European Offshore Wind Energy Conference 2009
Stockholm, Sweden, 14th – 16th September

Optimising Redundancy of Offshore Electrical Infrastructure Assets by Assessment of Overall Economic Cost

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Abstract*:*
This paper describes a robust and comprehensive method for Optimising the Redundancy of Offshore Electrical Infrastructure Assets, by taking account of the energy yield probability distribution, individual wind turbine availability, component failure statistics and realistic assumptions for costs and timing of replacement activity among other factors in determining the overall economic cost. By examining different network topologies and levels of redundancy and undertaking sensitivity studies for the principal assumptions, a robust method for determining the appropriate level of redundancy can be reached. The proposed method is applied to the example of offshore substation transformers and some results for typical North Sea applications are derived and presented.

1 Introduction

The electrical power generated by offshore wind farms has to be transmitted to shore and the transmission grid via an export system. Poor reliability of this transmission system would have a major impact on the viability of offshore wind energy and hence the transmission system needs to be designed to an appropriate level of availability, must be maintained in good condition and the electrical plant replaced at appropriate intervals. To date, there have been a number of failures of offshore wind farm transmission assets, the majority involving cables, and a consequence has been the evolution of network design towards greater redundancy. At the same time, the increase in capacity and distance from the grid of recent offshore wind farms has led to greater complexity of design. The projects serving the German offshore wind market will take this a step further in terms of length of connection, some being over 100km long, and type of technology, for example the first deployment of HVDC technology to serve an offshore wind farm.

However, irrespective of the type of technology and quality of design, at some point increasing redundancy will cease to improve the overall effectiveness of the transmission system. In order to analyse and identify the optimal level of redundancy and associated configuration, it is necessary to consider the system as a whole, including all major parameters of the transmission system, including:

- Export system capacity factors, based on the anticipated power production probability distribution
- Value of the power generated
- Reliability of the transmission assets
- Redundancy of the transmission assets
- CAPEX and OPEX costs
- Repair costs and timing

For this paper, the case of the high voltage transformer on the offshore substation is examined: i.e. what is the optimal level of redundancy for this unit. The following redundancy scenarios are examined, Table 1:

TABLE 1: TRANSFORMER REDUNDANCY SCENARIOS

Scenario	Architecture	Total Capacity
0	single 100% capacity rated unit	100%
1	Twin 50% units	100%
2	Twin 60% units	120%
3	Twin 100% units	200%
4	Triple 33% units	100%
5	Triple 50% units	150%

The analysis described here assumes an offshore wind farm with the following characteristics, Table 2.

TABLE 2: WIND FARM CHARACTERISTICS

Parameter	Assumption	Comment
Wind Turbines	100 multi-megawatt wind turbines	i.e. 3 - 6 MW
Wind Resource	9.8 m/s mean wind speed at hub height	Annual variability as per FINO1
Availability	Annual 93%, monthly variation profile	Monthly profile derived from published data, Figure 10
PPA	€125/MWh	Arguably a low assumption
Operating Life	40 years	Repowering or wind turbine life extension
Discount Rate	10%	Inflation not modelled

2 Method

The analysis is undertaken in two stages:

(1) pre-analysis to determine marginal energy loss coefficients during downtime for various availability scenarios, per month and annual overall (i.e. impact of 50% export transmission constraint during April for a wind farm with a mean annual availability of 95% as well as all other permutations)

(2) optimal redundancy analysis (the analysis tool)

The analysis tool, written in Excel, models the scheduled as well as unscheduled failure and repair costs in terms of the following parameters:

- Costs of scheduled repair or replacement:
    - asset, cost is modelled as a complete replacement; this may be conservative but value of the lost energy production will be significantly higher
    - installation,
    - lost energy production.

- Costs of unscheduled repair or replacement
    - asset,
    - installation,
    - lost energy production,
    - Failure probability profile with age of asset.

- O&M
    - Annual maintenance,
    - Copper and iron losses; note that these losses are calculated in this study to provide an understanding of the magnitude of the associated lifetime costs; however, since a uniform energy loss factor has been assumed, the costs are identical for all redundancy scenarios and hence, in this paper, this factor has no impact on the optimisation. This was felt to be justified since, from examining a limited number of transformer functional specifications, no discernable trend against transformer capacity could be observed within the scatter of the data.

The transformer age-related failure profile published by CIGRÉ [1] has been used as the primary reference within this study, smoothed to allow the model to function more efficiently and adjusted to take account of the special conditions offshore.

2.1 Analysis Model Description and Assumptions

Examining each factor in turn:

Asset costs, including installation as well as any additional structural costs associated with larger platform required for redundant systems, are assumed to depend pro-rata on the rated capacity of the unit, and have been estimated as per Table 3. An adjustment is made for whether the replacement was planned or unplanned.

TABLE 3: KEY MODELLING ASSUMPTIONS

Electrical Equipment	**Transformer**	**Comments**
Unit cost	€ 10,000 per MVA	
Assumed power factor	0.95 PF	For calculating unit cost
Multiple units adjustment	Two units: 130% three units: 160%	Multiple units are more expensive; [1] suggests cost $\propto$ power $^{0.5\text{-}0.6}$
Unit cost unscheduled multiplier	133%	To account for distressed negotiation position or holding costs for spare unit
vessel hire	€ 100,000 /day	Reflects recent rates, which are at a historically high
Miscellaneous	50%	Of transformer and installation costs
	Scheduled Repairs	
Repair vessel days for 1st unit	7 days	Hire duration including mobilisation
Repair vessel days for additional units	2 days	To replace each additional unit
Downtime for 1st unit	60 days	Including any waiting-on-weather, preparatory work and re-commissioning
Days per additional unit	20 days	To repair each additional unit
Month of scheduled repairs	July	To ensure minimal disruption to power production
	Unscheduled Repairs	
Repair vessel rate - unscheduled hire multiplier	200%	To account for distressed negotiation position
Repair vessel - duration multiplier	125%	To take account of possibility that unscheduled repair work may take place under challenging weather conditions (i.e. might not occur in July)
Unscheduled Time to Repair	6 months	Estimated average total duration of non-availability of unit
	Scheduled Maintenance	
Downtime for each unit	8 hours	Annual maintenance
Direct Maintenance costs	€10k / hour	To cover manpower as well as all associated costs
Month of scheduled maintenance	July	To ensure minimal disruption to power production
	Transformer Losses	
Transformer Copper & Iron Losses	0.078%	Of rated wind farm capacity (assumed independent of transformer capacity)

The value of lost production is more complicated to determine since it depends on, amongst other variables:

- Wind farm and transmission asset capacity
- Mean wind farm capacity factor
- Unit value of lost power production
- Annual average wind speed hence energy yield probability distribution
- Wind speed variability hence energy yield variability throughout the year
- Annual average wind farm availability
- Wind farm availability variability throughout the year

