that do not meet this requirement become *technical capacity not used* ( $E_{TCNU}$ ) instead.

*Disturbance outages* ( $E_D$ ) are total outages due to a fault on the HVDC link or in the AC-grid causing a total outage of the link. A disturbance outage occurs when the protection trips the link or, in rare cases, disconnected manually. Manual disconnection is usually categorised as unplanned maintenance.

*Unplanned maintenance outages* ( $E_{UM}$ ) occurs when the link is manually disconnected for emergency or urgent repair. In general, unplanned maintenance are outages that cannot wait until the next scheduled maintenance.

*Planned maintenance outages* ( $E_{PM}$ ) are total outages due to all technically motivated actions on the HVDC link or in the AC grid intended to retain an entity in, or restore it to, a state where it can perform its required function.

*Other outages* ( $E_{OO}$ ) are outages due to any other reason except those mentioned above. This could be, for example, black start or other tests or when the markets do not need the transmission capacity of the link and the link is disconnected.



## 4 Technical details of the HVDC links

Table 4.1 presents the main properties of the HVDC links while Table 4.2 presents the technical properties of the HVDC lines.

Schematic presentations of the HVDC links and their converter stations, both for line-commutated converters (LCC) and voltage-source converters (VSC) are presented in Appendix A.

Table 4.1: Main properties of the HVDC links.

Link	Commissioning year	Market connection	HVDC converter type	Rated power, monopolar (MW)	Parallel monopolar capacity (MW)	Bipolar capacity
Baltic Cable	1994	Yes	LCC	600		
COBRACable	2019	Yes	VSC	700		
EstLink 1	2006	Yes	VSC	350	1000	
EstLink 2	2014	Yes	LCC	650		
Fenno-Skan 1	1989	Yes	LCC	400	1200	1200
Fenno-Skan 2	2011	Yes	LCC	800		
Kontek	1995	Yes	LCC	600		
Konti-Skan 1 <sup>1</sup>	2008	Yes	LCC	357.5		715
Konti-Skan 2 <sup>1</sup>	1988	Yes	LCC	357.5		
LitPol Link	2015	Yes	LCC	500		
NordBalt	2016	Yes	VSC	700		
NordLink 1–2	2020	Yes	VSC	700×2		1400
NorNed	2008	Yes	LCC	700		
Skagerrak 1	1977	Yes	LCC	236	1000	1000
Skagerrak 2	1977	Yes	LCC	236		
Skagerrak 3	1993	Yes	LCC	478		
Skagerrak 4	2014	Yes	VSC	682		
Storebaelt	2010	Yes	LCC	600		
SwePol	2000	Yes	LCC	600		
Vyborg Link <sup>2</sup>	1981, 1982, 1984, 2000	Partly	LCC	1400		
<b>Total</b>				<b>10972</b>	<b>3940</b>	<b>2200</b>

<sup>1</sup> Konti-Skan bipole can export 740 MW and the import capacity is 715 MW. This counts in both directions since the reference-point is now on the importing side.

<sup>2</sup> Each commissioning increased capacity by 350 MW. However, the total commercial capacity of Vyborg Link is 1300 MW. Fingrid Oyj, the Finnish transmission system operator, allocates 100 MW for reserves.

Table 4.2: Technical details of the HVDC links

Link	Physical length (km)	Length of mass cable (km)	Length of PEX cable (km)	Length of DC overhead line (km)	Length of DC back-to-back connection (km)
Baltic Cable	262	250		12	
COBRACable	325	325	650 (2×325)	0	
EstLink 1	105		210 (2×105)		
EstLink 2	171	157		14	
Fenno-Skan 1	233	200		33	
Fenno-Skan 2	299	196		103	
Kontek	160		160		
Konti-Skan 1	150	89		61	
Konti-Skan 2	150	89		61	
LitPol Link	< 1				< 1
NordBalt	450		2×450		
NordLink 1–2	623			53	
NorNed	580	580			
Skagerrak 1	212.5	133.6		78.5	
Skagerrak 2	211.4	132.9		78.5	
Skagerrak 3	212.9	134.4		78.5	
Skagerrak 4	226	226			
Storebaelt	57	57			
SwePol	254	254			
Vyborg Link	< 1				< 1

## 5 Results

This chapter presents the utilisation and unavailability of all the HVDC links as well as individual presentations of each HVDC link connected to the Nordic and Baltic power system.

Section 5.1 provides an overview of the HVDC links for the year 2021 and Section 5.2 provides an overview of the years 2012–2021. Section 5.3 presents the availability and utilisation of each HVDC link for the year 2021 as well as an annual overview of the utilisation and a trend of the utilisation and the number of outages for the years 2012–2021.

### 5.1 Overview of 2021

Figure 5.1 presents the utilisation and unavailability (%) of each HVDC link in 2021. It should be noted that the usages of the links show big variations. Most links are market dependent, some are mostly used in one direction, and some are used for technical reasons to control power flow for system stability according to agreements. Sorted views of Figure 5.1 are shown in Appendix D.

In 2021, 66.9 TWh of electric energy was transmitted through the Nordic and Baltic HVDC links. The total number of disturbance outages registered was 81, preventing 2.4 TWh of potential energy transmission, or 2.2 % of the total technical capacity ( $E_{\max}$ ).

Maintenance outages amounted to 3.5 TWh, or 3.2 % of the total technical capacity ( $E_{\max}$ ), and limitations reduced the transmission capacity by 4.0 TWh (3.7 % of the total technical HVDC transmission capacity).

The most utilised market connections in 2021 were FI–EE (76.9 %) and DK2–DE (71.4 %). Six other market connections reached a utilisation rate of 60–70 % while the five remaining market connections were utilised between 44–57 % of the maximum technical capacity ( $E_{\max}$ ).

Figure 5.2 compares the availability and utilisation of the HVDC links between bidding zones. That is, it measures the utilisation of the energy transfer capacity between the bidding zones ignoring the performance of individual links. However, the number of HVDC links connecting different bidding zones varies. A map portraying the bidding zones and each HVDC link is presented in Figure 5.10.

Figure 5.3 presents the percentage unavailable technical capacity ( $E_U$ ) of the annual technical capacity ( $E_{\max}$ ) due to the disturbance outages. Figure 5.4 presents the number of all disturbance, maintenance and other outages. The explanations for the most notable unavailability in 2021 are listed below. Further details are presented in Section 5.3.

#### Review of notable unavailable technical capacity 2021

The HVDC links with most unavailable technical capacity due to outages were, in descending order, NorNed, LitPol Link, Konti-Skan 1 and COBRACable. NorNed had a major cable fault on the Dutch side in mid-January until March. Most of LitPol Link's unavailable capacity was due to longer than expected maintenances due to unplanned replacement of a converter transformer's bushing. The unavailable capacity of Konti-Skan 1 was due to a cable fault on land cable, and the unavailable capacity of COBRACable was due to the submarine cable fault from 2020 that also covered some of 2021 and planned maintenance to cover some exposed offshore cable. Fenno-Skan 1 had more than usual unavailability due to disturbance outages.

The unavailability of NordLink 1 and 2 is due testing and repairs during the first year after commissioning.

Limitations were prominent on Skagerrak 2 (22 % of the technical capacity), Fenno-Skan 2 (16 %), Skagerrak 3 (9 %) and Baltic Cable (8 %). Skagerrak 2 and 3 were limited in the north direction because of the multiple cable faults on Skagerrak 4 in the recent years.

Utilisation (%) by category for each HVDC link in 2021

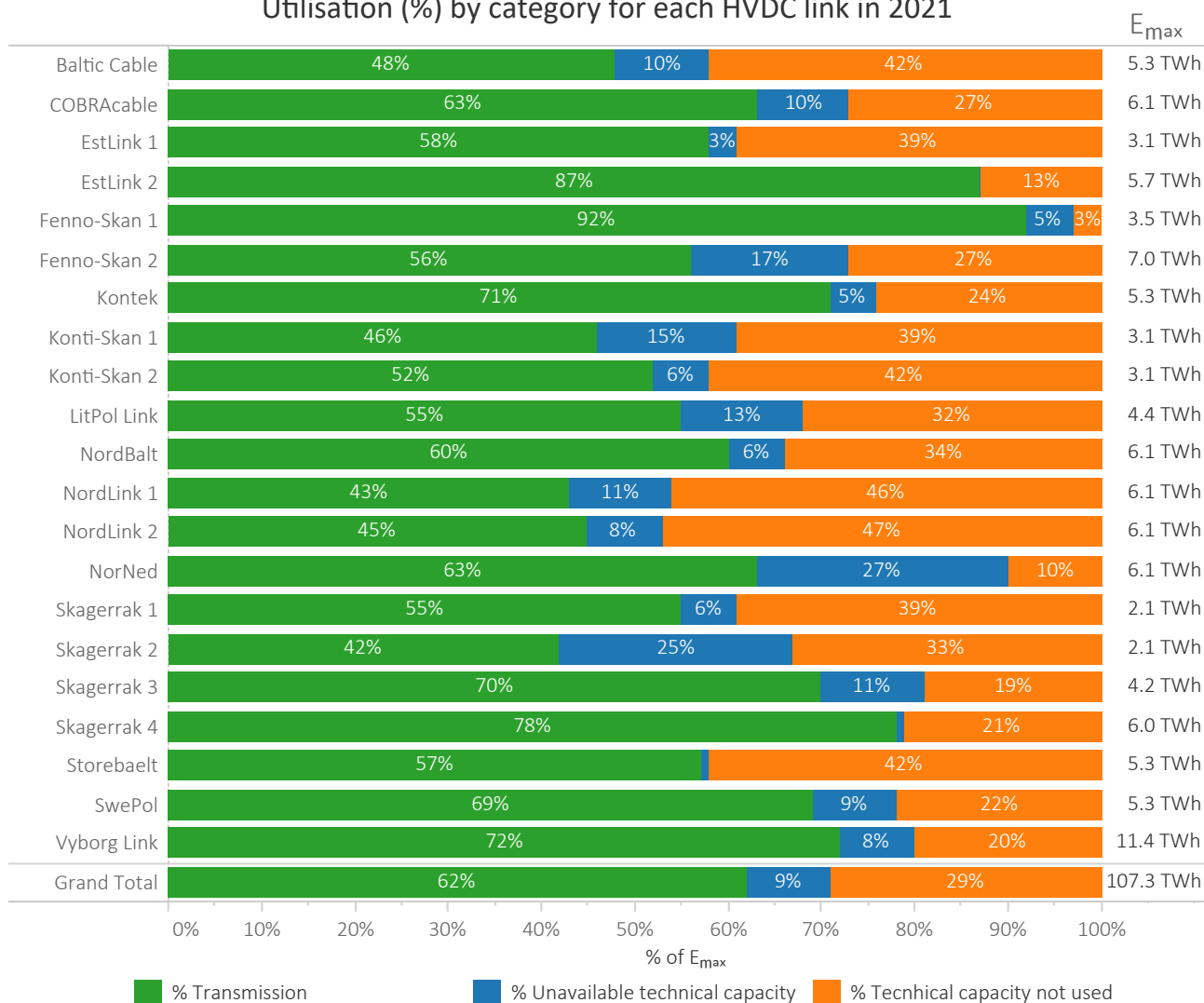


Figure 5.1: Utilisation (%) by category for each HVDC link in 2021. The unavailable technical capacity ( $E_U$ ) is the amount of technical capacity ( $E_{max}$ ) not available due to limitations or outages. Transmission ( $E_T$ ) is the amount of technical capacity ( $E_{max}$ ) transmitted through the HVDC link. Technical capacity not used ( $E_{TCNU}$ ) is the amount of energy that has not been transmitted or been unavailable due to limitations or outages. More detailed explanations can be read in Chapter 3.

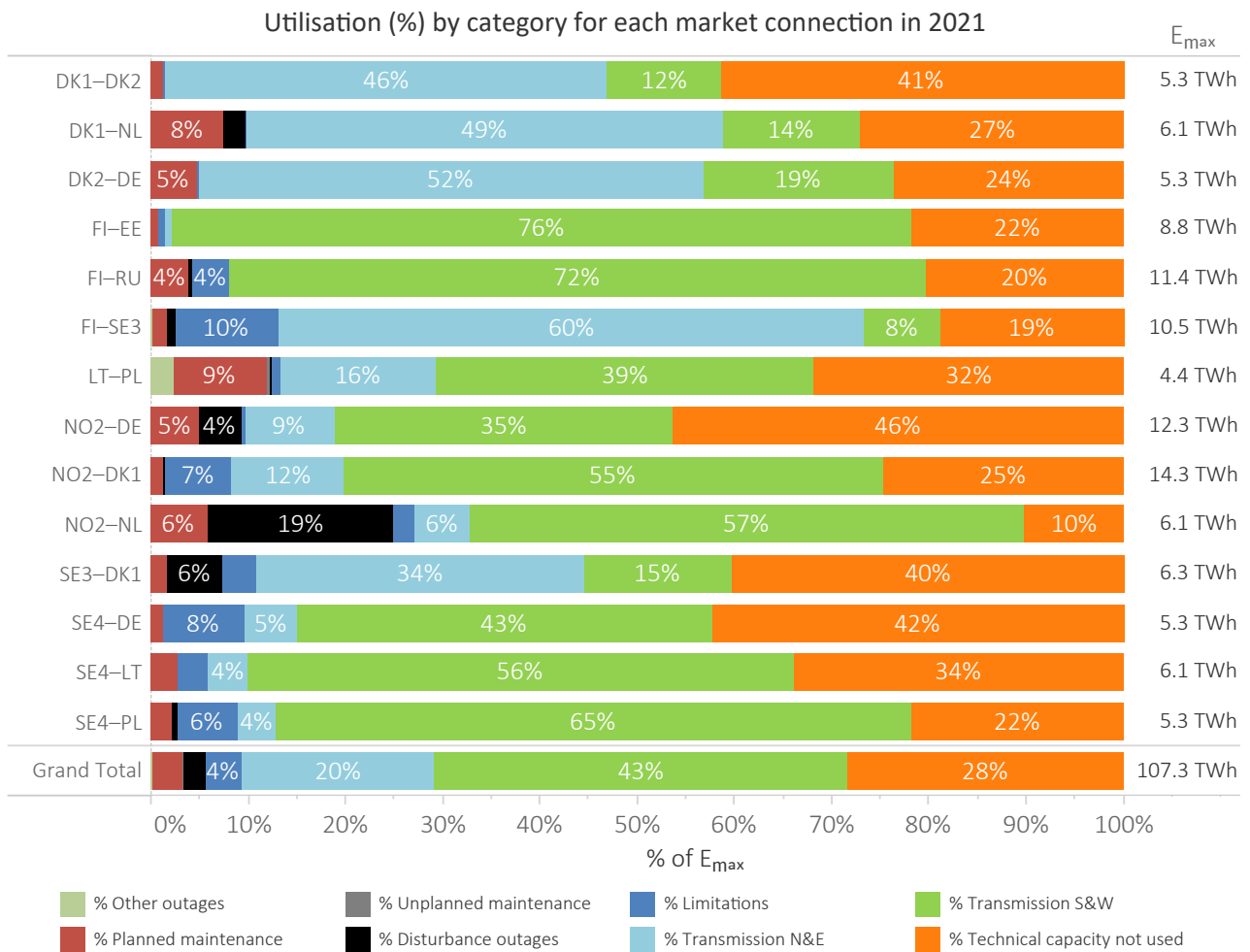


Figure 5.2: Utilisation (%) by category for each market connection in 2021. The categories are explained in Chapter 3.

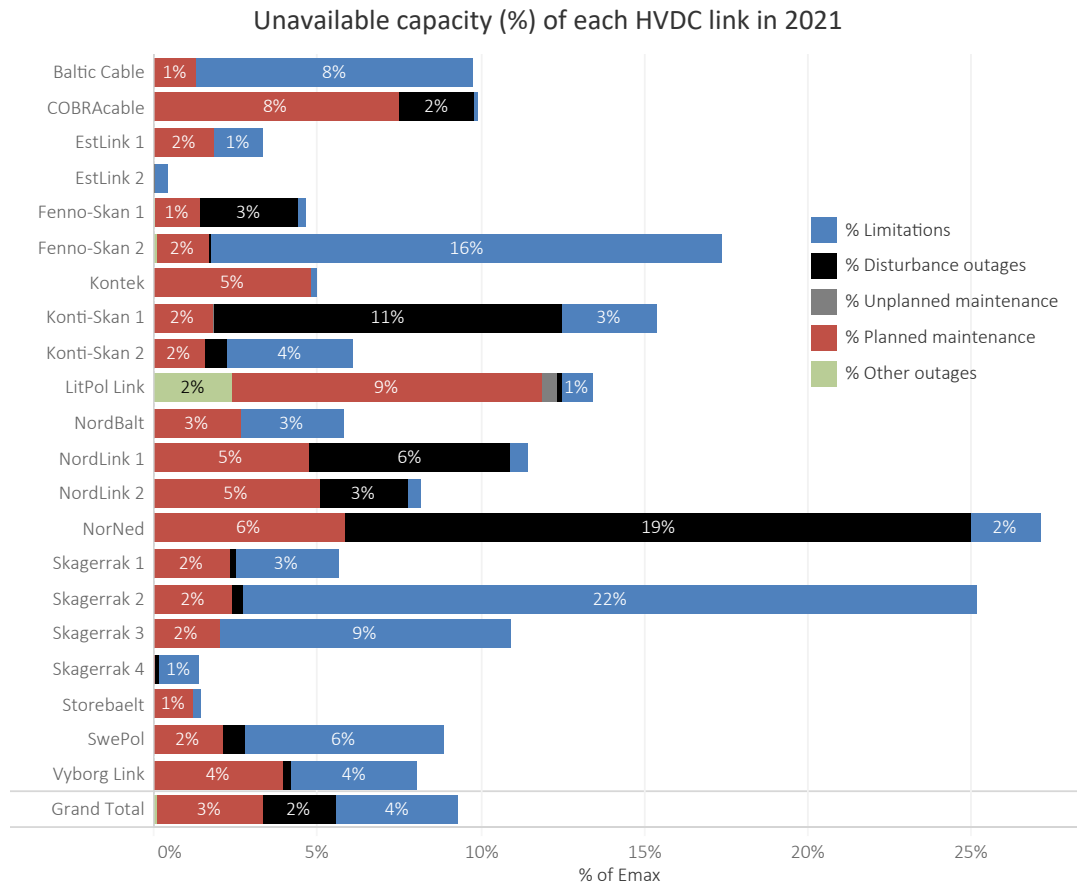


Figure 5.3: Unavailable technical capacity (%) for each HVDC link in 2021. The used unavailability categories are limitations, disturbance outages, unplanned and planned maintenances and other outages.

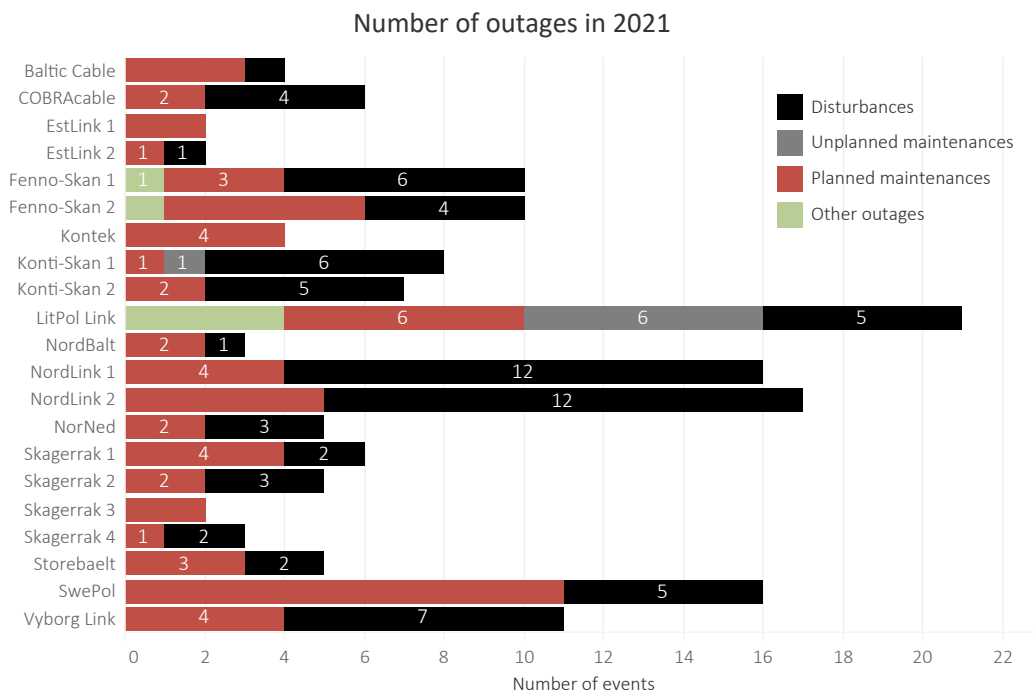


Figure 5.4: The number of disturbance outages, unplanned maintenance and planned maintenance outages and other outages for each link in 2021.

## 5.2 Overview of years 2012–2021

Figure 5.5 presents the annual utilisation (%) of all HVDC links and Figure 5.6 presents the annual utilisation with all utilisation categories.

The percentage of unavailable technical capacity ( $E_U$ ) in 2021 dropped to the same levels as in 2017 (9 %), while the percentage of transmission ( $E_T$ ) was high compared to previous years. Many of the HVDC links that have had a high share of unavailable capacity performed well in 2021, which is a good sign for the future.

The higher availability did not have a high impact on the utilisation rate, which increased from 61.6 % in 2020 to 62.3 % in 2021. On the other hand, the recently commissioned HVDC links have increased the total technical capacity ( $E_{max}$ ) available to the markets, as can be seen in

Figure 5.6. Compared to 2020 when 58.8 TWh of electricity was transmitted through the HVDC links, 8.1 TWh or almost 14 % more was transmitted in 2021. The amount of transmitted capacity has increased by almost 70 % since 2012–2014 when around 40 TWh was transmitted annually.

Figure 5.7 presents the annual utilisation rate grouped by utilisation percentage for all HVDC links. Figure 5.8 presents the annual unavailable technical capacity (%) by unavailability category. Figure 5.9 presents the annual unavailability hours (%) of the HVDC links.

Annual utilisation ( $E_T$ ), unavailability ( $E_U$ ) and technical capacity not used ( $E_{TCNU}$ ) percentages are presented in Table 5.1, Table 5.2 and Table 5.3, respectively.

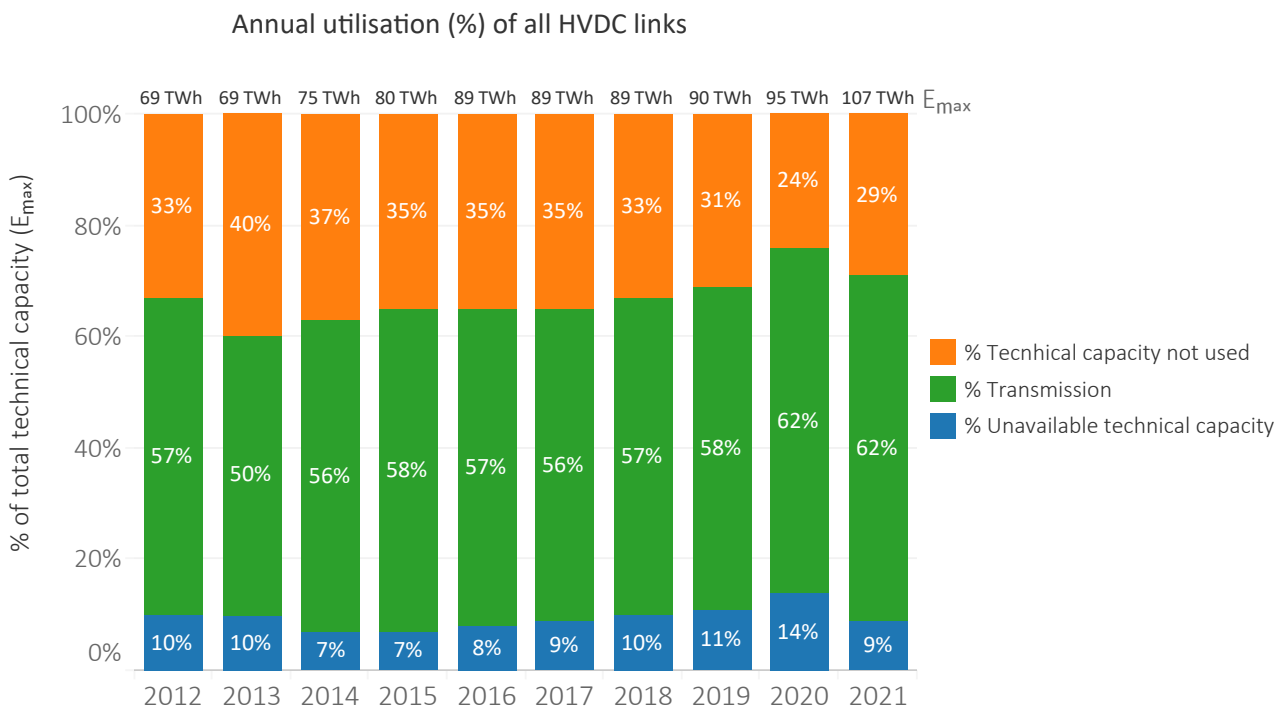


Figure 5.5: The annual utilisation percentage of all HVDC links since 2012. The unavailable technical capacity ( $E_U$ ) is the amount of technical capacity ( $E_{max}$ ) not available due to limitations or outages. Transmission ( $E_T$ ) is the amount of technical capacity ( $E_{max}$ ) transmitted through the HVDC links. Technical capacity not used ( $E_{TCNU}$ ) is the residual energy that has neither been transmitted nor been unavailable due to limitations or outages. More detailed explanations can be read in Chapter 3.

Annual utilisation of all HVDC links

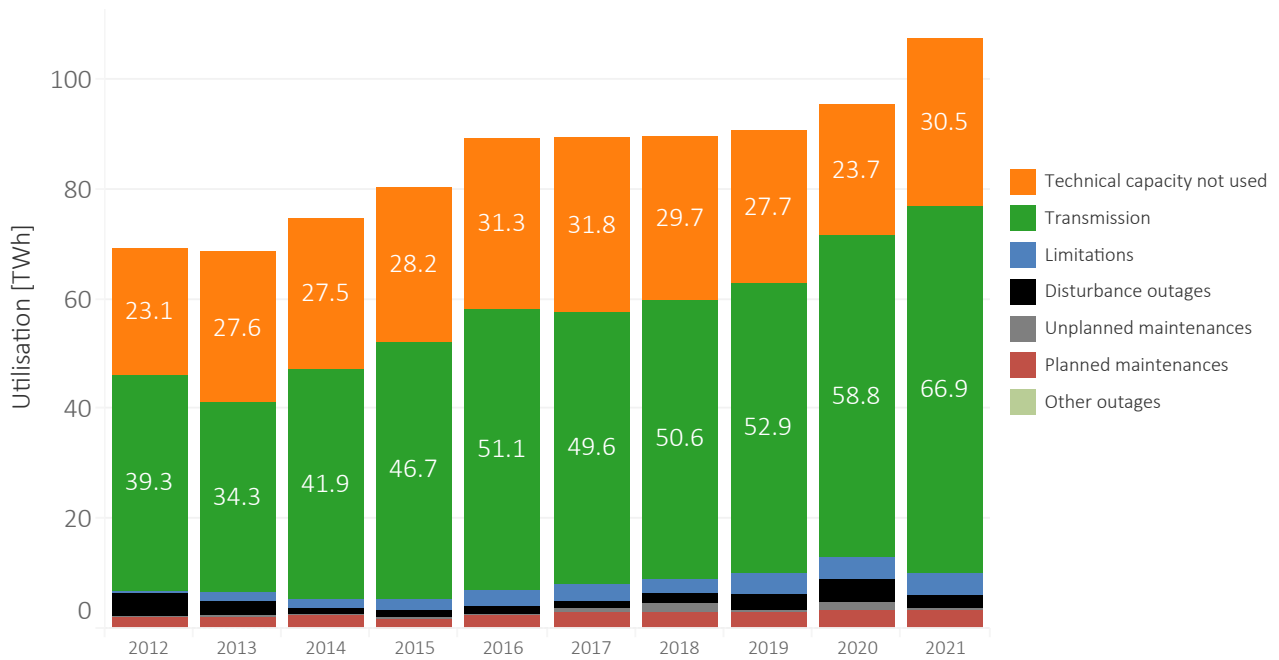


Figure 5.6: Annual utilisation (MWh) of all HVDC links. Transmission ( $E_T$ ) is the amount of technical capacity ( $E_{max}$ ) transmitted through the HVDC links. Limitations, disturbance outages, unplanned and planned maintenance outages and other outages form together the unavailable technical capacity ( $E_U$ ). Technical capacity not used ( $E_{TCNU}$ ) is the residual energy that has neither been transmitted nor been unavailable due to limitations or outages. The categories are explained in more detail in Chapter 3. The larger capacity increases in some years is due to new links being introduced to the report. The maximum technical capacity ( $E_{max}$ ) is marginally higher on leap years due to one extra day of operation.

Annual utilisation rates grouped by utilisation percentage, all HVDC links

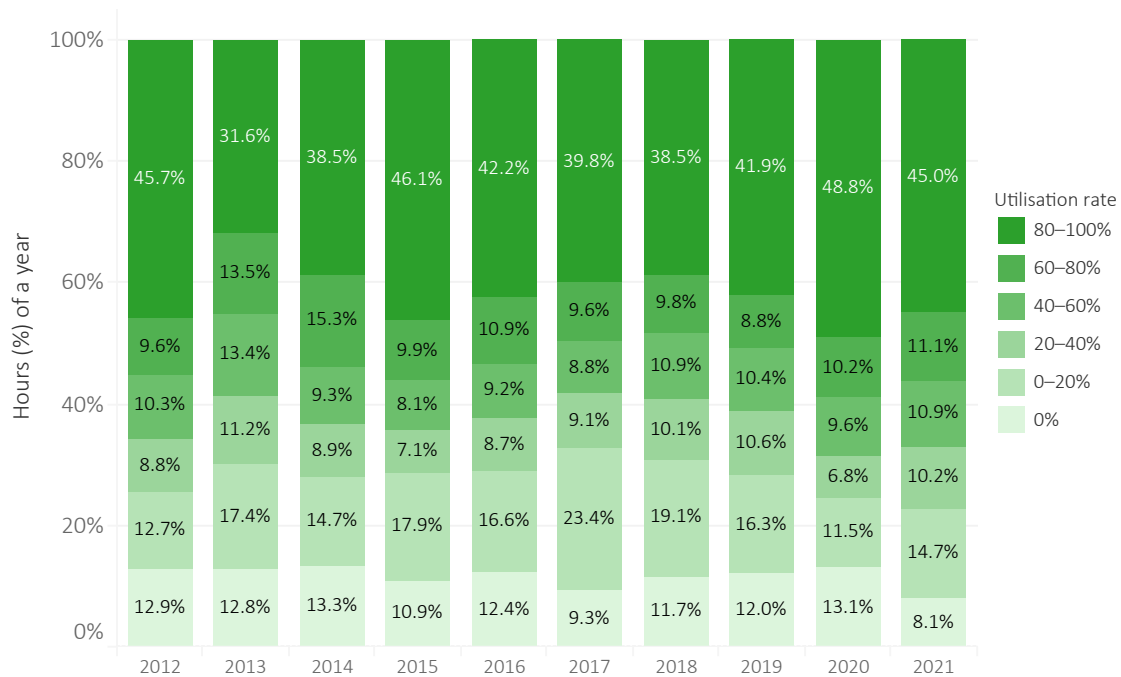


Figure 5.7: Annual utilisation rate grouped by utilisation percentage for all HVDC links. The HVDC links were utilised by more than 80 % of their respective maximum technical capacity 45 % of the time in 2020.



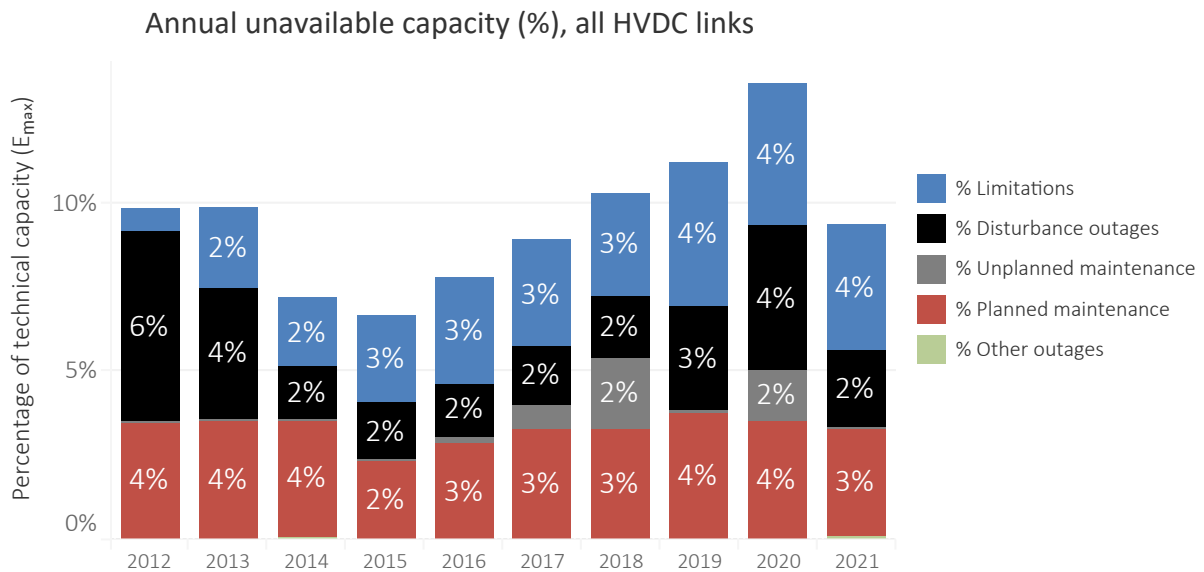


Figure 5.8: Unavailable technical capacity (%) by unavailability category for all HVDC links combined. The unavailability categories are limitations, disturbance outages, unplanned and planned maintenances and other outages.

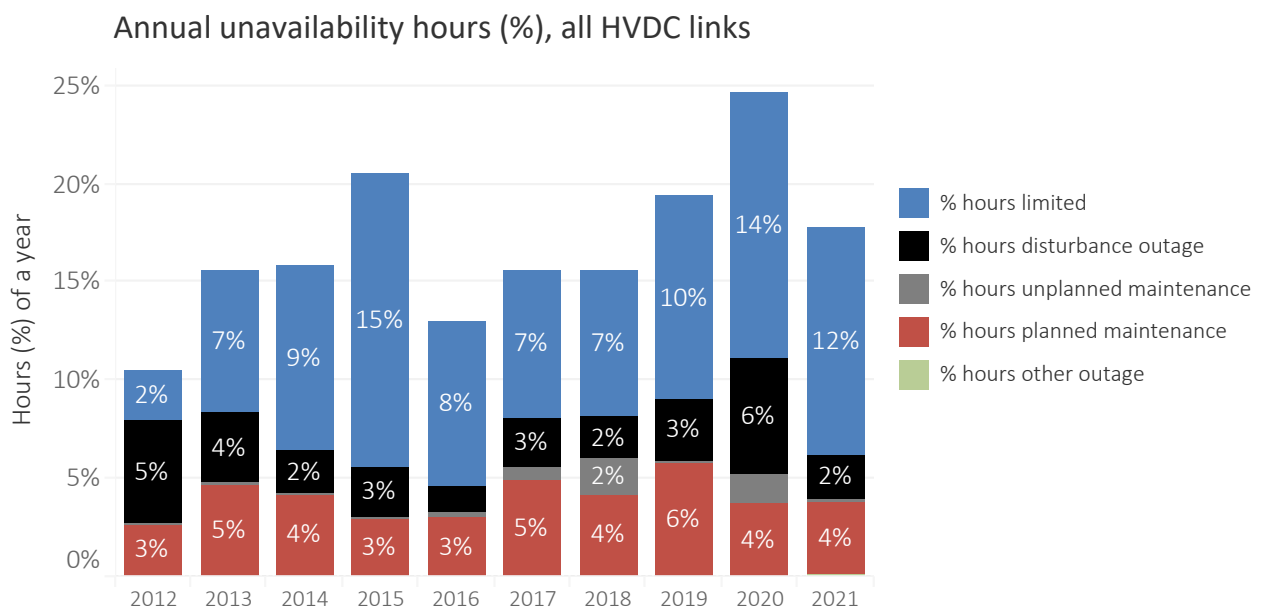


Figure 5.9: Annual unavailability hours (%) by unavailability category. The categories are limitation, unplanned or planned maintenance or a disturbance or other outage. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation. A higher value in the percentage of hours may indicate that the corresponding type of event has not fully disconnected the affected HVDC link from the system. A lower value may instead indicate that the corresponding event type has affected an HVDC link with a high rated capacity.

Table 5.1: Annual utilisation (%) of HVDC links per market connection.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
DK1-NL								79.7%	50.6%	63.0%
DK2-DE	70.0%	70.1%	73.2%	74.8%	66.8%	66.3%	53.3%	68.6%	47.4%	71.4%
DK2-DK1	44.9%	54.4%	58.3%	70.1%	78.0%	63.7%	63.4%	58.3%	70.7%	57.2%
FI-EE	58.6%	54.9%	40.7%	56.8%	42.3%	29.2%	37.0%	46.6%	75.3%	76.9%
FI-SE3	53.8%	52.5%	76.2%	75.8%	77.7%	70.2%	71.8%	81.2%	84.6%	68.0%
LT-PL					33.5%	46.7%	53.5%	61.5%	58.4%	54.8%
NO2-DE										44.0%
NO2-DK1	67.5%	60.7%	54.5%	54.0%	60.6%	54.1%	52.7%	46.2%	62.3%	67.0%
NO2-NL	89.4%	71.6%	90.5%	93.9%	72.5%	82.8%	68.3%	61.3%	76.7%	62.7%
RU-FI	33.8%	35.6%	25.4%	29.1%	45.8%	49.8%	66.7%	61.5%	23.1%	71.7%
SE3-DK1	55.9%	40.5%	49.3%	48.7%	58.8%	51.8%	52.7%	50.1%	57.3%	49.0%
SE4-DE	59.5%	32.1%	47.5%	30.5%	43.3%	45.6%	33.2%	36.0%	54.9%	47.9%
SE4-LT					43.6%	51.5%	50.5%	62.9%	76.2%	60.4%
SE4-PL	52.3%	33.9%	60.9%	67.2%	55.8%	62.3%	66.1%	62.1%	72.1%	69.3%
Grand Total	56.8%	49.9%	56.1%	58.2%	57.2%	55.5%	56.5%	58.3%	61.6%	62.3%

Table 5.2: Annual unavailability (%) of HVDC links per market connection.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
DK1-NL								5.1%	29.3%	9.9%
DK2-DE	5.8%	3.9%	3.5%	5.2%	10.4%	14.3%	25.9%	3.8%	30.0%	5.0%
DK2-DK1	2.9%	9.9%	4.6%	2.4%	2.8%	1.6%	2.2%	2.5%	0.3%	1.4%
FI-EE	2.6%	5.0%	14.7%	5.8%	3.6%	0.6%	3.6%	2.2%	2.7%	1.5%
FI-SE3	27.3%	17.2%	5.4%	9.5%	1.5%	1.2%	1.1%	4.7%	0.9%	13.1%
LT-PL					14.0%	10.1%	6.1%	3.6%	8.6%	13.4%
NO2-DE										9.8%
NO2-DK1	2.4%	7.9%	10.5%	6.5%	4.8%	18.0%	12.7%	27.0%	23.6%	8.2%
NO2-NL	3.4%	19.3%	4.5%	4.2%	8.1%	8.4%	13.8%	13.5%	16.9%	27.1%
RU-FI	9.8%	1.3%	0.4%	0.0%	1.5%	2.3%	5.2%	5.4%	11.5%	8.1%
SE3-DK1	4.7%	10.7%	16.1%	16.7%	5.5%	6.7%	4.3%	15.8%	16.7%	10.7%
SE4-DE	22.1%	18.1%	6.6%	12.5%	20.4%	27.1%	36.3%	26.2%	18.7%	9.8%
SE4-LT					25.7%	16.5%	22.0%	7.6%	5.5%	5.8%
SE4-PL	0.2%	3.3%	7.1%	7.3%	15.3%	5.9%	4.2%	14.0%	12.8%	8.9%
Grand Total	9.8%	9.9%	7.2%	6.7%	7.8%	8.9%	10.3%	11.2%	13.5%	9.3%

Table 5.3: Annual technical capacity not used (%) of HVDC links per market connection.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
DK1-NL								15.2%	20.1%	27.1%
DK2-DE	24.3%	26.1%	23.3%	20.1%	22.8%	19.4%	20.7%	27.7%	22.6%	23.6%
DK2-DK1	52.1%	35.6%	37.1%	27.5%	19.3%	34.7%	34.5%	39.2%	29.1%	41.3%
FI-EE	38.8%	40.0%	44.7%	37.3%	54.1%	70.2%	59.3%	51.2%	22.0%	21.6%
FI-SE3	18.9%	30.3%	18.4%	14.8%	20.7%	28.6%	27.1%	14.1%	14.6%	18.8%
LT-PL					52.5%	43.2%	40.3%	34.9%	33.0%	31.8%
NO2-DE										46.2%
NO2-DK1	30.1%	31.4%	34.9%	39.5%	34.6%	27.9%	34.6%	26.8%	14.2%	24.7%
NO2-NL	7.2%	9.1%	5.0%	1.9%	19.4%	8.8%	17.9%	25.2%	6.4%	10.2%
RU-FI	56.5%	63.1%	74.2%	70.9%	52.7%	47.9%	28.2%	33.1%	65.3%	20.3%
SE3-DK1	39.3%	48.8%	34.6%	34.6%	35.8%	41.4%	43.0%	34.1%	26.0%	40.2%
SE4-DE	18.4%	49.8%	45.9%	57.0%	36.3%	27.4%	30.6%	37.8%	26.4%	42.3%
SE4-LT					30.7%	32.1%	27.6%	29.4%	18.3%	33.8%
SE4-PL	47.5%	62.8%	32.0%	25.5%	28.9%	31.8%	29.7%	23.9%	15.1%	21.8%
Grand Total	33.4%	40.2%	36.8%	35.1%	35.0%	35.5%	33.2%	30.5%	24.9%	28.4%

### 5.3 Individual presentations of each HVDC link

This section presents the performance of each HVDC link. Figure 5.10 presents the geographical location of each HVDC link. The categories used in the following presentations of each separate HVDC link are presented and defined in Chapter 3.

Note that the sums in the tables for each link may show a

technical capacity  $E_{max}$  higher than the  $E_{max}$  stated in the diagram. This is due to power flows that may momentarily be higher than rated technical capacity of the links. Other times, when power flow is below the rated technical capacity (and there is no limitation reported), the difference is registered in the category “technical capacity not used”.

