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Matching Generators to Power Systems

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KATO ENGINEERING™

Contents:

1. Ratings and General Considerations

Frequency, Voltage, Current, & Power

- Rated frequency: determined by locale or application (usually 50 or 60 Hz but 400 Hz for aircraft ground power, other special)
  - Frequency variation: determined by governor and engine characteristics
  - Frequency is determined by RPM and poles:
    - $Frequency = \frac{Poles \times RPM}{120}$
    - $\mathrm{RPM} = \frac{Frequency \times 120}{Poles}$
  - 120: 60 seconds/minute, 2 pole pairs/cycle

Frequency, Voltage, Current, & Power

- Rated voltage (=>flux density) affected by:
  - Saturation flux density of steel, geometry
  - Frequency
  - Number of stator coils (i.e. number of slots)
  - Number of turns in each coil
  - Pitch of the coils (i.e. number of slots span)
  - Stator parallel connections and hookup
  - Length and diameter of the stator lamination stack
- $V = N_S \frac{d\emptyset}{dt}$, N_S is total series turns, Ø is flux

Frequency, Voltage, Current, & Power

- Most of the adjustable parameters (e.g. turns, parallels, slots) have discrete values (we can’t design to an exact voltage, so there are tradeoffs)
- Others may be determined by specifications, physics, or economic considerations (e.g. pitch, steel characteristics)

Frequency, Voltage, Current, & Power

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- Voltage constraints:
  - Poles depend on engine speed, frequency
  - Slots limited by phases, parallels, balance
  - Turns usually integer (maybe half turn)
  - Pitch limited by harmonics, reactances
  - Stack length limited by available frames
  - Ability to fit insulation into a reasonable size coil limits maximum voltage to around 15-20 kV
  - Ability to fit in reasonable size busbars limits maximum current to around 5000A

Frequency, Voltage, Current, & Power

- Voltage tolerance: depends on voltage regulator, generally ±1% or better
- Voltage adjustment range: usually ±5% but ±10% possible, required for some grid codes
  - Machine designs may be "broad range", for example a generator may be sold at the same kVA rating for 12.5-13.8 kV, with ±5% adjustment
  - Done by making the machine somewhat oversize and relying on higher quantity to keep costs down

Frequency, Voltage, Current, & Power

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Table 3 — Generator operating limit values

Term	Symbol	Unit	Operating limit values			
			Performance class			
			G1	G2	G3	G4
Related range of voltage setting	δU_s	%	$\leqslant \pm 5$[a]			AMC[b]
Steady-state voltage deviation	δU_{st}	%	± 5	± 2,5	± 1	AMC
Transient voltage[c,d,e] deviation on load increase	δU_{dyn}^{-}	%	− 30	− 24	− 18	AMC
Transient voltage[c,d,e] deviation on load decrease	δU_{dyn}^{+}	%	35	25	20	AMC
Voltage recovery time[c,d]	t_u	s	< 2,5	< 1,5	< 1,5	AMC
Voltage unbalance	$\delta U_{2,0}$	%	1[f]	1[f]	1[f]	1[f]

[a] Not necessary if no parallel operation or fixed voltage setting is required.

[b] AMC = by agreement between manufacturer and customer.

[c] Rated apparent power at rated voltage and rated frequency with constant impedance load. Other power factors and limit values may be by agreement between the manufacturer and customer.

[d] It should be appreciated that the choice of a grade of transient voltage deviation and/or recovery time lower than is actually necessary can result in a much larger generator. Since there is a fairly consistent relationship between transient voltage performance and transient reactance, the system fault level will also be increased.

[e] Higher values may be applied to generators with rated outputs higher than 5 MVA and speed of or below 600 min^{-1}.

[f] In the case of parallel operation, these values are reduced to 0,5.

From ISO-9528-3 2005 (no NEMA equivalent)

Frequency, Voltage, Current, & Power

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Q: Can I run a generator rated for xxx volts at yyy volts?

A: Maybe. If you are going down in voltage, you will need to derate power by the voltage ratio. The reactance in % will remain the same at the new voltage and power rating. Voltage overshoot will probably increase some.

If you are going up in voltage, you need to consider if the insulation is adequate, and unless you increase frequency proportionally, saturation will increase, leading to higher core loss and rotor I^2R loss. Best to consult vendor.

Frequency, Voltage, Current, & Power

Q: Can I run a generator rated for xxx volts at yyy volts?

A: (cont'd) Some generators are reconnectable. Changing from parallel to series windings doubles the voltage (if the insulation is designed for it) and vice-versa, changing from wye to delta reduces the voltage to 58%. Also depends on whether designed "broad range"

You also need to consider what the inspector will say, if the nameplate doesn't match the way you are using it. Some manufacturers may be able to supply a replacement nameplate.