The optimal Redundancy Architecture is assumed to be that where the DCF (Discounted Cash Flow) of the ownership cost is lowest. The ownership cost is assumed to consist of the original investment CAPEX, the OPEX, which is assumed to be constant and not increase with age of the transformer, and the repair costs, both scheduled and unscheduled, which are defined in Equations (1) to (3).

$$DCF = \sum_{year=1}^{Life} \begin{pmatrix} SR(year) \\ +O(year) \\ +UnR(year) \end{pmatrix} .(1-r)^{year} \qquad (1)$$

Where:
DCF = Discounted Cash Flow
SR (year) = Scheduled Replacement cost in that year
Life = lifetime of infrastructure
O (year) = Scheduled operation costs in that year
UnR (year) = Unscheduled Replacement costs in that year
Life = anticipated operating life of the substation
r = discount rate.

$$\begin{aligned} SR(year) = if\left(year = Y_{new}\right) \\ \begin{pmatrix} C_{asset} + C_{install} \\ + \Delta EY_{install}(month) \end{pmatrix} \end{aligned} \qquad (2)$$

Where:
C $_{asset}$ = cost of asset
C $_{install}$ = cost of installation
ΔEY$_{install}$ (season) = energy yield loss during installation and commissioning process; assumed to vary by month
Y$_{new}$ = year for scheduled renewal of plant

$$UnR_{year} = p_{fail}(year). \begin{pmatrix} C_{asset} + C_{install} \\ + \Delta EY_{wait} + \Delta EY_{install} \end{pmatrix} \qquad (3)$$

Where:
p$_{fail}$ (year) = probability of failure in that year
ΔEY$_{wait}$ = energy yield loss during wait for delivery of a replacement asset
EY$_{install}$ = energy yield loss during installation and commissioning process; taken as the average over the year

Scheduled Replacement costs, Table 3, are principally the cost of a planned replacement of the asset. They are calculated based on the cost of the asset and the cost of any installation vessel and associated spread hire. In addition, the cost of lost energy production due to transmission constraints is included here since this should impact any decision regarding whether and when to proceed with a replacement.

It is assumed that scheduled replacements will take place in July, since lost energy production is 46.8% of the annual average, due to the lower power production of the wind farm during the summer months, see Figure 10, and in spite of higher turbine availability.

Operating costs have been modelled in a simplified manner since it is assumed that they will depend more on parameters outside the scope of the analysis (i.e. design philosophy of manufacturer) than on the choice of redundancy. Examining this in greater detail:

- Maintenance costs are assumed to be a fixed per transformer unit; any savings (i.e. reduction in travel time) for multiple units are second order only.
- maintenance costs may well increase as the plant becomes older, however this increase is likely to be a second order effect compared with the increased costs as a consequence of the higher probability of unit failure;
- cost of losses within the transformer are assumed to depend on wind farm capacity and energy transmission profile as well as transformer design philosophy; redundancy is assumed to make a second order contribution only.

Unscheduled Replacement costs, Table 3, are calculated in a similar manner as the scheduled replacement costs with a number of modifications:

- capital costs may be higher, to take account of storing and maintaining a replacement, or to account for higher charges involved with emergency orders (i.e. the distressed customer syndrome)
- lost production will be higher to take account of the waiting time for the delivery of the new asset
- lost production will be higher to take account that the work could take place at any time during the year, rather than in summer, hence waiting on weather may be longer and since the work could take place during high wind farm production seasons, energy losses will also be higher
- since the extent of this study including configurations with multiple assets operating in parallel including redundant assets, the case where more than one unit fails simultaneously becomes relevant and in some cases drives the redundancy architecture decision;

2.2 Adjustment to Age-Related Failure Profile

The age related failure profiles are based on onland experience, hence it is considered necessary to make adjustments to take account of the different operating conditions offshore; for example, due to differences regarding:

(i) the loading regime (average power),
(ii) load cycling, comparing changes in wind speed with the daily consumer load profile,
(iii) the saline environment offshore,
(iv) the compliant support structure resulting in the transformer experiencing greater vibration motion,
(v) reduced opportunities to undertake O&M.

For the purposes of this study, following detailed analysis and discussion, lifetime adjustment factors were selected for each of the above parameters. Thus led to the conclusion that the assets would age around 70% faster offshore compared with the onshore case; hence an appropriate temporal adjustment is applied to the failure profile, as illustrated in Figure 1.

It may be that the offshore location will warrant investment in a more reliable tap-changer technology or even in not including a tap-changer on the offshore transformer; since failure statistics shows that tap-changers cause a high proportion of all failures, such a design change would mean failure rates should be proportionately reduced.

Hence, for the purposes of this analysis, it has been assumed that:

- the challenging environment offshore will result in higher failure rates than onshore, particularly after around 30-40 years
- The transformers will be operated through to failure; in reality it may be beneficial to proactively replace the transformer units at a certain age; an economic analysis suggests that this is not the case under the base case here but it does become beneficial for substation operating lifetimes of sixty years or more. In reality, the decision to replace a particular transformer would be based on condition-monitoring, however the analysis here is valid at the pre-construction design stage.

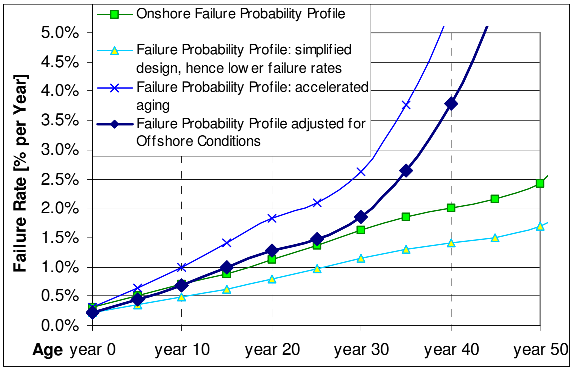


Figure 1: Onshore and Offshore Transformer Failure Rate

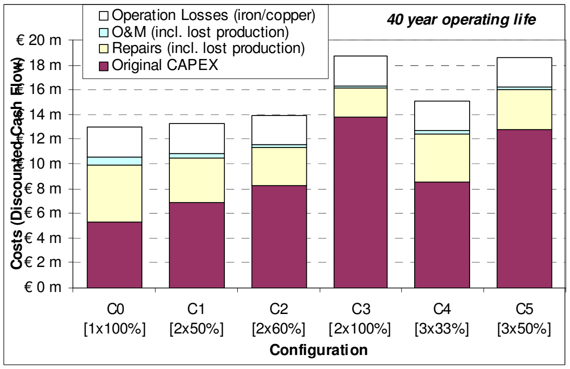


Figure 2: Ownership Costs for 40 year Operating Lifetime

3 Analysis

The total ownership costs over a 40 year operating lifetime are examined, for each of the six configurations listed in Table 1. Figure 2 shows that in this case Configurations 0 is optimal, i.e. a single transformer unit rated at 100%: although repair costs (capital equipment and production losses) over the forty years are higher than for the alternative configurations, these do not compensate for the higher capital costs. It should be noted that, at 2% or €0.2m, the difference is relatively small, hence the importance of examining the relevance of the assumptions to the particular case.