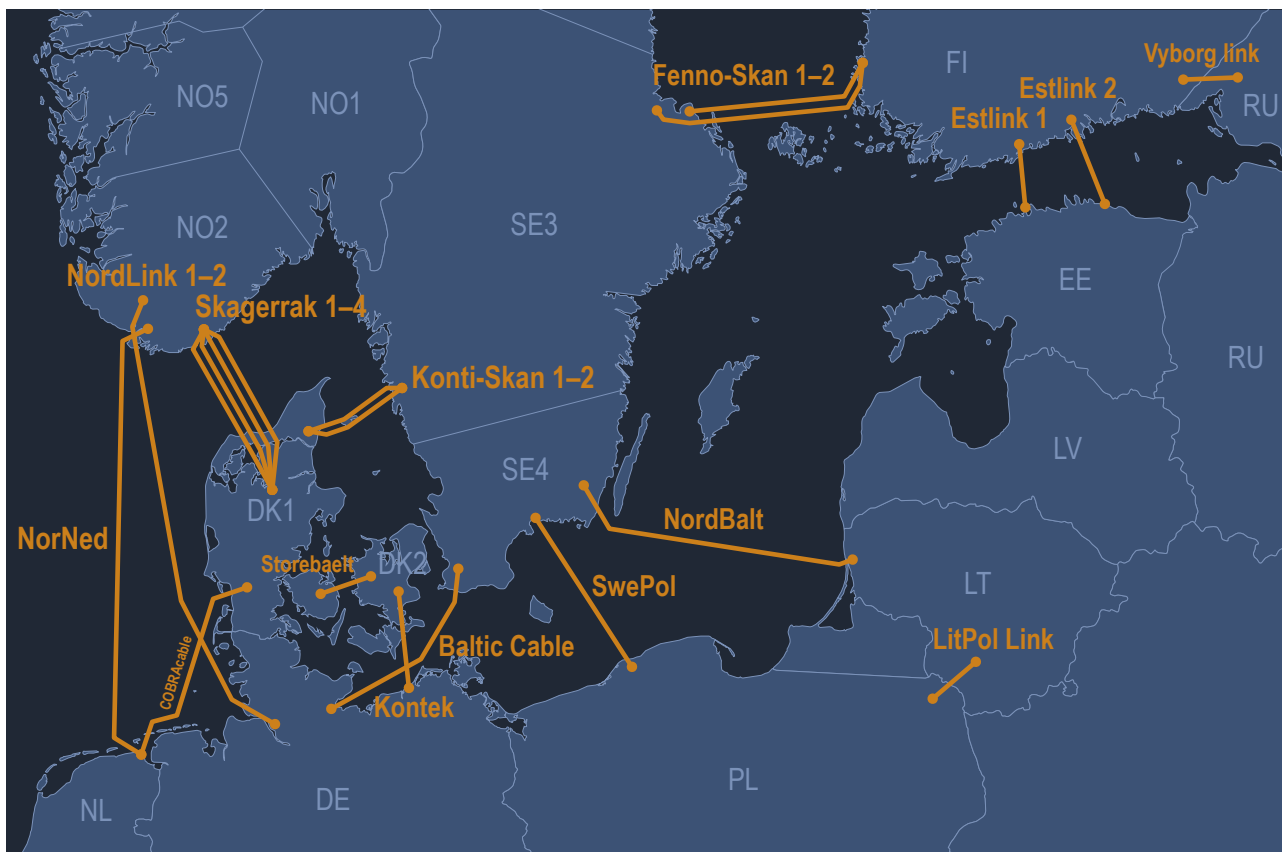


Figure 5.10: A map of the bidding zones and the 19 HVDC links included in this report.

### 5.3.1 Baltic Cable

Figure 5.11 presents the availability and utilisation of Baltic Cable for 2021 and Table 5.4 presents the numerical values behind it. Baltic Cable is connected between southern Sweden (bidding zone SE4) and Germany (bidding zone DE-TenneT). The operations started in 1994 and the transmission capacity is 600 MW.

In 2021, Baltic Cable had an available technical capacity of 90 %. The technical capacity not used was 42 %. Totally,

2.2 TWh (43 % of the technical capacity) was transmitted south (SE4→DE-TenneT) and 0.3 TWh (5 % of the technical capacity) was transmitted north (DE-TenneT→SE4).

The annual maintenance of Baltic Cable lasted 4 days in late August. Except for two short planned corrective maintenances and one short disturbance outage, there were no other outages on Baltic Cable in 2021.

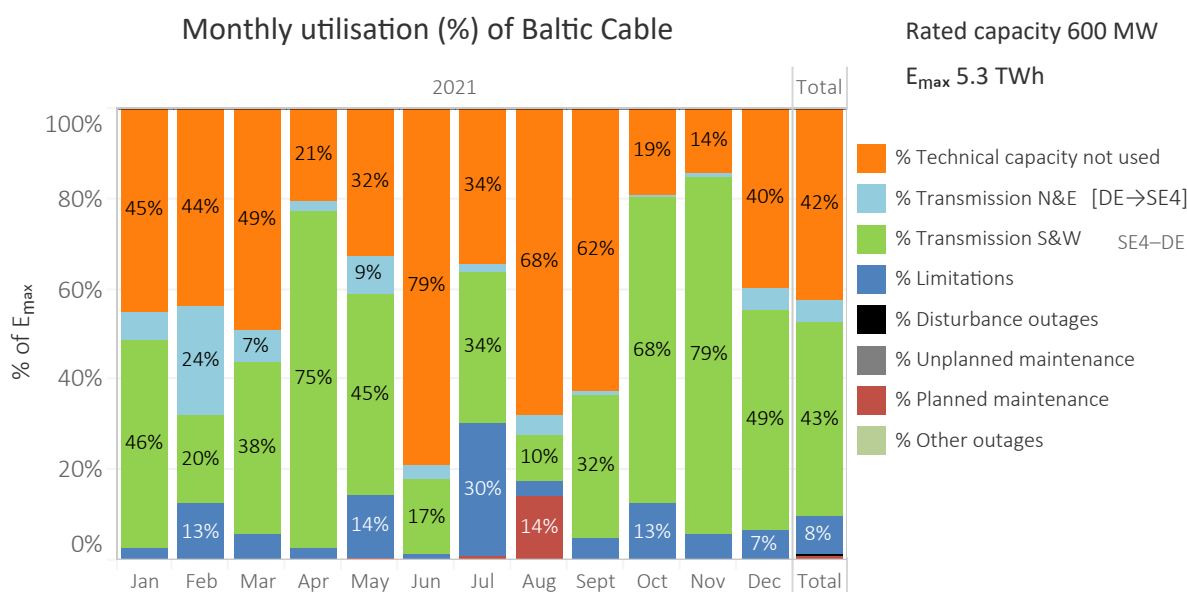


Figure 5.11: Monthly percentage allocation of utilisation by category for Baltic Cable in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.4: Monthly allocation of technical capacity (E<sub>max</sub>) for The Baltic Cable in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	201.6	176.5	219.9	89.0	145.1	341.0	153.7	303.7	269.5	85.7	61.6	176.7	2224.0	42.3%
Transmission N&E, GWh	28.9	96.7	31.6	9.2	38.5	13.2	7.1	18.3	4.2	1.1	4.4	23.4	276.8	5.3%
Transmission S&W, GWh	203.9	79.1	169.8	323.9	200.2	72.8	149.6	46.2	137.6	303.1	341.9	217.0	2245.1	42.7%
Limitations, GWh	12.8	51.3	25.6	11.3	61.2	5.1	132.5	14.7	20.7	56.6	23.5	29.3	444.6	8.5%
Disturbance outages, GWh	-	-	-	-	-	-	-	-	-	-	0.6	-	0.6	0.0%
Unplanned maintenance., GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	-	2.1	-	3.5	63.6	-	-	-	-	69.1	1.3%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	447.2	403.6	447.0	433.4	447.1	432.2	446.4	446.4	432.0	446.5	432.1	446.4	5260.3	100.0%
Losses SW, GWh	7.2	3.5	6.0	8.1	5.8	6.0	4.1	4.1	6.7	8.0	8.7	7.3	75.5	1.4%
Losses NE, GWh	0.7	2.0	0.7	0.2	0.8	0.3	0.1	0.4	0.1	-	0.1	0.4	5.8	0.1%

Figure 5.12 presents the annual utilisation of Baltic Cable per utilisation and unavailability category for the years 2012–2021.

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.14 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

Figure 5.13 presents the percentage of hours of a year Baltic Cable has been affected by either a limitation, a dis-

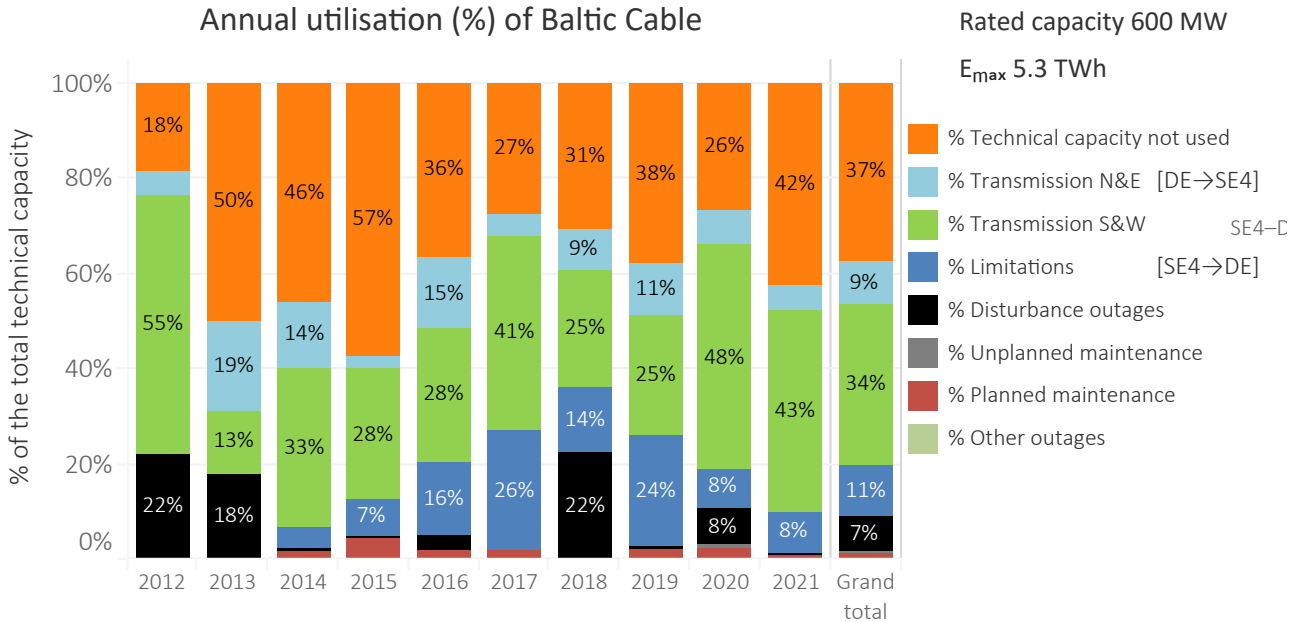


Figure 5.12: Annual utilisation of Baltic Cable per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

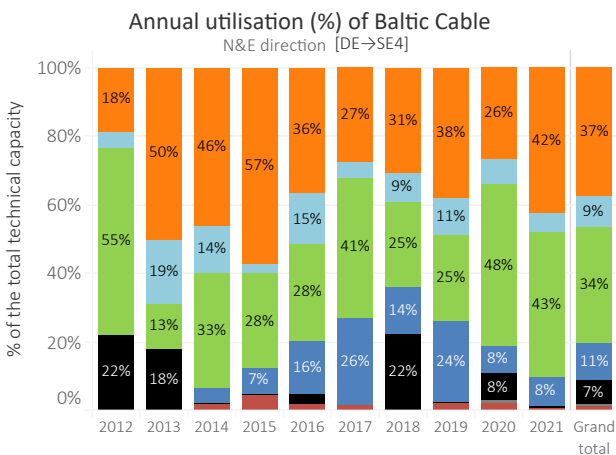


Figure 5.13: Percentage of hours Baltic Cable has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Percentage of unavailable hours annually per category for Baltic Cable

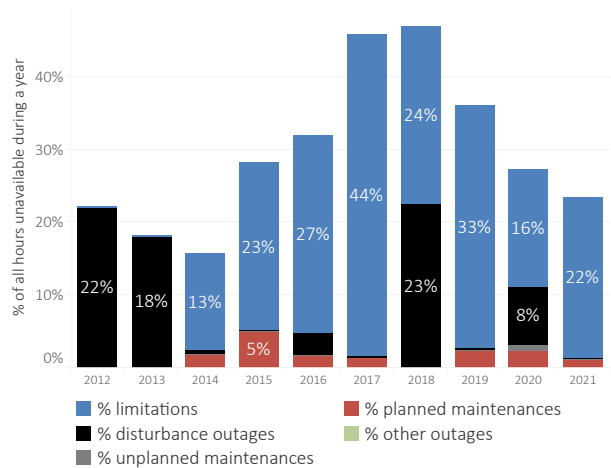


Figure 5.14: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Baltic Cable for the years 2012–2021. Baltic cable has not had any other outages during the years 2012–2021.

### 5.3.2 COBRACable

Figure 5.15 presents the availability and utilisation of COBRACable for 2021 and Table 5.5 presents the numerical values behind it. COBRACable has been in operation since 2019. In Denmark (bidding zone DK1) it is connected to Endrup substation and in Netherlands to Eemshaven (bidding zone APX NL). COBRACable was commissioned 5 November and has a transmission capacity of 700 MW.

In 2021, COBRACable had an available technical capacity of 90 %. The technical capacity not used was 27 %. Totally, 3.0 TWh (49 % of the technical capacity) was transmit-

ted south to the Netherlands (DK1→APX NL) and 0.9 TWh (14 % of the technical capacity) was transmitted north to Denmark (APX NL→DK1).

COBRACable had two maintenance outages in 2021. One was coverage of exposed offshore cable, and the other was annual maintenance. There were five disturbance outages: one was continuation of the cable fault from 2020, two of them came from a failed CPU card in MMS, and the last two were due to work in neighbouring substation which accidentally tripped COBRACable.

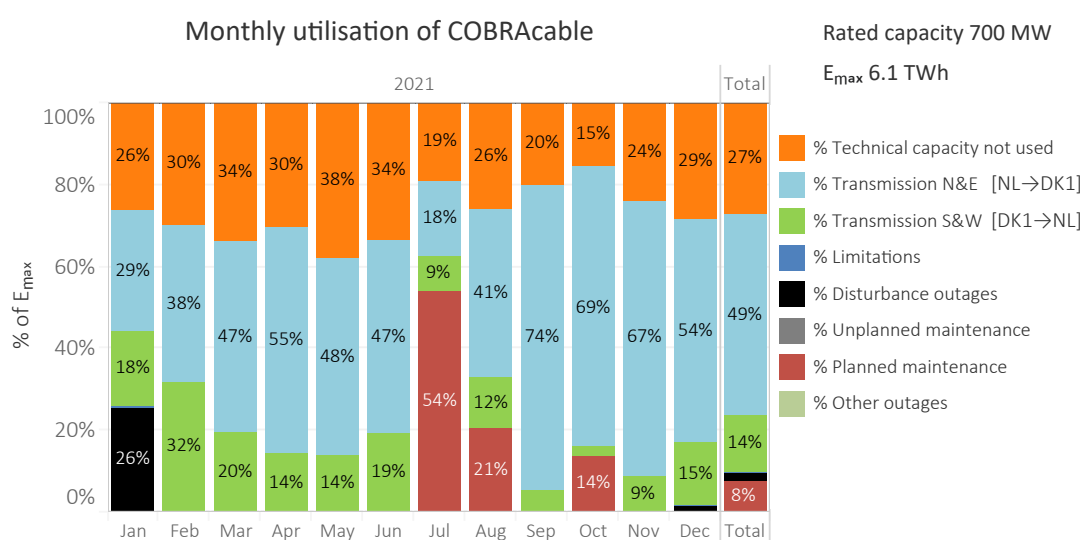


Figure 5.15: Monthly percentage allocation of utilisation by category for COBRACable in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.5: Monthly allocation of technical capacity (E<sub>max</sub>) for COBRACable in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

Monthly utilisation of COBRACable (South & West direction DK1→NL)	2021												Total	% total
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
Technical capacity not used, GWh	136.5	141.3	176.2	153.6	198.3	169.1	99.5	135.0	101.9	80.3	122.4	149.5	1663.6	27.1%
Transmission N&E, GWh	153.5	180.2	242.7	278.6	251.2	239.2	95.6	213.0	374.8	357.4	335.8	283.4	3005.5	49.0%
Transmission S&W, GWh	95.0	148.9	101.9	71.8	71.3	95.1	45.1	64.9	27.2	11.1	45.0	78.5	855.7	14.0%
Limitations, GWh	2.3	-	-	-	-	-	-	-	-	-	0.8	3.4	6.5	0.1%
Disturbance outages, GWh	133.6	-	-	-	-	0.6	-	-	-	-	-	6.0	140.2	2.3%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	-	-	-	280.5	108.0	-	71.9	-	-	460.4	7.5%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	520.8	470.4	520.8	504.0	520.8	504.0	520.8	520.8	504.0	520.8	504.0	520.8	6132.0	100.0%
Losses SW, GWh	2.1	3.4	2.3	1.6	1.7	2.2	0.9	1.5	0.7	0.3	1.0	1.8	19.4	0.3%
Losses NE, GWh	4.1	5.2	7.0	7.9	7.2	6.7	2.7	6.0	10.8	10.5	9.7	7.8	85.6	1.4%

Figure 5.16 presents the annual utilisation of COBRACable per utilisation and unavailability category for the years 2019–2021.

Figure 5.17 presents the percentage of hours of a year COBRACable has been affected by either a limitation, a disturbance outage, an unplanned or planned maintenance

outage or other outage annually during the years 2019–2021. Figure 5.18 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2019–2021.

Data for 2019 does not cover the whole year because COBRACable was commissioned in September 2019.

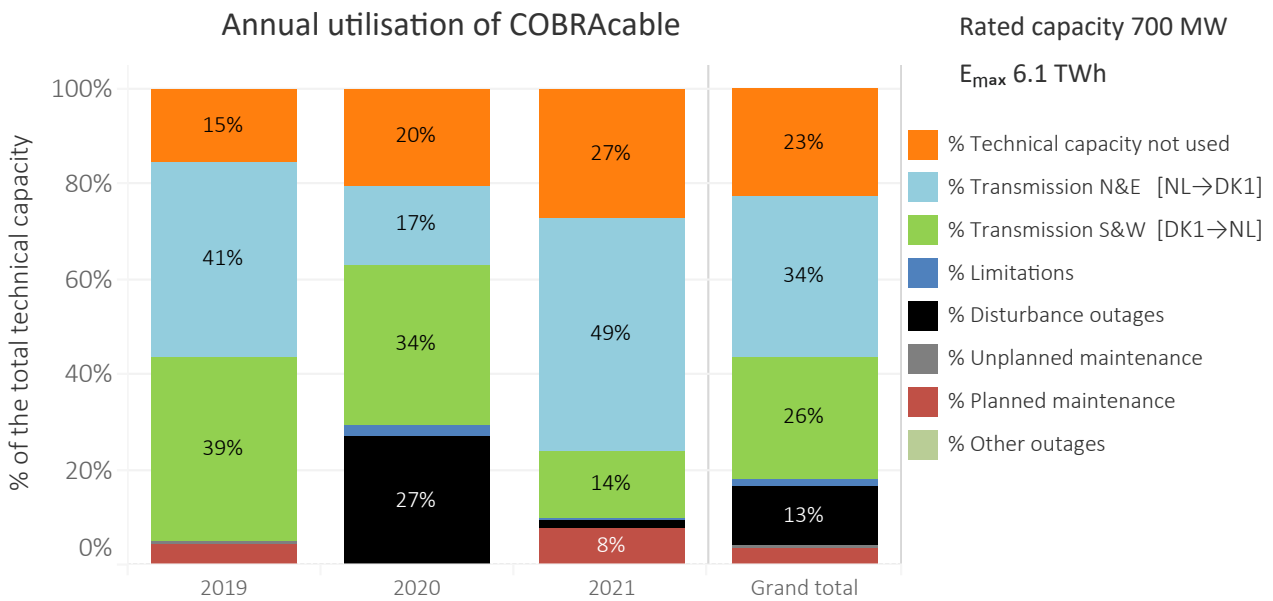


Figure 5.16: Annual utilisation of COBRACable per the utilisation and unavailability categories for the years 2019–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for COBRACable

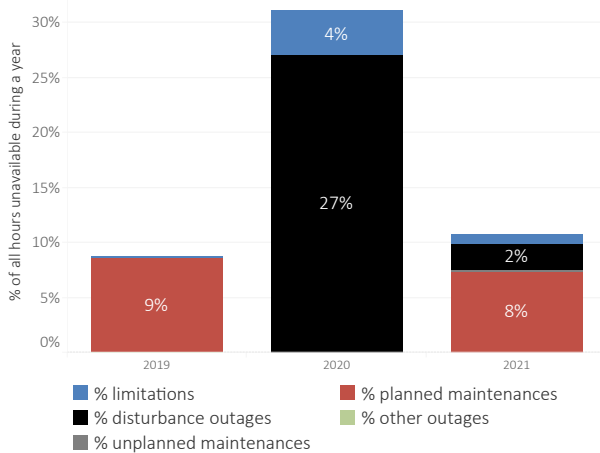


Figure 5.17: Percentage of hours COBRACable has been affected by either a limitation or an outage annually since 2019. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for COBRACable

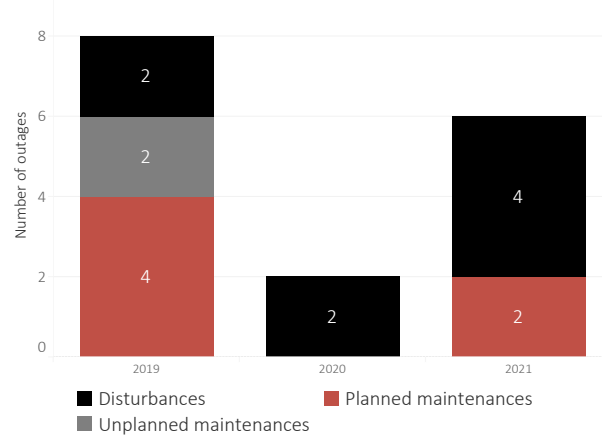


Figure 5.18: The annual number of disturbances, unplanned and planned maintenance outages and other outages for COBRACable for the years 2019–2021.

### 5.3.3 EstLink 1

Figure 5.19 presents the availability and utilisation of EstLink 1 for 2021 and Table 5.6 presents the numerical values behind it. EstLink 1 has been in operation since 2006 and is the first HVDC connection between Finland and Estonia. In Finland, it is connected to Espoo substation (bidding zone FI) and in Estonia, it is connected to Harku substation (bidding zone EE). The transmission capacity of EstLink 1 is 350 MW.

In 2021, EstLink 1 had an available technical capacity of 97 %. The technical capacity not used was 39 % because EstLink 2 is prioritised due to its lower transmission losses

and because EstLink 1 is often used in Automatic Frequency Control Mode. Totally, 1.8 TWh (57 % of the technical capacity) was transmitted south (FI→EE) and less than 0.1 TWh (0.5 % of the technical capacity) was transmitted north (EE→FI).

The annual maintenance of EstLink 1 lasted 5 days in June. Additionally, there was one 3-day planned maintenance outage for cable work and corrective maintenance of phase reactors on the Finnish side. Last, EstLink 1 had no disturbance outages in 2021.

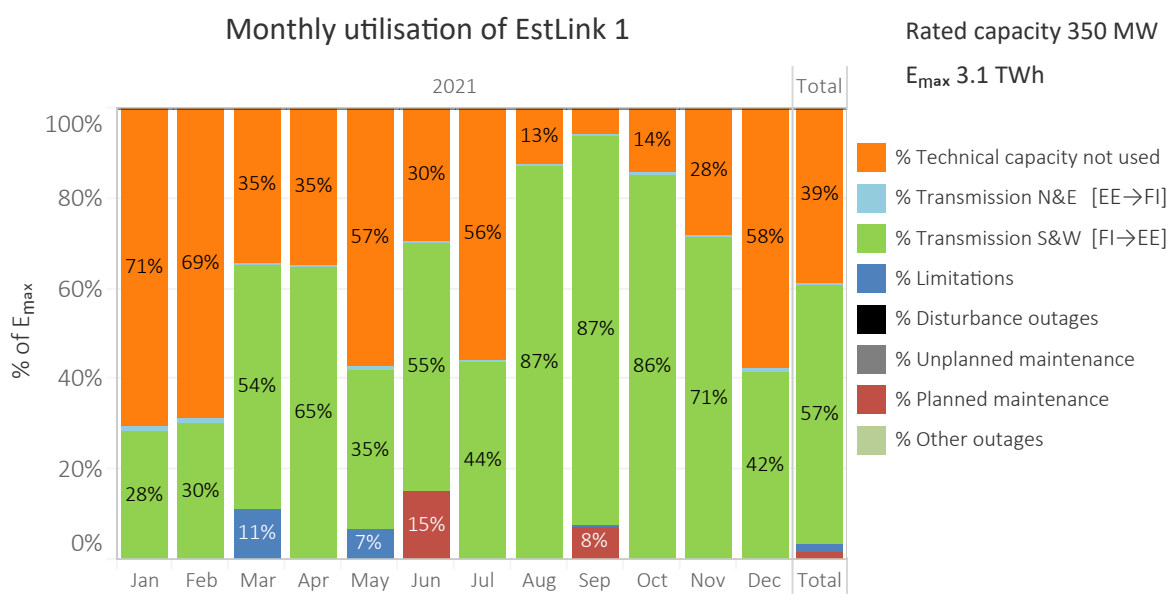


Figure 5.19: Monthly percentage allocation of utilisation by category for EstLink 1 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.6: Monthly allocation of technical capacity (E<sub>max</sub>) for EstLink 1 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	184.5	162.1	90.5	88.9	148.8	74.9	145.7	33.0	14.4	37.0	71.7	150.6	1202.1	39.0%
Transmission N&E, GWh	2.6	2.4	1.2	0.7	2.5	0.8	1.3	0.2	-	0.2	0.7	1.7	14.4	0.5%
Transmission S&W, GWh	74.1	71.3	141.4	164.2	92.6	139.3	114.1	229.2	220.3	225.5	181.7	108.9	1762.7	57.2%
Limitations, GWh	-	-	28.9	-	17.0	-	-	-	0.2	-	-	-	46.1	1.5%
Disturbance outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	-	-	38.2	-	-	19.4	-	-	-	57.6	1.9%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	261.1	235.8	262.0	253.8	260.9	253.2	261.1	262.5	254.4	262.7	254.2	261.2	3082.8	100.0%
Losses SW, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Losses NE, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-



Figure 5.20 presents the annual utilisation of EstLink 1 per utilisation and unavailability category for the years 2012–2021.

Figure 5.21 presents the percentage of hours of a year EstLink 1 has been affected by either a limitation, a dis-

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.22 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

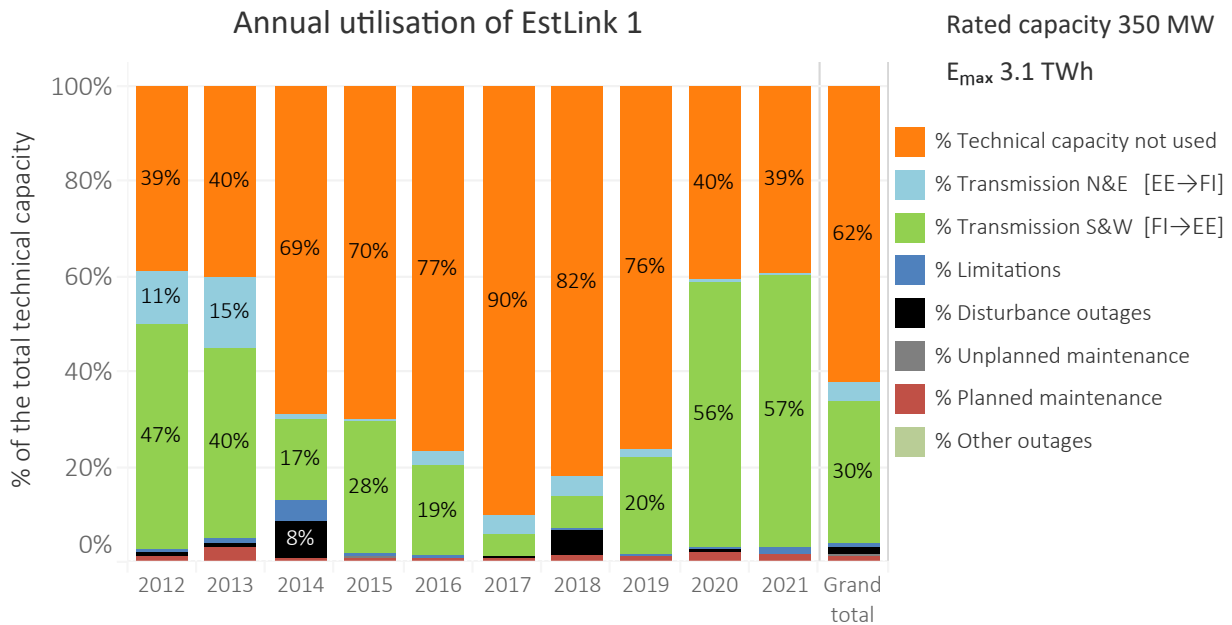


Figure 5.20: Annual utilisation of EstLink 1 per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for EstLink 1

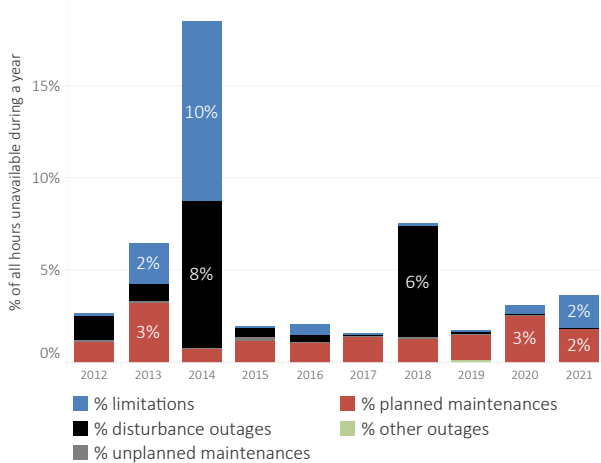


Figure 5.21: Percentage of hours EstLink 1 has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for EstLink 1

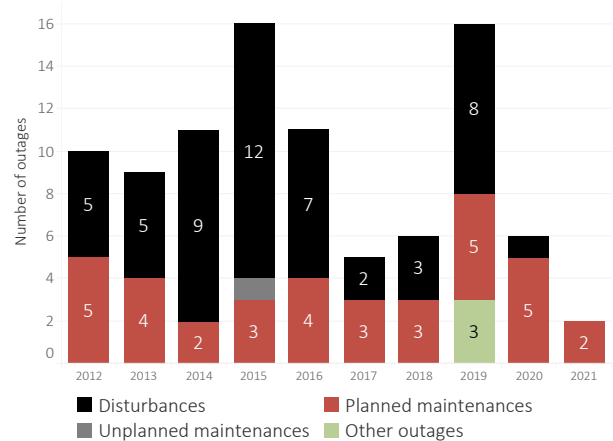


Figure 5.22: The annual number of disturbances, unplanned and planned maintenance outages and other outages for EstLink 1 for the years 2012–2021.

### 5.3.4 EstLink 2

Figure 5.23 presents the availability and utilisation of EstLink 2 for 2021 and Table 5.7 presents the numerical values behind it. EstLink 2 was commissioned in February 2014 and is the second HVDC connection between Finland and Estonia. In Finland, it is connected to Anttila substation (bidding zone FI) and in Estonia, it is connected to Püssi substation (bidding zone EE). The transmission capacity of EstLink 2 is 650 MW.

In 2021, EstLink 2 had an available technical capacity of 99.6 %. The technical capacity not used was 12 %. Totally, 4.9 TWh (86 % of the technical capacity) was transmitted

south (FI→EE) and less than 0.1 TWh (0.9 % of the technical capacity) was transmitted north (EE→FI).

No annual maintenance for EstLink 2 was held in 2021 as it is done every second year. There was one short maintenance outage for cable oil sampling and signal testing. The power was reduced 10–30MW for several months from June to mid-October due to sea cable temperature rise near the Finnish coast. One short power reduction occurred due too filter trip and another due to external AC network in Estonia. Additionally, there was one short disturbance due to human actions.

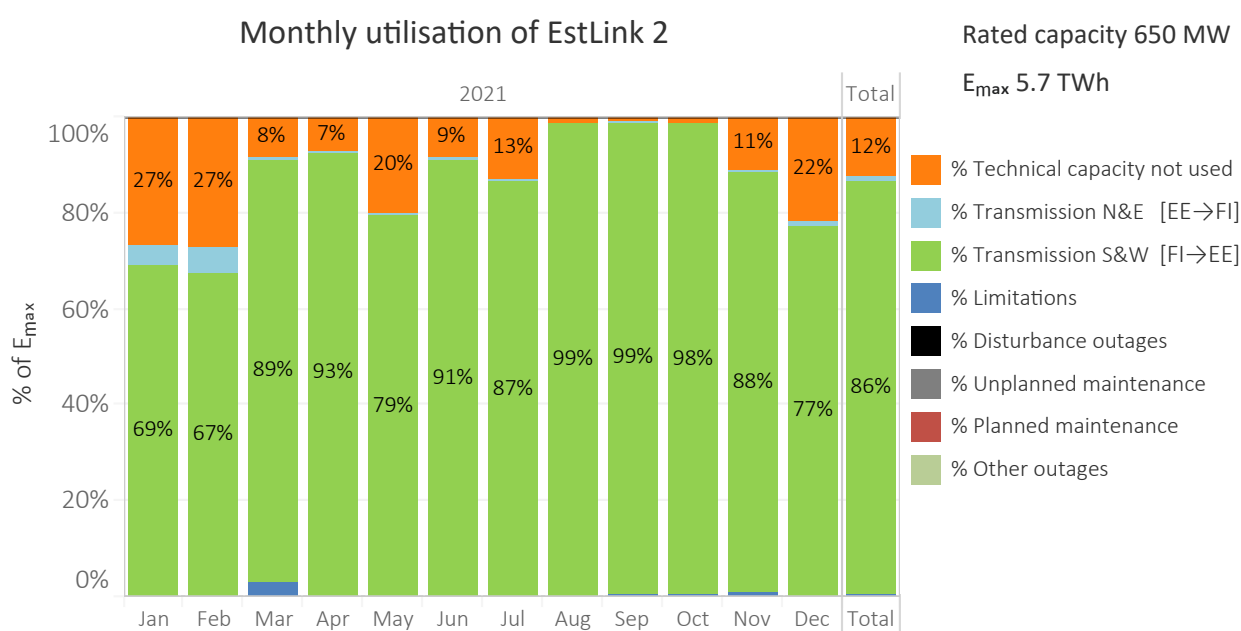


Figure 5.23: Monthly percentage allocation of utilisation by category for EstLink 2 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.7: Monthly allocation of technical capacity ( $E_{max}$ ) for EstLink 2 in 2021. Note that losses are not included in the technical capacity ( $E_{max}$ ), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	130.5	119.4	40.5	34.0	98.7	41.0	63.7	6.7	4.3	6.2	51.5	107.4	703.9	12.3%
Transmission N&E, GWh	20.1	23.4	0.9	-	1.2	0.6	2.0	-	0.1	-	2.4	2.7	53.4	0.9%
Transmission S&W, GWh	335.0	295.8	431.3	437.0	386.2	430.1	421.2	481.9	463.3	475.0	410.2	375.4	4942.4	86.3%
Limitations, GWh	-	-	14.3	-	-	-	-	-	2.6	2.3	3.1	0.6	23.0	0.4%
Disturbance outages, GWh	-	-	-	-	-	-	-	-	-	-	0.9	-	0.9	0.0%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	0.9	-	-	-	-	-	-	-	-	0.9	0.0%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	485.5	438.6	487.0	472.0	486.1	471.7	486.9	488.6	470.3	483.6	468.0	486.2	5724.4	100.0%
Losses SW, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Losses NE, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 5.24 presents the annual utilisation of EstLink 2 per utilisation and unavailability category for the years 2014–2021.

Figure 5.25 presents the percentage of hours of a year EstLink 2 has been affected by either a limitation, a disturbance outage, an unplanned or planned maintenance

outage or other outage annually during the years 2014–2021. Figure 5.26 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2014–2021.

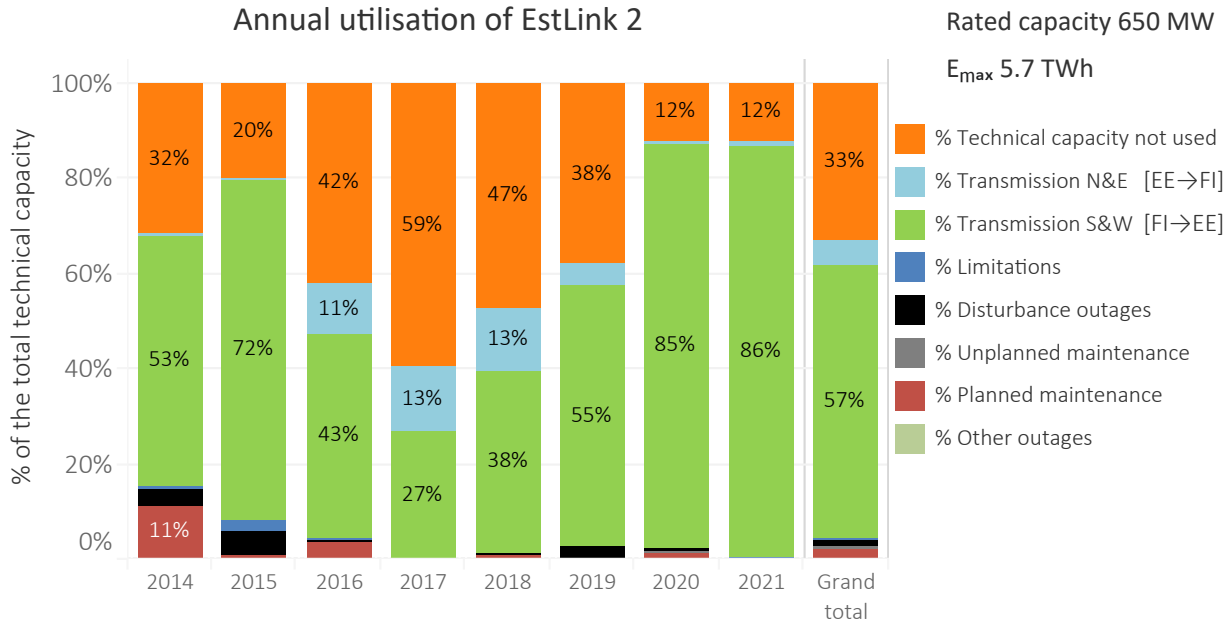


Figure 5.24: Annual utilisation of EstLink 2 per the utilisation and unavailability categories for the years 2014–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

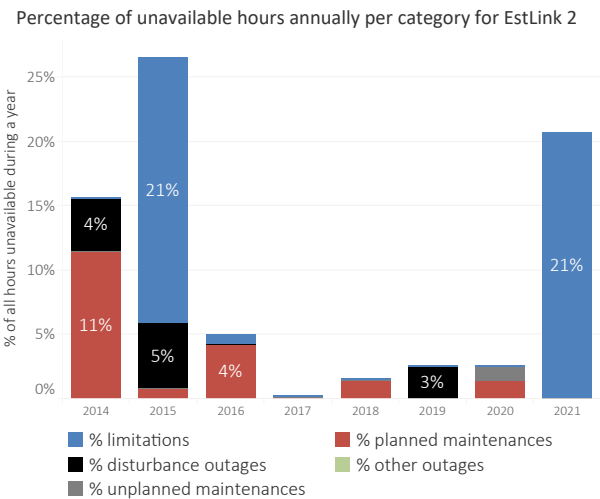


Figure 5.25: Percentage of hours EstLink 2 has been affected by either a limitation or an outage annually since 2014. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

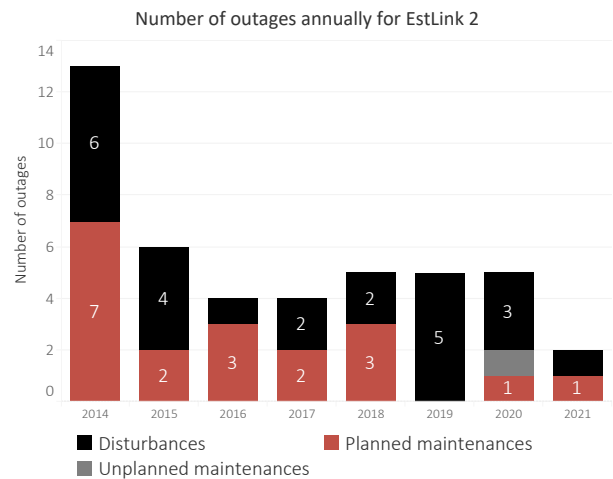


Figure 5.26: The annual number of disturbances, unplanned and planned maintenance outages and other outages for EstLink 2 for the years 2014–2021. EstLink 2 had neither unplanned maintenance nor other outages during this period.

### 5.3.5 Fenno-Skan 1

Figure 5.27 presents the availability and utilisation of Fenno-Skan 1 for 2021 and Table 5.8 presents the numerical values behind it. Fenno-Skan 1 has been in operation since 1989 and is the first HVDC connection between Finland and Sweden. In Finland (bidding zone FI), Fenno-Skan 1 is connected to Rauma and in Sweden to Dannebo (bidding zone SE3). The transmission capacity used to be 500 MW during summer and 550 MW during winter but was permanently decreased to 400 MW on 1 July 2014 after detailed DC-cable investigations were completed. The investigations were started after a cable fault 12 February 2013.

In 2021, Fenno-Skan 1 had an available technical capacity of 95 %. The technical capacity not used was 3 %. Totally, <0.1 TWh (0.7 % of the technical capacity) was transmitted west (FI→SE3) and 3.2 TWh (91 % of the technical capacity)

was transmitted east (SE3→FI).

The annual maintenance of Fenno-Skan 1 lasted 5 days in late September to early October. Additionally, there were 2 planned maintenance outages for corrective purposes — one for removing trees fallen on the neutral line, the other one for fault searching on the DC neutral bus CT. Fenno-Skan 1 had 6 disturbance outages of which 4 were due to repetitive fault in DC voltage divider and 2 due to human error. One other planned outage was due to grid operator testing at the start of the annual maintenance.

It should be noted that Fenno-Skan 1 and 2 is sometimes operated at equivalent transmission levels but with reversed directions to keep the temperature of Fenno-Skan 1 at adequate levels. The utilisation is still regarded as transmission even though the resulting net exchange between Finland and Sweden is zero.

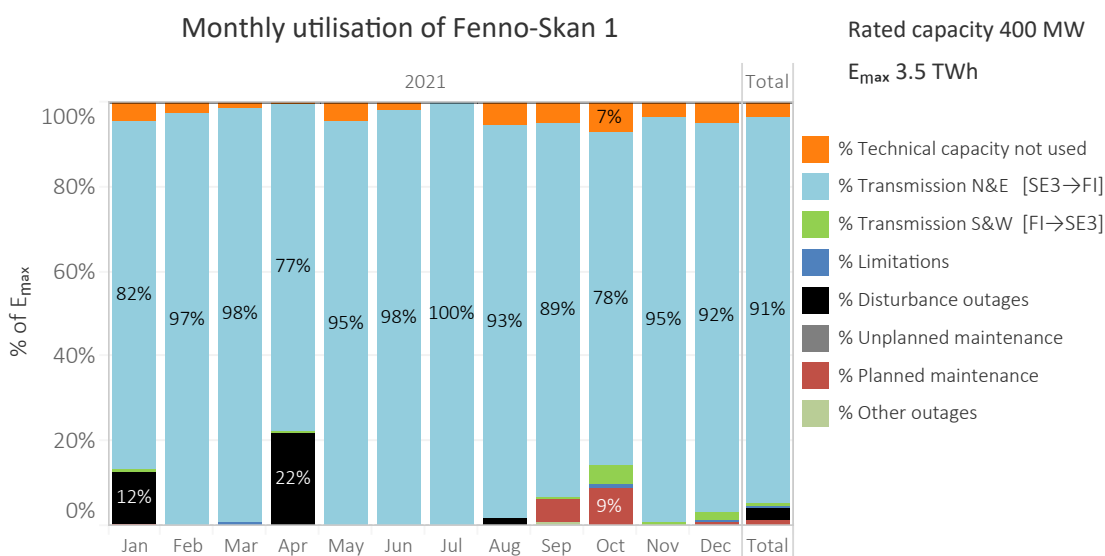


Figure 5.27: Monthly percentage allocation of utilisation by category for Fenno-Skan 1 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.8: Monthly allocation of technical capacity (E<sub>max</sub>) for Fenno-Skan 1 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	13.1	6.8	4.5	0.9	13.8	5.5	-	16.2	14.0	21.7	10.6	15.3	122.2	3.5%
Transmission N&E, GWh	245.4	262.3	291.2	222.8	284.5	283.1	298.9	276.9	255.3	233.5	274.9	272.6	3201.4	91.2%
Transmission S&W, GWh	1.9	-	-	0.1	-	-	-	-	-	13.3	2.3	5.8	23.4	0.7%
Limitations, GWh	-	0.2	2.4	1.5	-	-	-	-	-	3.1	0.5	0.6	8.3	0.2%
Disturbance outages, GWh	36.2	-	-	63.4	-	0.1	-	5.3	-	-	0.1	-	105.0	3.0%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	1.3	-	-	-	-	-	-	-	16.8	26.4	-	3.4	47.9	1.4%
Other outages, GWh	-	-	-	-	-	-	-	-	2.3	-	-	-	2.3	0.1%
Total, GWh	297.9	269.3	298.1	288.7	298.2	288.8	298.9	298.3	288.4	298.0	288.3	297.7	3510.6	100.0%
Losses SW, GWh	0.1	-	-	-	-	-	-	-	-	0.5	0.1	0.2	1.0	0.0%
Losses NE, GWh	6.7	7.0	8.3	6.1	7.7	7.4	7.5	7.5	7.0	6.0	7.4	7.1	85.7	2.4%

Figure 5.28 presents the annual utilisation of Fenno-Skan 1 per utilisation and unavailability category for the years 2012–2021.