Frequency, Voltage, Current, & Power

Q: Can I run a generator rated for 50 Hz at 60 Hz (or vice-versa)?

A: Maybe again. Changing the frequency also changes the saturation voltage by the same proportion, so a 3300V 50 Hz machine can be used at 4160V 60 Hz, *if* the insulation is rated for it, but you also need to ask if the unit can mechanically run at the higher speed. The bearings may overheat, or there may be a resonance vibration close to the 60 Hz speed.

Frequency reduction requires voltage reduction, maybe *further* derating due to lower fan speed.

Frequency, Voltage, Current, & Power

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- Rated current determined by:
  - Size of conductor (which is determined by size of slot and number of turns/coil as well as amount of insulation required)
  - Stator parallel connections and hookup
- Wider slots for larger conductor => narrower teeth, lower flux capacity, lower voltage
- Deeper slots for larger conductor => thinner yoke, lower flux capacity, lower voltage, also increased reactance, smaller coil spacing
- Optimum when slot width ~ tooth width

Frequency, Voltage, Current, & Power

- Current determines rated *apparent* power
  VA = Voltage*Current *√3
  - Not very dependent on *real* power (kW)
  - Higher power factor => *lower* rotor heating
  - Rated kW depends on engine rating
  - Nominal power factor usually 0.8, though 0.85 or 0.9 becoming more common, may be more appropriate for cogeneration where islanding is not intended
    - Higher power factor => smaller machine, lower cost (for a given kW) (but other penalties)

Power Rating

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- What power rating do you need?
  - For standby or emergency usage, load is primary determining factor
  - In USA, NEMA 70 (National Electric Code) and NFPA 110 (Emergency and Standby Power Systems) dictate sizing
    - Generator manufacturer is not expected to be expert on these standards – application may vary with jurisdiction
    - Many good webinars and white papers are available online covering these

Power Rating

- What power rating do you need?
  - For data centers, special standards may affect requirements, such as Uptime Institute, federal, state, and local standards
  - For cogen or peaking applications, power requirements will be negotiated with the power system operator.
  - Grossly oversizing a generator set may lead to problems such as wet-stacking, high short-circuit current, or inefficiency

Power Rating

- Multiple parallel generators preferable
  - Run generators at optimum power for best efficiency, reliability
  - Redundancy for failures or scheduled maintenance

Power Rating

- Thermal capacity factors:
  - Ambient temperature
  - Temperature rise/Load factors:
    - Duty cycle
    - Power factor
    - Unbalanced load
    - Harmonic load
    - Airflow
  - Cooling method (discussed later)
- Electrical capacity factors:
  - Available fault current
  - Ride-through
  - Load factors:
    - Harmonic voltages
    - Voltage unbalance
    - Leading PF load
  - Motor starting and voltage dip
  - (Above all related to reactances of machine)
  - Efficiency