4 Sensitivities

Should an operating lifetime of twenty years be assumed, the benefits of redundancy are reduced and the lifetime cost advantage of the single transformer increase to 5% or €0.6m, see Figure 3. It is not felt that this is a realistic scenario.

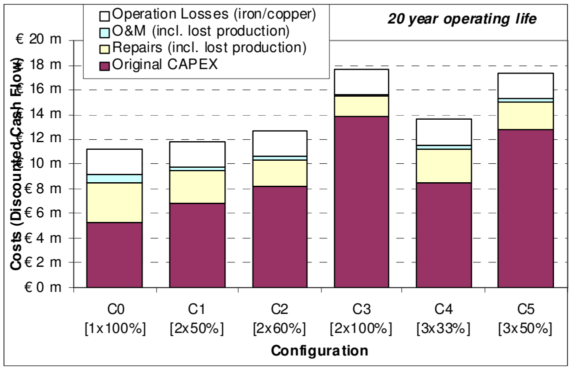


Figure 3: Ownership Costs for 20 year Operating Lifetime

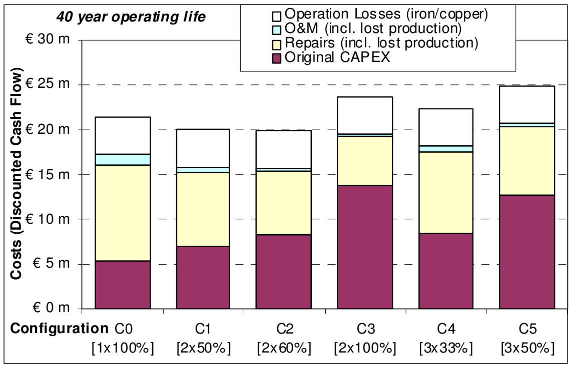


Figure 4: Ownership Costs for 5% Discount Rate

If a lower discount rate of 5% is assumed (note that as inflation is ignored this is a real as opposed to a nominal discount rate), there are clear benefits for redundancy, of around 7.5% or €1.5m for twin units each rated at 60% versus a single unit. The case for twin 50% rated transformers is marginally less attractive, by around 0.5% or less than €0.1m.

Failure rate assumptions are arguably optimistic with respect to the exclusion of a tap-changer from the offshore transformer. A tap-changer may be necessary for operating requirements. For this case, the reduction in failure rates illustrated in Figure 1 is not achieved and re-evaluation of the financial analysis leads to a different conclusion: Configuration 1, with two units each rated at 50%, is now preferential, Figure 5, by a margin of 1.2% or €0.2m.

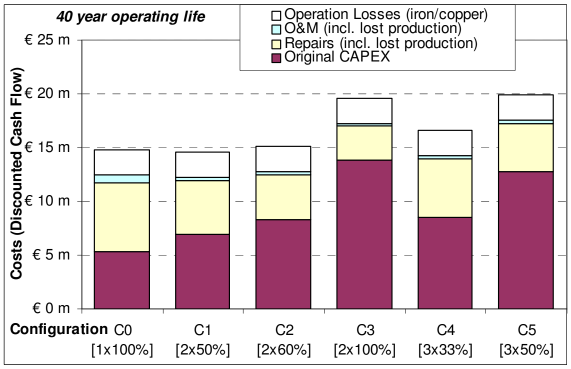


Figure 5: Impact of Tap Changer

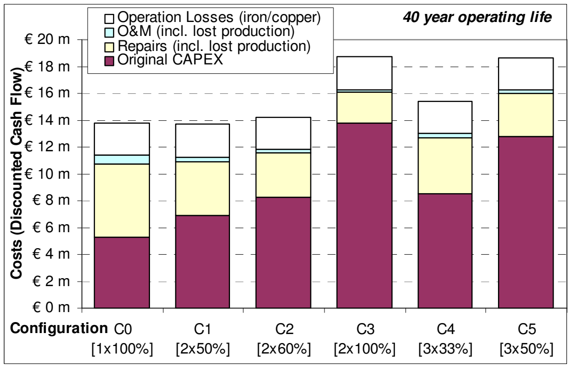


Figure 6: Impact of Higher Tariff (German REFIT)

A higher tariff strengthens the case for redundancy, Figure 6, where the twin 50% unit scenario saves just under 1% or €0.1m over the anticipated forty year lifetime. A tariff of €150/MWh is assumed, equivalent to the current German REFIT value; note that the German REFIT tariff is not indexed, which is an implicit assumption in the model settings used for this paper.

CIGRÉ [1] is used as the primary reference for transformer failure statistics. Table 4 (as illustrated in Figure 7) list alternative sources.

TABLE 4: FAILURE PROFILES REFERENCES

Reference	Comments
CIGRÉ 248 Substation [1] modified	Assumed to be most representative however see 1b; data modified
CIGRÉ 248 Substation [1]	Data smoothed to allow model to function more effectively [labelled modified]
CIGRÉ 248 Generator [1]	Assumed that generator transformers typically will experience regular and rapid ramping up and down and hence are less representative of offshore wind farm transformers
Bartley 07 [3]	Insurance industry perspective in the US
Blanc 08 [4]	French transformers; does not account for increase in failure rates with very old transformers
Geldenhuis 07 [5]	South African transformers; hence remote locations with aggressive environment
Jongen 07 [6]	Netherlands; focus on behaviour of transformers nearing ends of life hence ignores early failures
Bengtsson 02 [7] (scenario A and B)	Assumptions for modelling purposes; hence not necessarily based directly on real failure statistics; two cases: scenarios A and B

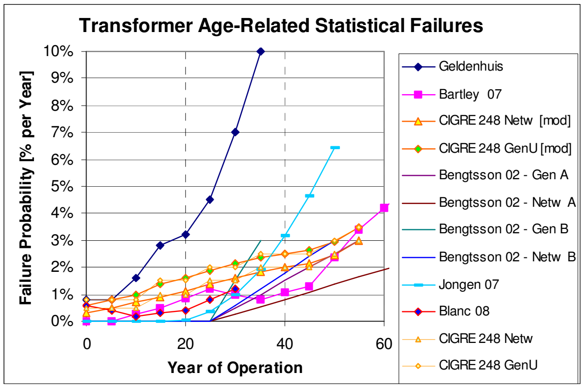


Figure 7: Transformer Age-Related Failure Rate Probability Curves

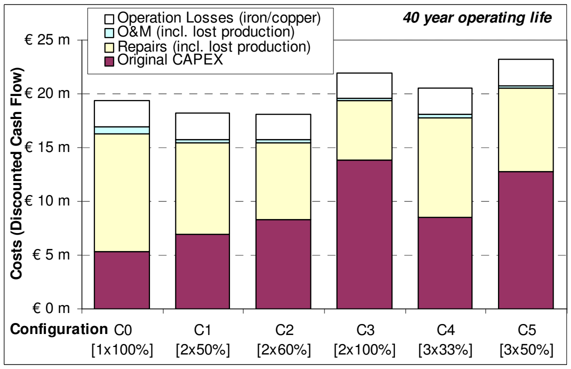


Figure 8: Sensitivity to Failure Rate Profile / Geldenhuis 07 [5]

Taking the most onerous profile, Geldenhuis 07 [5], reflects operating transformers in remote locations and environmentally strenuous conditions, albeit on land rather than offshore, hence the adjustments illustrated in Figure 1 are not applied. Figure 8 shows that repair costs are now significantly higher than the original CAPEX and the benefit of redundancy is marked. Of the scenarios analysed, the optimal degree of redundancy is for twin units, each rated at 60% capacity. The benefits over the single unit case are around 7% or €1.3m.