Figure 5.29 presents the percentage of hours of a year Fenno-Skan 1 has been affected by either a limitation, a disturbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.30 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

a disturbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.30 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

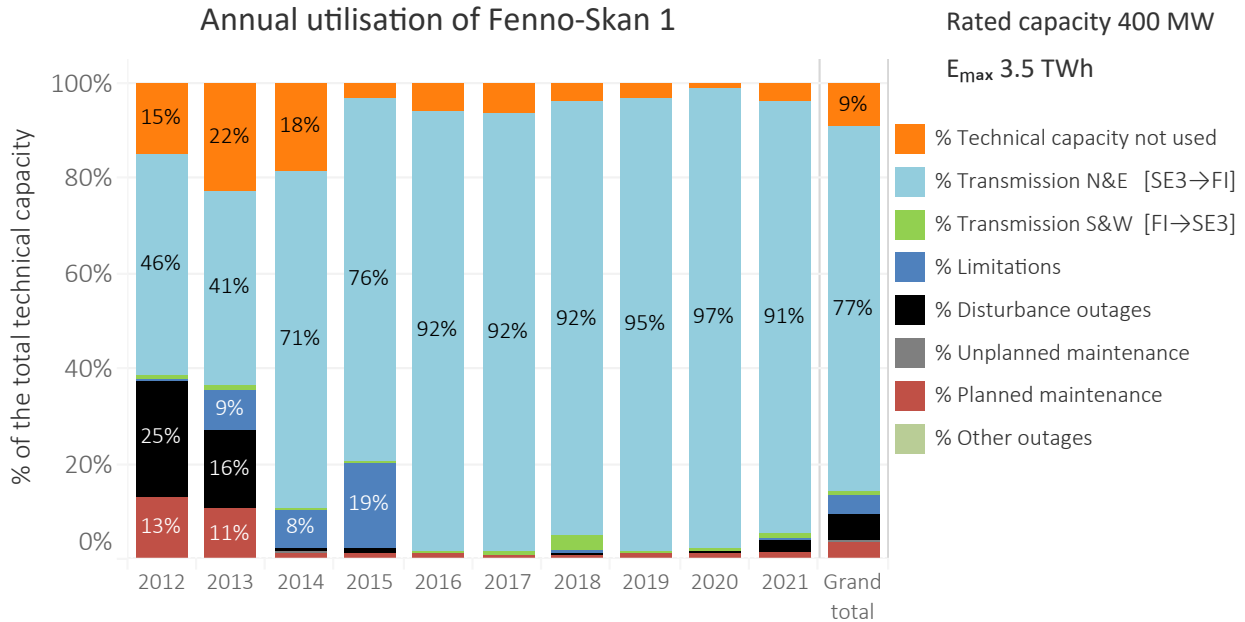


Figure 5.28: Annual utilisation of Fenno-Skan 1 per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Fenno-Skan 1

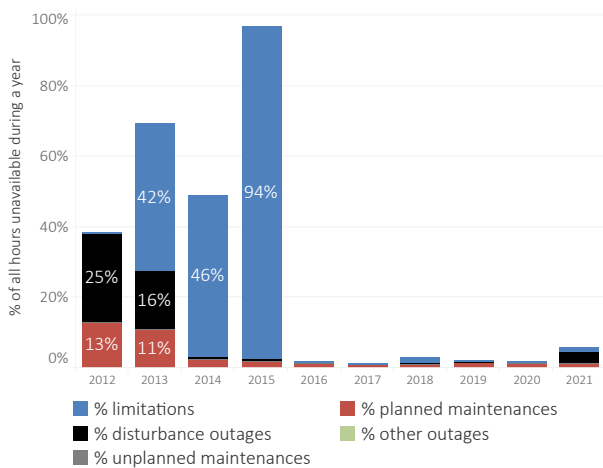


Figure 5.29: Percentage of hours Fenno-Skan 1 has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Fenno-Skan 1

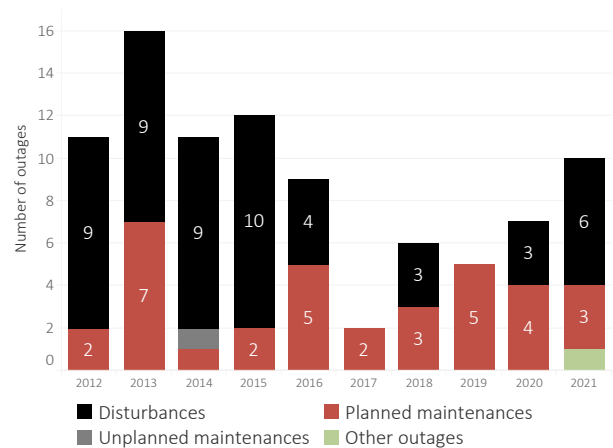


Figure 5.30: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Fenno-Skan 1 during 2012–2021. Fenno-Skan 1 had no other outages during the years 2012–2021.

### 5.3.6 Fenno-Skan 2

Figure 5.31 presents the availability and utilisation of Fenno-Skan 2 for 2021 and Table 5.9 presents the numerical values behind it. Fenno-Skan 2 has been in operation since 2011 and is the second HVDC connection between Finland and Sweden. In Finland (bidding zone FI) Fenno-Skan 2 is connected to Rauma and in Sweden to Finnböle (bidding zone SE3). The transmission capacity of Fenno-Skan 2 is 800 MW.

In 2021, Fenno-Skan 2 had an available technical capacity of 83 %. The technical capacity not used was 26 %. Totally, 0.8 TWh (11 % of the technical capacity) was transmitted west (FI→SE3) and 3.1 TWh (45 % of the technical capacity) was transmitted east (SE3→FI).

The annual maintenance of Fenno-Skan 2 lasted 5 days in early October. Additionally, there were 4 planned main-

tenance outages for corrective purposes, one for removing trees fallen on the neutral line, the other one for fault searching on the DC neutral bus CT, and two for repairing after cooling water leakage at the valve hall. Fenno-Skan 2 had 4 disturbance outages. Two of them were due to loss of auxiliary power supply in Sweden and one due to a human error while switching off AC filter breaker. One other planned outage was due to AC grid testing purposes at the end of October.

It should be noted that Fenno-Skan 1 and 2 is sometimes operated at equivalent transmission levels but with reversed directions to keep the temperature of Fenno-Skan 1 at adequate levels. The utilisation is still regarded as transmission even though the resulting net exchange between Finland and Sweden is zero.

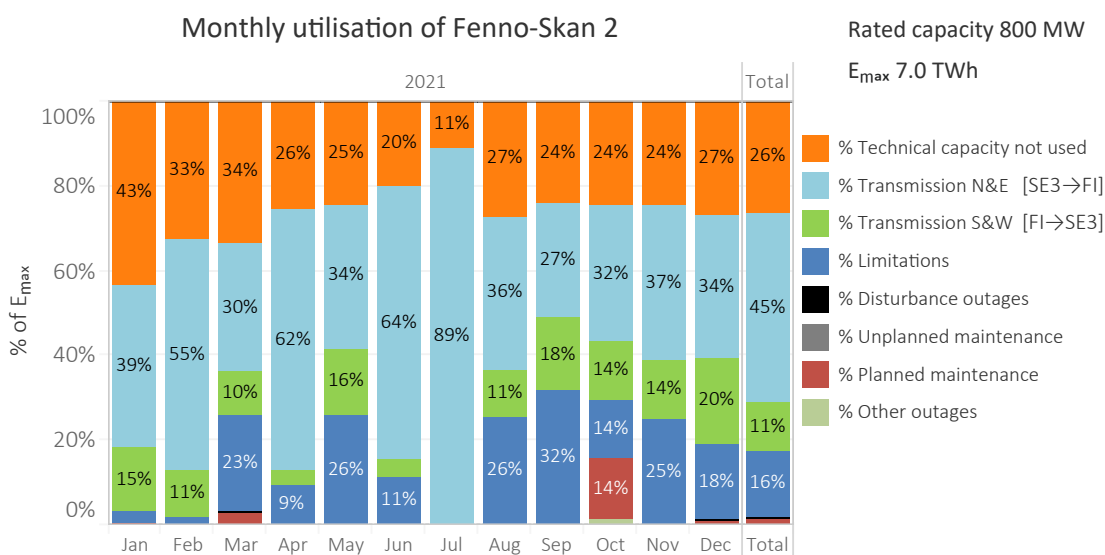


Figure 5.31: Monthly percentage allocation of utilisation by category for Fenno-Skan 2 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.9: Monthly allocation of technical capacity (E<sub>max</sub>) for Fenno-Skan 2 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

Monthly utilisation of Fenno-Skan 2 (South & West direction FI→SE3)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	257.5	175.6	199.4	147.5	146.8	115.1	65.5	163.4	138.4	145.2	141.0	158.4	1853.9	26.5%
Transmission N&E, GWh	230.0	293.5	181.2	355.1	200.5	371.0	530.0	214.5	153.6	191.1	211.3	202.1	3133.8	44.7%
Transmission S&W, GWh	89.3	58.5	60.3	20.6	94.2	25.5	-	65.5	102.3	83.1	79.5	120.5	799.2	11.4%
Limitations, GWh	15.9	9.0	135.3	52.9	153.8	64.5	-	151.9	181.7	82.7	144.3	105.8	1097.7	15.7%
Disturbance outages, GWh	-	1.0	2.7	-	-	-	-	-	-	-	-	1.5	5.2	0.1%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	2.5	-	16.4	-	-	-	-	-	-	85.4	-	7.0	111.3	1.6%
Other outages, GWh	-	-	-	-	-	-	-	-	-	7.8	-	-	7.8	0.1%
Total, GWh	595.2	537.7	595.2	576.0	595.2	576.1	595.5	595.3	576.0	595.3	576.1	595.3	7008.8	100.0%
Losses SW, GWh	1.7	1.2	1.0	0.4	1.8	0.4	-	1.2	1.8	1.8	1.5	2.4	15.1	0.2%
Losses NE, GWh	4.2	5.8	3.2	7.3	3.9	8.0	11.8	4.3	3.0	3.8	4.0	3.9	63.1	0.9%

Figure 5.32 presents the annual utilisation of Fenno-Skan 2 per utilisation and unavailability category for the years 2012–2021.

a disturbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.34 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

Figure 5.33 presents the percentage of hours of a year Fenno-Skan 2 has been affected by either a limitation,

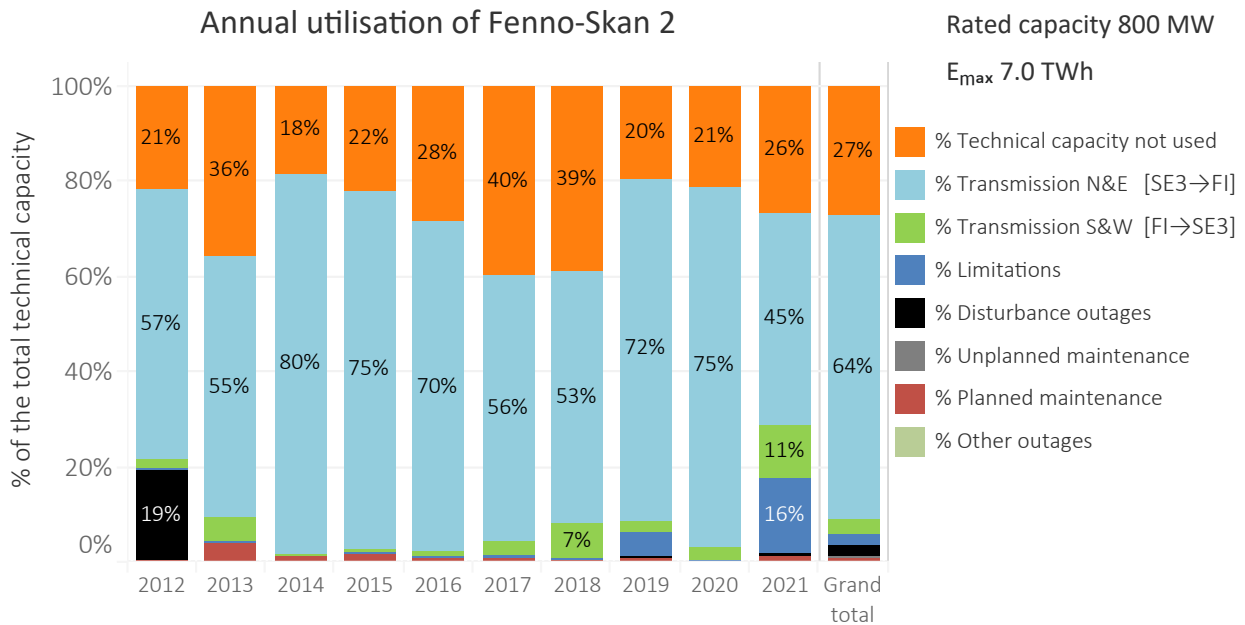


Figure 5.32: Annual utilisation of Fenno-Skan 2 per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Fenno-Skan 2

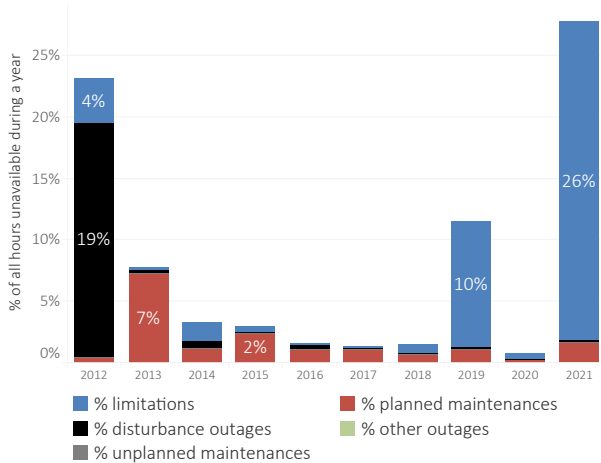


Figure 5.33: Percentage of hours Fenno-Skan 2 has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Fenno-Skan 2

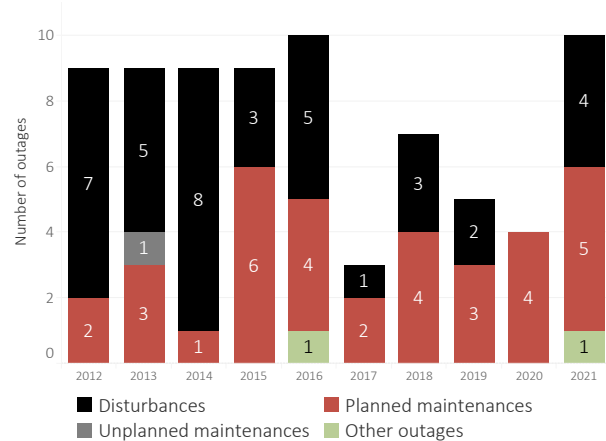


Figure 5.34: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Fenno-Skan 2 for the years 2012–2021.

### 5.3.7 Kontek

Figure 5.35 presents the availability and utilisation of Kontek for 2021 and Table 5.10 presents the numerical values behind it. Kontek has been in operation since 1995. In Denmark it is connected to Bjaeverskov (bidding zone DK2) and in Germany to Bentwisch (bidding zone DE-50Hertz). The transmission capacity of Kontek is 600 MW.

In 2021, Kontek had an available technical capacity of 70 %. The technical capacity not used was 23 %. Totally, 1.6 TWh

(30 % of the technical capacity) was transmitted south from Denmark to Germany and 0.9 TWh (18 % of the technical capacity) was transmitted north to Denmark.

Kontek had no disturbance outages in 2021. There were four planned maintenance outages: one was the annual maintenance, two were due to cable joint inspection due to oil leak and repair of that joint, and the last one was maintenance work on the converter transformer.

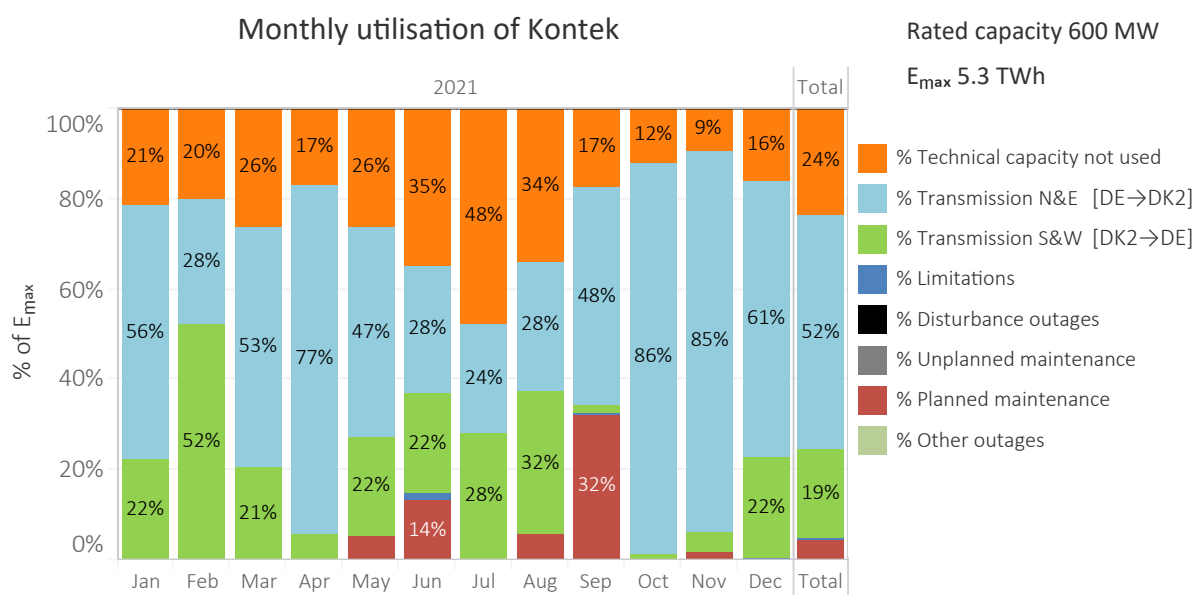


Figure 5.35: Monthly percentage allocation of utilisation by category for Kontek in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.10: Monthly allocation of technical capacity ( $E_{max}$ ) for Kontek in 2021. Note that losses are not included in the technical capacity ( $E_{max}$ ), as is shown in Figure 3.1.

Monthly utilisation of Kontek (South & West direction DK2->DE)														Total	% total
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec			
Technical capacity not used, GWh	94.9	81.0	116.6	73.8	117.2	151.1	212.6	152.1	74.9	54.3	40.5	71.8	1240.8	23.6%	
Transmission N&E, GWh	252.1	111.1	237.4	333.1	208.5	121.3	107.9	126.3	208.1	385.4	365.1	273.6	2729.9	51.9%	
Transmission S&W, GWh	99.4	211.1	92.3	25.0	97.6	96.8	125.9	142.8	8.4	6.7	19.2	99.3	1024.6	19.5%	
Limitations, GWh	-	-	-	-	-	4.3	-	-	0.7	-	-	1.7	6.7	0.1%	
Disturbance outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Unplanned maintenance., GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Planned maintenance, GWh	-	-	-	-	23.2	58.6	-	25.2	140.0	-	7.1	-	254.0	4.8%	
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total, GWh	446.4	403.2	446.4	432.0	446.4	432.0	446.4	446.4	432.0	446.4	432.0	446.4	5256.0	100.0%	
Losses SW, GWh	2.0	4.4	1.9	0.5	2.0	1.9	2.5	2.9	0.2	0.1	0.4	2.0	20.8	0.4%	
Losses NE, GWh	5.3	2.3	4.9	7.1	4.3	2.4	2.2	2.6	4.4	8.2	7.8	6.0	57.5	1.1%	



Figure 5.36 presents the annual utilisation of Kontek per utilisation and unavailability category for the years 2012–2021.

Figure 5.37 presents the percentage of hours of a year Kontek has been affected by either a limitation, a distur-

bance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.38 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

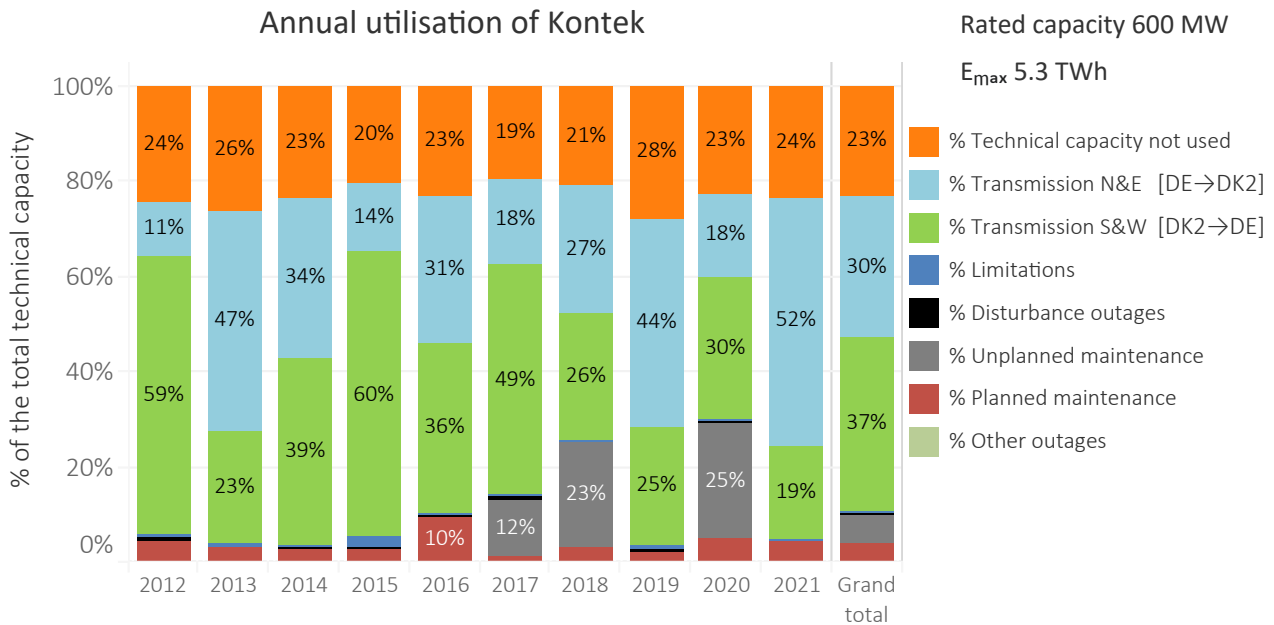


Figure 5.36: Annual utilisation of Kontek per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

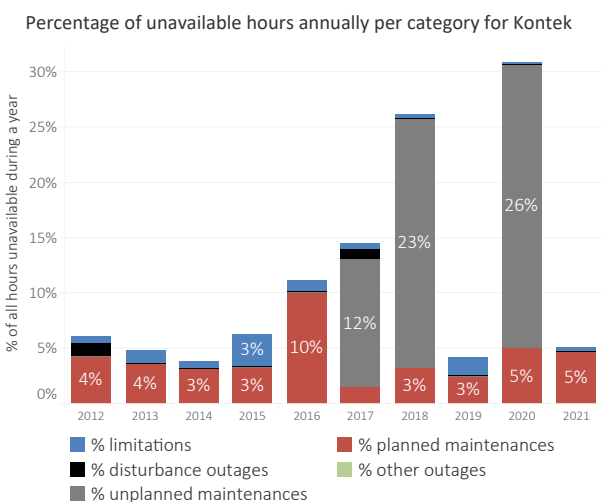


Figure 5.37: Percentage of hours Kontek has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

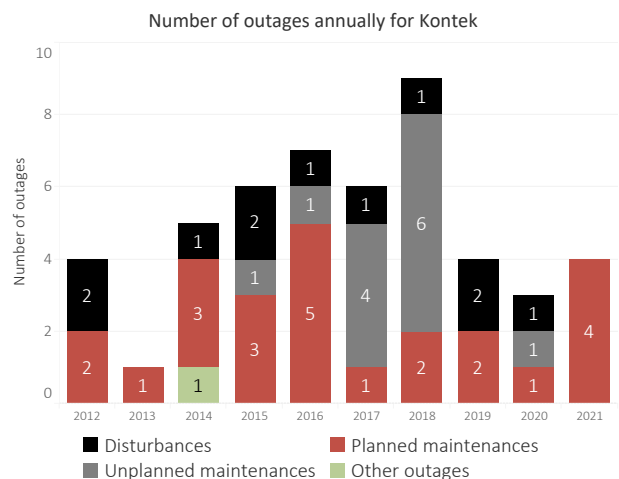


Figure 5.38: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Kontek for the years 2012–2021.

### 5.3.8 Konti-Skan 1

Figure 5.39 presents the availability and utilisation of Konti-Skan 1 for 2021 and Table 5.11 presents the numerical values behind it. Konti-Skan 1 has been in operation since 1965 and it is connected in south-western Sweden to Lindome (bidding zone SE3) and in Denmark to Vester Hassing (bidding zone DK1).

The rated capacity of Konti-Skan 1 and 2 was updated to 715 MW in both directions on 1 February 2020 (357.5 MW per link). The rated capacity was previously asymmetric depending on the flow direction: 740 MW towards east (370+370) and 680 MW towards west (340+340). The reason of the asymmetric rated capacity was due to historical limitations and reserve requirements, along with transmission measurements only being done in DK1.

In 2021, Konti-Skan 1 had an available technical capacity of 85 % and the technical capacity not used was 39 %. Totally, 0.4 TWh (14 % of the technical capacity) was transmitted west to Denmark (SE3→DK1) and 1.0 TWh (32 % of the technical capacity) was transmitted east to Sweden (DK1→SE3).

Annual maintenance of Konti-Skan 1 lasted 6 days in September, and there was one minor unplanned maintenance due to an oil leakage from a condenser in December. Konti-Skan 1 had six disturbance outages were a cable fault on the land cable was most severe. The other five were minor and due to either ELIS protection or during exchange of auxiliary system due to an error in the converter protection.

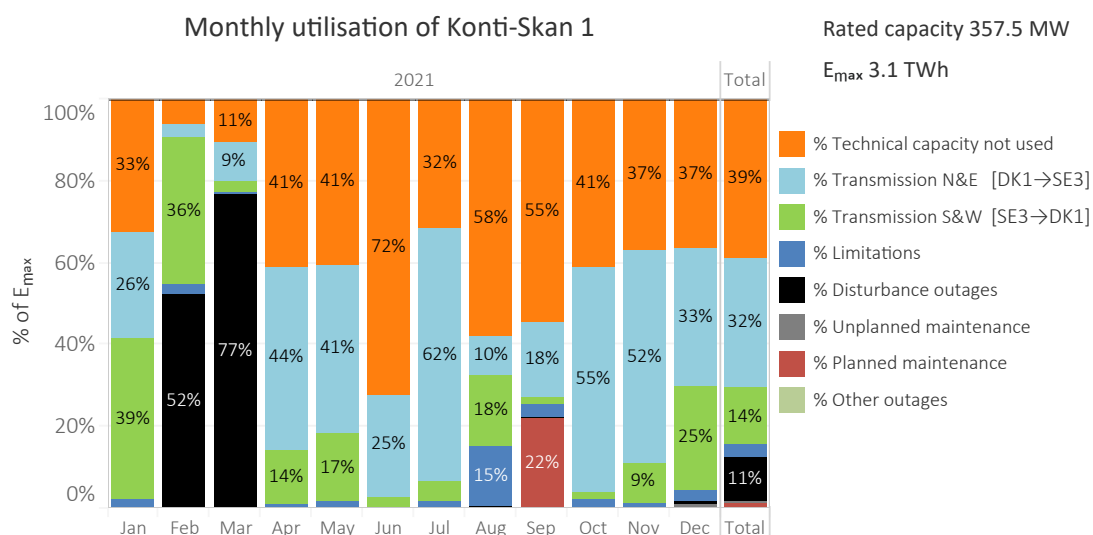


Figure 5.39: Monthly percentage allocation of utilisation by category for Konti-Skan 1 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.11: Monthly allocation of technical capacity (E<sub>max</sub>) for Konti-Skan 1 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	86.5	15.1	27.9	106.2	108.5	186.2	83.8	153.9	140.6	109.0	95.1	97.6	1210.4	38.6%
Transmission N&E, GWh	68.7	7.1	25.2	113.8	108.4	63.7	164.7	25.5	46.5	146.0	134.1	89.1	992.9	31.7%
Transmission S&W, GWh	104.9	86.0	7.5	34.8	44.9	6.8	12.8	46.6	5.1	5.4	24.4	67.0	446.1	14.2%
Limitations, GWh	5.8	6.8	1.4	2.5	4.3	0.7	4.7	39.3	8.3	5.6	3.3	8.3	90.8	2.9%
Disturbance outages, GWh	-	125.3	204.0	-	-	-	-	0.8	0.6	-	0.4	1.8	333.0	10.6%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	2.4	2.4	0.1%
Planned maintenance, GWh	-	-	-	-	-	-	-	-	56.3	-	-	-	56.3	1.8%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	266.0	240.2	266.0	257.4	266.0	257.4	266.0	266.0	257.4	266.0	257.4	266.1	3132.0	100.0%
Losses SW, GWh	2.4	2.0	0.2	0.9	1.1	0.2	0.3	1.0	0.2	0.1	0.6	1.6	10.7	0.3%
Losses NE, GWh	1.4	0.1	0.4	2.0	2.0	1.1	3.5	0.4	0.9	2.7	2.6	1.8	19.1	0.6%

Figure 5.40 presents the annual utilisation of Konti-Skan 1 per utilisation and unavailability category for the years 2012–2021.

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.42 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

Figure 5.41 presents the percentage of hours of a year Konti-Skan 1 has been affected by either a limitation, a dis-

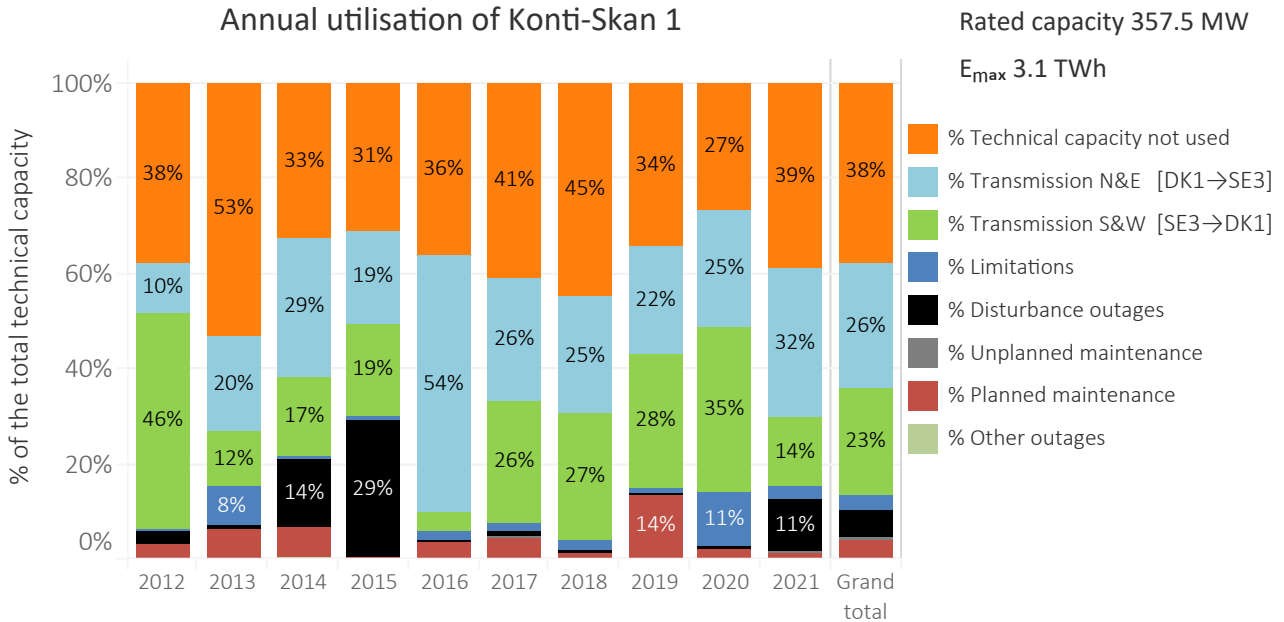


Figure 5.40: Annual utilisation of Konti-Skan 1 per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Konti-Skan 1

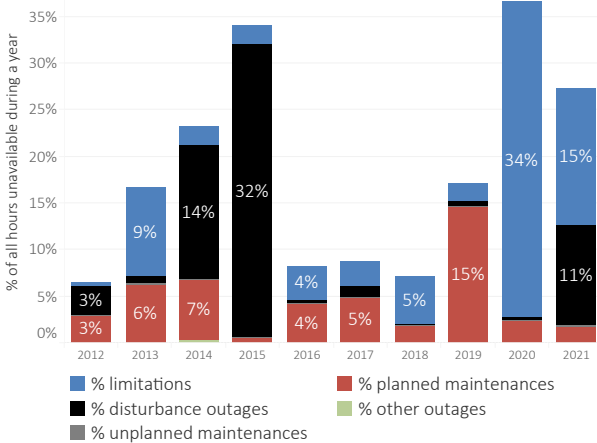


Figure 5.41: Percentage of hours Konti-Skan 1 has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Konti-Skan 1

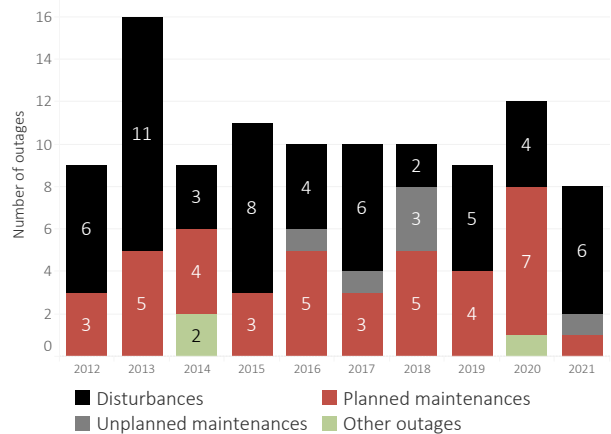


Figure 5.42: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Konti-Skan 1 for the years 2012–2021.

### 5.3.9 Konti-Skan 2

Figure 5.43 presents the availability and utilisation of Konti-Skan 2 for 2021 and Table 5.12 presents the numerical values behind it. Konti-Skan 2 is connected between Sweden and Denmark in parallel to Konti-Skan 1 and has been in operation since 1988.

The rated capacity of Konti-Skan 1 and 2 was updated to 715 MW in both directions on 1 February 2020 (357.5 MW per link). The rated capacity was previously asymmetric depending on the flow direction: 740 MW towards east (370+370) and 680 MW towards west (340+340). The reason of the asymmetric rated capacity was due to historical limitations and reserve requirements, along with transmis-

sion measurements only being done in DK1.

In 2021, Konti-Skan 2 had an available technical capacity of 94 % and the technical capacity not used was 42 %. Totally, 0.5 TWh (16 % of the technical capacity) was transmitted west to Denmark (SE3→DK1) and 1.1 TWh (36 % of the technical capacity) was transmitted east to Sweden (DK1→SE3).

Annual maintenance for Konti-Skan 2 lasted 6 days in September. There were five minor disturbances of which the most severe one was a fault in Konti-Skan 2's new 132 kV AC breaker.

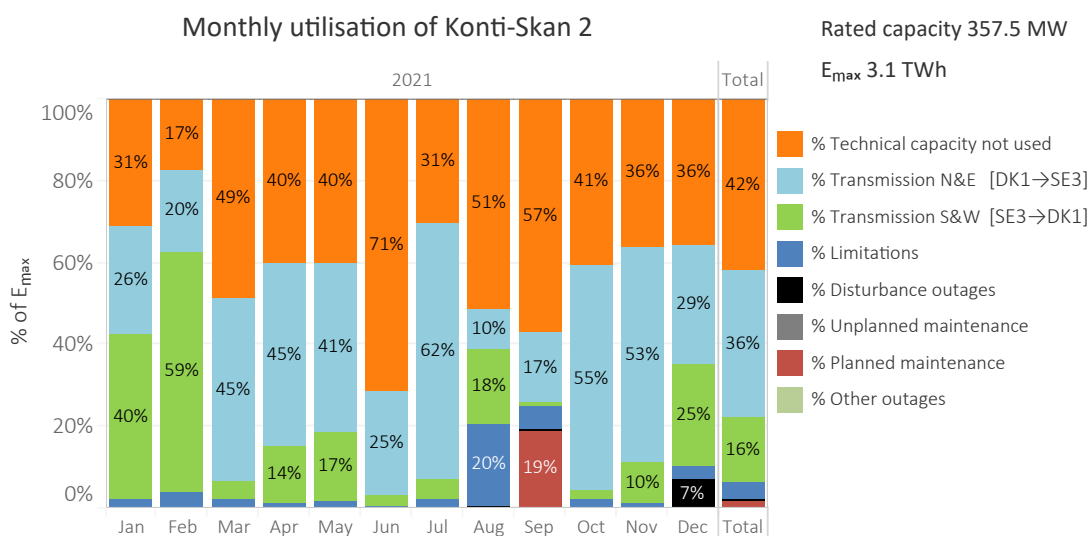


Figure 5.43: Monthly percentage allocation of utilisation by category for Konti-Skan 2 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.12: Monthly allocation of technical capacity (E<sub>max</sub>) for Konti-Skan 2 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

Monthly utilisation of Konti-Skan 2 (South & West direction SE3→DK1)														Total	% total
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total	
Technical capacity not used, GWh	83.5	41.6	129.3	103.9	107.0	183.9	81.4	136.9	147.4	107.8	93.2	95.0	1310.9	41.9%	
Transmission N&E, GWh	69.9	48.5	119.2	115.0	109.5	65.2	166.5	26.2	43.1	146.7	135.6	77.0	1122.3	35.8%	
Transmission S&W, GWh	106.4	140.5	12.1	35.4	45.3	7.6	12.9	47.9	2.7	5.8	25.0	66.5	508.3	16.2%	
Limitations, GWh	6.2	9.5	5.4	3.2	4.2	0.6	5.7	54.0	14.2	5.7	3.6	8.3	120.8	3.9%	
Disturbance outages, GWh	-	-	-	-	-	-	-	0.9	0.6	-	-	19.1	20.7	0.7%	
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Planned maintenance, GWh	-	-	-	-	-	-	-	-	49.3	-	-	-	49.3	1.6%	
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total, GWh	266.0	240.2	266.0	257.4	266.0	257.4	266.5	266.0	257.4	266.0	257.4	266.0	3132.3	100.0%	
Losses SW, GWh	2.7	4.0	0.3	0.9	1.1	0.2	0.3	1.2	0.1	0.1	0.6	1.7	13.3	0.4%	
Losses NE, GWh	1.5	1.4	3.3	2.3	2.2	1.2	3.9	0.5	0.9	2.9	2.8	1.6	24.4	0.8%	

Figure 5.44 presents the annual utilisation of Konti-Skan 2 per utilisation and unavailability category for the years 2012–2021.

Figure 5.45 presents the percentage of hours of a year Konti-Skan 2 has been affected by either a limitation, a dis-

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.46 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

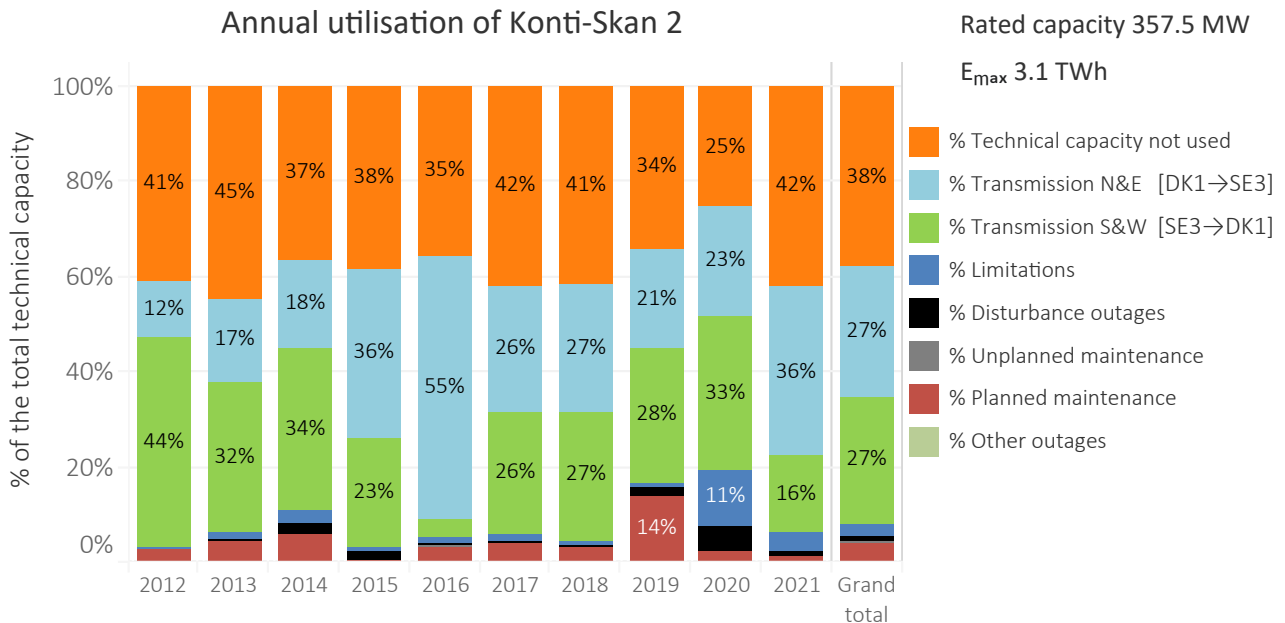


Figure 5.44: Annual utilisation of Konti-Skan 2 per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Konti-Skan 2

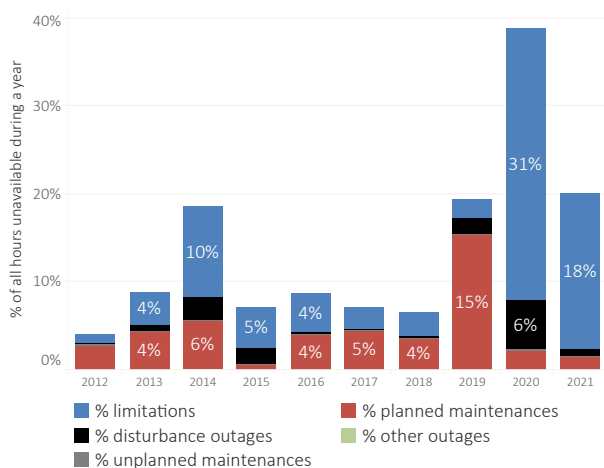


Figure 5.45: Percentage of hours Konti-Skan 2 has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Konti-Skan 2

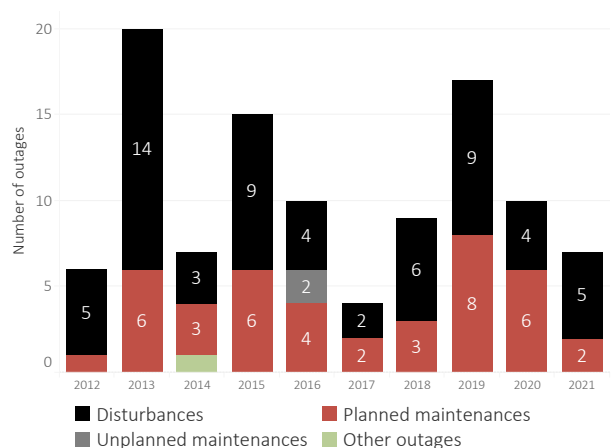


Figure 5.46: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Konti-Skan 2 for the years 2012–2021.