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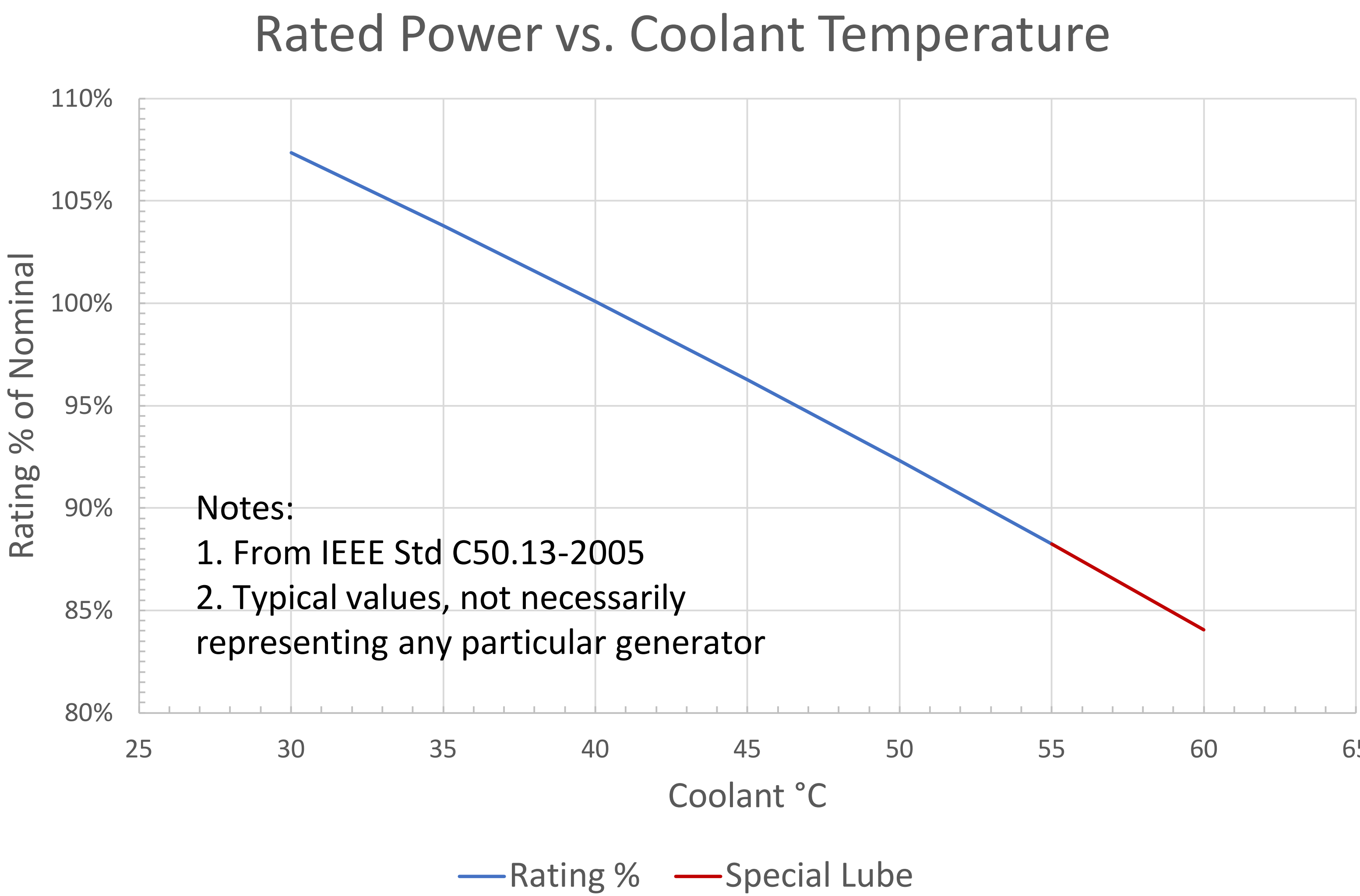
Ambient Temperature

- Higher-temperature air obviously doesn't cool a generator as well as cooler air, so the maximum air temperature limits power.
- *Normal* maximum ambient temperature is 40ºC (104ºF). This is common to NEMA, IEEE, IEC, most every other commercial standard.
- Marine agency standards generally increase this to 45-50ºC. If the machine is air-cooled (but most marine units are water-cooled), a derating factor of about 88-90% must be applied to maintain temperature rise.

Ambient Temperature



Ambient Temperature

- Generators that use water or other substances as a coolant have power ratings dependent on the temperature of the cooling substance, rather than the surrounding air
- Heat exchangers increase the temperature:
  – Typical air-to-water heat exchanger has an air output temperature 8-15ºC above the water inlet temperature
  – Typical air-to-air heat exchanger has air output temperature 25-30ºC above the external air inlet temp. (derate ~35%)

Power Rating

- Thermal capacity factors:
  - Ambient temperature
  - Temperature rise/Load factors:
    - Altitude
    - Duty cycle
    - Power factor
    - Unbalanced load
    - Harmonic load
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  - Cooling method (discussed later)
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Temperature Rise

- NEMA, IEEE, IEC, and other standards groups have defined “classes” of insulation systems with different temperature capabilities
- Extensive testing at elevated temperatures, cyclic stresses (including vibration) and high humidity to prove that the insulation can survive a long time at these operating temperatures (20,000 hours is sometimes used as a nominal lifetime, but not official). IEEE Std 117 and 101 define testing methods.
- Why? Running machine warmer means you can tolerate more loss, get more output.

Temperature Rise

Machine Part	Method of Temperature Determination	Class B	Class F	Class H
Indirectly cooled stator windings	Embedded detector (RTD or thermocouple)	85	110	130
Directly cooled stator windings	Air discharge from bar Water discharge from bar	80 50	100 50	N/A 50
Indirectly cooled rotor windings	Resistance	85	110	135
Directly air-cooled rotor windings	Resistance	60-80	75-95	N/A
Cores and mechanical parts, whether or not in contact with insulation	Detector or thermometer	Not detrimental to insulation of that part or any adjacent part		

Temperature rise over 40ºC ambient. From IEEE Std C50.13, but IEC 60034 and other standards are quite similar.