5 CONCLUSIONS AND RECOMMENDATIONS

The method described here may aid the decision making process regarding which degree and type of redundancy is most appropriate for the electrical infrastructure for individual offshore wind farms.

A base scenario together with a number of sensitivity scenarios are examined for the example of the offshore substation transformer, with the principal conclusions being:

- For the case of an operating lifetime for the infrastructure assets of 40 years assessed against a 10% real discount rate, the case of no transformer redundancy is optimal.
- A lower real discount rate of 5% alters the balance of CAPEX costs and reduced lost production benefits and twin transformer units, each rated at 60%, are now optimal.
- Assumptions of higher failure rates due to presence of conventional tap-changer technology or generally more conservative assumptions, longer network operating lifetimes, or a higher tariff also strengthen the case for redundancy.

APPENDICES

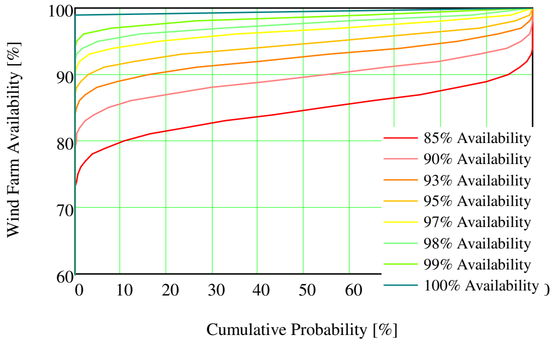
APPENDIX A NOMENCLATURE

CIGRÉ	Conseil International des Grands Reseaux Électriques International Council for Large Electrical Networks
DCF	Discount Cash Flow
FINO1	Met mast in German sector of the North Sea; adjacent to the Alpha Ventus wind farm
PF	Power Factor
PPA	Power Purchase Agreement typically feed-in tariff or market based contract
REFIT	Renewable Energy Feed-In Tariff

APPENDIX B ASSUMPTIONS

This work is based on a number of assumptions, including:

- Wind climate and time series, based on the met mast measurements at FINO1 [2], four years of time series data is utilised here (January 2003 through to December 2006)
- An assumption for the cumulative wind farm production power curve taking account of the wakes losses within the wind farm, in the order of 10% to 20%;
- An assumptions regarding availability of the wind turbines in the wind farm; starting with a base assumption for wind turbine availability of between 85% and 100% together with the assumption that individual wind turbine availability is completely uncorrelated, an average availability for the wind farm can be generated Figure 9; note that individual wind turbine availability may indeed correlate: for example inability to access the wind turbines during severe weather could result in several wind turbines requiring attention; when a weather window arises, it may not be possible to attend to all wind turbines immediately resulting in correlated non-availability; a second and much more serious example would be serial failures of a major component within the wind turbine. However these factors are not expected to have a major impact on any conclusions derived from the assumptions presented here.



As a function of individual wind turbine availability

Figure 9: Wind Farm Availability Probability Distribution

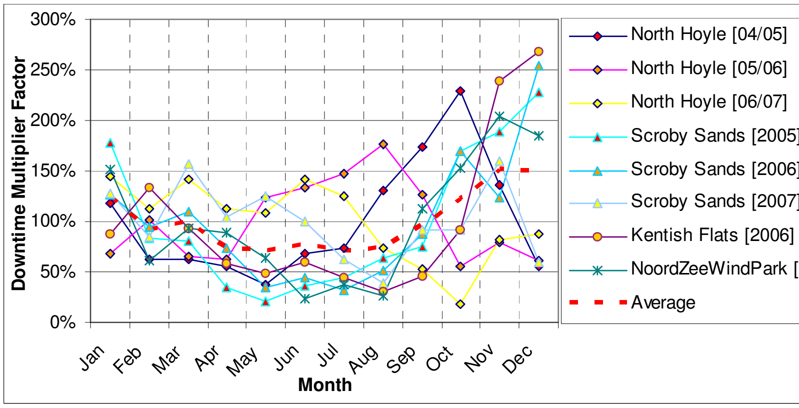


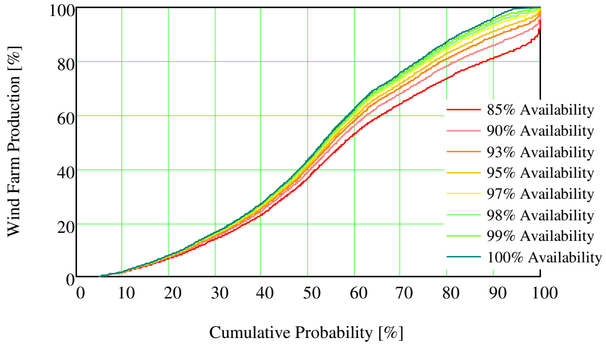
Figure 10: Recorded Wind Farm Monthly Availability (Normalised)

- Monthly variation of mean wind speed,

- Down time of offshore wind farms will vary significantly throughout the year, with availability being generally poorer in the winter months due to difficulties in gaining access to the wind turbine to make any necessary repairs, Figure 10. This has a disproportionate impact on wind farm energy yield. Monthly variation of wind turbine non-availability is modelled as per the bold dashed line in Figure 10; this monthly downtime adjustment factor is multiplied against the assumed mean annual downtime value.