### 5.3.10 LitPol Link

Figure 5.47 presents the availability and utilisation of LitPol Link for 2021 and Table 4.1 presents the numerical values behind it. LitPol Link has been in operation since the end of 2015. In Lithuania, it is connected to Alytus (bidding zone LT) and in Poland to Elk (bidding zone PL). The transmission capacity of LitPol Link is 500 MW.

In 2021, LitPol Link had an available technical capacity of 87 %. The technical capacity not used was 32 %. Totally, 1.7 TWh (39 % of the technical capacity) as transmitted west (LT→PL) and 0.7 TWh (16 % of the technical capacity)

was transmitted east (PL→LT).

The annual maintenance of LitPol Link lasted 25 days in May. The annual maintenance was longer than expected due to unplanned replacement of the bushing of a converter transformer. Additionally, there were 12 maintenance outages of which 8 were caused by external AC grid corrective maintenance. Last, LitPol Link had 5 disturbance outages and 4 other outages (for the tests in AC external grid) with minimal impact in 2021.

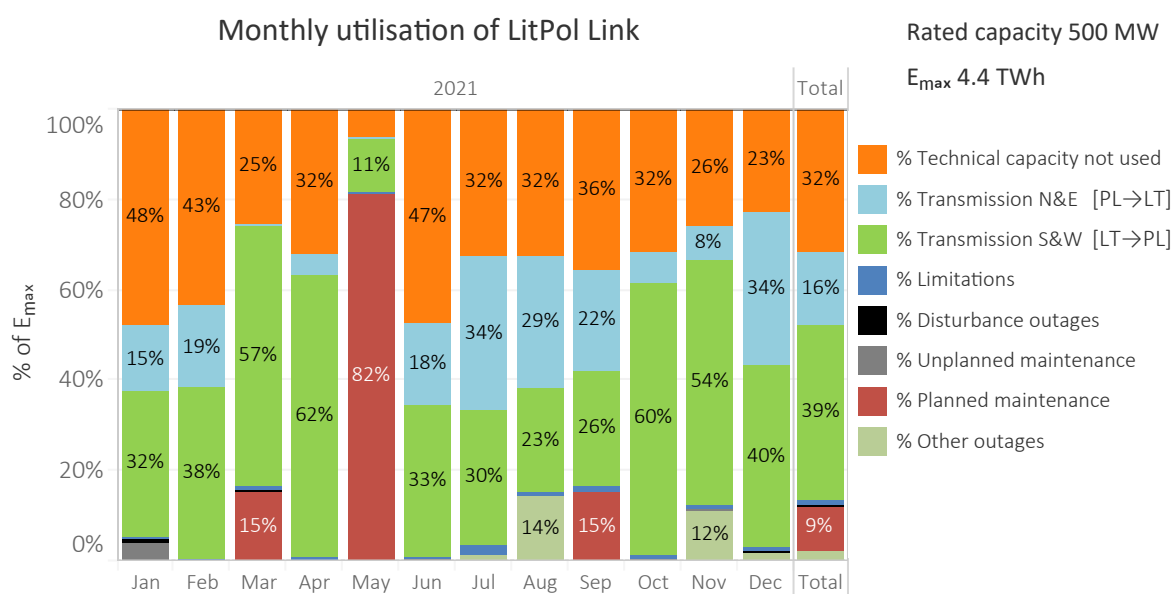


Figure 5.47: Monthly percentage allocation of utilisation by category for LitPol Link in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.13: Monthly allocation of technical capacity (E<sub>max</sub>) for LitPol Link in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	177.6	145.0	94.0	116.2	23.3	170.6	120.7	120.7	129.1	118.6	92.8	85.2	1394.0	31.8%
Transmission N&E, GWh	55.7	62.3	2.4	15.7	2.2	66.0	126.3	108.7	79.2	23.7	27.6	125.6	695.5	15.9%
Transmission S&W, GWh	118.2	126.7	213.6	224.9	42.4	119.9	111.4	86.4	92.0	224.3	194.1	149.6	1703.5	38.9%
Limitations, GWh	1.9	2.1	3.5	3.2	0.5	1.9	8.5	3.5	5.2	3.3	3.1	4.0	40.8	0.9%
Disturbance outages, GWh	3.7	-	1.3	-	-	-	-	-	-	-	-	1.6	6.6	0.1%
Unplanned maintenance, GWh	15.0	-	-	-	-	1.5	-	-	-	2.0	1.0	-	19.5	0.4%
Planned maintenance, GWh	-	-	57.2	-	303.5	-	-	-	54.5	-	-	-	415.1	9.5%
Other outages, GWh	-	-	-	-	-	-	5.0	52.6	-	-	41.4	6.0	105.0	2.4%
Total, GWh	372.0	336.0	372.0	360.0	372.0	360.0	372.0	372.0	360.0	372.0	360.0	372.0	4380.0	100.0%
Losses SW, GWh	1.9	2.0	3.1	3.4	0.6	2.0	1.8	1.4	1.6	3.5	2.8	2.2	26.5	0.6%
Losses NE, GWh	1.0	1.0	0.1	0.3	-	1.2	2.0	1.7	1.3	0.5	0.5	2.0	11.5	0.3%

Figure 5.48 presents the annual utilisation of LitPol Link per utilisation and unavailability category for the years 2016–2021.

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2016–2021. Figure 5.50 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2016–2021.

Figure 5.49 presents the percentage of hours of a year LitPol Link has been affected by either a limitation, a dis-

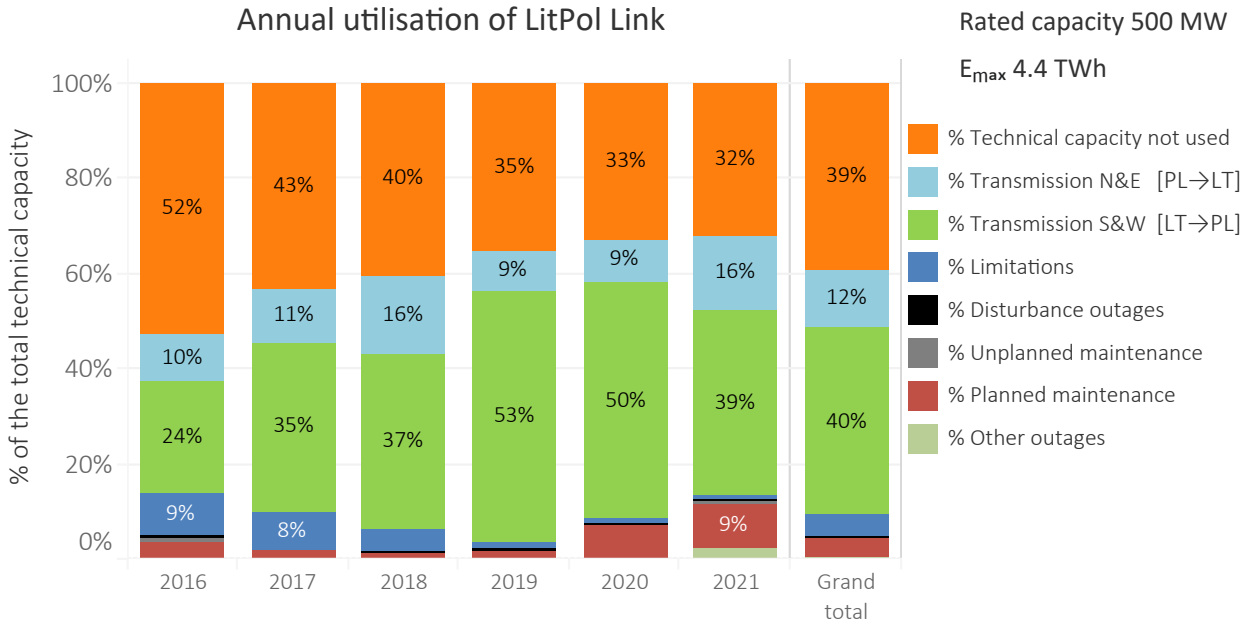


Figure 5.48: Annual utilisation of LitPol Link per the utilisation and unavailability categories for the years 2016–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for LitPol Link

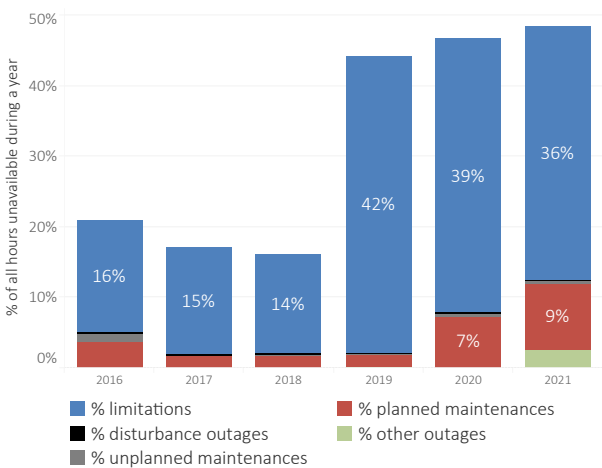


Figure 5.49: Percentage of hours LitPol Link has been affected by either a limitation or an outage annually since 2016. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for LitPol Link

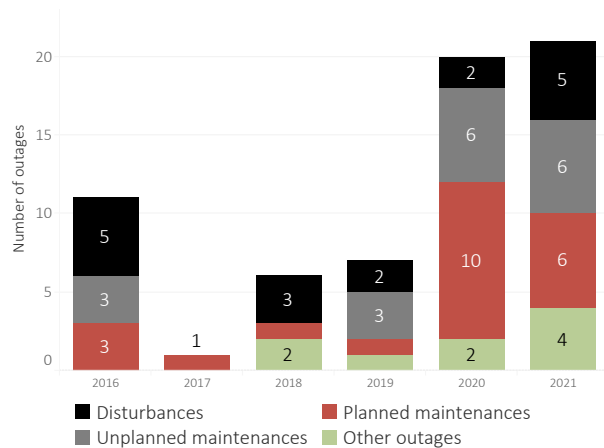


Figure 5.50: The annual number of disturbances, unplanned and planned maintenance outages and other outages for LitPol Link for the years 2016–2021.

### 5.3.11 NordBalt

Figure 5.51 presents the availability and utilisation of NordBalt for 2021 and Table 5.14 presents the numerical values behind it. NordBalt has been in operation since 2016. In Sweden, it is connected to Nybro (bidding zone SE4) and in Lithuania to Klaipeda (bidding zone LT). The transmission capacity of NordBalt is 700 MW at the receiving end.

In 2021, NordBalt had an available technical capacity of 94 %. The technical capacity not used was 34 %. Totally, 3.4 TWh (56 % of the technical capacity) was transmitted

south to Lithuania (SE4→LT) and 0.3 TWh (4 % of the technical capacity) was transmitted north to Sweden (LT→SE4).

The annual maintenance of Nordbalt lasted 7 days in September. Additionally, Nordbalt had 1 short planned outage for corrective maintenance. Nordbalt had one short disturbance in 2021 due to a problem with sensors of the door to the DC valve hall in the converter station in Nybro.

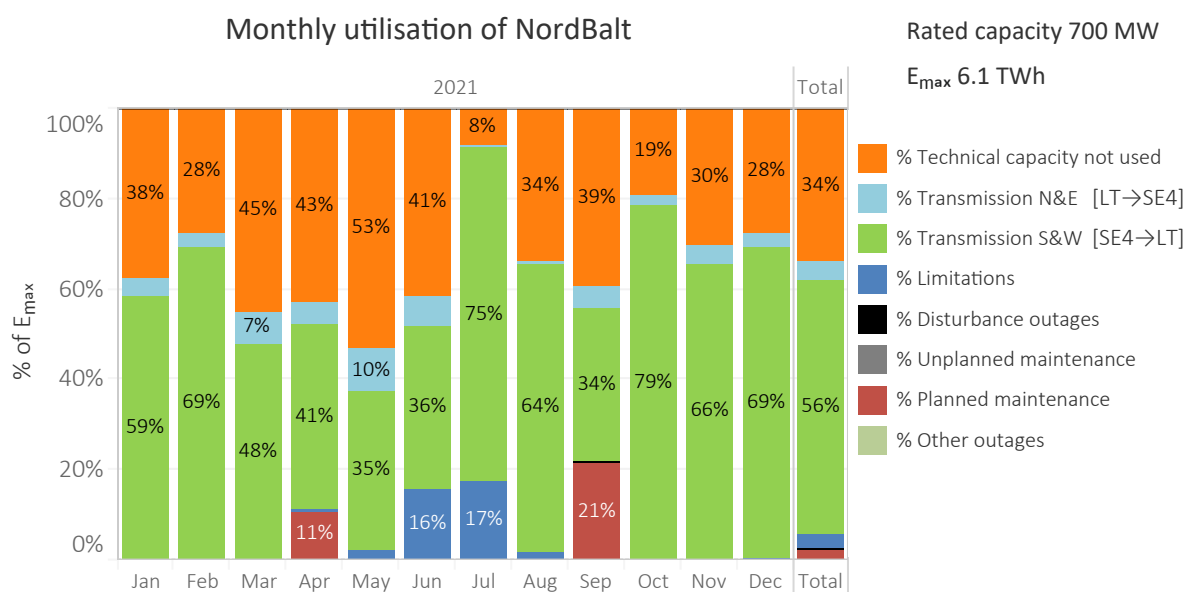


Figure 5.51: Monthly percentage allocation of utilisation by category for NordBalt in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.14: Monthly allocation of technical capacity (E<sub>max</sub>) for NordBalt in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	196.3	131.1	235.7	215.0	275.7	208.9	40.9	176.4	197.3	100.0	152.6	143.7	2073.7	33.8%
Transmission N&E, GWh	19.5	12.8	35.2	25.0	50.6	33.7	0.6	3.2	25.2	10.7	19.8	16.8	253.2	4.1%
Transmission S&W, GWh	305.0	326.5	249.9	207.5	183.0	183.0	389.6	332.5	171.8	410.1	331.6	357.2	3447.6	56.2%
Limitations, GWh	-	-	-	0.1	11.5	78.3	89.7	8.7	-	-	-	3.1	191.5	3.1%
Disturbance outages, GWh	-	-	-	-	-	-	-	-	2.4	-	-	-	2.4	0.0%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	56.4	-	-	-	-	107.3	-	-	-	163.6	2.7%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	520.8	470.4	520.8	504.0	520.8	504.0	520.8	520.8	504.0	520.8	504.0	520.8	6132.0	100.0%
Losses SW, GWh	13.2	14.4	10.6	8.6	7.3	6.6	15.3	14.0	7.0	18.8	14.6	15.8	146.2	2.4%
Losses NE, GWh	0.7	0.4	1.3	0.8	1.8	1.2	-	0.2	0.9	0.3	0.7	0.6	9.0	0.1%



Figure 5.52 presents the annual utilisation of NordBalt per utilisation and unavailability category for the years 2016–2021.

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2016–2021. Figure 5.54 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2016–2021.

Figure 5.53 presents the percentage of hours of a year NordBalt has been affected by either a limitation, a dis-

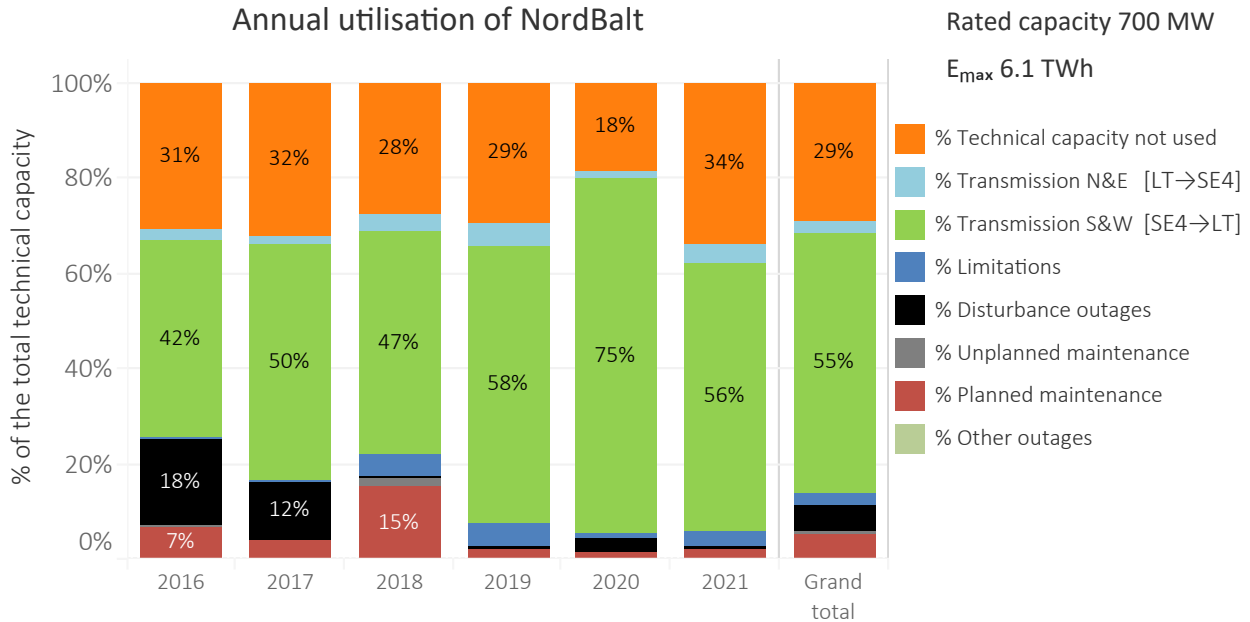


Figure 5.52: Annual utilisation of NordBalt per the utilisation and unavailability categories for the years 2016–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

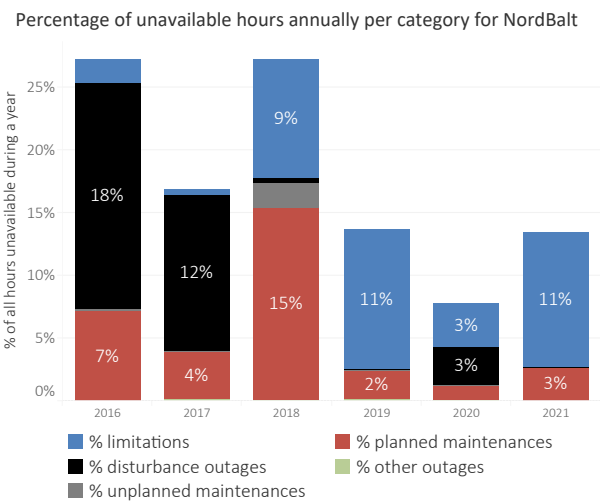


Figure 5.53: Percentage of hours NordBalt has been affected by either a limitation or an outage annually since 2016. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

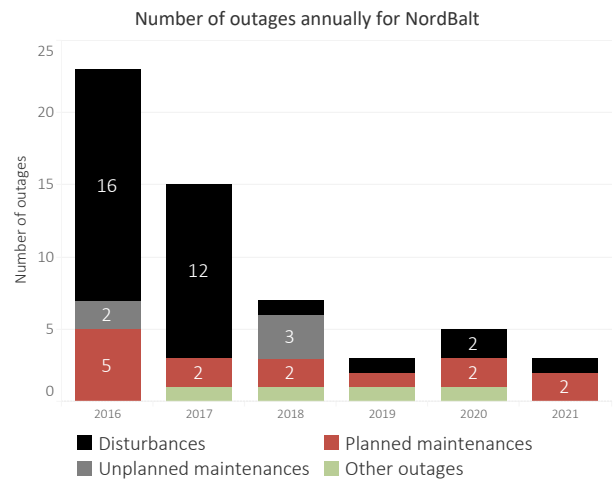


Figure 5.54: The annual number of disturbances, unplanned and planned maintenance outages and other outages for NordBalt for the years 2016–2021.

### 5.3.12 NordLink 1

Figure 5.55 presents the availability and utilisation of NordLink 1 for 2021 and Table 5.15 presents the numerical values behind it. NordLink 1 is the newly commissioned HVDC link located between Tonstad/Ertsmyra in Sirdal municipality in Norway (bidding zone NO2) and Wilster in Schleswig-Holstein in Germany (bidding zone DE). The parallel NordLink 1 and 2 links were commissioned on December 2020 and have each a transmission capacity of 700 MW (1400 MW in total).

In 2021, NordLink 1 had an available technical capacity of 89 %. The technical capacity not used was 46 %. Totally, 2.1 TWh (34 % of the technical capacity) was transmitted south to Germany (NO2→DE) and 0.5 TWh (9 % of the technical capacity) was transmitted north to Norway (DE→NO2).

HVDC links are normally utilised less during the first year due to testing and minor repairs.

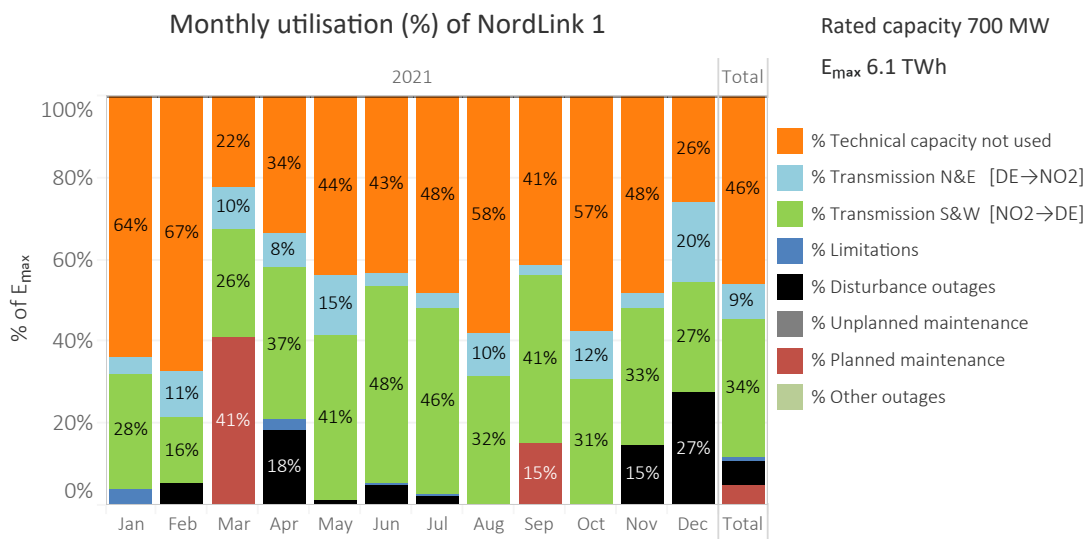


Figure 5.55: Percentage distribution of the availability and utilisation per category according to month for NordLink 1 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.15: Monthly distribution of the technical capacity ( $E_{max}$ ) for NordLink 1 in 2021. Note that losses are not included in the technical capacity ( $E_{max}$ ), as is shown in Figure 3.1.

Monthly utilisation of NordLink 1 (South & West direction NO2→DE)														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	331.7	316.8	115.5	169.4	228.1	218.2	250.5	301.3	208.8	299.0	242.4	134.6	2816.4	45.9%
Transmission N&E, GWh	22.5	53.4	53.3	41.2	75.7	16.0	19.1	54.3	10.7	61.7	19.5	103.4	530.9	8.7%
Transmission S&W, GWh	146.7	75.7	137.4	187.9	211.0	243.9	237.8	165.2	208.3	160.1	168.3	139.7	2082.1	34.0%
Limitations, GWh	19.9	-	-	13.5	-	0.1	0.7	-	-	-	-	-	34.2	0.6%
Disturbance outages, GWh	-	24.5	-	91.6	6.1	25.8	12.7	-	-	-	73.8	143.2	377.5	6.2%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	214.6	0.6	-	-	-	-	76.2	-	-	-	291.4	4.8%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	520.8	470.4	520.9	504.1	520.9	504.0	520.8	520.8	504.0	520.8	504.0	520.9	6132.5	100.0%
Losses SW, GWh	3.9	2.1	3.7	4.9	6.0	6.6	6.2	4.3	6.0	4.4	4.7	3.9	56.8	0.9%
Losses NE, GWh	0.7	1.7	1.7	1.2	2.2	0.5	0.6	1.6	0.3	1.9	0.6	3.3	16.3	0.3%

### 5.3.13 NordLink 2

Figure 5.56 presents the availability and utilisation of NordLink 2 for 2021 and Table 5.16 presents the numerical values behind it. NordLink 2 is the newly commissioned HVDC link located between Tonstad/Ertsmyra in Sirdal municipality in Norway (bidding zone NO2) and Wilster in Schleswig-Holstein in Germany (bidding zone DE). The parallel NordLink 1 and 2 links were commissioned on December 2020 and have each a transmission capacity of 700 MW (1400 MW in total).

In 2021, NordLink 2 had an available technical capacity of 92 %. The technical capacity not used was 46 %. Totally, 2.1 TWh (36 % of the technical capacity) was transmitted south to Germany (NO2→DE) and 0.5 TWh (9 % of the technical capacity) was transmitted north to Norway (DE→NO2).

HVDC links are normally utilised less during the first year due to testing and minor repairs.

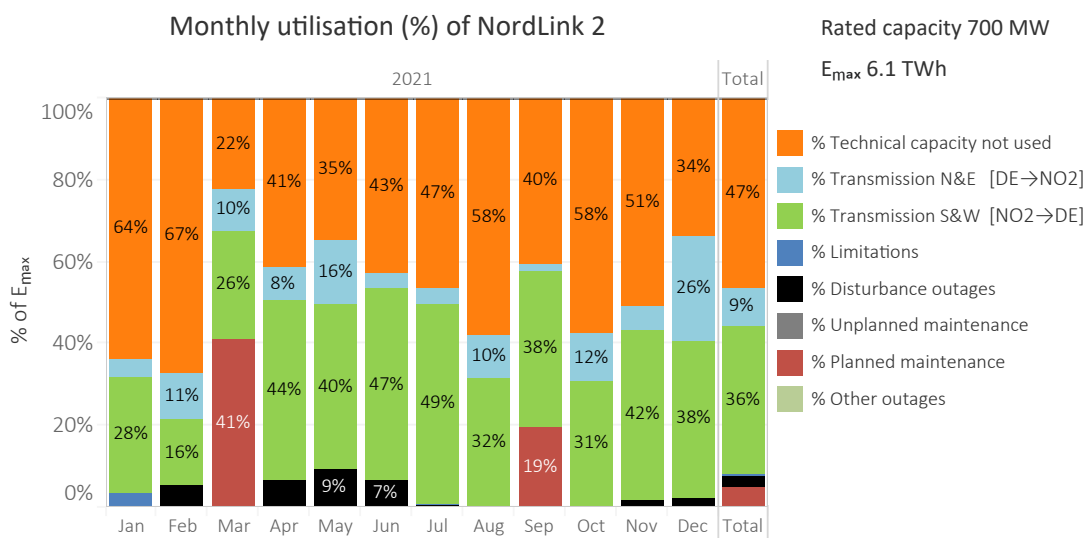


Figure 5.56: Percentage distribution of the availability and utilisation per category according to month for NordLink 2 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.16: Monthly distribution of the technical capacity (E<sub>max</sub>) for NordLink 2 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

Monthly utilisation of NordLink 2 (South & West direction NO2→DE)														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	332.5	317.2	116.1	208.5	181.2	216.9	242.7	302.1	203.6	299.6	257.3	176.8	2854.5	46.6%
Transmission N&E, GWh	22.4	53.3	52.7	40.4	80.8	16.0	19.1	54.1	10.7	61.6	28.8	133.1	573.0	9.3%
Transmission S&W, GWh	146.3	75.4	137.4	220.8	210.1	237.4	254.1	164.6	191.4	159.6	209.6	198.6	2205.2	36.0%
Limitations, GWh	19.6	-	-	-	-	-	2.3	-	-	-	-	-	21.9	0.4%
Disturbance outages, GWh	-	24.5	-	33.8	48.6	33.7	2.7	-	-	-	8.3	12.3	164.0	2.7%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	214.7	0.6	-	-	-	-	98.2	-	-	-	313.4	5.1%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	520.8	470.4	520.8	504.0	520.8	504.0	520.8	520.8	504.0	520.8	504.0	520.8	6132.1	100.0%
Losses SW, GWh	4.0	2.1	3.8	6.8	5.9	6.3	6.6	4.3	5.3	4.4	6.8	6.5	62.9	1.0%
Losses NE, GWh	0.7	1.7	1.6	1.2	2.5	0.5	0.6	1.7	0.3	1.8	1.1	4.7	18.4	0.3%

### 5.3.14 NorNed

Figure 5.57 presents the availability and utilisation of NorNed for 2021 and Table 5.17 presents the numerical values behind it. NorNed has been in operation since 2008, and is, with a length of 580 km, the longest HVDC link connected to the Nordic power system. In Norway on the south-western coast (bidding zone NO2) it is connected to Feda substation and in Netherlands to Eemshaven (bidding zone APX NL). The transmission capacity of NorNed is 700 MW.

In 2021, NorNed had an available technical capacity of

73 %. The technical capacity not used was 10 %. Totally, 3.5 TWh (57 % of the technical capacity) was transmitted south to Netherlands (NO2→DE) and 0.3 TWh (6 % of the technical capacity) was transmitted north to Norway (DE→NO2).

NorNed had a major cable fault on the Dutch side in mid-January until March. There was also longer annual maintenance in August/September. In December a broken neutral-point isolator in Feda caused a disturbance outage.

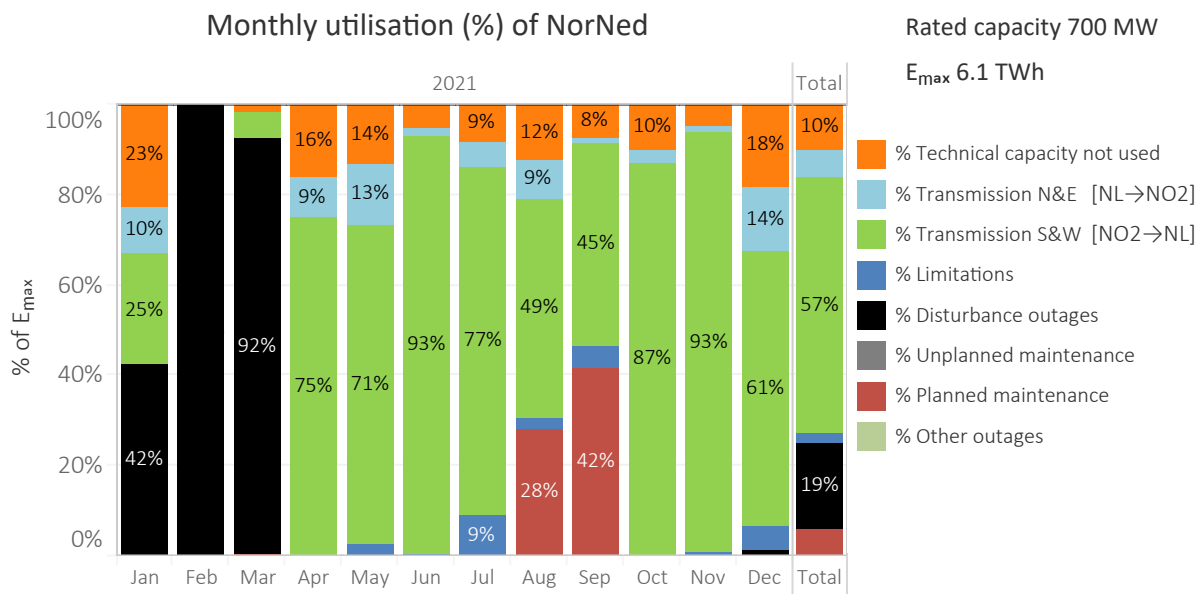


Figure 5.57: Monthly percentage allocation of utilisation by category for NorNed in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.17: Monthly allocation of technical capacity (E<sub>max</sub>) for NorNed in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

Monthly utilisation of NorNed (South & West direction NO2→NL)														Total	% total
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total	
Technical capacity not used, GWh	117.6	-	9.2	81.1	70.8	26.3	45.1	64.3	38.2	52.6	25.6	95.5	626.4	10.2%	
Transmission N&E, GWh	53.6	-	-	45.0	68.4	9.1	27.1	44.6	4.9	15.9	6.0	75.1	349.7	5.7%	
Transmission S&W, GWh	129.4	-	30.4	379.4	369.3	467.4	401.8	254.2	227.8	453.8	470.2	315.5	3499.1	57.0%	
Limitations, GWh	-	-	-	-	13.3	2.3	47.1	11.7	23.1	-	3.7	29.2	130.5	2.1%	
Disturbance outages, GWh	220.5	470.4	478.1	-	-	-	-	-	-	0.6	-	5.9	1175.5	19.1%	
Unplanned maintenance., GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Planned maintenance, GWh	-	-	3.2	-	-	-	-	146.3	210.6	-	-	-	360.1	5.9%	
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total, GWh	521.1	470.4	520.9	505.5	521.8	505.1	521.0	521.1	504.7	523.0	505.6	521.2	6141.4	100.0%	
Losses SW, GWh	4.4	-	1.2	14.5	14.2	18.2	14.0	9.5	8.2	17.7	18.4	11.2	131.3	2.1%	
Losses NE, GWh	2.0	-	-	1.7	2.5	0.4	1.0	1.7	0.2	0.6	0.2	2.9	13.3	0.2%	

Figure 5.58 presents the annual utilisation of NorNed per utilisation and unavailability category for the years 2012–2021.

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.60 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

Figure 5.59 presents the percentage of hours of a year NorNed has been affected by either a limitation, a dis-

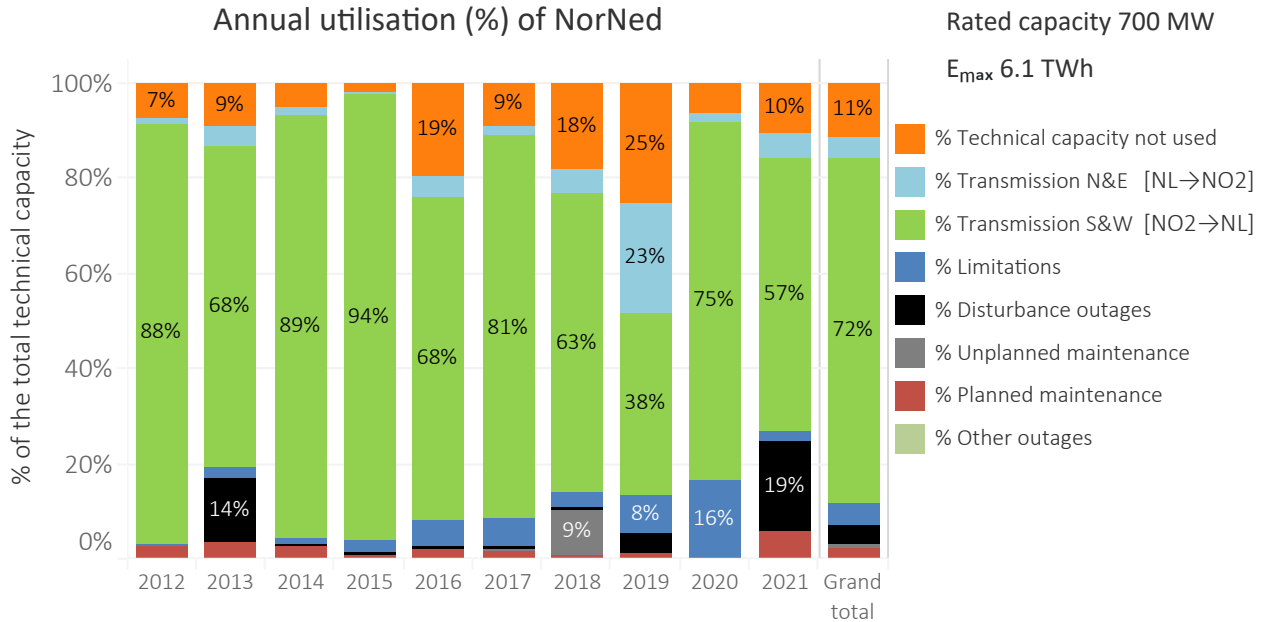


Figure 5.58: Annual utilisation of NorNed per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

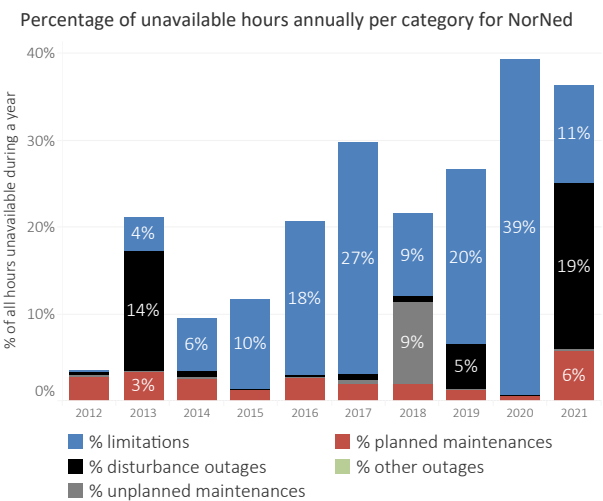


Figure 5.59: Percentage of hours NorNed has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

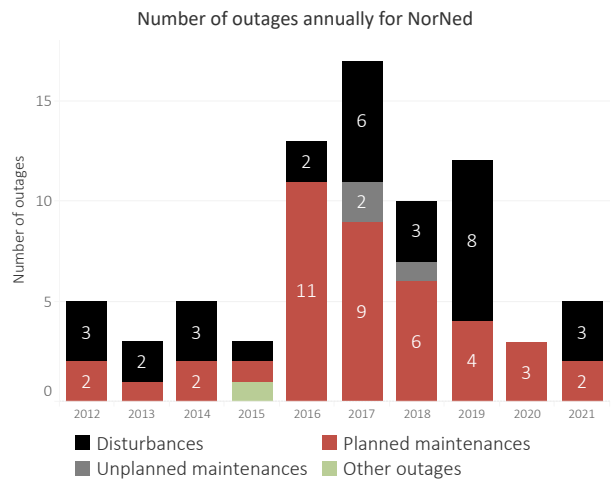


Figure 5.60: The annual number of disturbances, unplanned and planned maintenance outages and other outages for NorNed for the years 2012–2021.

### 5.3.15 Skagerrak 1

Figure 5.61 presents the availability and utilisation of Skagerrak 1 for 2021 and Table 5.18 presents the numerical values behind it. Skagerrak 1 and Skagerrak 2 have been in operation since 1976 and are the oldest HVDC links in operation in the Nordic countries. In Norway, the links are connected to Kristiansand on the southern coast (bidding zone NO2) and in Denmark to Tjele (bidding zone DK1), 15 km east of the town of Viborg in the northern part of Jutland. The transmission capacity is 236 MW at the receiving end.

In 2021, Skagerrak 1 had an available technical capacity of 94 %. The technical capacity not used was 39 %. Totally, 0.8 TWh (41 % of the technical capacity) was transmitted south to Denmark (NO2→DK1) and 0.3 TWh (14 %

of the technical capacity) was transmitted north to Norway (DK1→NO2).

Annual maintenance for Skagerrak 1 lasted 5 days. There were two minor disturbance outages.

Skagerrak 1, 2, 3 and 4 have been limited due to “careful operation” since the Skagerrak 4 cable faults in December 2019. In 2021, the south direction continued to be prioritised. The careful operation of the Skagerrak links has impacted each of the links differently based on the transmission direction and which links are in operation. For example, if all links are available and the transmission goes from Denmark to Norway (i.e., north), Skagerrak 2 is limited to 0 MW and Skagerrak 3 is limited to 200 MW to maintain acceptable electrode current levels.

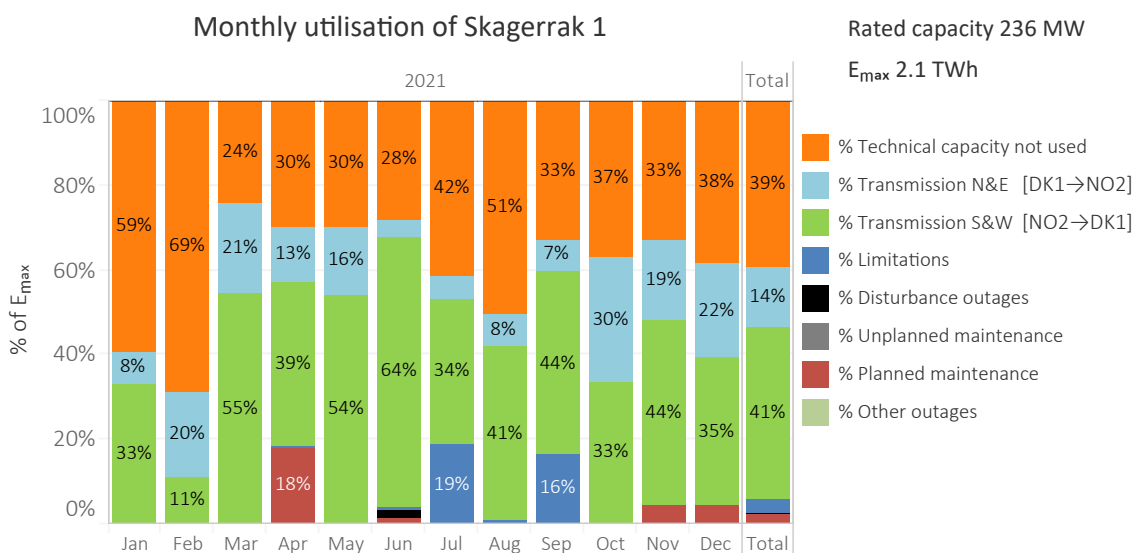


Figure 5.61: Monthly percentage allocation of utilisation by category for Skagerrak 1 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.18: Monthly allocation of technical capacity (E<sub>max</sub>) for Skagerrak 1 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	104.3	109.1	42.0	50.9	52.8	48.0	73.0	88.8	56.3	64.8	55.9	67.4	813.3	39.3%
Transmission N&E, GWh	13.2	31.9	37.7	21.8	27.8	6.7	9.5	13.4	11.6	52.2	32.2	39.1	297.2	14.4%
Transmission S&W, GWh	58.1	17.5	96.0	66.0	95.0	108.4	60.0	72.0	74.0	58.7	74.1	61.1	840.9	40.7%
Limitations, GWh	-	-	-	0.2	-	2.0	33.1	1.3	28.0	-	-	-	64.6	3.1%
Disturbance outages, GWh	-	0.1	-	-	-	2.7	-	-	-	-	-	-	2.8	0.1%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	31.1	-	2.3	-	-	-	-	7.8	7.9	49.2	2.4%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	175.6	158.6	175.6	170.0	175.6	170.0	175.6	175.6	170.0	175.8	170.0	175.6	2067.9	100.0%
Losses SW, GWh	2.8	0.9	4.8	3.4	5.0	5.3	2.5	3.5	3.2	2.9	3.4	2.8	40.4	2.0%
Losses NE, GWh	0.5	1.2	1.6	0.9	1.2	0.3	0.4	0.6	0.5	2.3	1.4	1.6	12.5	0.6%

Figure 5.62 presents the annual utilisation of Skagerrak 1 per utilisation and unavailability category for the years 2012–2021.