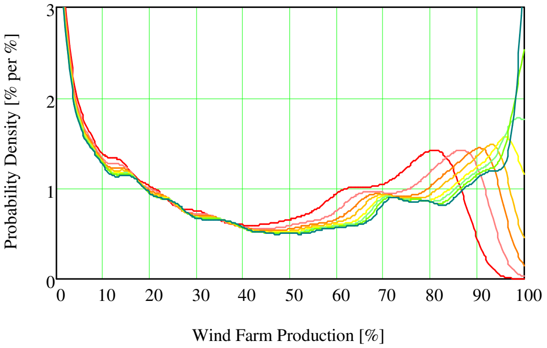
APPENDIX C ANNUAL AVERAGE PRODUCTION PROBABILITY DISTRIBUTION

- Combining the wind farm availability, Figure 9, with the power production curve, allows a wind farm production probability to be derived, see Figure 11; assuming wind turbine availability of 93%, this suggests that wind farm power production will reach 95% of the rated capacity for only 1.4% of the time and 100% effectively never (estimated to be 0.02% or 35 hours over the nominal 20 year operating lifetime of the wind farm)



As a function of individual wind turbine availability

Figure 11: Wind Farm Power Production Cumulative Probability

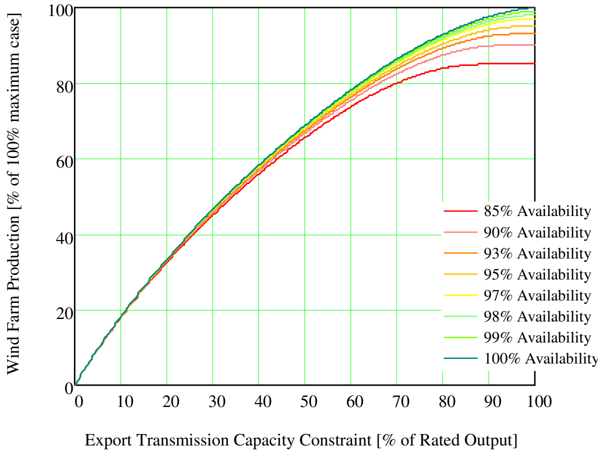


As a function of individual wind turbine availability
Note: irregularity within detail of curve is due to use of numerical integration methods

Figure 12: Wind Farm Power Production Probability Distribution

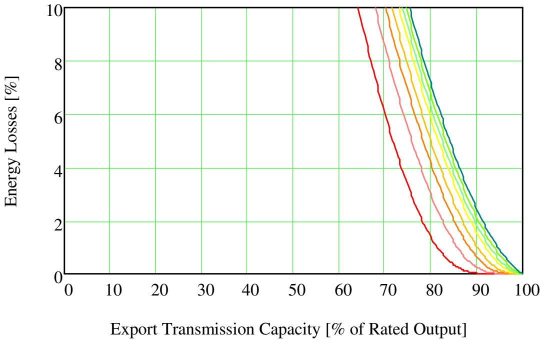
- In terms of probability distribution of energy production, Wind farms generate a distinctive signature, with considerable periods spent near both zero and full production and an irregular curve function in between, affected by numerous factors, including, wind speed distribution, turbine rated power level, in-farm wake effects, availability levels etc. A numerical method was utilised to derive Figure 11 which does not generate an equally smooth probability density distribution hence post-calculation smoothing has been applied to the data behind Figure 12.

It follows that for typical offshore wind turbine availability levels (i.e. 95% and below), the wind farm operates at full power for a small proportion of the time only. Hence, for systems with inbuilt redundancy, during periods of transformer downtime, power could be re-routed via the parallel units with limited impact on power transmitted, particularly if downtimes occurred during summer month (for example planned maintenance). Figure 13 and Figure 14 illustrate the impact in terms of energy production and energy losses (i.e. the opposite) respectively. Note that this analysis does not consider changes in transformer losses, for example the increased losses when the entire wind farm production is transmitted through a single rather than two transformer units. Considering this factor would require a sophisticated approach since losses at low production levels could be reduced for the single unit case, as no-load (iron) losses would be lower, and increased at high production levels, as load (copper) losses would be higher.



As a function of individual wind turbine availability

Figure 13: Impact of Export Constraints on Power Production



As a function of individual wind turbine availability

Figure 14: Energy Losses due to Export Constraints

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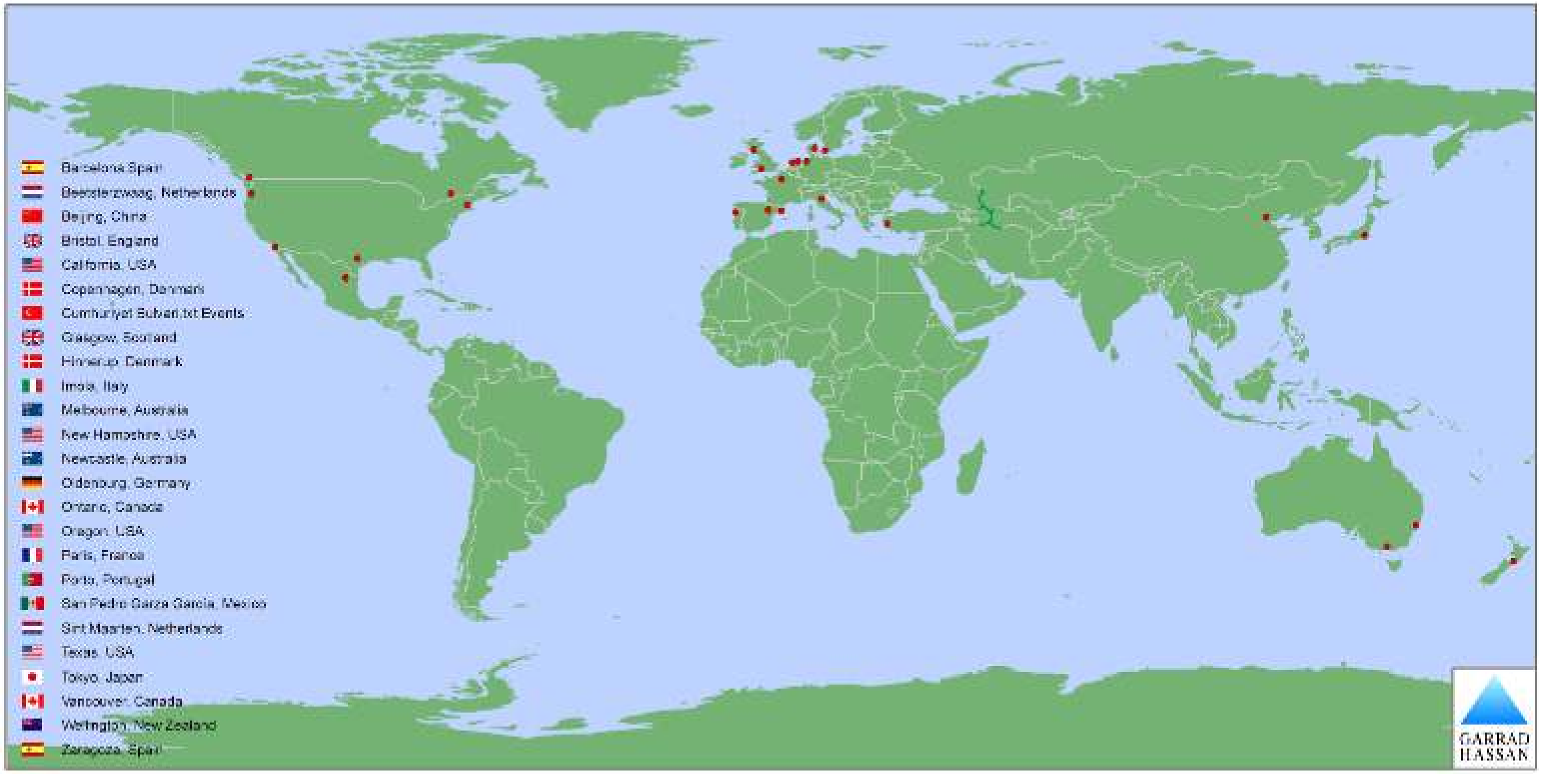
About us