Figure 5.63 presents the percentage of hours of a year Skagerrak 1 has been affected by either a limitation, a dis-

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.64 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

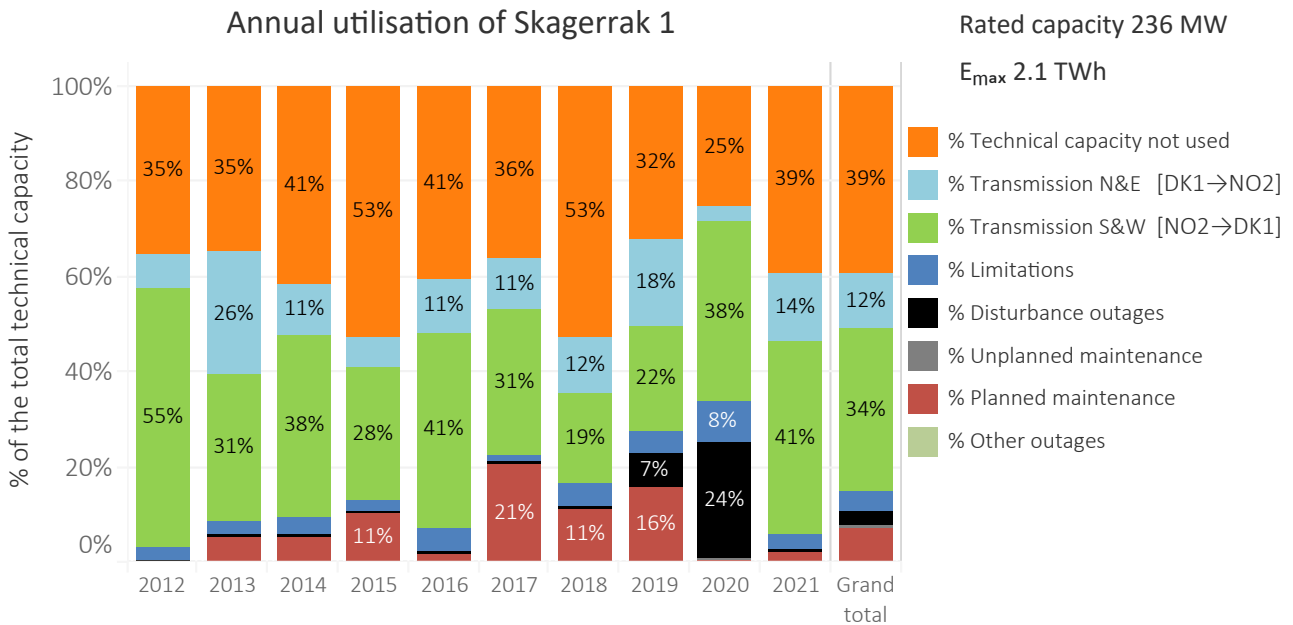


Figure 5.62: Annual utilisation of Skagerrak 1 per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Skagerrak 1

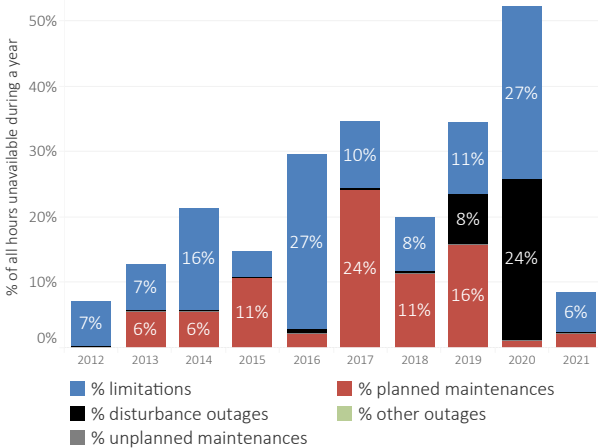


Figure 5.63: Percentage of hours Skagerrak 1 has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Skagerrak 1

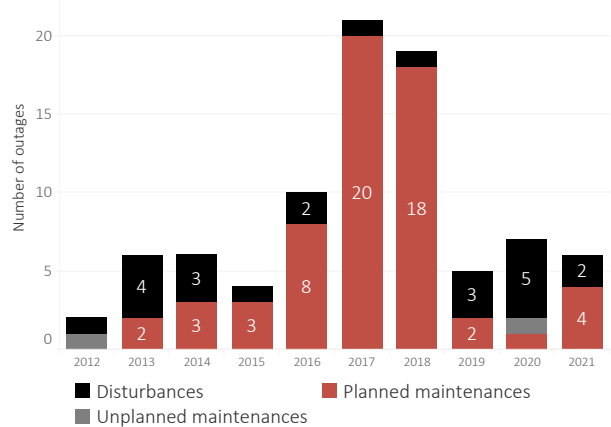


Figure 5.64: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Skagerrak 1 for the years 2012–2021. Skagerrak 1 had no other outages during the years 2012–2021.

### 5.3.16 Skagerrak 2

Figure 5.65 presents the availability and utilisation of Skagerrak 2 for 2021 and Table 5.19 presents the numerical values behind it. Skagerrak 1 and Skagerrak 2 have been in operation since 1976 and are the oldest HVDC links in operation in the Nordic countries. In Norway, the links are connected to Kristiansand on the southern coast (bidding zone NO2) and in Denmark to Tjele (bidding zone DK1), 15 km east of the town of Viborg in the northern part of Jutland. The transmission capacity of Skagerrak 2 is 236 MW at the receiving end.

In 2021, Skagerrak 2 had an available technical capacity of 75 %. The technical capacity not used was 33 %. Totally, 0.8 TWh (40 % of the technical capacity) was transmitted south to Denmark (NO2→DK1) and <0.1 TWh (1 %

of the technical capacity) was transmitted north to Norway (DK1→NO2).

Annual maintenance for Skagerrak 2 lasted 5 days in April. There were three minor disturbance outages.

Skagerrak 1, 2, 3 and 4 have been limited due to “careful operation” since the Skagerrak 4 cable faults in December 2019. In 2021, the south direction continued to be prioritised. The careful operation of the Skagerrak links has impacted each of the links differently based on the transmission direction and which links are in operation. For example, if all links are available and the transmission goes from Denmark to Norway (i.e., north) Skagerrak 2 is limited to 0 MW and Skagerrak 3 is limited to 200 MW to maintain acceptable electrode current levels.

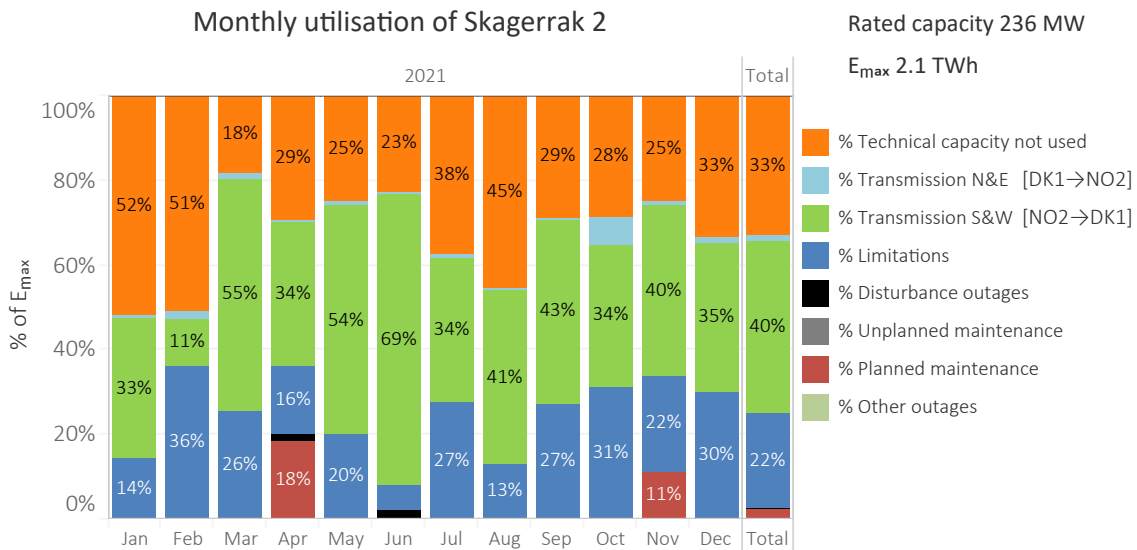


Figure 5.65: Monthly percentage allocation of utilisation by category for Skagerrak 2 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.19: Monthly allocation of technical capacity (E<sub>max</sub>) for Skagerrak 2 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	91.2	80.9	32.4	49.7	43.5	38.6	66.2	79.8	49.3	49.9	42.4	58.6	682.6	33.0%
Transmission N&E, GWh	1.1	2.6	2.3	1.3	1.7	0.5	1.2	1.0	0.8	11.7	1.9	2.6	28.7	1.4%
Transmission S&W, GWh	58.2	17.5	95.9	57.4	95.3	117.5	59.9	72.0	73.8	58.9	68.2	61.5	836.2	40.4%
Limitations, GWh	25.1	57.6	44.9	27.5	35.1	9.9	48.2	22.8	46.0	55.1	38.2	52.9	463.3	22.4%
Disturbance outages, GWh	-	-	-	3.3	-	3.5	-	-	-	-	-	-	6.8	0.3%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	30.8	-	-	-	-	-	-	19.2	-	50.1	2.4%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	175.6	158.6	175.6	170.0	175.6	170.0	175.6	175.6	169.9	175.6	169.9	175.6	2067.6	100.0%
Losses SW, GWh	2.8	0.9	4.7	2.9	4.7	6.0	2.7	3.7	3.5	2.9	3.4	3.1	41.2	2.0%
Losses NE, GWh	0.1	0.2	0.2	0.1	0.2	-0.1	0.1	0.1	0.1	0.7	0.2	0.2	2.2	0.1%



Figure 5.66 presents the annual utilisation of Skagerrak 2 per utilisation and unavailability category for the years 2012–2021.

Figure 5.67 presents the percentage of hours of a year Skagerrak 2 has been affected by either a limitation, a dis-

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.68 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

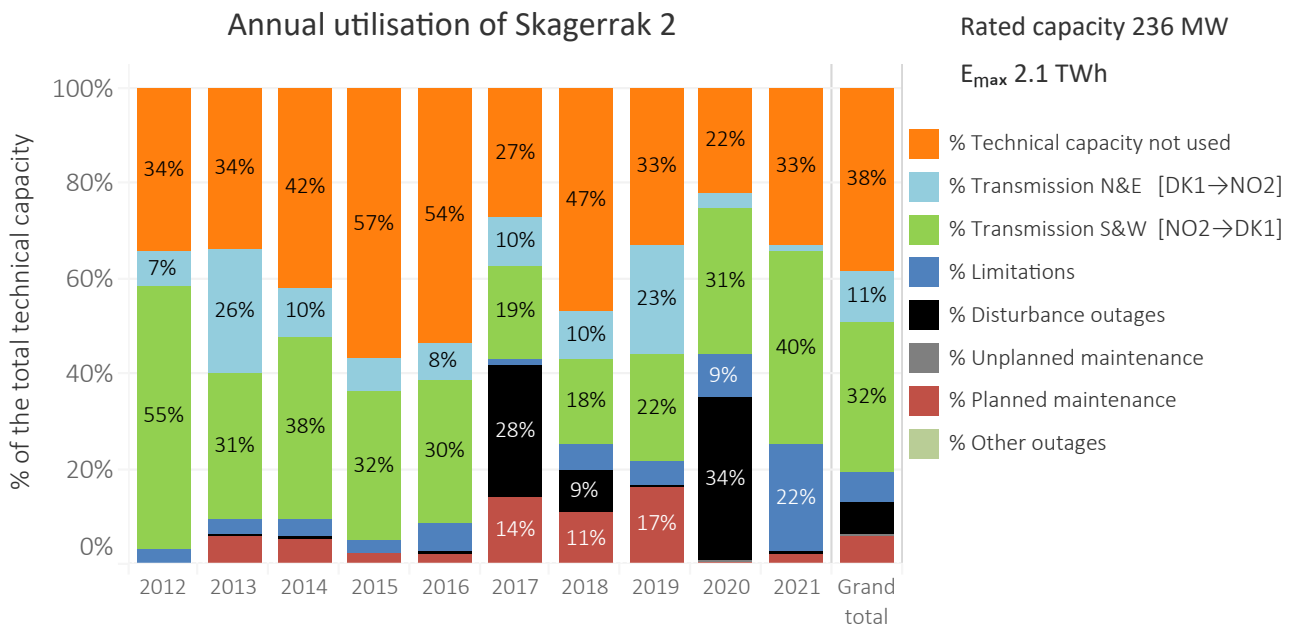


Figure 5.66: Annual utilisation of Skagerrak 2 per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Skagerrak 2

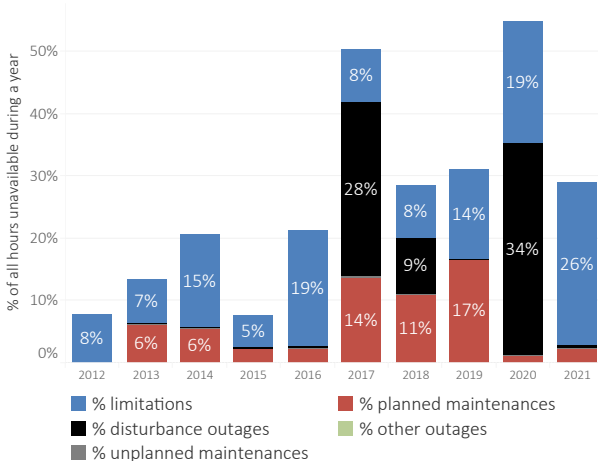


Figure 5.67: Percentage of hours Skagerrak 2 has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Skagerrak 2

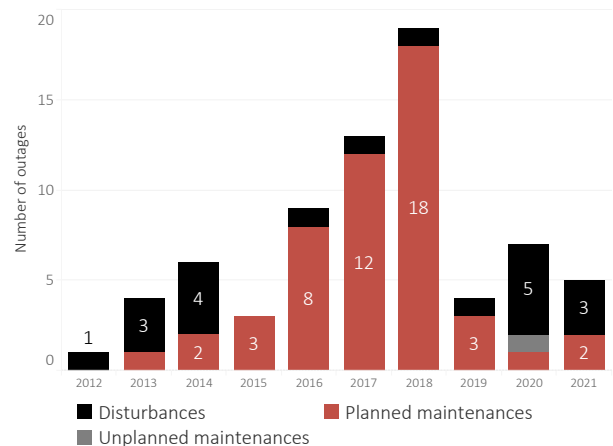


Figure 5.68: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Skagerrak 2 for the years 2012–2021. Skagerrak 2 had no other outages during the years 2012–2021.

### 5.3.17 Skagerrak 3

Figure 5.69 presents the availability and utilisation of Skagerrak 3 for 2021 and Table 5.20 presents the numerical values behind it. Skagerrak 3 has been in operation since 1993. In Norway, it is connected to Kristiansand (bidding zone NO2) and in Denmark to Tjele (bidding zone DK1). The transmission capacity of Skagerrak 3 is 478 MW at the receiving end.

In 2021, Skagerrak 3 had an available technical capacity of 89 %. The technical capacity not used was 19 %. Totally, 2.6 TWh (61 % of the technical capacity) was transmitted south to Denmark (NO2→DK1) and 0.4 TWh (9 % of the technical capacity) was transmitted north to Norway (DK1→NO2).

Annual maintenance for Skagerrak 3 lasted 4 days. There were no disturbance outages, and only one other planned maintenance were Skagerrak 3 had to be disconnected due to repair of a fault on a voltage transformer.

Skagerrak 1, 2, 3 and 4 have been limited due to “careful operation” since the Skagerrak 4 cable faults in December 2019. In 2021, the south direction continued to be prioritised. The careful operation of the Skagerrak links has impacted each of the links differently based on the transmission direction and which links are in operation. For example, if all links are available and the transmission goes from Denmark to Norway (i.e., north), Skagerrak 2 is limited to 0 MW and Skagerrak 3 is limited to 200 MW to maintain acceptable electrode current levels.

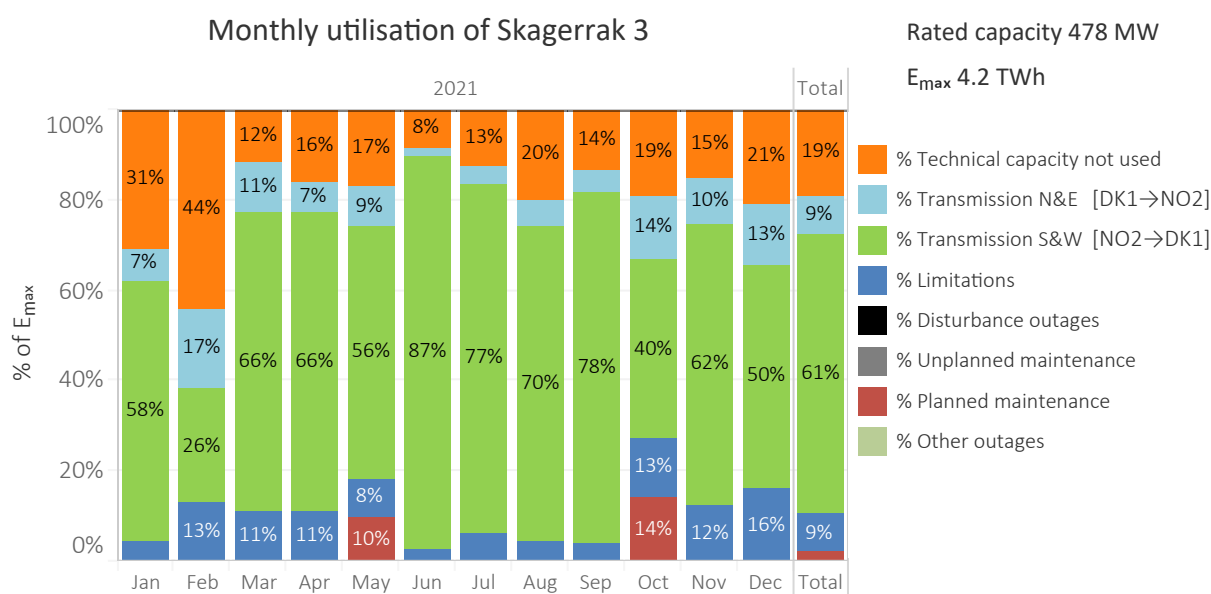


Figure 5.69: Monthly percentage allocation of utilisation by category for Skagerrak 3 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.20: Monthly allocation of technical capacity (E<sub>max</sub>) for Skagerrak 3 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	110.6	142.6	41.3	55.9	60.0	28.6	45.4	71.9	46.9	68.5	52.9	75.5	800.0	19.0%
Transmission N&E, GWh	24.2	55.1	39.5	23.0	32.0	7.0	14.1	20.7	15.7	48.6	35.9	47.3	363.0	8.6%
Transmission S&W, GWh	205.8	82.9	235.9	228.4	199.8	300.4	275.4	248.1	268.4	142.3	214.4	176.4	2578.2	61.4%
Limitations, GWh	16.3	41.1	40.6	38.2	29.3	9.8	22.3	15.8	13.7	46.3	42.6	56.8	372.6	8.9%
Disturbance outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unplanned maintenance., GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	-	35.8	-	-	-	-	50.3	-	-	86.1	2.1%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	356.9	321.6	357.3	345.5	356.9	345.7	357.1	356.6	344.7	355.9	345.7	356.0	4199.8	100.0%
Losses SW, GWh	5.0	1.9	6.0	5.6	5.1	8.0	7.1	6.4	7.0	3.7	5.4	4.4	65.6	1.6%
Losses NE, GWh	0.6	1.4	1.0	0.6	0.8	0.2	0.4	0.6	0.4	1.3	0.9	1.2	9.5	0.2%

Figure 5.70 presents the annual utilisation of Skagerrak 3 per utilisation and unavailability category for the years 2012–2021.

Figure 5.71 presents the percentage of hours of a year Skagerrak 3 has been affected by either a limitation, a disturbance outage, an unplanned or planned maintenance

outage or other outage annually during the years 2012–2021. Figure 5.72 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

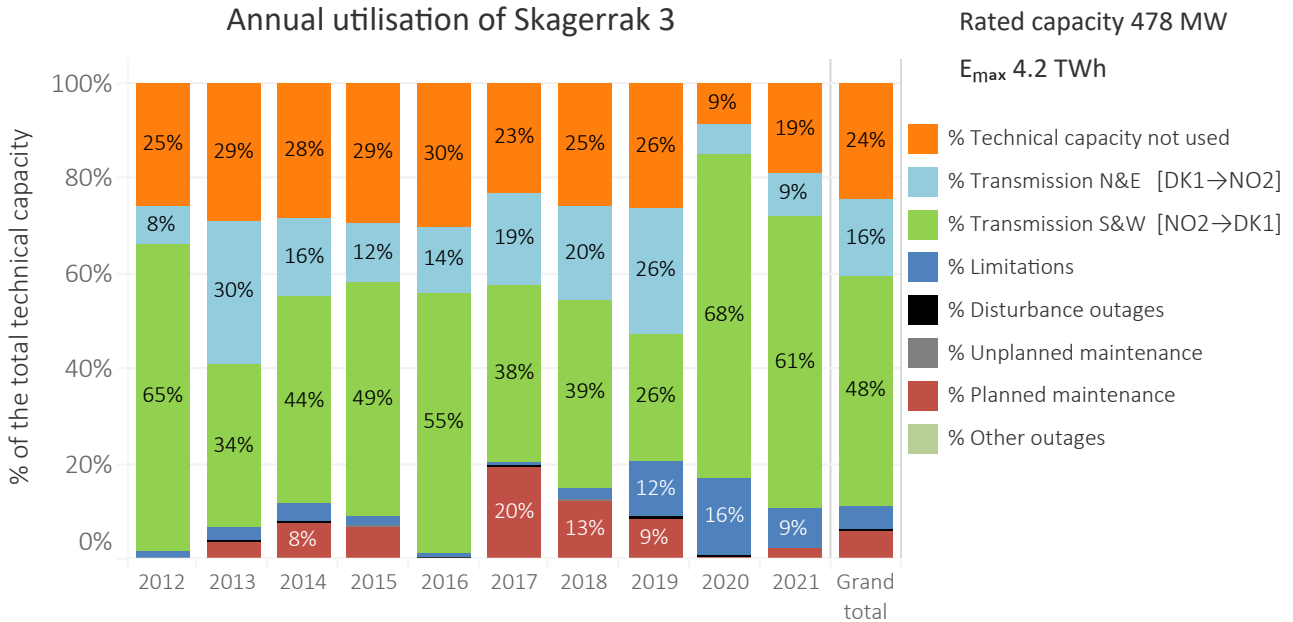


Figure 5.70: Annual utilisation of Skagerrak 3 per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Skagerrak 3

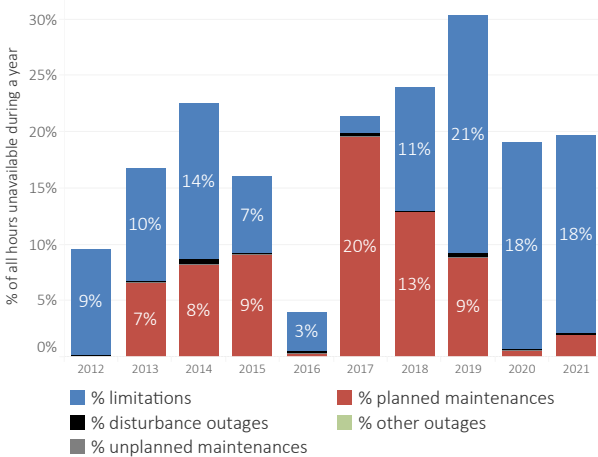


Figure 5.71: Percentage of hours Skagerrak 3 has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Skagerrak 3

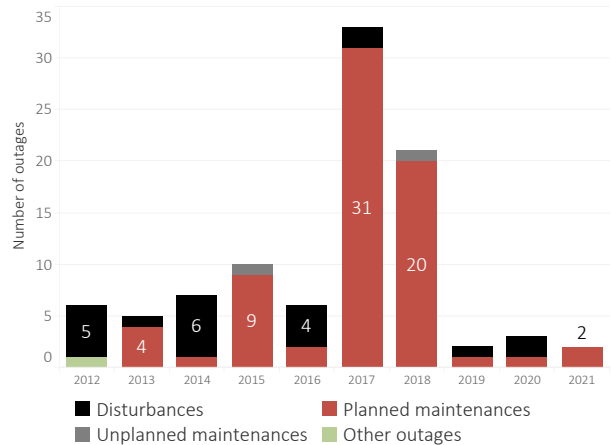


Figure 5.72: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Skagerrak 3 for the years 2012–2021.

### 5.3.18 Skagerrak 4

Figure 5.73 presents the availability and utilisation of Skagerrak 4 for 2021 and Table 5.21 presents the numerical values behind it. Skagerrak 4 has been in commercial operation since 29 December 2014. In Norway, it is connected to Kristiansand (bidding zone NO2) and in Denmark to Tjele (bidding zone DK1). The transmission capacity is 682 MW at the receiving end.

In 2021, Skagerrak 4 had an available technical capacity of 97 %. The technical capacity not used was 27 %. Totally, 2.6 TWh (61 % of the technical capacity) was transmitted south to Denmark (NO2→DK1) and 0.4 TWh (9 % of the technical capacity) was transmitted north to Norway (DK1→NO2).

There were no annual maintenance for Skagerrak 4 in 2021. There were one minor planned maintenance outage and two minor disturbance outages.

Skagerrak 1, 2, 3 and 4 have been limited due to “careful operation” since the Skagerrak 4 cable faults in December 2019. In 2021, the south direction continued to be prioritised. The careful operation of the Skagerrak links has impacted each of the links differently based on the transmission direction and which links are in operation. For example, if all links are available and the transmission goes from Denmark to Norway (i.e., north), Skagerrak 2 is limited to 0 MW and Skagerrak 3 is limited to 200 MW to maintain acceptable electrode current levels.

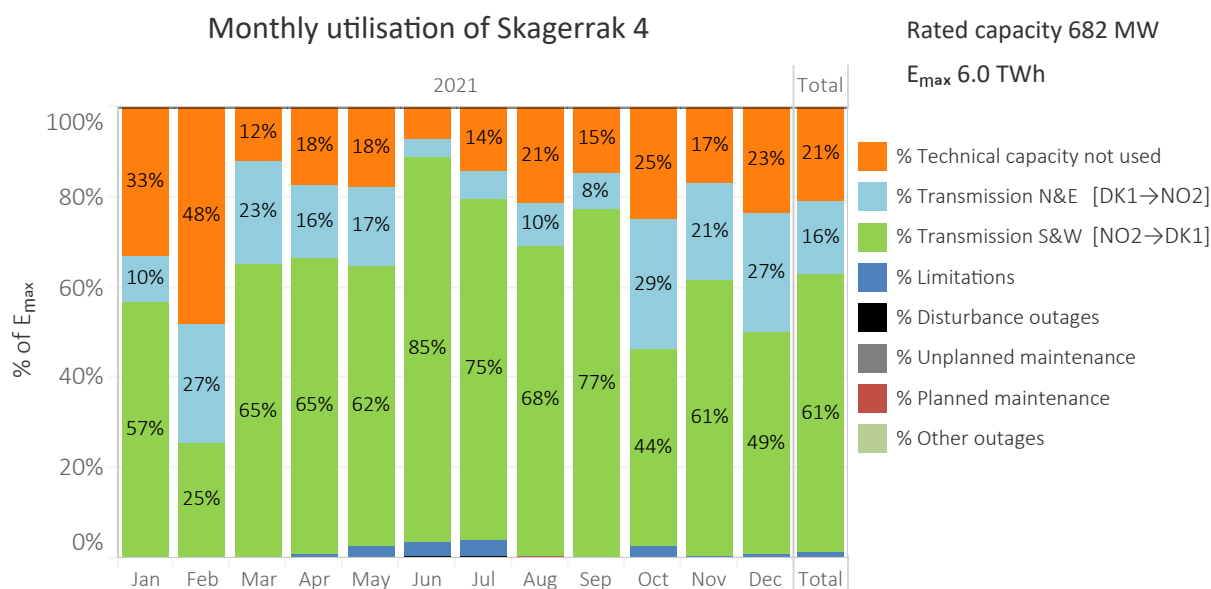


Figure 5.73: Monthly percentage allocation of utilisation by category for Skagerrak 4 in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.21: Monthly allocation of technical capacity (E<sub>max</sub>) for Skagerrak 4 in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	167.3	220.2	62.1	86.4	91.1	34.4	72.4	109.0	73.2	125.8	83.5	119.2	1244.6	20.8%
Transmission N&E, GWh	53.0	122.0	114.4	78.4	86.9	20.1	32.1	48.3	39.0	145.2	104.6	134.7	978.8	16.4%
Transmission S&W, GWh	287.1	116.1	331.0	320.8	315.0	418.6	382.2	346.9	378.8	222.9	300.9	249.1	3669.2	61.4%
Limitations, GWh	-	-	-	5.4	14.4	15.0	18.7	-	-	13.5	2.4	4.4	73.9	1.2%
Disturbance outages, GWh	-	-	-	-	-	3.0	1.9	-	-	-	-	-	4.9	0.1%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	-	-	-	-	3.4	-	-	-	-	3.4	0.1%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	507.4	458.3	507.4	491.0	507.4	491.0	507.4	507.5	491.0	507.4	491.4	507.4	5974.8	100.0%
Losses SW, GWh	5.6	2.3	6.7	6.5	6.5	8.4	7.6	7.2	7.8	4.7	6.1	5.0	74.4	1.2%
Losses NE, GWh	1.5	3.3	3.2	2.2	2.5	0.6	0.9	1.4	1.1	4.1	2.9	3.7	27.4	0.5%

Figure 5.74 presents the annual utilisation of Skagerrak 4 per utilisation and unavailability category for the years 2015–2021.

Figure 5.75 presents the percentage of hours of a year Skagerrak 4 has been affected by either a limitation, a dis-

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2015–2021. Figure 5.76 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2015–2021.

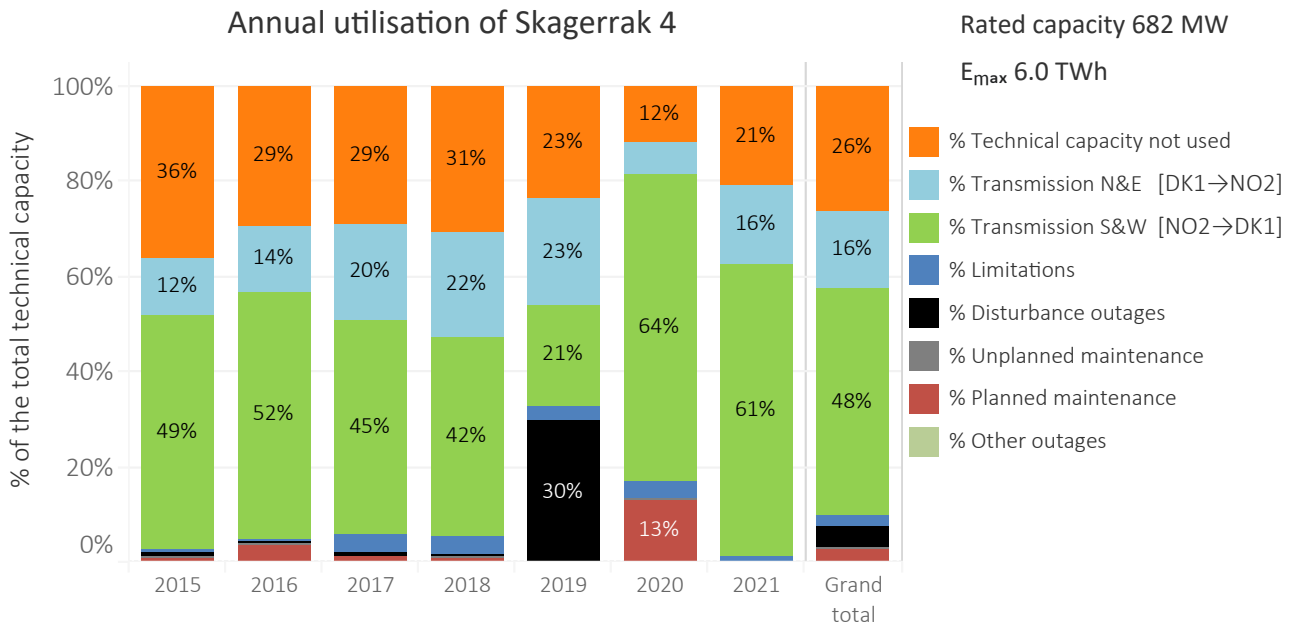


Figure 5.74: Annual utilisation of Skagerrak 4 per the utilisation and unavailability categories for the years 2015–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Skagerrak 4

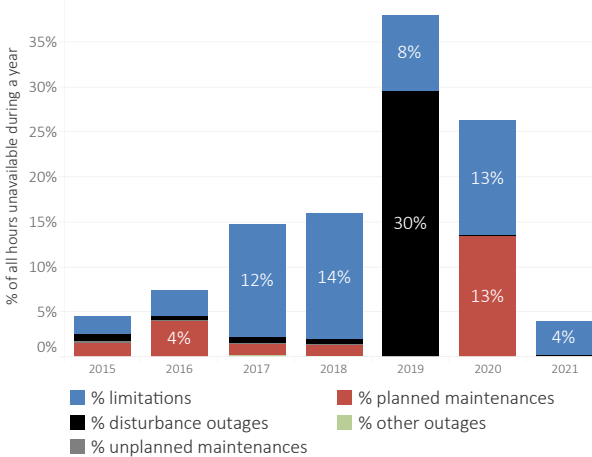


Figure 5.75: Percentage of hours Skagerrak 4 has been affected by either a limitation or an outage annually since 2015. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Skagerrak 4

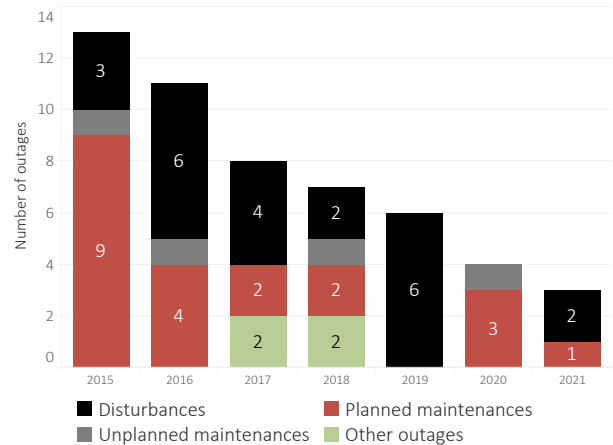


Figure 5.76: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Skagerrak 4 for the years 2015–2021.

### 5.3.19 Storebaelt

Figure 5.77 presents the availability and utilisation of Storebaelt for 2021 and Table 5.22 presents the numerical values behind it. Storebaelt has been in operation since 2010. It connects the western part of the Danish system, which belongs to the Continental European synchronous system (Jutland and the island of Fynen), with the eastern part, belonging to the Nordic synchronous system (Zealand). The link is connected to Fraugde on Fynen (bidding zone DK1) and to Herslev on Zealand (bidding zone DK2). The transmission capacity is 600 MW.

In 2021, Storebaelt had an available technical capacity of 99 %. The technical capacity not used was 41 %. Totally, 2.4 TWh (46 % of the technical capacity) was transmitted east to Zealand (DK1→DK2) and 0.6 TWh (12d % of the technical capacity) was transmitted west to Jutland (DK2→DK1).

Annual maintenance for Storebaelt lasted 4 days. There were two minor planned maintenance outages and two minor disturbance outages.

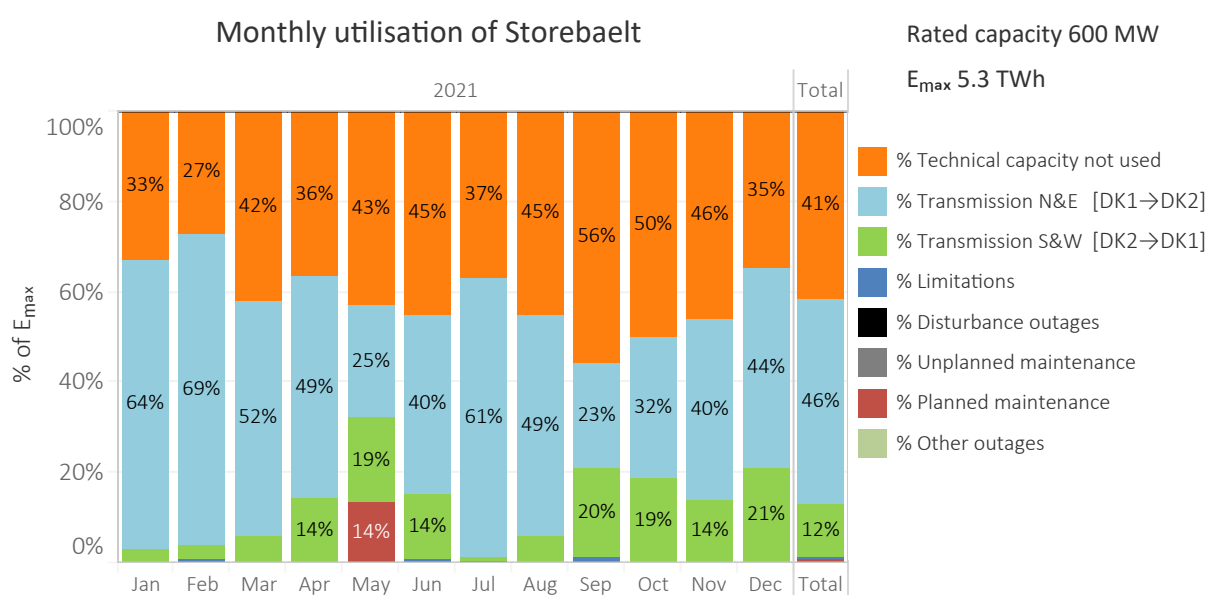


Figure 5.77: Monthly percentage allocation of utilisation by category for Storebaelt in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.22: Monthly allocation of technical capacity ( $E_{max}$ ) for Storebaelt in 2021. Note that losses are not included in the technical capacity ( $E_{max}$ ), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	148.2	109.7	187.6	157.3	191.2	194.1	165.4	200.7	241.2	222.2	198.4	156.2	2172.1	41.3%
Transmission N&E, GWh	283.7	277.3	231.9	212.3	110.8	172.2	274.3	219.2	100.7	141.1	173.3	196.5	2393.4	45.5%
Transmission S&W, GWh	14.1	13.5	26.9	62.4	83.8	61.4	4.4	26.5	85.3	83.1	60.3	93.7	615.2	11.7%
Limitations, GWh	0.4	0.4	-	-	-	3.6	2.3	-	4.9	-	-	-	11.5	0.2%
Disturbance outages, GWh	-	-	-	-	-	0.1	-	-	-	-	0.1	-	0.2	0.0%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	2.3	-	-	60.6	0.6	-	-	-	-	-	-	63.6	1.2%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	446.4	403.2	446.4	432.0	446.4	432.0	446.4	446.4	432.0	446.4	432.0	446.4	5256.0	100.0%
Losses SW, GWh	0.3	0.2	0.4	0.9	1.3	1.0	0.1	0.4	1.3	1.3	1.0	1.5	9.7	0.2%
Losses NE, GWh	4.9	4.8	3.9	3.6	1.8	2.8	4.6	3.7	1.7	2.4	2.9	3.4	40.4	0.8%

Figure 5.78 presents the annual utilisation of Storebaelt per utilisation and unavailability category for the years 2012–2021.

Figure 5.79 presents the percentage of hours of a year Storebaelt has been affected by either a limitation, a dis-

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.80 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

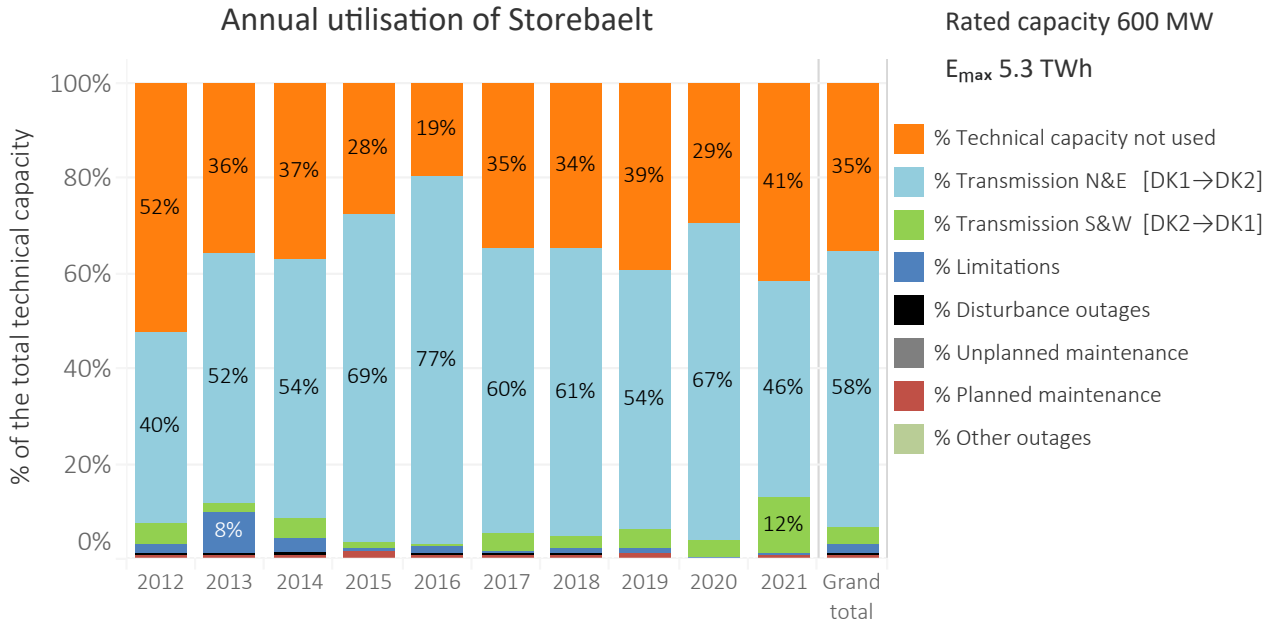


Figure 5.78: Annual utilisation of Storebaelt per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

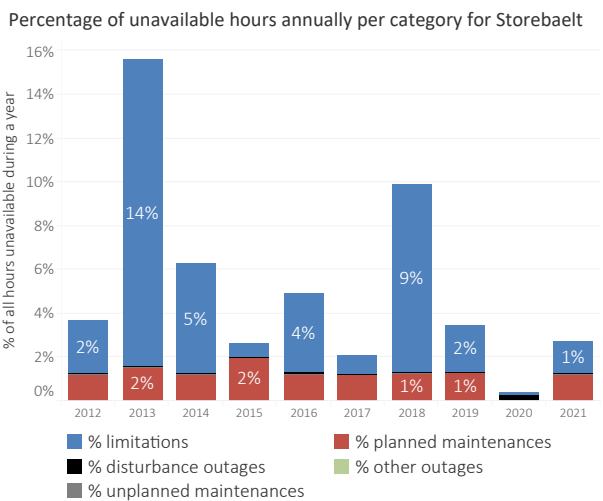


Figure 5.79: Percentage of hours Storebaelt has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

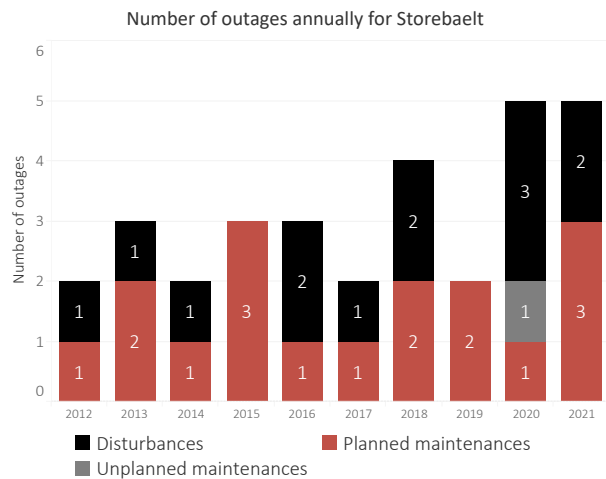


Figure 5.80: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Storebaelt for the years 2012–2021. Storebaelt had no other outages during the years 2012–2021.

### 5.3.20 SwePol

Figure 5.81 presents the availability and utilisation of SwePol for 2021 and Table 5.23 presents the numerical values behind it. SwePol Link has been in operation since 2000 and it connects the Swedish and Polish transmission grids. In south-eastern Sweden (bidding zone SE4) it is connected to Stårnö and in Poland (bidding zone PL) to Slupsk. The transmission capacity is 600 MW.

In 2020, SwePol had an available technical capacity of 91 %. The technical capacity not used was 22 %. Totally, 3.4 TWh

(65 % of the technical capacity) was transmitted south (SE4→PL) and 0.2 TWh (4 % of the technical capacity) was transmitted north (PL→SE4).