- Founded in 1984 in UK
- Now part of GL group
- Now have 26 offices worldwide – 600+ staff
- Local understanding informs global perspective



Offshore Wind at GH

- First offshore wind work: 1987

- 200+ commercial contracts
  - 5,000 MW offshore O&M studies
  - 8,000 MW offshore energy assessments
  - 8,000 MW of Technical Due Diligence
  - 1,500 MW+ of FEED Studies

- 50+ Offshore Windfarms
  - 20+ UK
  - 10+ Germany
  - Also NL, FR, DK, SE, ES, BE
  - Rest of the world (USA, China, Korea)

- Team now includes >80 engineer-years in offshore wind

Contents

- Introduction
  - What level of redundancy is appropriate
- Method
  - Lifetime costs including of replacements and lost production
- Some Results (for a case of)
  - Wind farm in North Sea with 100 turbines
  - Substation Transformer
- Conclusions

Introduction

- What level of redundancy is appropriate
  - Historically offshore substations had no transformer redundancy
  - Apparent current trend to redundancy
- Impact of Failure
  - Potentially no power production for prolonged period (4½ months - >year)
- Approach is Applicable to Other Components
  - Transformers and cables are arguably most critical
    - in terms of impact of failure and ability to repair quickly

Introduction: Configurations

- Level of Redundancy
  - 6 scenarios examined, including over capacity

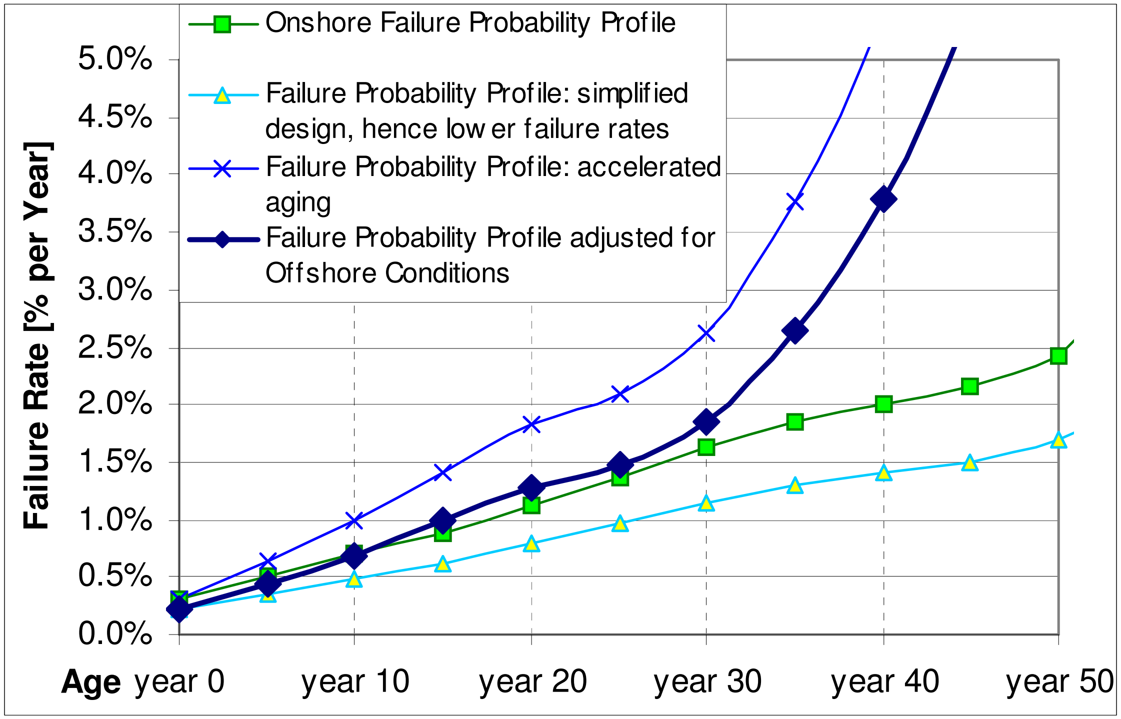
Scenario	Architecture	Total Capacity
0	single 100% capacity rated unit	100%
1	Twin 50% units	100%
2	Twin 60% units	120%
3	Twin 100% units	200%
4	Triple 33% units	100%
5	Triple 50% units	150%

Method

- Scheduled and Unscheduled repairs/replacements
  - Cost of asset
  - Cost of installation
  - Cost of lost power production
- Failure Probability Varies with Age
  - Gradual increase in failure rates
  - Offshore likely to differ from onshore
- Lost Power Production
  - Similar order of magnitude as asset and installation costs
  - Product of probability of failure and impact on production
- Scheduled O&M
  - Cost of lost power production
- Transformer Losses
  - Differential between configurations not considered