The annual maintenance of SwePol lasted 6 days in September. Additionally, SwePol had 10 other planned maintenance outages during 2021. There were 5 minor disturbance outages, of which one lasted more than 8 hours. SwePol was offline due to disturbance outages for 49 hours in total in 2021.

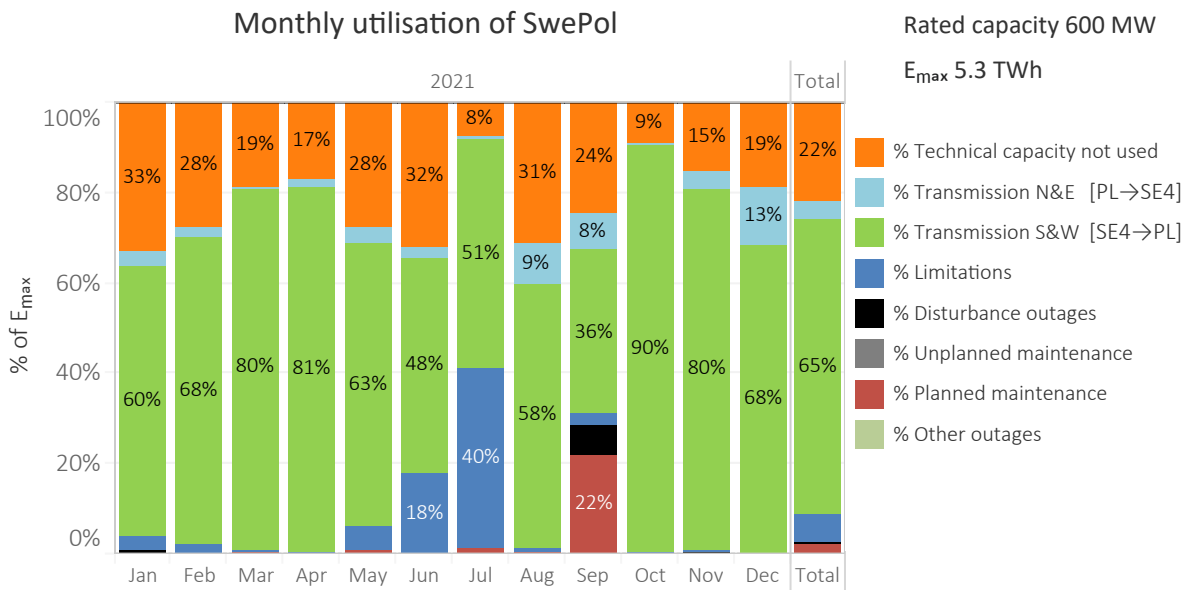


Figure 5.81: Monthly percentage allocation of utilisation by category for SwePol in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.23: Monthly allocation of technical capacity (E<sub>max</sub>) for SwePol in 2021. Note that losses are not included in the technical capacity (E<sub>max</sub>), as is shown in Figure 3.1.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	147.7	112.0	82.9	72.4	123.3	139.1	34.5	138.6	105.7	40.3	64.7	84.4	1145.7	21.8%
Transmission N&E, GWh	13.9	9.0	1.1	7.8	16.1	9.4	0.9	41.5	34.8	1.3	18.2	56.2	210.2	4.0%
Transmission S&W, GWh	266.6	273.2	357.5	349.9	279.3	207.1	227.8	259.3	157.5	403.3	345.7	305.1	3432.4	65.3%
Limitations, GWh	14.3	8.4	1.3	1.9	24.1	76.4	177.3	4.3	9.7	1.4	1.2	0.7	321.0	6.1%
Disturbance outages, GWh	3.9	0.6	-	-	-	-	-	-	30.2	-	1.1	-	35.7	0.7%
Unplanned maintenance., GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	3.6	-	3.5	-	5.8	2.6	94.2	0.1	1.2	-	110.9	2.1%
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	446.4	403.2	446.4	432.0	446.4	432.0	446.4	446.4	432.0	446.4	432.0	446.4	5256.0	100.0%
Losses SW, GWh	7.3	7.8	10.3	9.9	7.6	5.1	4.9	7.1	4.3	11.9	10.1	8.8	95.1	1.8%
Losses NE, GWh	0.3	0.2	-	0.2	0.4	0.2	-	1.1	0.9	-	0.5	1.6	5.5	0.1%



Figure 5.82 presents the annual utilisation of SwePol per utilisation and unavailability category for the years 2012–2021.

Figure 5.83 presents the percentage of hours of a year SwePol has been affected by either a limitation, a distur-

bance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.84 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

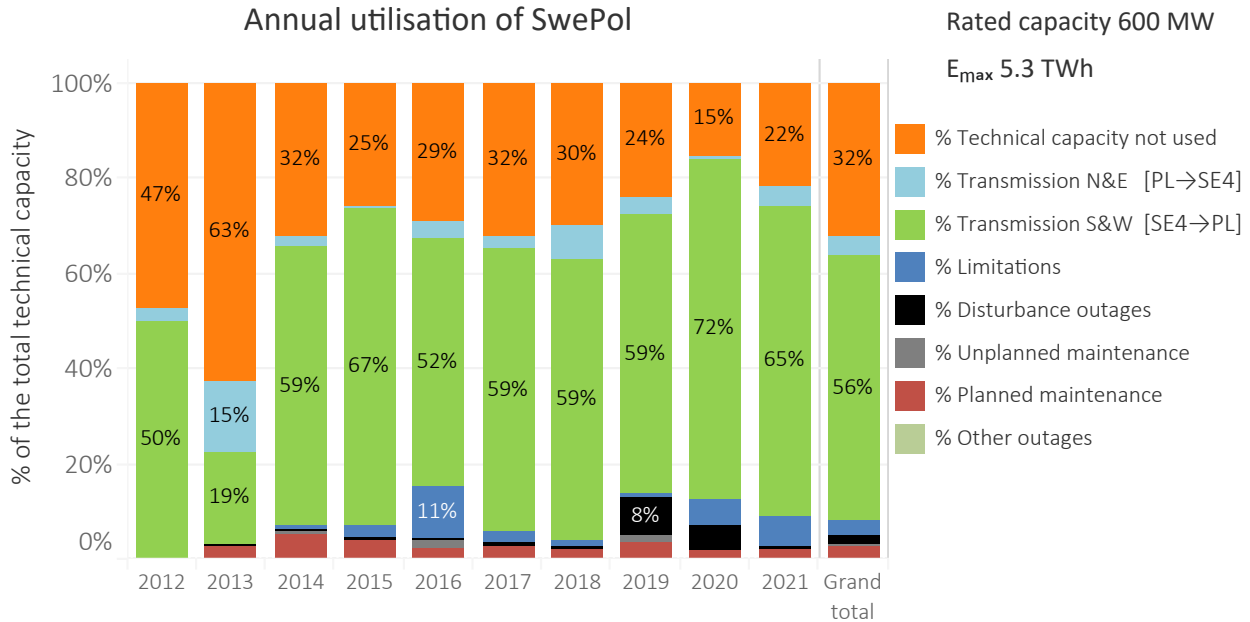


Figure 5.82: Annual utilisation of SwePol per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

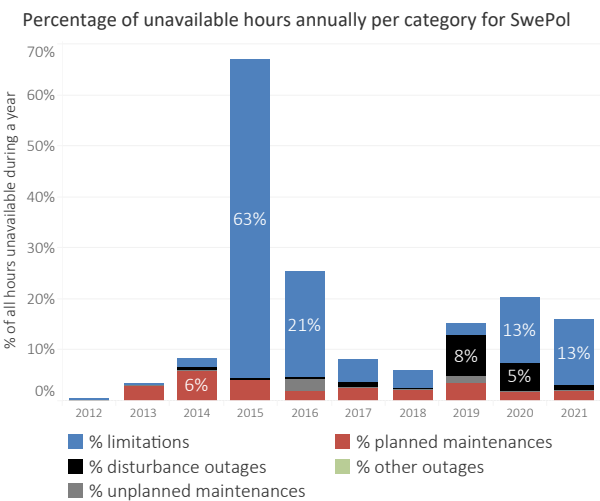


Figure 5.83: Percentage of hours SwePol has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

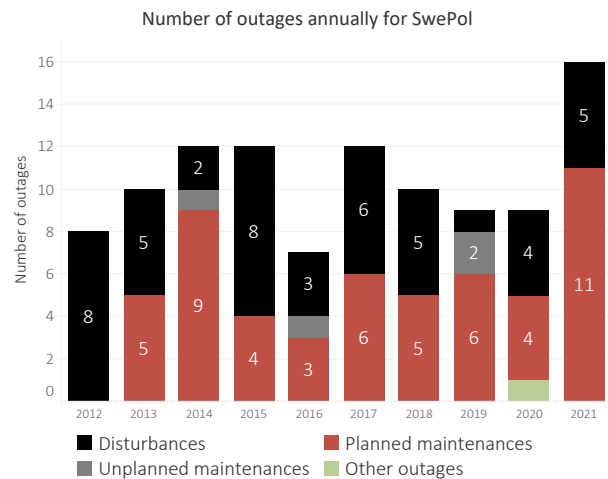


Figure 5.84: The annual number of disturbances, unplanned and planned maintenance outages and other outages for SwePol for the years 2012–2021. SwePol had no other outages during the years 2012–2021.

### 5.3.21 Vyborg Link

Figure 5.85 and Figure 5.86 present the monthly availability and utilisation of the Vyborg Link separately for each direction for 2021. Table 5.24 and Table 5.25 present the numerical values behind the monthly figures. Vyborg Link is a back-to-back HVDC connection between Russia and Finland. The HVDC substation is located in Vyborg, Russia, and the 400 kV lines from Vyborg are connected to substations Ylikkälä and Kymi in southern Finland.

Vyborg link was first commissioned in 1981 with a rated capacity of 350 MW. Additional 350 MW converter blocks were installed in 1982, 1984, and 2000. The total technical capacity is 4x350 MW and the commercial transmission capacity is 1.3 GW (with 100 MW allocated for reserves).

The transmission direction before 2014 was only to Finland. In September 2014, one 350 MW unit was tested to also transmit in the other direction. As a result, the trade to Russia was possible with 320 MW (with 30 MW allocated for reserves) in December 2014.

The trade between Russia and Finland ended on 14 May

2022 as a result of the war started by Russia against Ukraine on 24 February 2022.

In 2021, the Vyborg Link had an available technical capacity of 94 % in the direction RU→FI. The technical capacity not used was 23 %. Totally, 8.2 TWh (72 % of the technical capacity) was transmitted west to Finland (RU→FI).

The available technical capacity was 78 % in the direction FI→RU. The technical capacity not used was 78 %. No energy was transmitted east to Russia (FI→RU).

In 2021, there were two annual maintenances of Vyborg Link, lasting 31 days in July and 28 days in May. Additionally, there were two other planned maintenance outages in October. Maintenance work on Vyborg Link causes normally only limitations because the 350 MW units are not worked on simultaneously. Vyborg Link had seven disturbance outages during 2021, of which two lasted longer than 24 hours. Furthermore, there were five planned and 13 unplanned limitations.

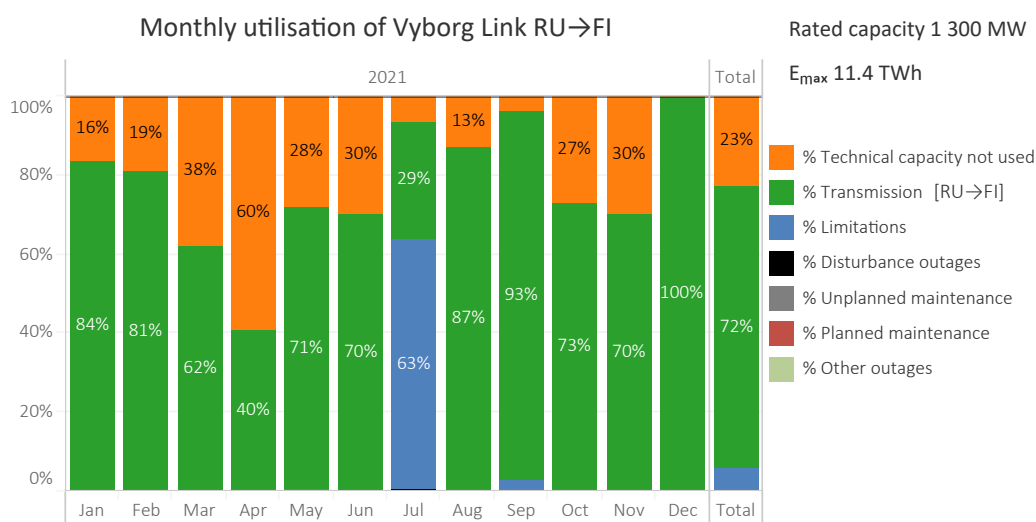


Figure 5.85: Monthly percentage allocation of utilisation by category for Vyborg Link in direction RU→FI in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.24: Monthly allocation of technical capacity (E<sub>max</sub>) in direction RU→FI for Vyborg Link in 2021.

Monthly utilisation of Vyborg Link RU→FI	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	% total
Technical capacity not used, GWh	159.4	166.6	365.2	557.6	272.6	281.2	66.6	126.5	38.6	261.4	278.2	4.0	2578.0	22.6%
Transmission, GWh	807.8	707.0	602.0	378.4	690.5	654.8	281.7	840.0	872.1	705.8	656.5	963.2	8159.8	71.7%
Limitations, GWh	-	-	-	-	4.1	-	613.9	0.7	25.3	-	1.3	-	645.3	5.7%
Disturbance outages, GWh	-	-	-	-	-	-	5.0	-	-	-	-	-	5.0	0.0%
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Planned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total, GWh	967.2	873.6	967.2	936.0	967.2	936.0	967.2	967.2	936.0	967.2	936.0	967.2	11388.0	100.0%

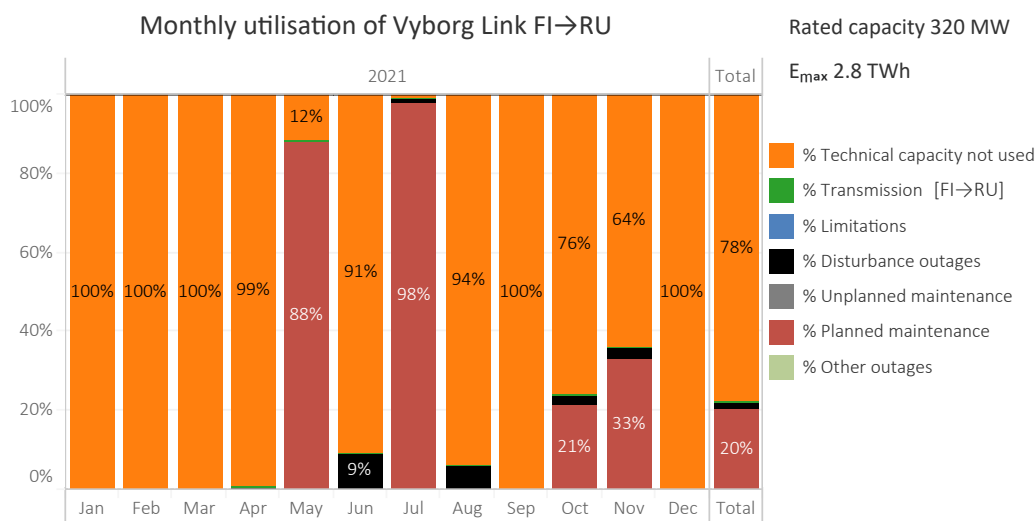


Figure 5.86: Monthly percentage allocation of utilisation by category for Vyborg Link in direction FI→RU in 2021. The availability and utilisation categories are defined in detail in Chapter 3.

Table 5.25: Monthly allocation of technical capacity (E<sub>max</sub>) in direction FI→RU for Vyborg Link in 2021.

Monthly utilisation of Vyborg Link FI→RU														Total	% total
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec			
Technical capacity not used, GWh	238.1	215.0	238.1	228.1	27.8	208.9	2.4	223.0	230.4	180.5	147.5	238.1	2178.0	77.7%	
Transmission, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	
Limitations, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Disturbance outages, GWh	-	-	-	2.3	-	21.5	2.4	15.0	-	6.9	6.8	-	54.8	2.0%	
Unplanned maintenance, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Planned maintenance, GWh	-	-	-	-	210.2	-	233.3	-	-	50.7	76.2	-	570.4	20.3%	
Other outages, GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total, GWh	238.1	215.0	238.1	230.4	238.1	230.4	238.1	238.1	230.4	238.1	230.4	238.1	2803.2	100.0%	

Figure 5.87 presents the annual utilisation of Vyborg Link per utilisation and unavailability category for the years 2012–2021.

Figure 5.88 presents the percentage of hours of a year Vyborg Link has been affected by either a limitation, a dis-

turbance outage, an unplanned or planned maintenance outage or other outage annually during the years 2012–2021. Figure 5.89 presents the annual number of disturbance outages, unplanned and planned maintenances and other outages during the years 2012–2021.

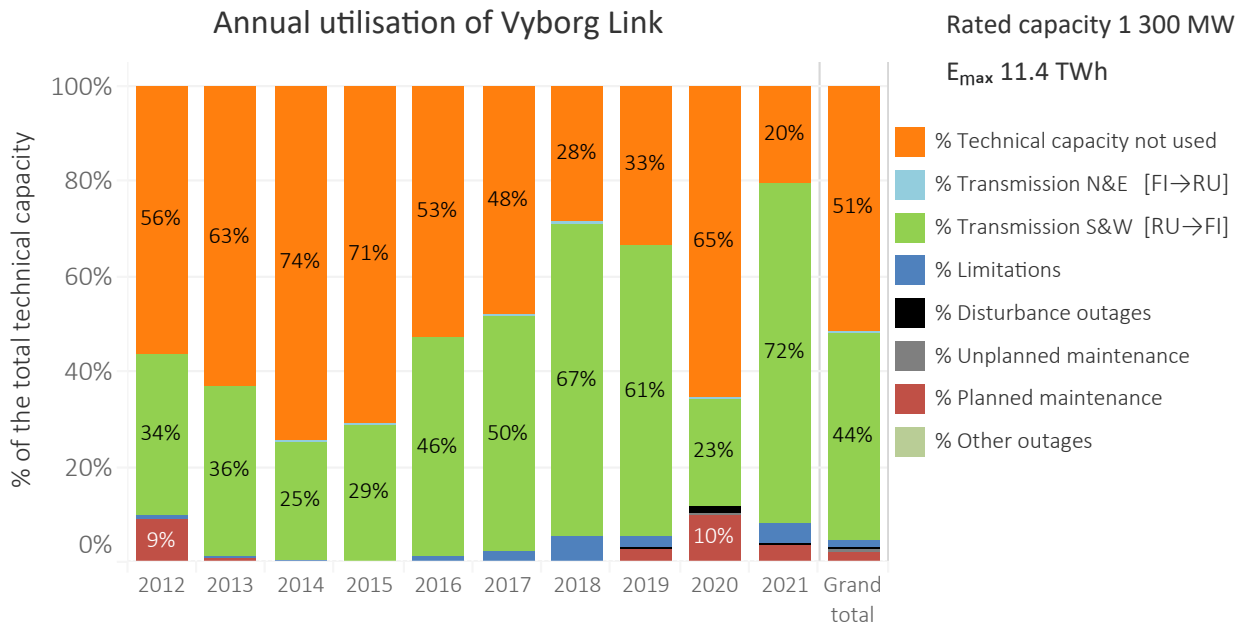


Figure 5.87: Annual utilisation of Vyborg Link per the utilisation and unavailability categories for the years 2012–2021. The utilisation and unavailability categories are described in more detail in Chapter 3.

Percentage of unavailable hours annually per category for Vyborg Link

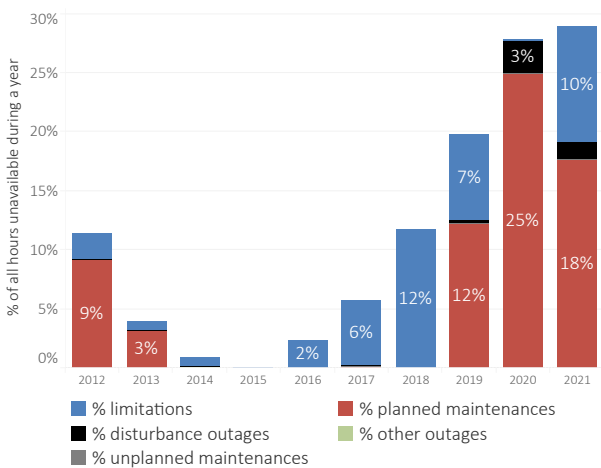


Figure 5.88: Percentage of hours Vyborg Link has been affected by either a limitation or an outage annually since 2012. The percentage is calculated by counting the number of hours with a limitation or outage and dividing it by the total number of hours in a year. It should be noted that any single hour can be affected by both an outage and a limitation.

Number of outages annually for Vyborg Link

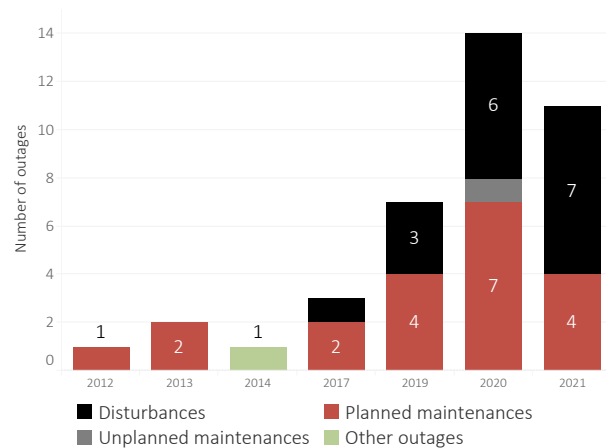


Figure 5.89: The annual number of disturbances, unplanned and planned maintenance outages and other outages for Vyborg Link for the years 2012–2021.

## References

- [1] DISTAC, "Nordic Grid Disturbance Statistics 2010." [https://eepublicdownloads.entsoe.eu/clean-documents/pre2015/publications/entsoe/RG\\_SOC\\_Nordic/110831\\_NORDIC\\_GRID\\_DISTURBANCE\\_AND\\_FAULT\\_STATISTICS\\_2010.pdf](https://eepublicdownloads.entsoe.eu/clean-documents/pre2015/publications/entsoe/RG_SOC_Nordic/110831_NORDIC_GRID_DISTURBANCE_AND_FAULT_STATISTICS_2010.pdf), August 2010.
- [2] CIGRE Technical Brochure, "Protocol for reporting the operational performance of HVDC Transmission Systems," technical brochure, CIGRE, 2014.

## Glossary

**DISTAC** Disturbance Statistics Group. Reports to Regional Group Nordic (RGN) in ENTSO-E.

**ENTSO-E** European Network of Transmission System Operators for Electricity.

**HVAC** High-voltage alternating current.

**HVDC** High-voltage direct current.

**LCC** Line-commutated converters.

**NordAM** Nordic Asset Management Forum.

**PEX** Cross-linked polyethylene.

**RGN** Regional Group Nordic.

**TSO** Transmission System Operator.

**VSC** Voltage-source converters.

# Appendices

# A Schematic presentation of HVDC links

Figure A.1 and Figure A.2 show the schematic presentations of a HVDC converter station having line-commutated converters (LCC) and voltage-source converters (VSC), respectively. All the figures also show definitions for the origin of an event. The origin of each event is used for categorizing a disturbance or a limitation for statistical purposes.

The figures also show the locations of the circuit breakers and measurement points for transferred energy on a link.

It should be noted that these figures are only show an example of a possible LCC or VSC converter station as there are multiple different ways to construct one.

## Schematic of a line-commutated converter HVDC station

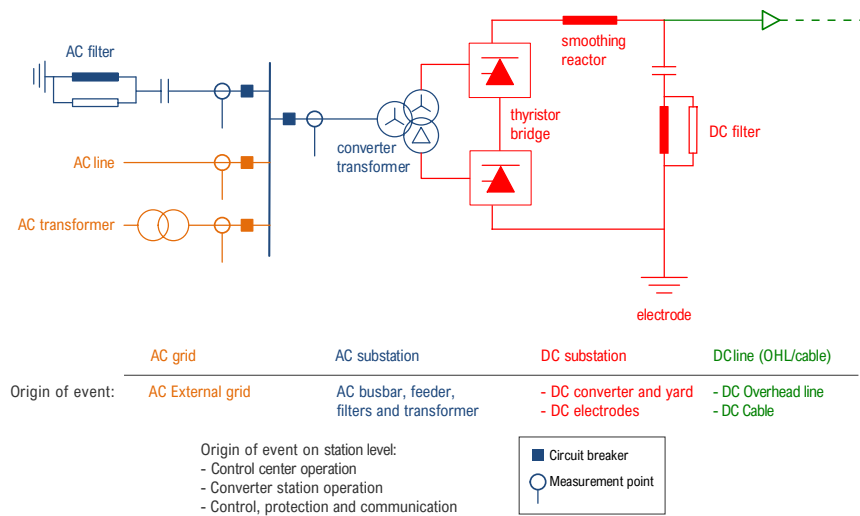


Figure A.1: An example of a line-commutated converter (LCC) station schematic with the connection to the AC grid. The other remote side of the HVDC link has a similar albeit mirrored version of the converter station.

## Schematic of a voltage-source converter HVDC station

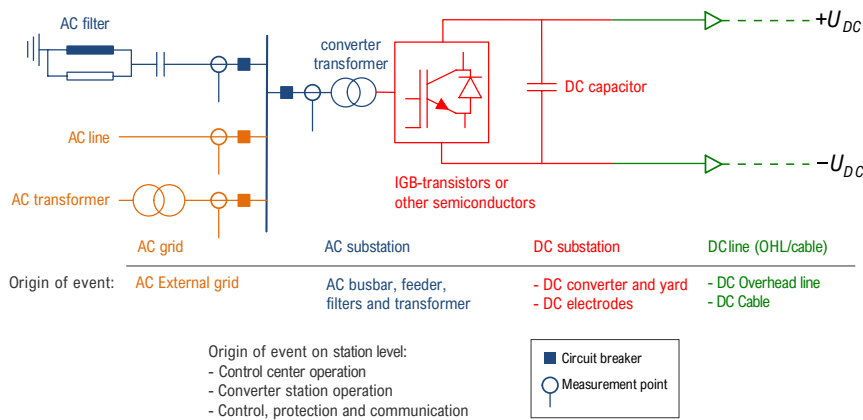


Figure A.2: An example of a voltage-source converter (VSC) station schematic with the connection to the AC grid. The other remote side of the HVDC link has a similar albeit mirrored version of the converter station.



## B DISTAC/CIGRE origin of event classification

Table B.1 show the DISTAC origins and their subcategories and the corresponding CIGRE outage codes [2]. It should be noted that full compatibility is not achieved in control and protection areas. The schematics in Appendix A can be helpful in visualizing the different categories.

Table B.1: The DISTAC origin of event categories and subcategories and the corresponding CIGRE outage codes.

DISTAC Origin of event	DISTAC / CIGRE Subcategory / Outage Code	Comment
Multiple places	-	Used primarily for annual maintenance in DISTAC.
Control centre operation <sup>1</sup>	C-P.L – Local HVDC Control & Protection <sup>1</sup>	Control, protection or monitoring equipment of the local HVDC station, for example, converter firing control, current and voltage regulators, converter and dc yard protections, valve control and protection, and local control sequences.
	C-P.M – Master HVDC Control & Protection <sup>1</sup>	Equipment used for inter-station coordination of current and voltage orders, inter-station sequences, auxiliary controls such as damping controls or higher level controls such as run-back/run-up power control or frequency control.
	C-P.T – Control & Protection and Telecommunication <sup>1</sup>	Equipment for coding of control and indication information to be sent over a telecommunication circuit including the telecommunication circuit itself (microwave, PLC or optical).
Converter station operation <sup>1</sup>	Same as for “Control centre operation” above	
Control, protection and communication <sup>1</sup>	Same as for “Control centre operation” above	
AC External grid AC and auxiliary equipment	EXT – External AC System	
	AC-E.F – AC Filter and Shunt Bank	Including AC filter CTs, arresters as well as PLC/RI, SVC, STAT-COM, series capacitor at HVDC station.
	AC-E.SW – Other AC Switchyard Equipment	For example, switches, surge arresters, busbars, insulators.
	AC-E.CP – AC Control and Protection	AC C&P including CTs, VTs, also for auxiliary power and valve cooling.
	AC-E.TX – Converter Transformer	Including interface transformers.
DC converter and yard	AC-E.SC – Synchronous Compensator	Including SC cooling system and exciter.
	AC-E.AX – Auxiliary Equipment and Auxiliary Power	For example, auxiliary transformers, pumps, battery chargers, heat exchangers, cooling system instrumentation, LV switchgear, motor control centres, fire protection, civil works.
	V.E – Valve Electrical	
	V.VC – Valve Cooling	Valve Cooling pipes and parts in valve hall.
	V.C – Valve Capacitor	
	DC-E.F – DC Filters	
	DC-E.SR – DC Smoothing Reactor	
DC-E.SW – DC Switching Equipment		
DC Electrodes	DC-E.ME – DC Measuring Equipment	
	DC-E.O – Other DC Yard and Valve Hall Equipment	
	DC-E.GE – DC Ground Electrode	
DC Overhead line	DC-E.EL – DC Ground Electrode Line	
DC Cable	TL-OH – DC Overhead Transmission Line	
Other or unknown	TL-C – DC Underground / submarine Cable	
	O – Other	

<sup>1</sup> There is no direct one-to-one compatibility between DISTAC and CIGRE for these definitions.

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## D Sorted overview of utilisation and unavailability for all HVDC links

This chapter presents sorted versions of Figure 5.1 Utilisation (%) by category for each HVDC link in 2021.

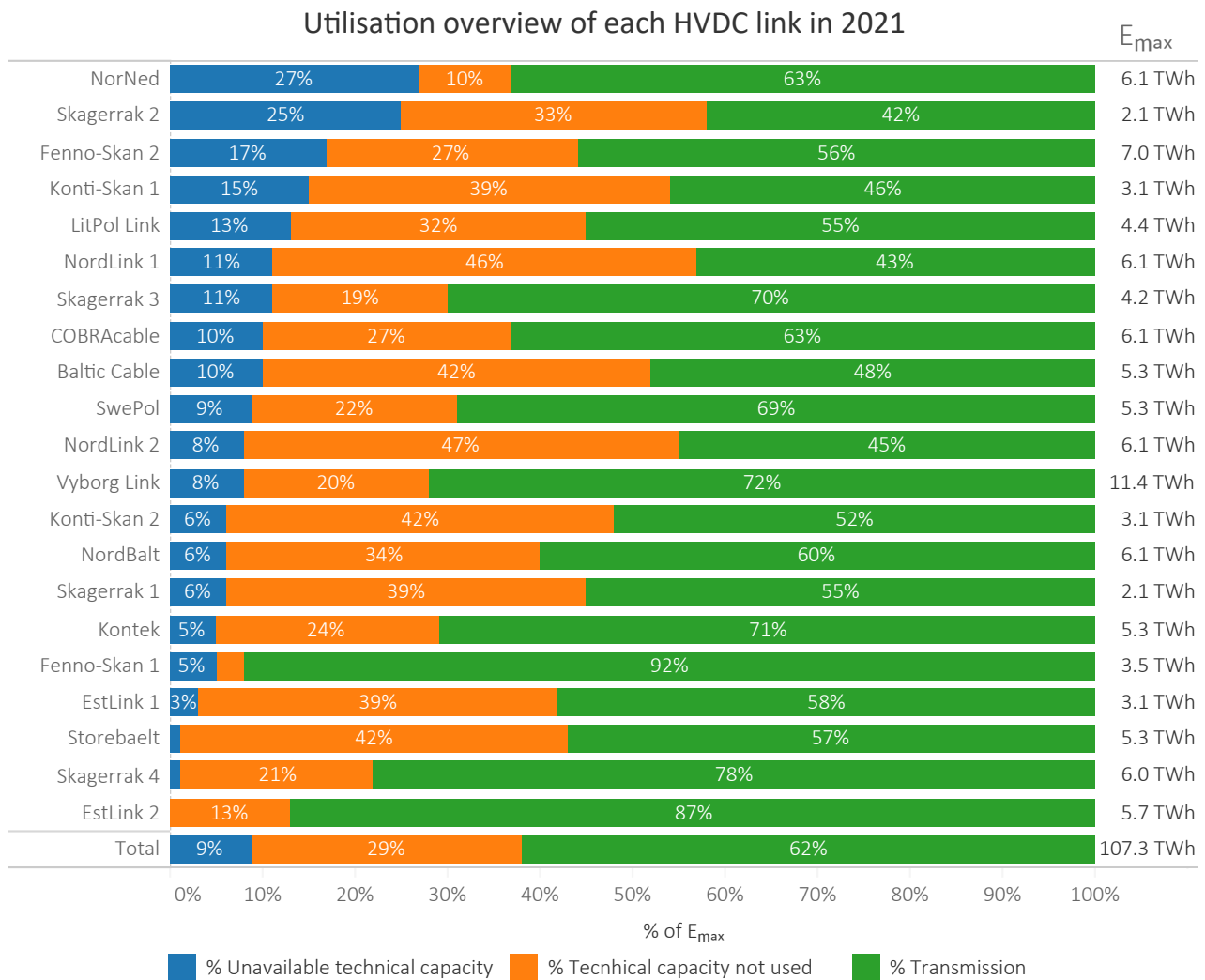


Figure D.1: Overview of each HVDC link sorted by descending unavailable technical capacity ( $E_U$ ) in 2021.

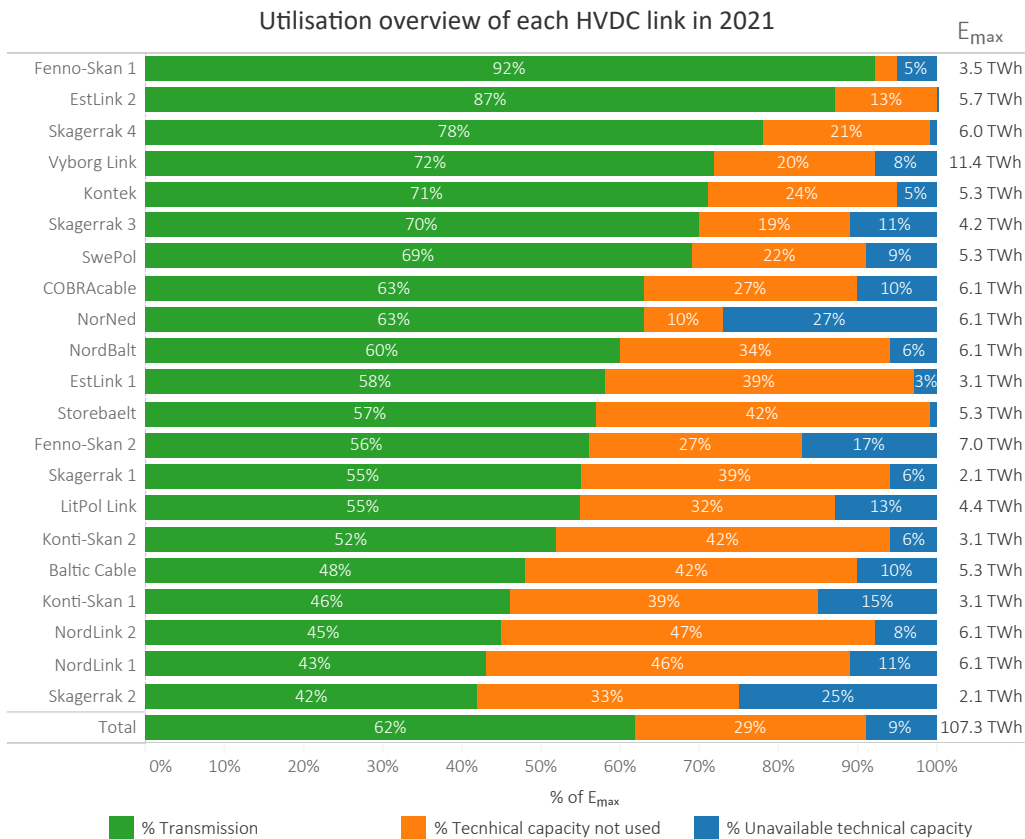


Figure D.2: Overview of each HVDC link sorted by descending transmission ( $E_T$ ) in 2021.

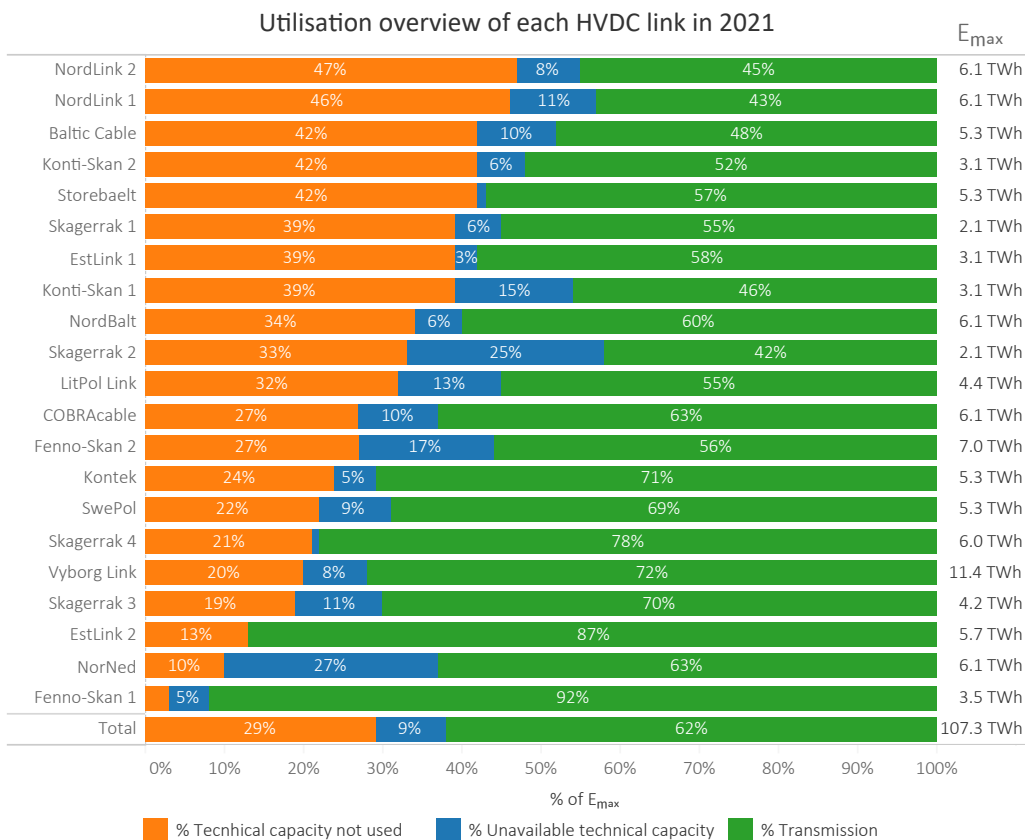


Figure D.3: Overview of each HVDC link sorted by descending technical capacity not used ( $E_{TCNU}$ ) in 2021.

## E Additional figures

This appendix was introduced to allow experimenting with new kinds of figures without affecting the rest of the report. Furthermore, it shows what kind of statistical data can be derived from the data collected by the DISTAC group.

### E.1 Annual utilisation per type of HVDC converter

Figure E.1 presents the annual utilisation of all HVDC links using line-commutated converters (LCC) and Figure E.2 all HVDC links using voltage-source converters (VSC).

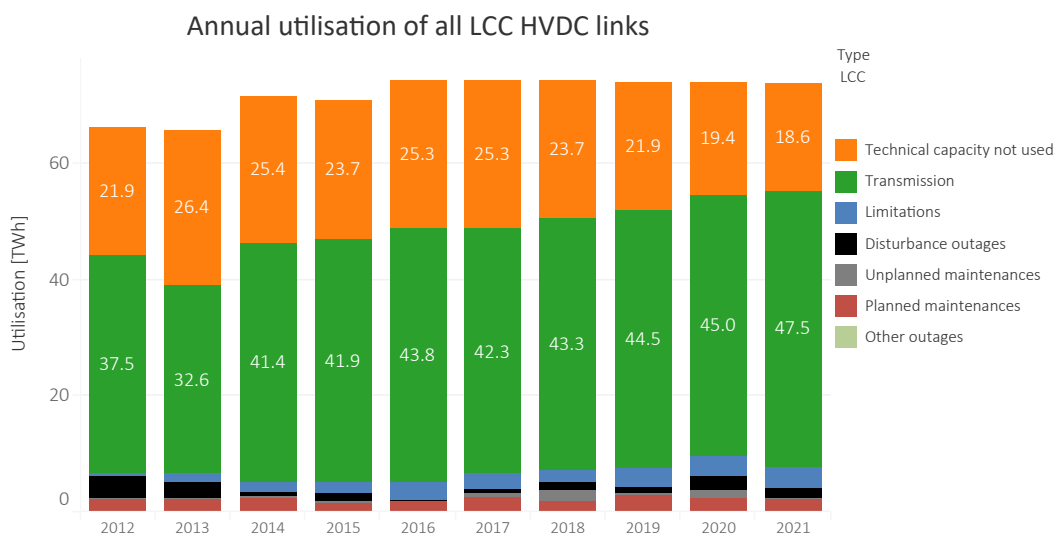


Figure E.1: Annual utilisation of all HVDC links using line-commutated converters (LCC) together presented in megawatt hours (MWh).

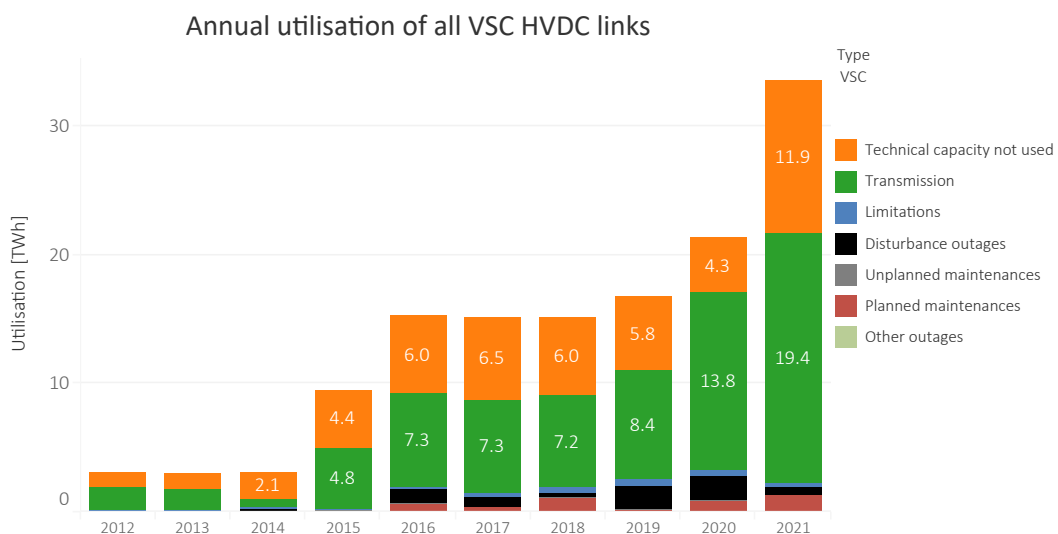


Figure E.2: Annual utilisation of all HVDC links using voltage-source converters (VSC) together presented in megawatt hours (MWh).

## E.2 Additional figures with percentages of hours unavailable

This section presents additional figures with a more detailed categorisation of unavailability. Figure E.3 presents the hours (%) limited due to seasonal causes annually for all HVDC links. Figure E.4 presents the hours (%) limited by limitation origin and type annually for all HVDC links. The limitation origins are AC and DC limiting conditions, and the types are planned or unplanned.

Figure E.5 presents the hours (%) limited by limitation origin and type in 2021 for each HVDC link. Figure E.6 presents the same but for each market connection.

Figure E.7 presents hours (%) unavailable due to planned maintenance by primary cause in 2021 for each HVDC link and the corresponding annual values for all HVDC links combined.

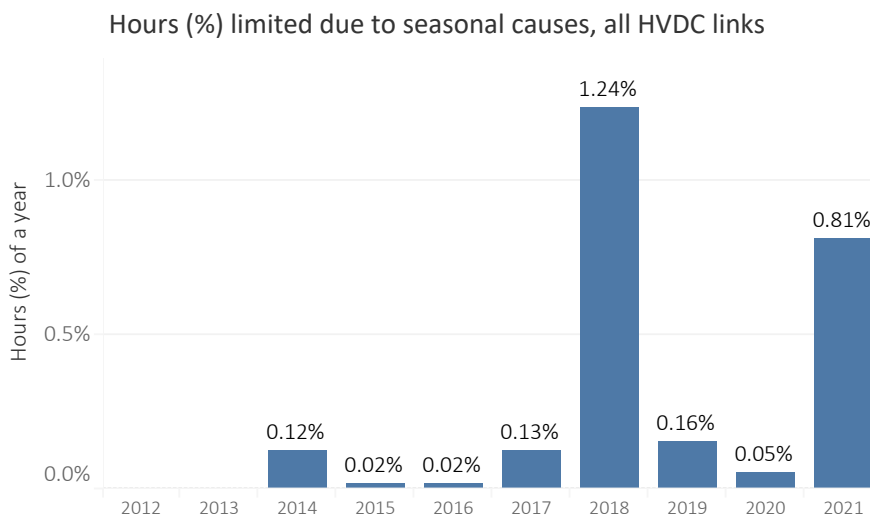


Figure E.3: Hours (%) limited due seasonal causes for all HVDC links. The percentage is calculated by counting the number of hours with a limitation due to seasonal causes and dividing it by the total number of hours in a year.

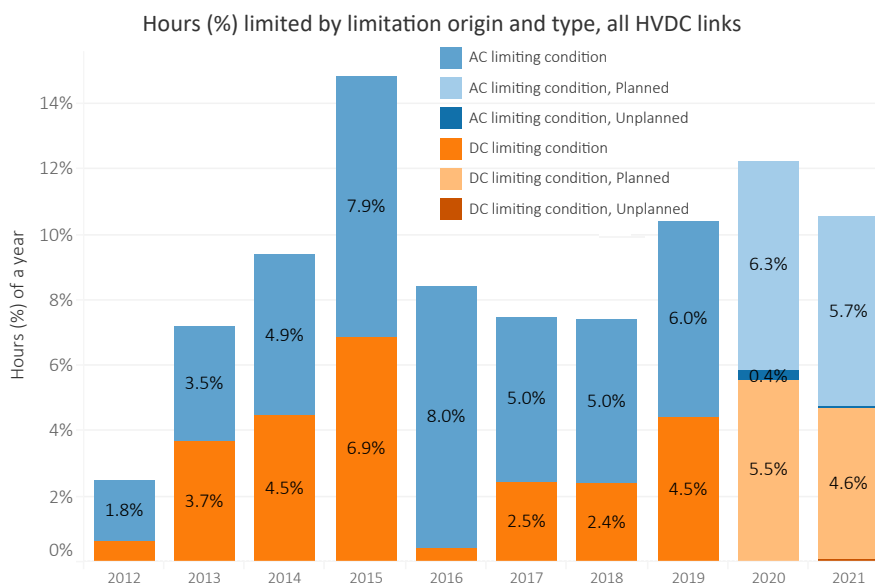


Figure E.4: Hours (%) by limitation origin and type annually for all HVDC links. The limitation origins are AC limiting and DC limiting and the types are planned and unplanned. The percentage is calculated by counting the number of hours with the specific limitation origin and type and dividing it by the total number of hours in a year. Limitation type was not recorded prior to 2020.

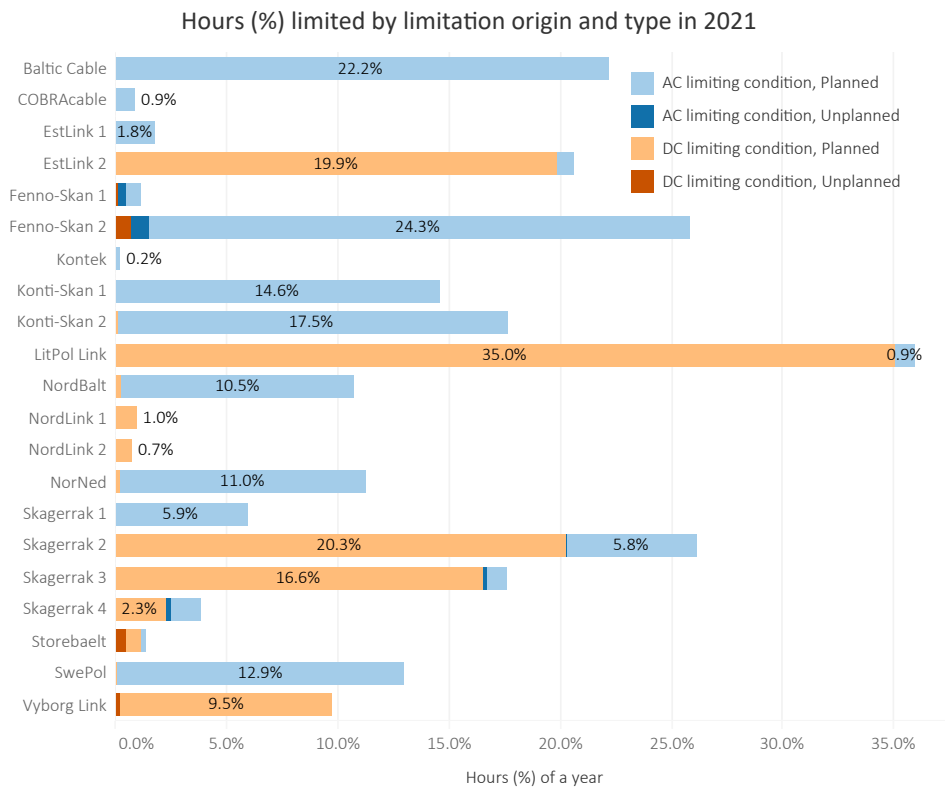


Figure E.5: Hours (%) limited by limitation origin and type in 2021 for each HVDC link. The percentage is calculated by counting the number of hours with the specific limitation origin and type and dividing it by the total number of hours in a year.

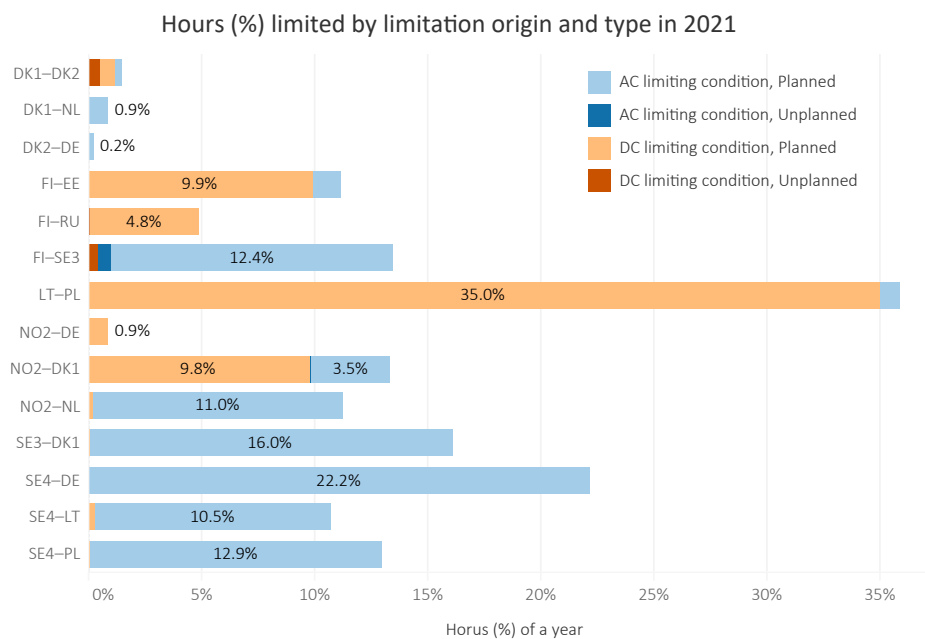
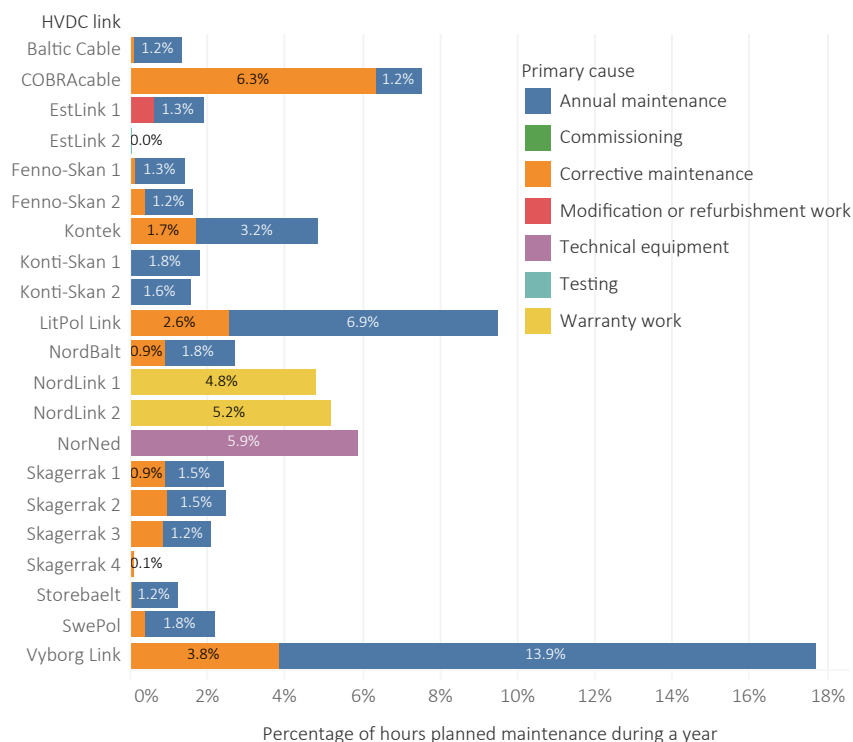


Figure E.6: Hours (%) limited by limitation origin and type for each market connection in 2021. The percentage is calculated by counting the number of hours with the specific limitation origin and type and dividing it by the total number of hours in a year.

Hours (%) with planned maintenance by primary cause in 2021



Annual hours (%) planned maintenance, all HVDC links

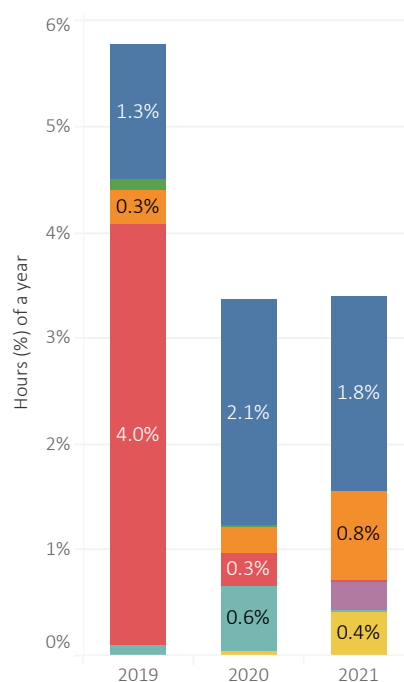


Figure E.7: On the left: hours (%) with planned maintenance by primary cause for each HVDC link in 2021. On the right: hours (%) with planned maintenance by primary cause annually for all HVDC links combined. The percentage is calculated by counting the number of hours with a planned maintenance and dividing it by the total number of hours in a year.



### E.3 Additional figures with origin of event

This section presents additional figures about disturbance and maintenance outages, with a focus on their origin of the event. Origin of event corresponds to the location on the HVDC link that the event originated from. The origin of event categories and subcategories are presented in Appendix B. The HVDC link schematics in Appendix A can be helpful in visualising the categories.

Figure E.8 presents the number of disturbance outages divided by the number of HVDC links annually grouped by origin. Figure E.9 presents the annual unavailable capacity due to disturbance outages by origin of event for all HVDC

links combined. Last, Table E.1 presents the numerical values behind Figure E.9 with further subcategorisation of the origin.

Figure E.10 presents the annual unavailable capacity due to maintenance outages by primary cause. Figure E.11 presents the annual unavailable capacity due to corrective maintenances by origin of event for all HVDC links, and the number of corrective maintenances divided by the number of HVDC links annually grouped by origin of event. Primary cause of outages has not been recorder prior to the year 2019.

Number of disturbance outages divided by the number of HVDC links by origin of event

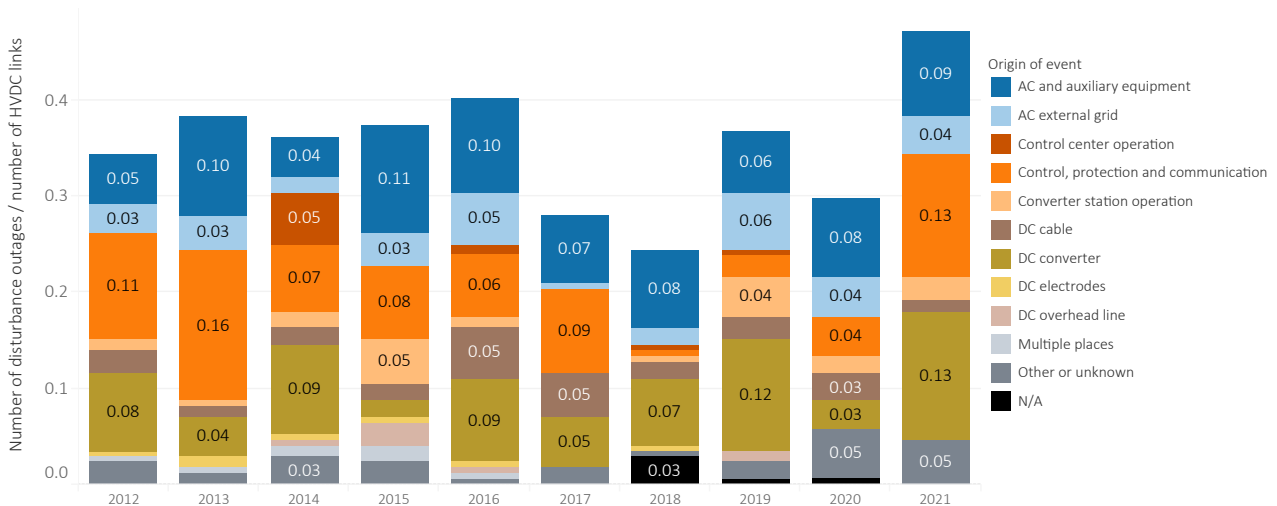


Figure E.8: Number of disturbance outages divided by the number of HVDC links, grouped by origin of event.

Annual unavailable capacity due to disturbance outages by origin of event

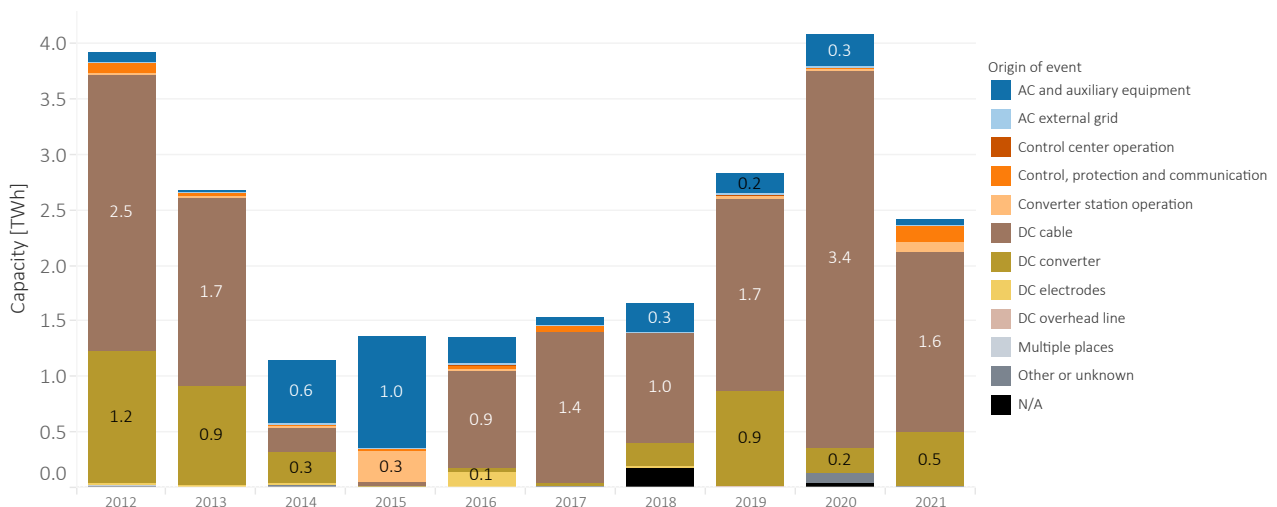


Figure E.9: Annual unavailable capacity due to disturbances outages by origin of event for all HVDC links.

**Table E.1: Annual unavailable capacity due to disturbances outages by origin of event and subcategory for all HVDC links. N/A means not available. Note that the level of detail in the data collection has increased since 2019.**

Origin	Subcategory	GWh									
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
AC and auxiliary equipment	AC-E.AX - Auxiliary Equipment and Auxiliary Power	-	-	-	-	-	-	-	1.5	280.1	12.9
	AC-E.CP - AC Control and Protection	-	-	-	-	-	-	-	15.0	3.6	6.7
	AC-E.F - AC Filter and Shunt Bank	-	-	-	-	-	-	-	0.1	0.6	0.1
	AC-E.SW - Other AC Switchyard Equipment	-	-	-	-	-	-	-	0.2	1.1	18.6
	AC-E.TX - Converter Transformer	-	-	-	-	-	-	-	168.7	0.2	3.3
	N/A	93.9	13.5	556.5	1005.9	228.9	65.2	260.5	0.8	1.3	1.1
AC external grid	EXT - External AC System	-	-	-	-	-	-	-	8.0	9.2	4.9
	N/A	11.4	10.4	1.9	6.2	13.6	0.5	2.2	-	-	9.1
Control center operation	N/A	-	-	5.1	-	9.6	-	0.2	0.0	-	-
Control, protection and communication	C-P.L - Local HVDC Control & Protection	-	-	-	-	-	-	-	6.8	10.3	106.2
	C-P.M - Master HVDC Control & Protection	-	-	-	-	-	-	-	-	6.6	37.3
	C-P.T - Control & Protection and Telecommunicati..	-	-	-	-	-	-	-	-	0.7	-
	N/A	79.8	38.3	23.1	12.6	26.3	63.5	0.6	2.7	-	1.3
Converter station operation	C-P.L - Local HVDC Control & Protection	-	-	-	-	-	-	-	21.1	0.8	84.2
	C-P.M - Master HVDC Control & Protection	-	-	-	-	-	-	-	8.2	0.6	-
	N/A	0.4	5.9	2.3	290.4	20.1	-	1.5	-	-	-
DC cable	TL-C - DC Underground / submarine Cable	-	-	-	-	-	-	-	1729.1	3410.9	1623.7
	N/A	2505.5	1704.1	226.9	32.2	876.0	1361.8	996.5	-	-	-
DC converter	DC-E.F - DC Filters	-	-	-	-	-	-	-	-	-	0.1
	DC-E.ME - DC Measuring Equipment	-	-	-	-	-	-	-	65.2	3.6	148.3
	DC-E.O - Other DC Yard and Valve Hall Equipment	-	-	-	-	-	-	-	2.8	-	18.6
	DC-E.SR - DC Smoothing Reactor	-	-	-	-	-	-	-	245.3	174.5	-
	V.C - valve capacitor	-	-	-	-	-	-	-	36.5	-	-
	V.E - Valve Electrical	-	-	-	-	-	-	-	36.9	33.6	217.0
	V.VC - Valve Cooling	-	-	-	-	-	-	-	52.8	13.5	91.4
	N/A	1192.2	888.1	283.0	3.3	37.2	33.8	210.6	424.4	-	12.4
DC electrodes	N/A	3.2	18.4	6.8	9.0	136.3	-	4.6	-	-	-
DC overhead line	TL-OH - DC Overhead Transmission Line	-	-	-	-	-	-	-	3.1	-	-
	N/A	-	-	0.6	3.0	2.3	-	-	-	-	-
Multiple places	N/A	24.3	2.1	0.2	0.2	0.7	-	-	-	-	-
N/A	N/A	-	-	-	-	-	-	186.5	0.7	42.8	-
Other or unknown	O - Other	-	-	-	-	-	-	-	0.0	4.5	1.2
	N/A	13.2	0.9	34.5	1.4	0.7	8.4	0.7	3.1	83.1	17.1

Annual unavailable capacity due to maintenance outages by primary cause

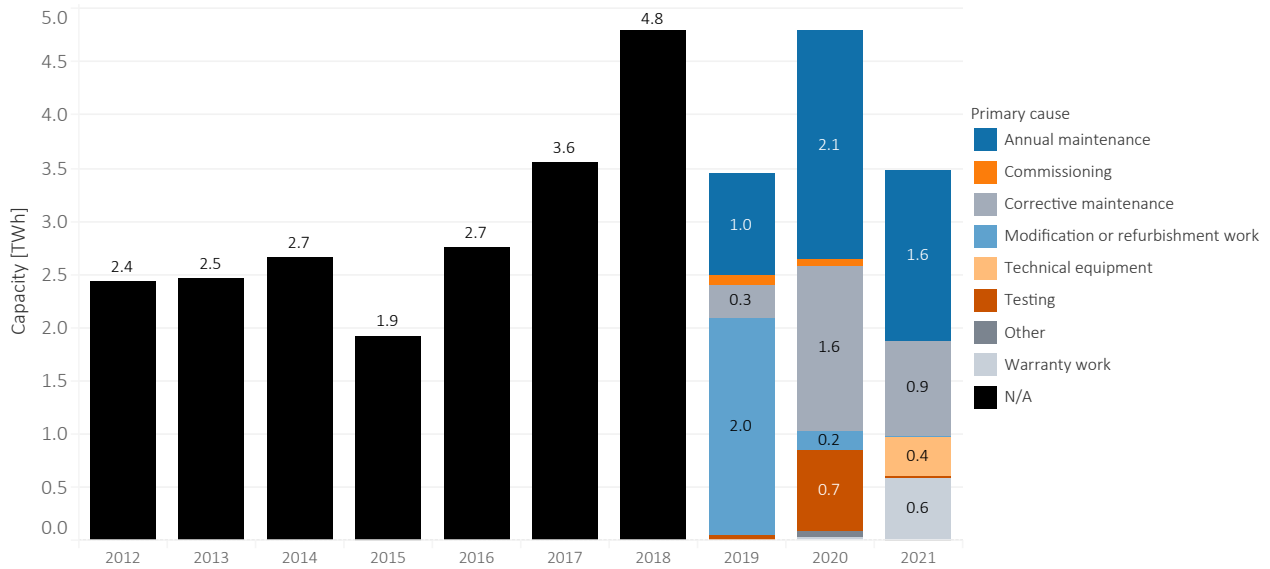


Figure E.10: Annual unavailable capacity due to maintenance outages by primary cause for all HVDC links. Primary cause of outages has not been recorded prior to 2019.

Annual unavailable capacity due to corrective maintenance by origin of event

Number of corrective maintenances divided by number of HVDC links, by origin of event

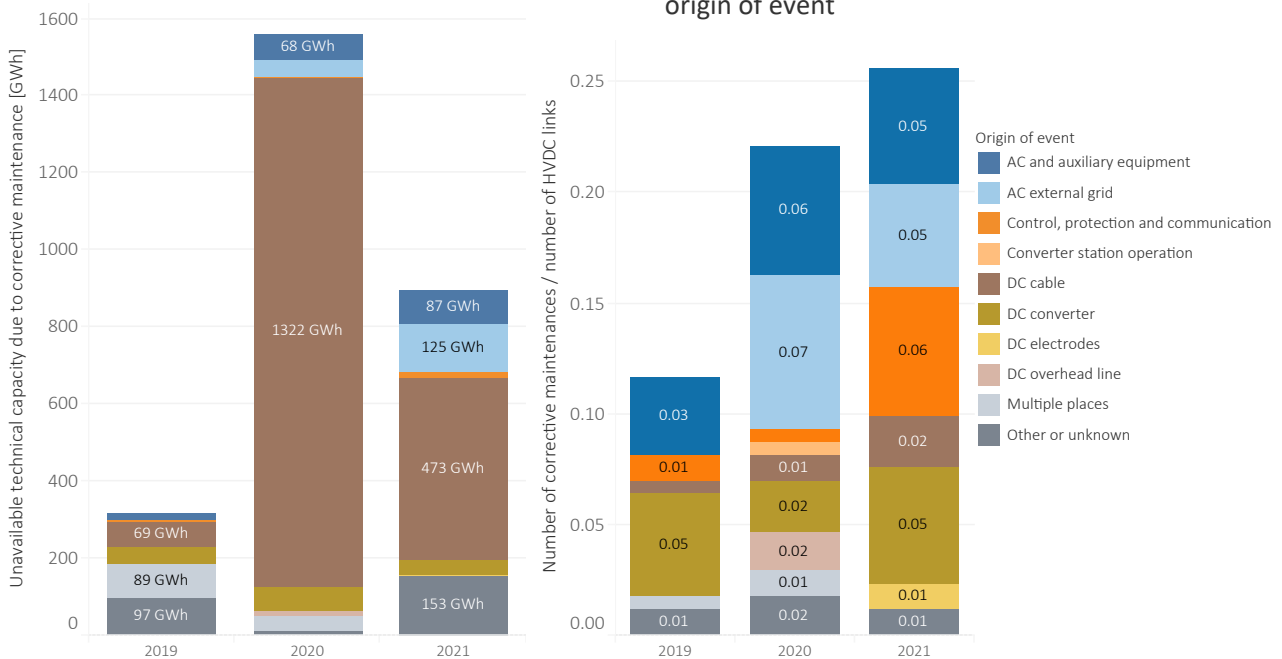


Figure E.11: On the left: annual unavailable capacity due to corrective maintenance outages by origin of event for all HVDC links. On the right: number of corrective maintenance outages divided by the number of HVDC links annually grouped by origin of event. Primary cause of outages has not been recorder prior to the year 2019.

**[ID 12481]**

***Progetto di un impianto agrivoltaico, della potenza complessiva pari a 34,769 MWp, da realizzarsi in località Villamuscas - Comune di Uta (CA)***

***Osservazioni***

***Allegato-2***



Analisi costi benefici e approfondimenti  
del collegamento HVDC Sicilia-Campania  
(East Link)

**Estratto**

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## 1 Executive Summary

A partire dal Piano di Sviluppo 2018, Terna ha pianificato la realizzazione di un collegamento HVDC (alta tensione in corrente continua) tra la penisola italiana, la Sicilia e la Sardegna, denominato Collegamento HVDC Continente – Sicilia – Sardegna (di seguito indicato come “Tyrrhenian Link” o “TL” o “configurazione Full”) per garantire la sicurezza e l’adeguatezza del sistema elettrico a fronte dell’atteso decommissioning degli impianti a carbone e degli impianti più obsoleti e a maggior impatto ambientale, permettere una migliore penetrazione della generazione rinnovabile, limitando fenomeni di curtailment, e ridurre i costi sul mercato dell’energia e dei servizi per il dispacciamento, riducendo le congestioni sulla rete. Il Tyrrhenian Link è il progetto più importante di abilitazione al processo di decarbonizzazione e della transizione ecologica del settore elettrico.

Il Tyrrhenian Link è costituito da due collegamenti HVDC punto–punto e quattro Stazioni di Conversione (SdC), ciascuna con capacità di conversione pari a 1000 MW. I due collegamenti, Sardegna- Sicilia (di seguito anche West Link) e Sicilia–Continente (di seguito anche East Link) interagiscono strettamente fra loro in tutte le condizioni di esercizio, anche attraverso logiche di controllo delle rispettive SdC.

Il presente documento fa seguito alla richiesta dell’ARERA, inclusa nel Parere del 22 Dicembre 2020 n. 574/2020/I/EEL sui Piani di Sviluppo 2019 e 2020, di effettuare l’analisi costi benefici ed ulteriori approfondimenti per il solo tratto del collegamento HVDC Sicilia – Continente prendendo come riferimento gli scenari utilizzati per la predisposizione del Piano di sviluppo 2021.

In particolare, ARERA ha richiesto di effettuare:

- **l’analisi costi benefici del collegamento HVDC Sicilia-Continente**, nelle seguenti ipotesi:
  - I. in presenza e in assenza dell’interconnessione Italia - Tunisia;
  - II. con la valorizzazione del beneficio B7 “variazione dei costi per servizi di rete e per approvvigionamento di risorse sul mercato per il servizio di dispacciamento” con riferimento ai costi sostenuti dagli operatori per fornire servizi e ai costi di approvvigionamento delle risorse nel mercato dei servizi.
- **ulteriori approfondimenti e valutazioni finalizzate ad evidenziare le interdipendenze** dell’intervento HVDC Sicilia-Continente con gli elettrodotti Caracoli - Ciminna (codice 627-P) e Assoro - Sorgente 2 - Villafranca (codici 604-P e 619-P), considerando anche i nuovi interventi infrastrutturali in Sicilia previsti nel PdS 21.

Nel presente rapporto sono contenute le analisi richieste da ARERA e informazioni ulteriori utili ai fini di una piena valutazione dell’utilità economica del collegamento HVDC Sicilia-Continente.

In merito alla valorizzazione del beneficio B7 – ovvero del risparmio nel costo di approvvigionamento delle risorse nel mercato dei servizi di dispacciamento – l’analisi è stata condotta in linea con la metodologia di cui all’allegato metodologico al PdS (Metodologia analisi costi benefici – ACB 2.0), considerando che le nuove UP alimentate a gas nelle isole siano contrattualizzate nell’ambito del Capacity Market. Pertanto, le offerte a salire di tali impianti sono state ipotizzate pari allo strike price del Capacity Market, per la quantità per cui dette UP sono essenziali. Per quanto riguarda, invece, la valorizzazione del beneficio B4 è stato considerato il costo di reintegrazione del Capacity Market per la nuova capacità termoelettrica installata, pari a 75 k€/MW.

Terna per valutare l’efficienza della realizzazione del collegamento HVDC Sicilia-Continente ha ritenuto corretto effettuare un’analisi di comparazione dei costi totali degli impianti e delle infrastrutture alternative

al collegamento necessarie, comunque, a garantire una gestione in sicurezza del sistema elettrico della Sicilia (analisi costi totali infrastrutturali).

I risultati dell'analisi costi benefici, del confronto infrastrutturale, nonché degli approfondimenti tecnici, dettagliati nel seguito del presente report, dimostrano l'efficienza della soluzione proposta rispetto alle alternative infrastrutturali possibili e la piena sostenibilità economica in termini di analisi costi-benefici del collegamento HVDC Sicilia – Continente.

In particolare, gli studi effettuati ai fini dell'analisi costi-benefici del collegamento East Link evidenziano:

- **benefici derivanti dalla realizzazione del collegamento** principalmente legati a:
  - raggiungimento degli obiettivi prefissati per la transizione energetica in atto, in termini di phase out degli impianti a maggiori emissioni inquinanti (carbone e olio nelle Isole maggiori), mantenendo le condizioni di sicurezza e adeguatezza delle Isole;
  - integrazione di nuova generazione da fonti rinnovabili;
  - risoluzione delle condizioni di essenzialità di capacità nelle Isole e riduzione della capacità termoelettrica complessivamente necessaria in Italia;
  - possibilità di esercire il collegamento Sicilia Sardegna a piena potenza;
- **valori elevati dell'indice di utilità (IUS) e di valore attuale netto sia in presenza che in assenza del collegamento HVDC Italia-Tunisia:** con valori di IUS nell'intervallo 2,5 -3,1 nello scenario NT-IT 2030-2040 e 1,5-1,7 nello scenario BAU 2030-2040.

**L'analisi delle interdipendenze** con gli altri progetti pianificati evidenzia che l'utilità del collegamento East Link è confermata nelle diverse configurazioni di rete previste negli scenari futuri così come è confermata l'utilità economica dei medesimi progetti in presenza del nuovo collegamento East Link.

Per quanto riguarda l'analisi di **comparazione infrastrutturale**:

- la configurazione con entrambi i collegamenti in esercizio (configurazione Full) risulta essere quella con i **minori costi infrastrutturali complessivi** nell'orizzonte di 25 anni considerato nell'analisi e quella che garantisce l'esercizio in sicurezza di entrambe le isole con minimizzazione della necessità di capacità termoelettrica installata e dell'over generation di sistema;
- In assenza del ramo East Link, non è possibile esercire a piena capacità il ramo West-link garantendo adeguati standard di esercizio per le Isole. Pertanto, sarebbero necessari circa 700 MW di capacità di generazione termoelettrica rispetto alla configurazione completa del Tyrrhenian Link, di cui 300 MW di capacità termoelettrica addizionali in Sardegna (ovverosia sarebbero necessari 850 MW in luogo dei 550 MW previsti) o, in alternativa, aggiuntivi in Sicilia occidentale.

Il presente report è strutturato come segue:

- Cap. 2.2 Analisi costi benefici del collegamento East Link in presenza del collegamento Italia – Tunisia;
- Cap. 2.3 Analisi costi benefici del collegamento East Link in assenza dell'intervento HVDC Italia – Tunisia;
- Cap. 3 Approfondimenti sulle interdipendenze con i principali interventi in altissima tensione (AAT) previsti in Sicilia;
- Cap. 4 Analisi comparativa dei costi per il sistema in relazione alle infrastrutture necessarie alla gestione in sicurezza dei sistemi elettrici di Sicilia e Sardegna.



*[Omissis...]*

## 4 Analisi comparativa dei costi per il sistema in relazione alle infrastrutture necessarie alla gestione in sicurezza dei sistemi elettrici di Sicilia e Sardegna

Nel seguente paragrafo è riportata una valutazione comparativa dei costi complessivi per il sistema necessari per esercire al 2030 i sistemi elettrici di Sicilia e Sardegna in sicurezza.

L'obiettivo dell'analisi è stata l'individuazione della capacità programmabile minima da installare nelle due isole – successivamente al phase out degli impianti a olio/carbone ed in assenza degli sviluppi degli accumuli previsti nello scenario National Trend Italia – rispetto a due diverse configurazioni del collegamento Tyrrhenian Link, di seguito rappresentate:

- **Configurazione 1:** (nel seguito denominata Full): che prevede la presenza del collegamento HVDC bipolare da 1000 MW tra Sicilia e Sardegna e dell'analogo collegamento tra Sicilia e Campania;
- **Configurazione 2:** (nel seguito denominata West Link 1000): che prevede in servizio il solo tratto Sardegna-Sicilia del collegamento HVDC.

Per ciascuna delle configurazioni infrastrutturali ipotizzate, è stata individuata la capacità minima di generazione termoelettrica a gas necessaria a soddisfare il fabbisogno elettrico delle due isole ed a garantire target adeguati all'esercizio in sicurezza (sia in termini di Energia Non Fornita (ENF) che di fabbisogno di riserva non coperto a salire). Al contempo si è valutato anche il livello di OG (a livello nazionale) per le configurazioni infrastrutturali analizzate.

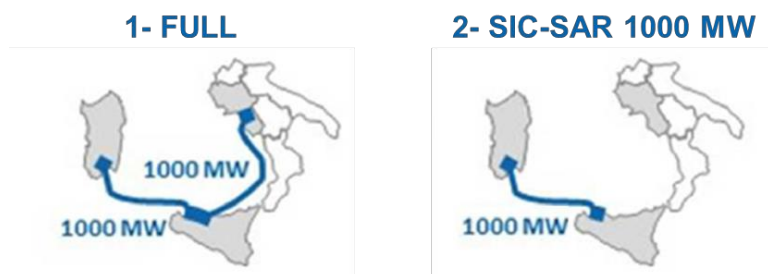


Figura 11 - Configurazioni infrastrutturali considerate

Per poter effettuare la comparazione dei costi complessivi di sistema sono stati considerati i costi di investimento, i costi fissi e i costi variabili per ciascuna infrastruttura ipotizzata nelle configurazioni. In particolare, i costi variabili attribuiti al termoelettrico sono stati valorizzati mediante il prodotto tra il differenziale di OG ottenuto (su isole e continente) rispetto al caso che registra minore OG ed il costo medio di generazione degli impianti termoelettrici presenti sul territorio nazionale.

Per soddisfare la stessa domanda di energia elettrica, l'OG aggiuntiva ottenuta nelle diverse opzioni rispetto al caso migliore simulato viene infatti sostituita da analoga quantità di generazione termoelettrica; per questo si è ritenuto che il modo più corretto di valorizzare il differenziale di costo variabile tra le due configurazioni fosse valorizzare direttamente il delta di OG, trascurando anche l'ulteriore aumento dei costi dovuto all'utilizzo di mix di generazione meno efficiente in caso di realizzazione del solo tratto Sicilia-Sardegna e, quindi, sottodimensionando i costi variabili di tale configurazione rispetto a quella Full.

#### 4.1.1 Ipotesi e Metodologia adottate per l'analisi

L'analisi comparativa dei costi di seguito riportata esamina le due configurazioni in presenza (configurazione Full) e in assenza del collegamento East Link (denominata configurazione West Link). In entrambe le configurazioni il tratto Sicilia-Sardegna è in servizio con una capacità di interconnessione pari a 1000 MW).

Date queste premesse, l'analisi è stata effettuata seguendo un approccio che:

- prende come riferimento lo scenario NT Italia, pubblicato da Terna e Snam a Febbraio 2021, per gli anni 2030 e 2040; rispetto a questo scenario, mantenendo la domanda elettrica ed un livello di penetrazione delle fonti rinnovabili identici a quelli previsti nello scenario NT nelle due isole, è stato prevista:
  - l'assenza di sistemi di accumulo (di seguito: SdA) aggiuntivi rispetto alla situazione attuale;
  - la dismissione degli impianti termoelettrici attualmente alimentati a olio/carbone (San Filippo del Mela, Fiume Santo, Saras, Sulcis, Ottana), per poi individuare il fabbisogno minimo di nuova capacità di generazione a gas.

Nella successiva tabella sono riportati i valori di domanda e di capacità produttiva installata nelle due isole maggiori nello scenario di partenza utilizzato per le simulazioni.

NT 30	Sardegna	Sicilia
Domanda [TWh]	9.8	20.6
Domanda di picco [GW]	1.9	3.9
Termoelettrico <sup>4</sup> [GW]	0.2	3.6
Storage [GW]	0.3	0.6
Solare + Eolico [GW]	4.7	7.9
NT 40	Sardegna	Sicilia
Domanda [TWh]	11.4	23.6
Domanda di picco [GW]	2.5	4.8
Termoelettrico <sup>4</sup> [GW]	0.2	3.4
Storage [GW]	0.3	0.6
Solare + Eolico [GW]	7.1	10.8

Tabella 10 - Installato e domanda in Sicilia e Sardegna nello scenario di partenza

- considera l'attualizzazione dei costi delle configurazioni infrastrutturali e dal loro valore residuo;
- considera un orizzonte temporale di 25 anni;
- calcola l'over generation (OG) variabile negli anni studio al 2030 e al 2040 ai fini della valorizzazione dei costi variabili del termoelettrico, considerando l'evoluzione di domanda e della capacità installata da fonti energetiche non programmabili negli scenari NT 2030 e 2040.

Ai fini dell'individuazione della capacità termoelettrica necessaria per l'esercizio in sicurezza nelle due isole, l'analisi:

- considera input derivanti dagli esiti di altre analisi di sicurezza della rete (analisi di rete statiche in N e N-1 o analisi dinamiche) condotte come ulteriori approfondimenti rispetto all'opera e descritte in questo documento;

<sup>4</sup> Comprende quota biomasse e altre non RES

- prevede simulazioni di mercato e di affidabilità iterative, come riportato in Figura 12, incrementando la capacità termica installata nelle due isole fino a raggiungere gli standard di adeguatezza e sicurezza utilizzati nella gestione del sistema di trasmissione.

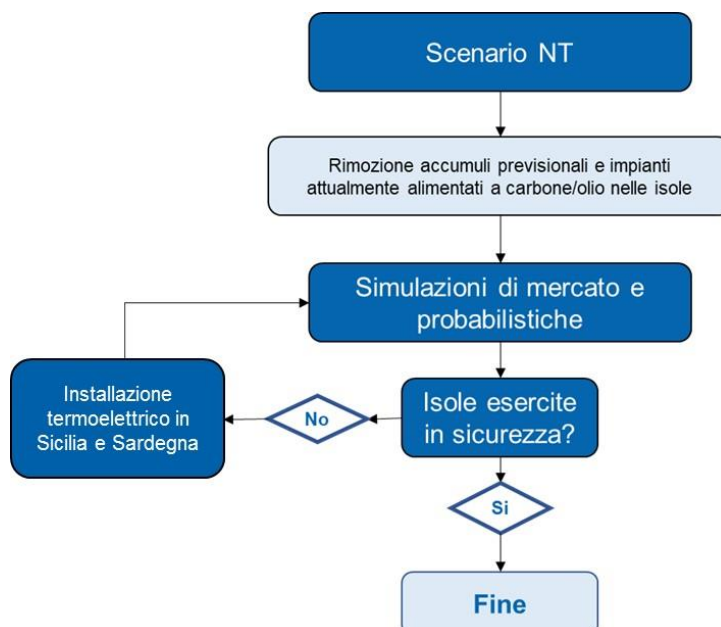


Figura 12 - Metodo iterativo utilizzato

Infine, relativamente al calcolo di adeguatezza, si tiene a precisare che è stato utilizzato un tool di simulazione probabilistico, metodo normalmente impiegato anche in ambito Europeo per le analisi di adeguatezza della rete su orizzonti temporali di lungo periodo. Tali strumenti eseguono simulazioni annuali statiche con granularità orarie fornendo come output i valori medi di energia non fornita e di ore in cui il carico non viene soddisfatto. I risultati ottenuti, in termini di capacità infrastrutturale minima, possono essere considerati come il valore minimo per garantire mediamente l'adeguatezza del sistema.

#### 4.1.2 Definizione dei costi infrastrutturali

Nel presente paragrafo vengono riportate le assunzioni per la stima dei costi utilizzati (costi di investimento iniziali e costi di O&M annuali per il Tyrrhenian Link ed impianti termoelettrici e costi variabili annuali di generazione termoelettrica) nelle diverse configurazioni infrastrutturali.

Relativamente al Tyrrhenian Link, nella Tabella 11 sono rappresentate le stime dei costi iniziali di investimento e dei costi annuali di O&M per le configurazioni individuate, assumendo una vita utile pari a 40 anni, valore determinato come media della vita utile regolatoria prevista per le linee elettriche di trasmissione e per le stazioni.

Costi Tyrrhenian Link	FULL	WEST LINK	EAST LINK
Investimento opera [B€]	3,7	1,9	1,8
Costi O&M [M€/y]	≈ 7	≈ 3,5	≈ 3,4
Vita Utile [y]	40	40	40

Tabella 11 - Stima dei costi per le diverse configurazioni del TL

Per quanto riguarda gli impianti di generazione termoelettrica a gas necessari nelle diverse configurazioni sono stati utilizzati i dati presenti in Tabella 12, il costo unitario di 650.000 €/MW è riferito alla tecnologia CCGT estratto dal documento RSE<sup>5</sup> “Energia elettrica, anatomia dei costi (Aggiornamento dati al 2015)”.

Costo Termoelettrico a gas	
Investimento specifico opera [M€/MW]	0,65
Costi fissi [€/MW/y]	15 000
Costi variabili 2030 [€/MWh]	56,3
Costi variabili 2040 [€/MWh]	76,1
Vita utile [anni]	25

Tabella 12 - Stima dei costi relativi alla capacità di generazione termoelettrica necessaria nelle diverse configurazioni

I costi fissi sono riferiti alla nuova capacità di generazione<sup>6</sup>, mentre i costi variabili (che comprendono anche i costi di combustibile e della CO<sub>2</sub>) corrispondono al costo variabile unitario della tecnologia CCGT dello scenario National Trend Italia, senza considerare il differenziale di costo associato all’approvvigionamento a gas nell’isola.

Le analisi condotte hanno evidenziato che il numero di ore equivalenti annue di funzionamento della nuova capacità a gas in Sardegna varia tra circa 1700 e circa 2100 nello scenario NT-IT 30, e tra circa 2300 e circa 2800 nello scenario NT-IT 40, rispettivamente con e senza il ramo EAST. Si consideri che le ore riportate si riferiscono ad un funzionamento del parco termoelettrico a piena potenza; considerando, invece, l’utilizzo medio del parco – come risultante dalle simulazioni per esigenze di copertura del fabbisogno, fornitura di riserva e bilanciamento – le ore di presenza in servizio si attestano tra poco meno di 4000 e poco più di 6000, a seconda dello scenario e configurazione dell’opera considerata.