Method: Failure Profile

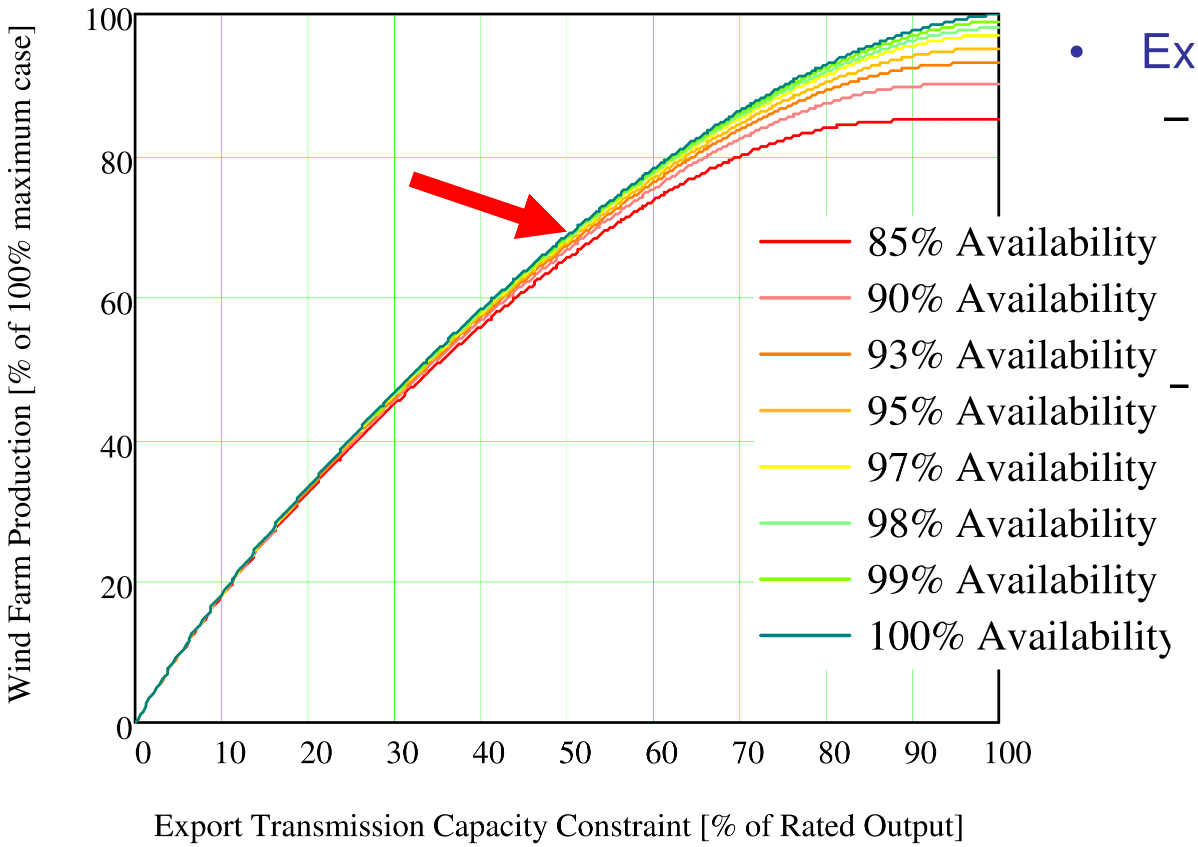
- Assumed to increase with age
  - Early life failures may also be present
- Offshore anticipated to have higher failure rates than Onshore
  - Modelled here as acceleration of aging and as failure rate scalar adjustment
    - Assumed to reduce due to tap-changer design modifications



- Contributory Factors could include
  - Time spend at full load
  - Load cycling
  - Salinity
  - Reduced O&M
  - Design Modifications (i.e. tap-changer)

Method: Lost Production

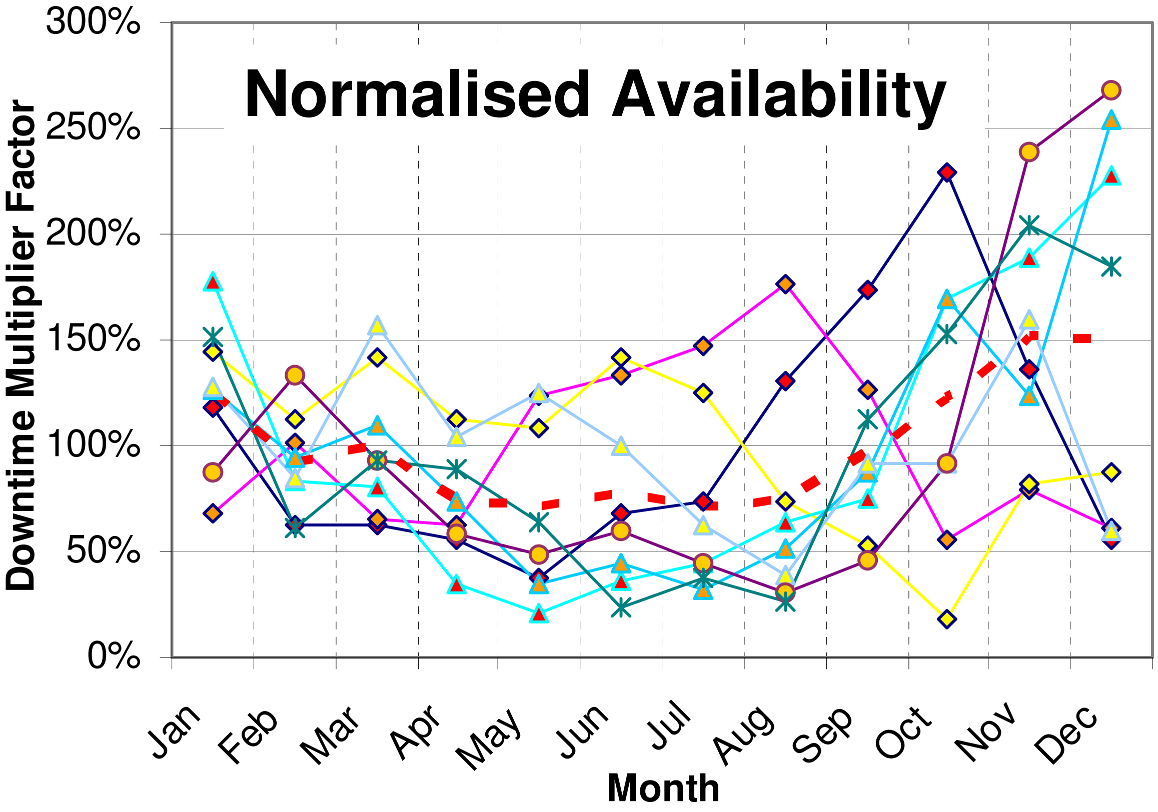
- Depends on wind farm characteristics
  - Wind speed distribution, turbine power curve, turbine availability etc.



- Example
  - i.e. a wind farm with 100% turbine availability constrained to a maximum 50% generation would generate 30% less power
  - If the wind turbine availability was 85%, 50% generation would generate approximately 24% less power than the unconstrained case (85%→65%)

Method: Timing

- Random Failures could occur at any time
  - Impact is greatest in winter (higher production to be lost; longer wait to repair)
- Published Availability Figures of Operational Offshore Wind Farms are Consistently Lower in Winter



- Scheduled Repairs would be timed for the summer months
  - Lost production would be small for a system with some redundancy