Un tale regime di funzionamento rende più conveniente l’installazione di impianti a ciclo combinato rispetto ad impianti turbogas, anche considerando il maggior costo di investimento (CAPEX) generalmente associato agli impianti CCGT.

Per quanto riguarda i costi variabili di generazione termoelettrica, questi sono stati valorizzati moltiplicando il differenziale di OG ottenuto rispetto al caso Full (sia nello scenario NT al 2030 che al 2040) per il costo medio di generazione degli impianti termoelettrici presenti sul territorio nazionale, senza considerare il differenziale di costo riconducibile all’approvvigionamento del gas sulle isole.

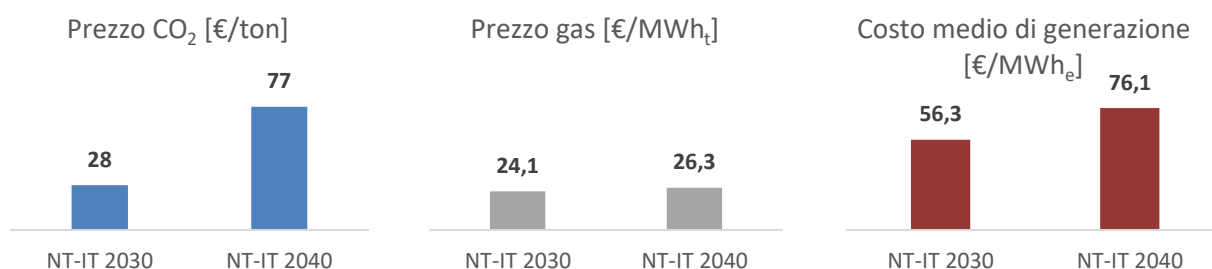
Al fine di riflettere l’evoluzione attesa dei prezzi di CO<sub>2</sub> e gas nell’orizzonte temporale considerato per l’analisi, il costo medio di generazione è stato fatto evolvere interpolando linearmente i seguenti valori nell’orizzonte 2030-2040:

- 56,3 €/MWh (costo da scenario NT 2030);
- 76,1 €/MWh (costo da scenario NT 2040);

e mantenendoli invece fissi all’esterno di tale intervallo.

<sup>5</sup> Valore tratto dal documento RSE “Energia elettrica, anatomia dei costi (Aggiornamento dati al 2015)”, disponibile al seguente [link](#)

<sup>6</sup> In coerenza con le ipotesi utilizzate da ENTSO-E per l’elaborazione degli scenari a supporto del TYNDP 2020 ([https://www.entsos-tyndp2020-scenarios.eu/wp-content/uploads/2020/07/TYNDP\\_2020\\_Scenario\\_Building-Guidelines\\_03\\_Annex\\_2\\_Cost\\_Assumptions\\_final\\_report.pdf](https://www.entsos-tyndp2020-scenarios.eu/wp-content/uploads/2020/07/TYNDP_2020_Scenario_Building-Guidelines_03_Annex_2_Cost_Assumptions_final_report.pdf))



Infine, si riportano le ipotesi alla base dell'analisi economica, come elencate di seguito:

- ai fini dell'attualizzazione è stato utilizzato un tasso di sconto del 3% <sup>7</sup> (in termini reali) rispetto all'anno 2021;
- i costi totali di investimento per tutti gli impianti sono stati imputati all'anno 2028, assunto per semplicità come anno di entrata in esercizio delle configurazioni infrastrutturali complete, in linea con l'anno di entrata in esercizio del Tyrrhenian Link in configurazione Full;
- il resto dei costi (O&M e costi variabili di generazione termoelettrica) sono stati considerati annualmente dall'anno successivo a quello di entrata in esercizio per un orizzonte di 25 anni (dal 2029 al 2053), in coerenza con l'orizzonte di analisi considerato per le analisi costi-benefici applicate agli interventi presenti nei Piani di Sviluppo della trasmissione elettrica;
- il valore residuo degli impianti al termine dell'orizzonte temporale oggetto di analisi (pari a 25 anni) è stato calcolato come valore netto del costo di investimento ancora da ammortizzare negli anni di vita rimanenti dell'impianto fino al termine della sua vita utile.

#### 4.1.3 Esiti dell'analisi

Nella tabella seguente si riportano gli esiti dello studio in termini di capacità termoelettrica necessaria da installare nelle due isole, di OG differenziale tra i due casi analizzati e di costi complessivi per il sistema elettrico nell'orizzonte considerato.

Configurazione	Termoelettrico necessario nelle isole [MW]	$\Delta$ OG (NT-IT 2030) [GWh]	$\Delta$ OG (NT-IT 2040) [GWh]	Totale Costi Attualizzati [M€]
<b>FULL</b>	550	-	-	<b>2.977</b>
<b>WEST LINK 1000</b>	1.250	≈600	≈1.400	<b>3.390</b>

Tabella 13 – Esiti dell'analisi comparativa dei costi per le configurazioni infrastrutturali ipotizzate

La comparazione dei risultati ottenuti evidenzia che:

<sup>7</sup> Seguendo le recenti Linee guida della Commissione Europea per le analisi dei Fondi di coesione e sviluppo regionale in tema di "social discount rate"

- **la configurazione Full riesce a garantire l'esercizio in sicurezza di entrambe le isole, favorendo la dismissione di 700 MW** di capacità termoelettrica presente nelle due Isole e **minimizzando l'OG di sistema** rispetto alla configurazione con il solo West Link;
- **con la configurazione West Link 1000 MW sarebbero necessari 700 MW di nuova capacità termoelettrica**, localizzata per **400 MW in Sicilia e 300 MW dislocabili anche in Sardegna (o in Sicilia occidentale)**, al fine di poter esercire il tratto West del TL a piena potenza e garantire adeguati standard di esercizio in Sicilia e Sardegna;
- la maggiore capacità di generazione installata nella **configurazione West Link 1000 comporta un volume di OG maggiore** rispetto al caso Full, **che, nell'anno studio 2040 porta ad un differenziale di più di 1 TWh tra le due configurazioni;**
- **la configurazione Full risulta essere quella con i minori costi totali** da sostenere nell'orizzonte considerato (con un risparmio maggiore del 10% rispetto alla configurazione West Link 1000).

**[ID 12481]**


***Progetto di un impianto agrivoltaico, della potenza complessiva pari a 34,769 MWp, da realizzarsi in località Villamuscas - Comune di Uta (CA)***

***Osservazioni***

***Allegato-3***



# SCIENTIFIC REPORTS



OPEN

## The Photovoltaic Heat Island Effect: Larger solar power plants increase local temperatures

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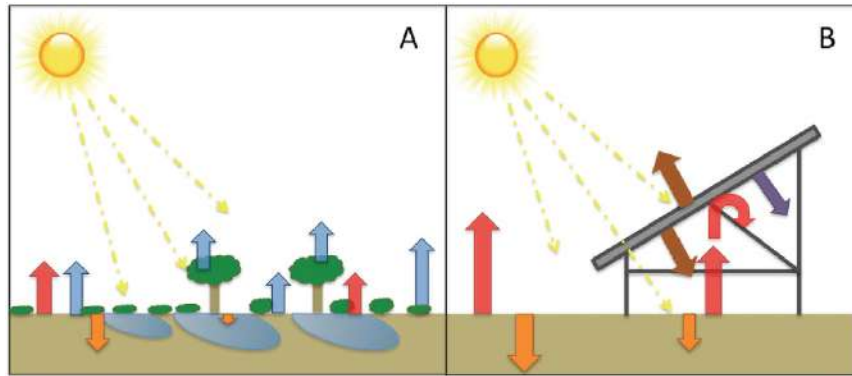
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While photovoltaic (PV) renewable energy production has surged, concerns remain about whether or not PV power plants induce a “heat island” (PVHI) effect, much like the increase in ambient temperatures relative to wildlands generates an Urban Heat Island effect in cities. Transitions to PV plants alter the way that incoming energy is reflected back to the atmosphere or absorbed, stored, and reradiated because PV plants change the albedo, vegetation, and structure of the terrain. Prior work on the PVHI has been mostly theoretical or based upon simulated models. Furthermore, past empirical work has been limited in scope to a single biome. Because there are still large uncertainties surrounding the potential for a PVHI effect, we examined the PVHI empirically with experiments that spanned three biomes. We found temperatures over a PV plant were regularly 3–4 °C warmer than wildlands at night, which is in direct contrast to other studies based on models that suggested that PV systems should decrease ambient temperatures. Deducing the underlying cause and scale of the PVHI effect and identifying mitigation strategies are key in supporting decision-making regarding PV development, particularly in semiarid landscapes, which are among the most likely for large-scale PV installations.

Electricity production from large-scale photovoltaic (PV) installations has increased exponentially in recent decades<sup>1–3</sup>. This proliferation in renewable energy portfolios and PV powerplants demonstrate an increase in the acceptance and cost-effectiveness of this technology<sup>4,5</sup>. Corresponding with this upsurge in installation has been an increase in the assessment of the impacts of utility-scale PV<sup>4,6–8</sup>, including those on the efficacy of PV to offset energy needs<sup>9,10</sup>. A growing concern that remains understudied is whether or not PV installations cause a “heat island” (PVHI) effect that warms surrounding areas, thereby potentially influencing wildlife habitat, ecosystem function in wildlands, and human health and even home values in residential areas<sup>11</sup>. As with the Urban Heat Island (UHI) effect, large PV power plants induce a landscape change that reduces albedo so that the modified landscape is darker and, therefore, less reflective. Lowering the terrestrial albedo from ~20% in natural deserts<sup>12</sup> to ~5% over PV panels<sup>13</sup> alters the energy balance of absorption, storage, and release of short- and longwave radiation<sup>14,15</sup>. However, several differences between the UHI and potential PVHI effects confound a simple comparison and produce competing hypotheses about whether or not large-scale PV installations will create a heat island effect. These include: (i) PV installations shade a portion of the ground and therefore could reduce heat absorption in surface soils<sup>16</sup>, (ii) PV panels are thin and have little heat capacity per unit area but PV modules emit thermal radiation both up and down, and this is particularly significant during the day when PV modules are often 20 °C warmer than ambient temperatures, (iii) vegetation is usually removed from PV power plants, reducing the amount of cooling due to transpiration<sup>14</sup>, (iv) electric power removes energy from PV power plants, and (v) PV panels reflect and absorb upwelling longwave radiation, and thus can prevent the soil from cooling as much as it might under a dark sky at night.

Public concerns over a PVHI effect have, in some cases, led to resistance to large-scale solar development. By some estimates, nearly half of recently proposed energy projects have been delayed or abandoned due to local opposition<sup>11</sup>. Yet, there is a remarkable lack of data as to whether or not the PVHI effect is real or simply an issue

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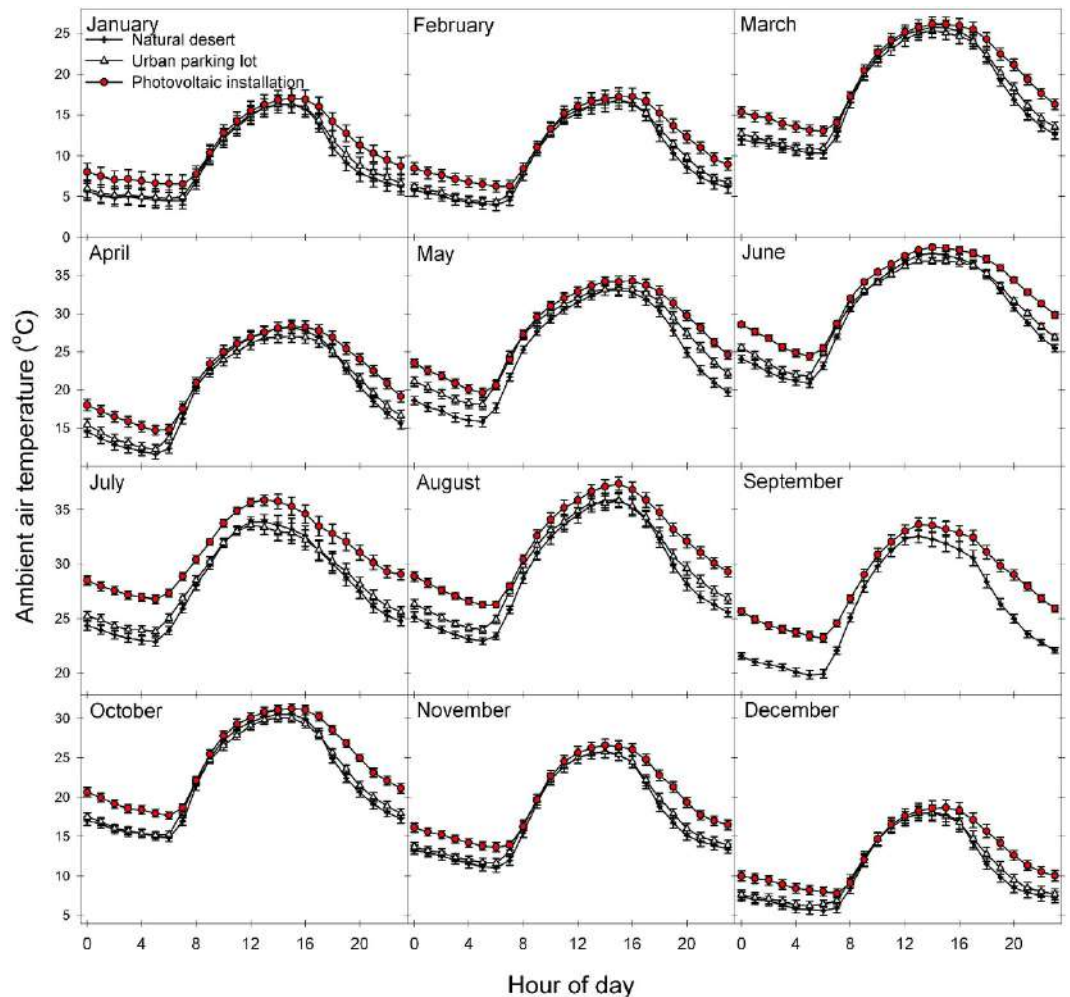
**Figure 1. Illustration of midday energy exchange.** Assuming equal rates of incoming energy from the sun, a transition from (A) a vegetated ecosystem to (B) a photovoltaic (PV) power plant installation will significantly alter the energy flux dynamics of the area. Within natural ecosystems, vegetation reduces heat capture and storage in soils (orange arrows), and infiltrated water and vegetation release heat-dissipating latent energy fluxes in the transition of water-to-water vapor to the atmosphere through evapotranspiration (blue arrows). These latent heat fluxes are dramatically reduced in typical PV installations, leading to greater sensible heat fluxes (red arrows). Energy re-radiation from PV panels (brown arrow) and energy transferred to electricity (purple arrow) are also shown.

associated with perceptions of environmental change caused by the installations that lead to “not in my backyard” (NIMBY) thinking. Some models have suggested that PV systems can actually cause a cooling effect on the local environment, depending on the efficiency and placement of the PV panels<sup>17,18</sup>. But these studies are limited in their applicability when evaluating large-scale PV installations because they consider changes in albedo and energy exchange within an urban environment (rather than a natural ecosystem) or in European locations that are not representative of semiarid energy dynamics where large-scale PV installations are concentrated<sup>10,19</sup>. Most previous research, then, is based on untested theory and numerical modeling. Therefore, the potential for a PVHI effect must be examined with empirical data obtained through rigorous experimental terms.

The significance of a PVHI effect depends on energy balance. Incoming solar energy typically is either reflected back to the atmosphere or absorbed, stored, and later re-radiated in the form of latent or sensible heat (Fig. 1)<sup>20,21</sup>. Within natural ecosystems, vegetation reduces heat gain and storage in soils by creating surface shading, though the degree of shading varies among plant types<sup>22</sup>. Energy absorbed by vegetation and surface soils can be released as latent heat in the transition of liquid water to water vapor to the atmosphere through evapotranspiration – the combined water loss from soils (evaporation) and vegetation (transpiration). This heat-dissipating latent energy exchange is dramatically reduced in a typical PV installation (Fig. 1 transition from A-to-B), potentially leading to greater heat absorption by soils in PV installations. This increased absorption, in turn, could increase soil temperatures and lead to greater sensible heat efflux from the soil in the form of radiation and convection. Additionally, PV panel surfaces absorb more solar insolation due to a decreased albedo<sup>13,23,24</sup>. PV panels will re-radiate most of this energy as longwave sensible heat and convert a lesser amount (~20%) of this energy into usable electricity. PV panels also allow some light energy to pass, which, again, in unvegetated soils will lead to greater heat absorption. This increased absorption could lead to greater sensible heat efflux from the soil that may be trapped under the PV panels. A PVHI effect would be the result of a detectable increase in sensible heat flux (atmospheric warming) resulting from an alteration in the balance of incoming and outgoing energy fluxes due to landscape transformation. Developing a full thermal model is challenging<sup>17,18,25</sup>, and there are large uncertainties surrounding multiple terms including variations in albedo, cloud cover, seasonality in advection, and panel efficiency, which itself is dynamic and impacted by the local environment. These uncertainties are compounded by the lack of empirical data.

We addressed the paucity of direct quantification of a PVHI effect by simultaneously monitoring three sites that represent a natural desert ecosystem, the traditional built environment (parking lot surrounded by commercial buildings), and a PV power plant. We define a PVHI effect as the difference in ambient air temperature between the PV power plant and the desert landscape. Similarly, UHI is defined as the difference in temperature between the built environment and the desert. We reduced confounding effects of variability in local incoming energy, temperature, and precipitation by utilizing sites contained within a 1 km area.

At each site, we monitored air temperature continuously for over one year using aspirated temperature probes 2.5 m above the soil surface. Average annual temperature was  $22.7 \pm 0.5$  °C in the PV installation, while the nearby desert ecosystem was only  $20.3 \pm 0.5$  °C, indicating a PVHI effect. Temperature differences between areas varied significantly depending on time of day and month of the year (Fig. 2), but the PV installation was always greater than or equal in temperature to other sites. As is the case with the UHI effect in dryland regions, the PVHI effect delayed the cooling of ambient temperatures in the evening, yielding the most significant difference in overnight temperatures across all seasons. Annual average midnight temperatures were  $19.3 \pm 0.6$  °C in the PV installation, while the nearby desert ecosystem was only  $15.8 \pm 0.6$  °C. This PVHI effect was more significant in terms of actual degrees of warming ( $+3.5$  °C) in warm months (Spring and Summer; Fig. 3, right).



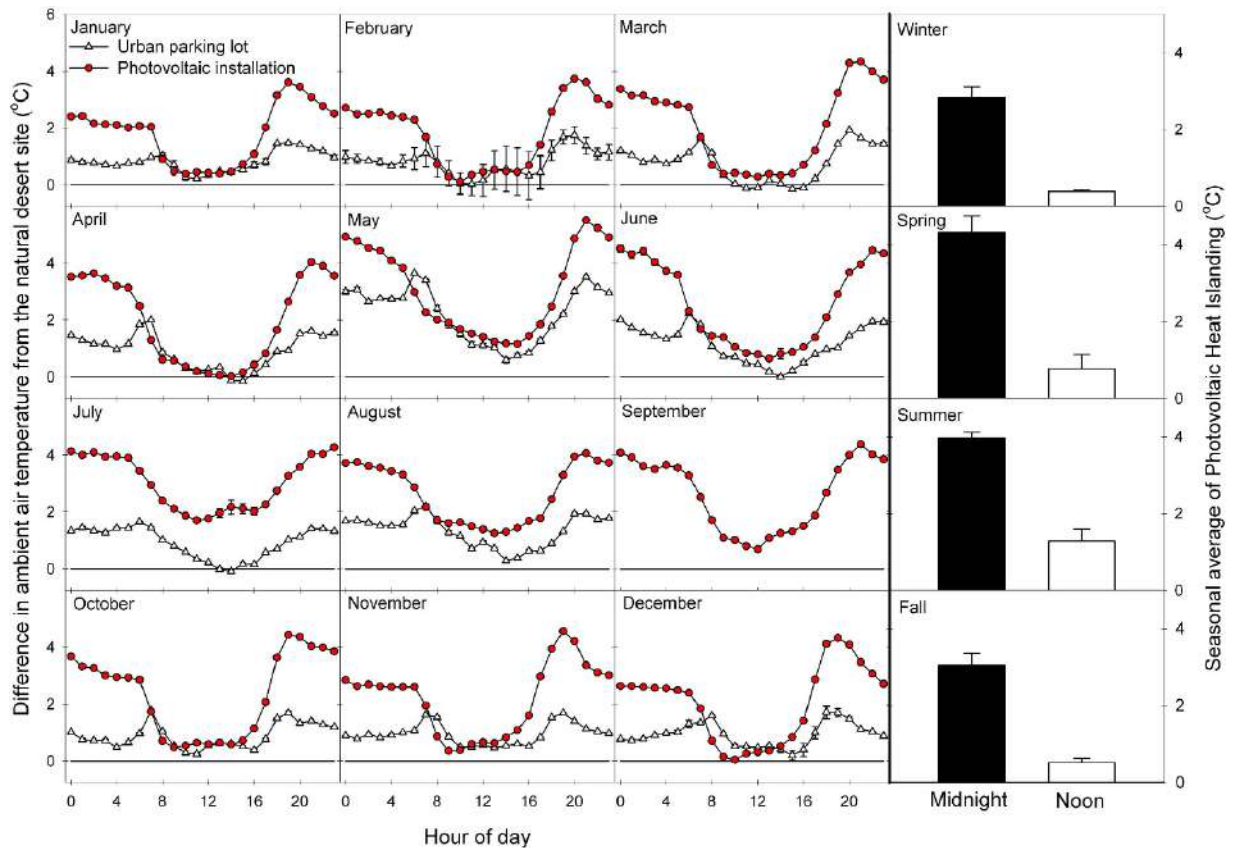
**Figure 2.** Average monthly ambient temperatures throughout a 24-hour period provide evidence of a photovoltaic heat island (PVHI) effect.

In both PVHI and UHI scenarios, the greater amount of exposed ground surfaces compared to natural systems absorbs a larger proportion of high-energy, shortwave solar radiation during the day. Combined with minimal rates of heat-dissipating transpiration from vegetation, a proportionally higher amount of stored energy is reradiated as longwave radiation during the night in the form of sensible heat (Fig. 1)<sup>15</sup>. Because PV installations introduce shading with a material that, itself, should not store much incoming radiation, one might hypothesize that the effect of a PVHI effect would be lesser than that of a UHI. Here, we found that the difference in evening ambient air temperature was consistently greater between the PV installation and the desert site than between the parking lot (UHI) and the desert site (Fig. 3). The PVHI effect caused ambient temperature to regularly approach or be in excess of 4 °C warmer than the natural desert in the evenings, essentially doubling the temperature increase due to UHI measured here. This more significant warming under the PVHI than the UHI may be due to heat trapping of re-radiated sensible heat flux under PV arrays at night. Daytime differences from the natural ecosystem were similar between the PV installation and urban parking lot areas, with the exception of the Spring and Summer months, when the PVHI effect was significantly greater than UHI in the day. During these warm seasons, average midnight temperatures were  $25.5 \pm 0.5$  °C in the PV installation and  $23.2 \pm 0.5$  °C in the parking lot, while the nearby desert ecosystem was only  $21.4 \pm 0.5$  °C.

The results presented here demonstrate that the PVHI effect is real and can significantly increase temperatures over PV power plant installations relative to nearby wildlands. More detailed measurements of the underlying causes of the PVHI effect, potential mitigation strategies, and the relative influence of PVHI in the context of the intrinsic carbon offsets from the use of this renewable energy are needed. Thus, we raise several new questions and highlight critical unknowns requiring future research.

### What is the physical basis of land transformations that might cause a PVHI?

We hypothesize that the PVHI effect results from the effective transition in how energy moves in and out of a PV installation versus a natural ecosystem. However, measuring the individual components of an energy flux model remains a necessary task. These measurements are difficult and expensive but, nevertheless, are indispensable in identifying the relative influence of multiple potential drivers of the PVHI effect found here. Environmental



**Figure 3.** (Left) Average monthly levels of Photovoltaic Heat Islanding (ambient temperature difference between PV installation and desert) and Urban Heat Islanding (ambient temperature difference between the urban parking lot and the desert). (Right) Average night and day temperatures for four seasonal periods, illustrating a significant PVHI effect across all seasons, with the greatest influence on ambient temperatures at night.

conditions that determine patterns of ecosystem carbon, energy, and water dynamics are driven by the means through which incoming energy is reflected or absorbed. Because we lack fundamental knowledge of the changes in surface energy fluxes and microclimates of ecosystems undergoing this land use change, we have little ability to predict the implications in terms of carbon or water cycling<sup>4,8</sup>.

### What are the physical implications of a PVHI, and how do they vary by region?

The size of an UHI is determined by properties of the city, including total population<sup>26–28</sup>, spatial extent, and the geographic location of that city<sup>29–31</sup>. We should, similarly, consider the spatial scale and geographic position of a PV installation when considering the presence and importance of the PVHI effect. Remote sensing could be coupled with ground-based measurements to determine the lateral and vertical extent of the PVHI effect. We could then determine if the size of the PVHI effect scales with some measure of the power plant (for example, panel density or spatial footprint) and whether or not a PVHI effect reaches surrounding areas like wildlands and neighborhoods. Given that different regions around the globe each have distinct background levels of vegetative ground cover and thermodynamic patterns of latent and sensible heat exchange, it is possible that a transition from a natural wildland to a typical PV power plant will have different outcomes than demonstrated here. The paucity in data on the physical effects of this important and growing land use and land cover change warrants more studies from representative ecosystems.

### What are the human implications of a PVHI, and how might we mitigate these effects?

With the growing popularity of renewable energy production, the boundaries between residential areas and larger-scale PV installations are decreasing. In fact, closer proximity with residential areas is leading to increased calls for zoning and city planning codes for larger PV installations<sup>32,33</sup>, and PVHI-based concerns over potential reductions in real estate value or health issues tied to Human Thermal Comfort (HTC)<sup>34</sup>. Mitigation of a PVHI effect through targeted revegetation could have synergistic effects in easing ecosystem degradation associated with development of a utility scale PV site and increasing the collective ecosystem services associated with an area<sup>4</sup>. But what are the best mitigation measures? What tradeoffs exist in terms of various means of revegetating degraded PV installations? Can other albedo modifications be used to moderate the severity of the PVHI?





**Figure 4. Experimental sites. Monitoring a (1) natural semiarid desert ecosystem, (2) solar (PV) photovoltaic installation, and (3) an “urban” parking lot – the typical source of urban heat islanding – within a 1 km<sup>2</sup> area enabled relative control for the incoming solar energy, allowing us to quantify variation in the localized temperature of these three environments over a year-long time period. The Google Earth image shows the University of Arizona’s Science and Technology Park’s Solar Zone.**

To fully contextualize these findings in terms of global warming, one needs to consider the relative significance of the (globally averaged) decrease in albedo due to PV power plants and their associated warming from the PVHI against the carbon dioxide emission reductions associated with PV power plants. The data presented here represents the first experimental and empirical examination of the presence of a heat island effect associated with PV power plants. An integrated approach to the physical and social dimensions of the PVHI is key in supporting decision-making regarding PV development.

## Methods

**Site Description.** We simultaneously monitored a suite of sites that represent the traditional built urban environment (a parking lot) and the transformation from a natural system (undeveloped desert) to a 1 MW PV power plant (Fig. 4; Map data: Google). To minimize confounding effects of variability in local incoming energy, temperature, and precipitation, we identified sites within a 1 km area. All sites were within the boundaries of the University of Arizona Science and Technology Park Solar Zone (32.092150°N, 110.808764°W; elevation: 888 m ASL). Within a 200 m diameter of the semiarid desert site’s environmental monitoring station, the area is composed of a sparse mix of semiarid grasses (*Sporobolus wrightii*, *Eragrostis lehmanniana*, and *Muhlenbergia porteri*), cacti (*Opuntia* spp. and *Ferocactus* spp.), and occasional woody shrubs including creosote bush (*Larrea tridentata*), whitethorn acacia (*Acacia constricta*), and velvet mesquite (*Prosopis velutina*). The remaining area is bare soil. These species commonly co-occur on low elevation desert bajadas, creosote bush flats, and semiarid grasslands. The photovoltaic installation was put in place in early 2011, three full years prior when we initiated monitoring at the site. We maintained the measurement installations for one full year to capture seasonal variation due to sun angle and extremes associated with hot and cold periods. Panels rest on a single-axis tracker system that pivot east-to-west throughout the day. A parking lot with associated building served as our “urban” site and is of comparable spatial scale as our PV site.

**Monitoring Equipment & Variables Monitored.** Ambient air temperature (°C) was measured with a shaded, aspirated temperature probe 2.5 m above the soil surface (Vaisala HMP60, Vaisala, Helsinki, Finland in the desert and Microdaq U23, Onset, Bourne, MA in the parking lot). Temperature probes were cross-validated for precision (closeness of temperature readings across all probes) at the onset of the experiment. Measurements of temperature were recorded at 30-minute intervals throughout a 24-hour day. Data were recorded on a data-logger (CR1000, Campbell Scientific, Logan, Utah or Microstation, Onset, Bourne, MA). Data from this

instrument array is shown for a yearlong period from April 2014 through March 2015. Data from the parking lot was lost for September 2014 because of power supply issues with the datalogger.

**Statistical analysis.** Monthly averages of hourly (on-the-hour) data were used to compare across the natural semiarid desert, urban, and PV sites. A Photovoltaic Heat Island (PVHI) effect was calculated as differences in these hourly averages between the PV site and the natural desert site, and estimates of Urban Heat Island (UHI) effect was calculated as differences in hourly averages between the urban parking lot site and the natural desert site. We used midnight and noon values to examine maximum and minimum, respectively, differences in temperatures among the three measurement sites and to test for significance of heat islanding at these times. Comparisons among the sites were made using Tukey's honestly significant difference (HSD) test<sup>35</sup>. Standard errors to calculate HSD were made using pooled midnight and noon values across seasonal periods of winter (January-March), spring (April-June), summer (July-September), and fall (October-December). Seasonal analyses allowed us to identify variation throughout a yearlong period and relate patterns of PVHI or UHI effects with seasons of high or low average temperature to examine correlations between background environmental parameters and localized heat islanding.

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### Author Contributions

G.A.B.-G., R.L.M. and N.A.A. established research sites and installed monitoring equipment. G.A.B.-G. directed research and R.L.M. conducted most site maintenance. G.A.B.-G., N.A.A., A.D.C. and M.A.P.-Z. led efforts to secure funding for the research. All authors discussed the results and contributed to the manuscript.

### Additional Information

**Competing financial interests:** The authors declare no competing financial interests.

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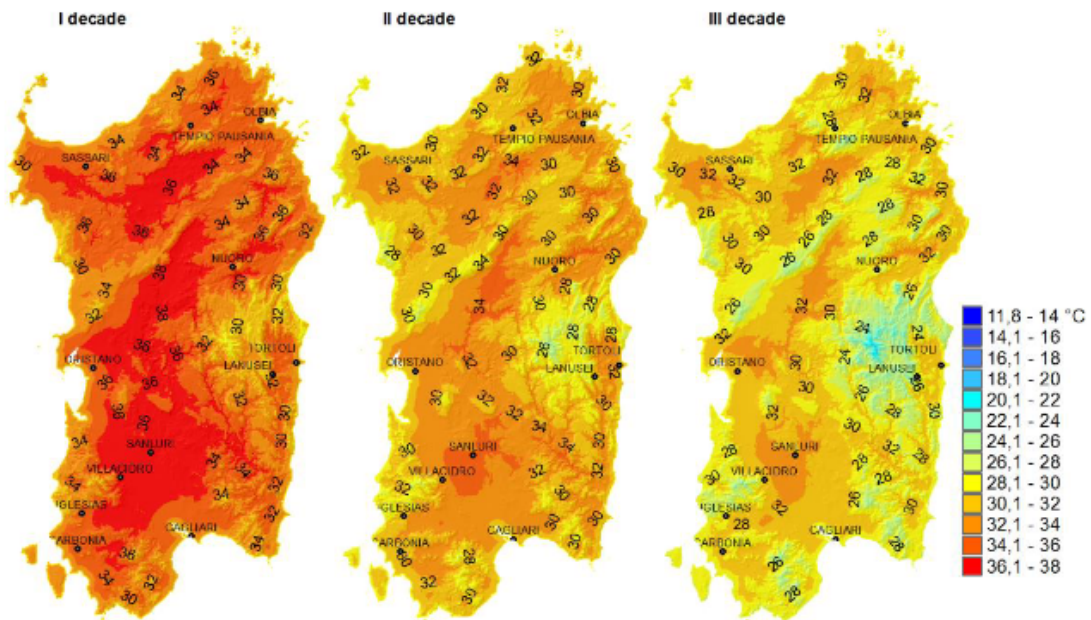
***Progetto di un impianto agrivoltaico, della potenza complessiva pari a 34,769 MWp, da realizzarsi in località Villamuscas - Comune di Uta (CA)***

***Osservazioni***

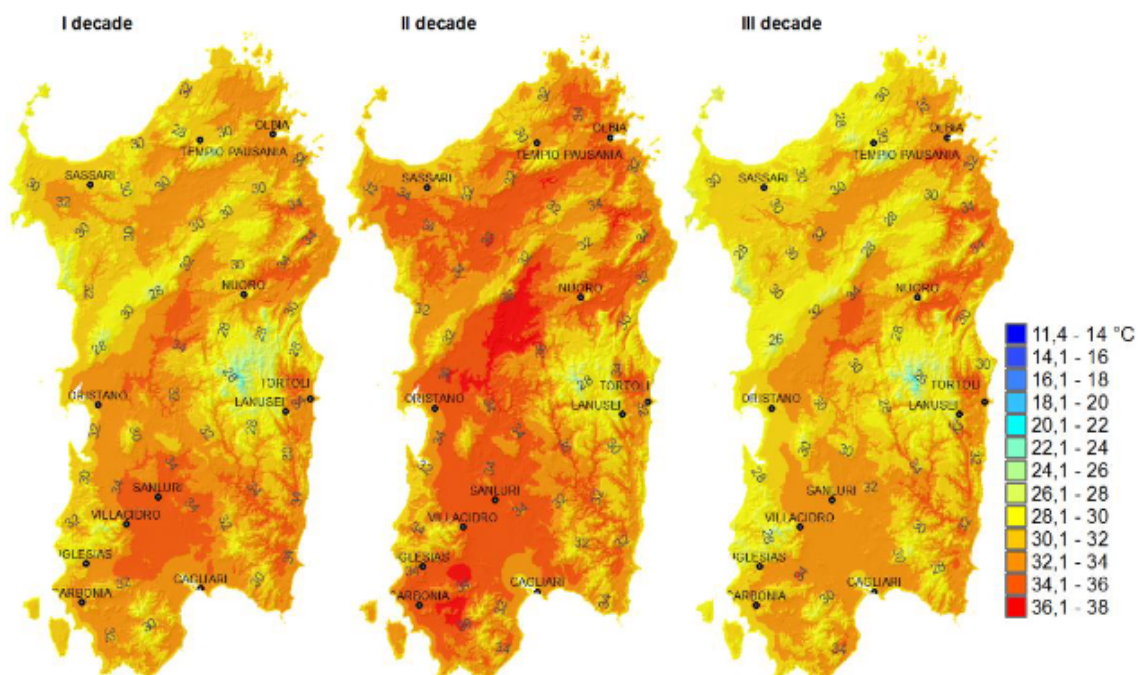
***Allegato-4***



**Estratto da: ARPA–Sardegna - Dipartimento Meteorologico - Servizio Meteorologico, Agrometeorologico ed Ecosistemi - Riepilogo mensile meteorologico e agrometeorologico - Mese: Agosto – Quinquennio 2019-2023**



**Figura 1: Valori medi decadali delle temperature massime registrate nel mese di Agosto 2019**



**Figura 2: Valori medi decadali delle temperature massime registrate nel mese di Agosto 2020**

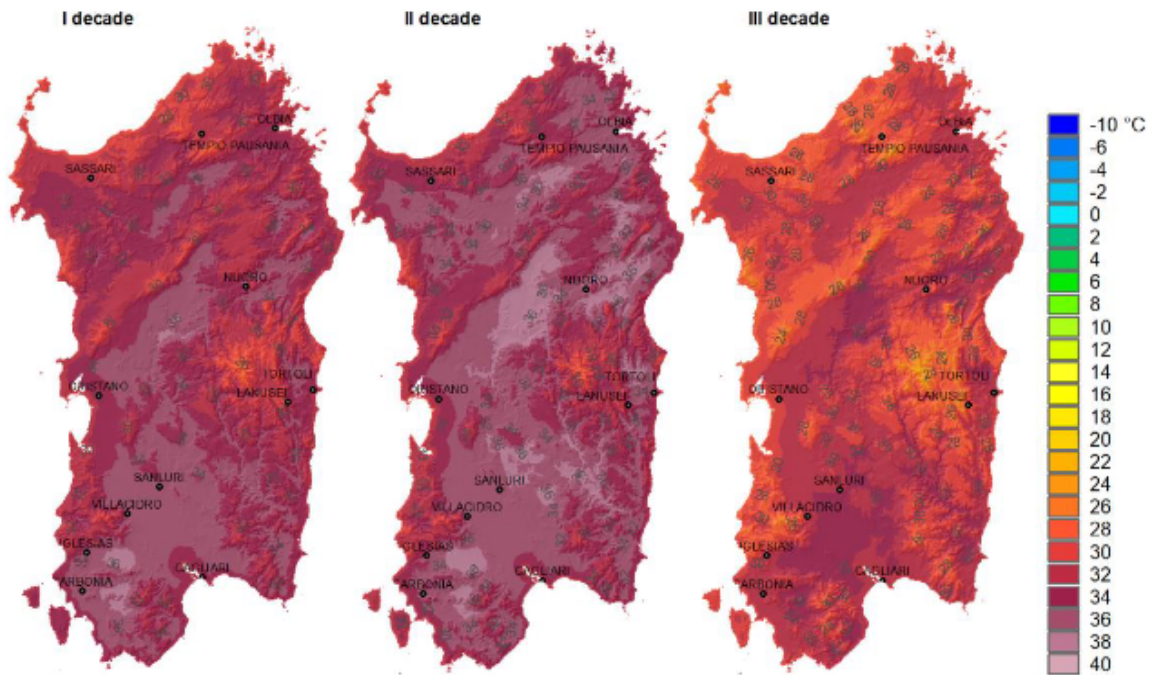


Figura 3: Valori medi decadali delle temperature massime registrate nel mese di Agosto 2021

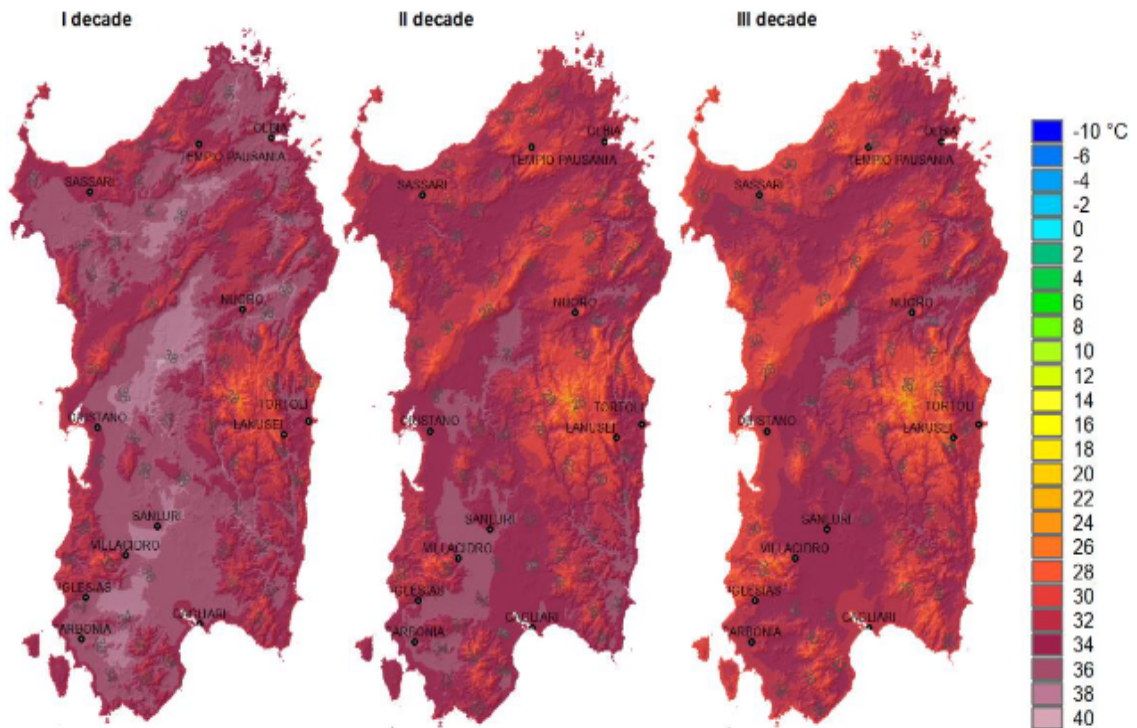
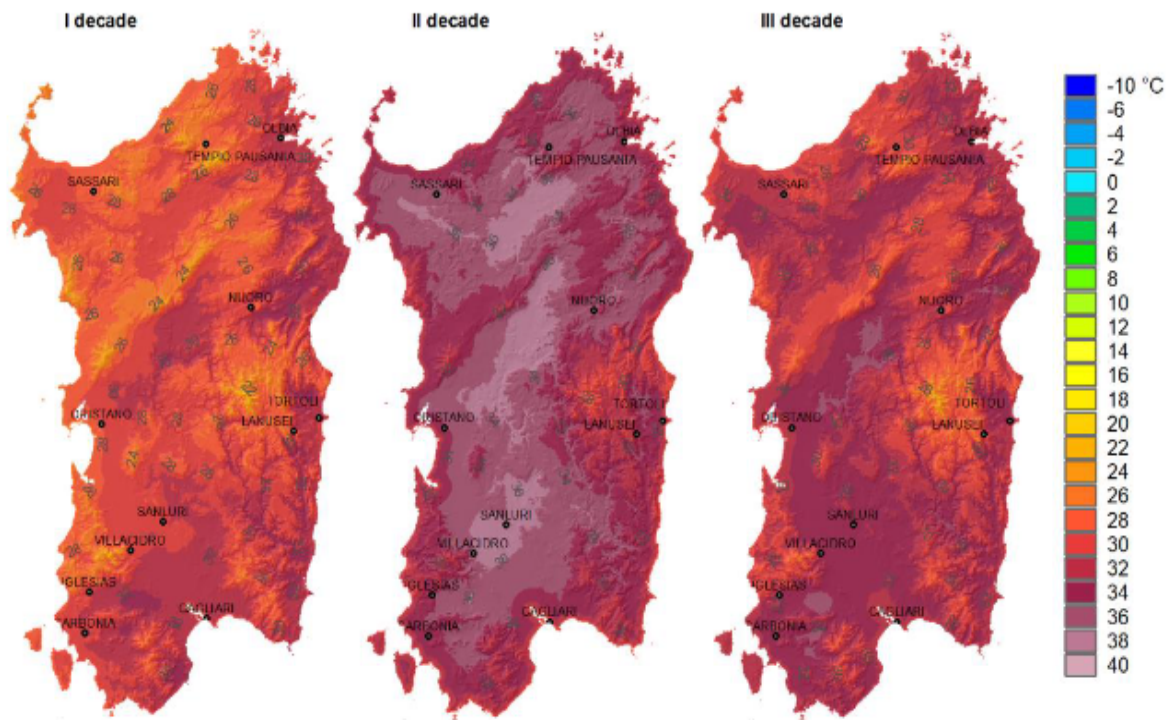


Figura 4: Valori medi decadali delle temperature massime registrate nel mese di Agosto 2022





**Figura 5: Valori medi decadali delle temperature massime registrate nel mese di Agosto 2023**

**N.B.:** Report originali integrali disponibili a richiesta