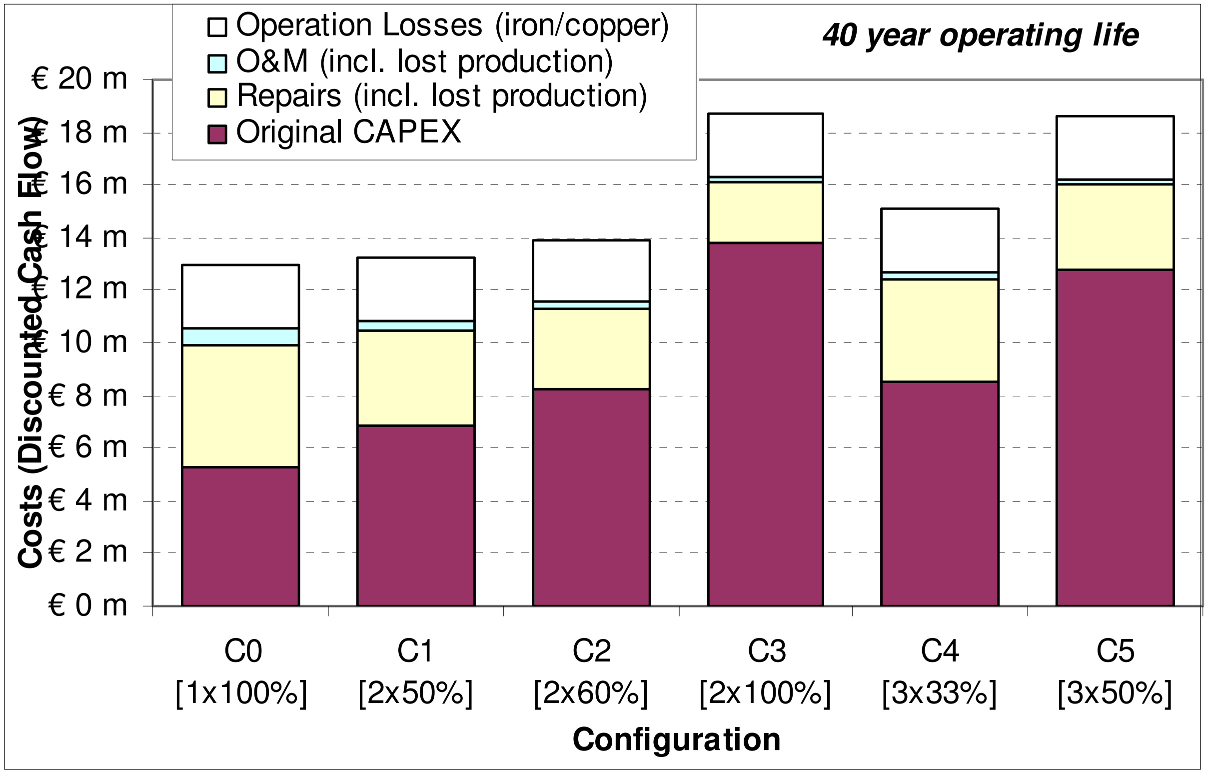
Sources: various, all public

Results: Base Case

- Wind Farm
  - 100 wind turbines
  - Between 3 and 6MW
  - 93% annual availability (with monthly variation)
  - Wind speed as per FINO1 (German North Sea)
- Financials
  - PPA of €125/MWh
  - 10% Discount Rate (inflation not modelled)

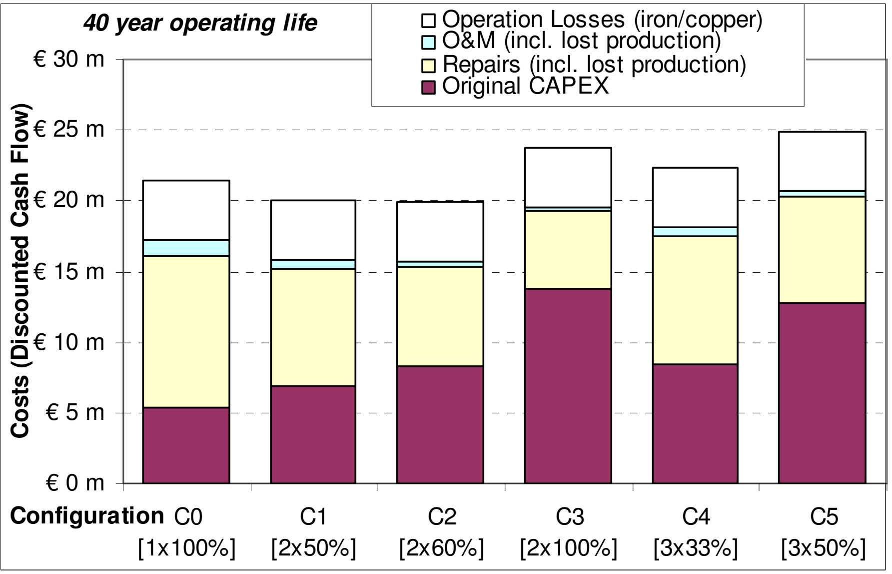
Results: Base Case

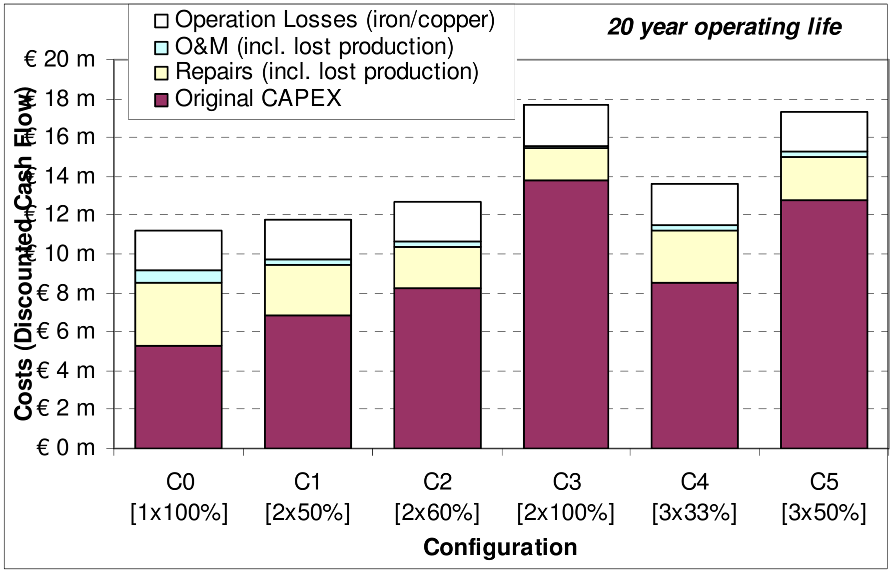
- Optimal: Single Unit
  - Generally higher production losses countered by larger savings in Capex
  - Lifetime saving versus twin 50% unit is around 2% (or €0.2m)
  - Hence Assessment of Individual Project Necessary (Sensitivities)



Results: Sensitivities

- 5% Discount Rate (40 Year life)
  - Twin Units, each rated at 60%
  - Lifetime saving versus single 100% unit is around 7.5% (or €1.5m)
  - Difference versus single 50% unit is marginal (0.5%)
- 20 Year Life (10% Discount Rate)
  - Benefit of Single Unit increases to around 5% (or €0.6m





Conclusions

- Impact of Redundancy is typically Dependant on Assumptions
  - Probably why different conclusions are reached for different projects
  - Changes in value of loss production and changes in investment costs are of similar order of magnitude
  - In some scenarios, value of redundancy can be significant, €ms over project lifetime
- Major Uncertainties
  - Transformer Failure Profile
- Other Factors also important
  - Losses during scheduled maintenance
  - Operational losses (iron and copper); calculated but no differential modelled here

Thank You for Your Attention

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