Temperature Rise

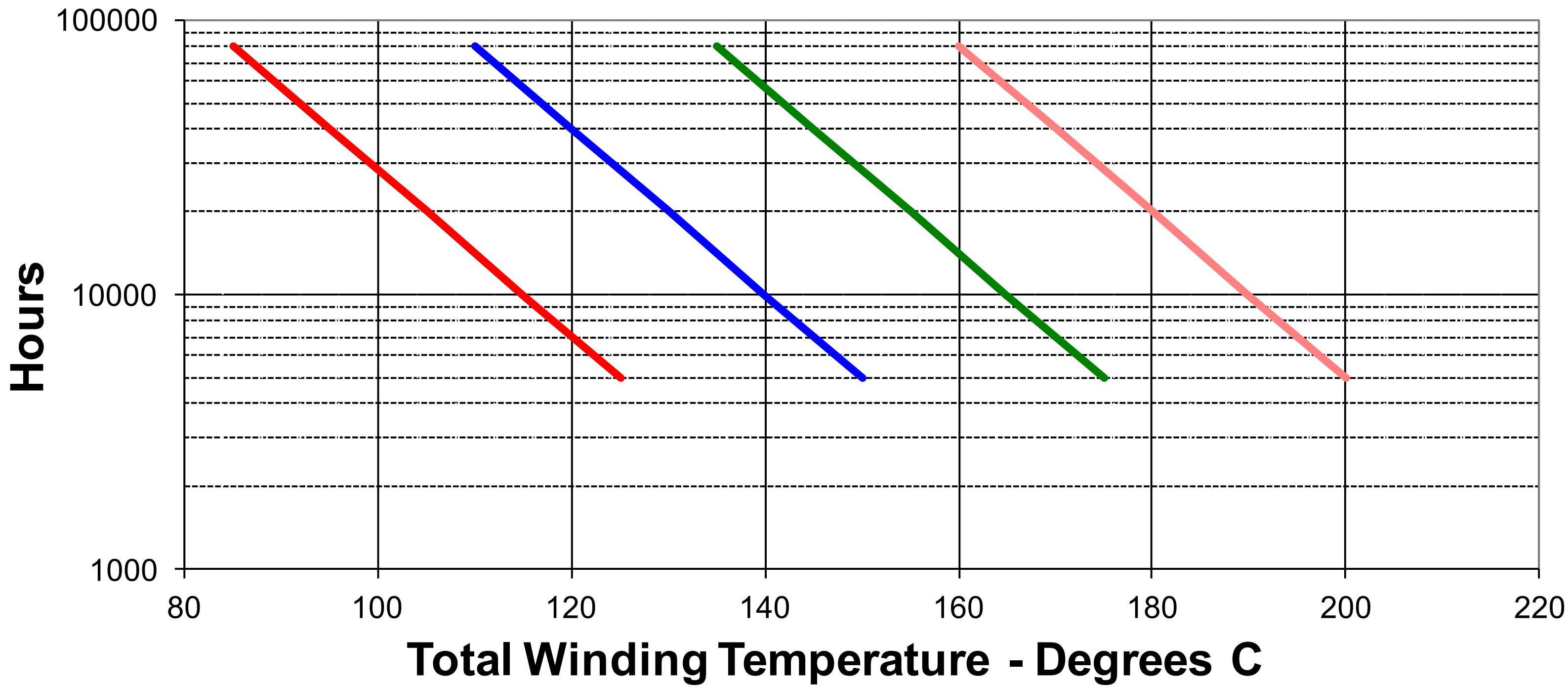
- Most insulation systems are Class F or H now
- Insulation class maximum temperature may be exceeded during overload conditions, and to some extent at “hot spots”
- Some standards (e.g. IEEE Std 11) allow higher temperature rises. NEMA “Standby” rating allows additional 25ºC rise for presumed short-term operation.
- Some standards (especially agency approval standards like ABS, Lloyds, etc.) have *more* restrictive temperature rise requirements

Temperature Rise

- User may choose a lower temperature rise than specified for the class of insulation:
  - Because the ambient temperature may be greater than 40ºC (Middle East location, ship's engine room, etc.)
  - To obtain longer expected life from the insulation
    - Class B rise with Class F or Class H insulation is a common specification for gas turbine application

Temperature Rise

Arrhenius equation: 2X life for every 10º C the temp is lowered (based on 20,000 hour life as the thermal index). This is a rough rule of thumb, not rigorous.



Temperature Rise

Svante August Arrhenius
(19 February 1859 – 2 October 1927) was a Swedish scientist. Originally a physicist, but often referred to as a chemist, Arrhenius was one of the founders of the science of physical chemistry. He received the Nobel Prize for Chemistry in 1903, becoming the first Swedish Nobel laureate. In 1905, he became director of the Nobel Institute, where he remained until his death. Discoverer of global warming.
--Wikipedia

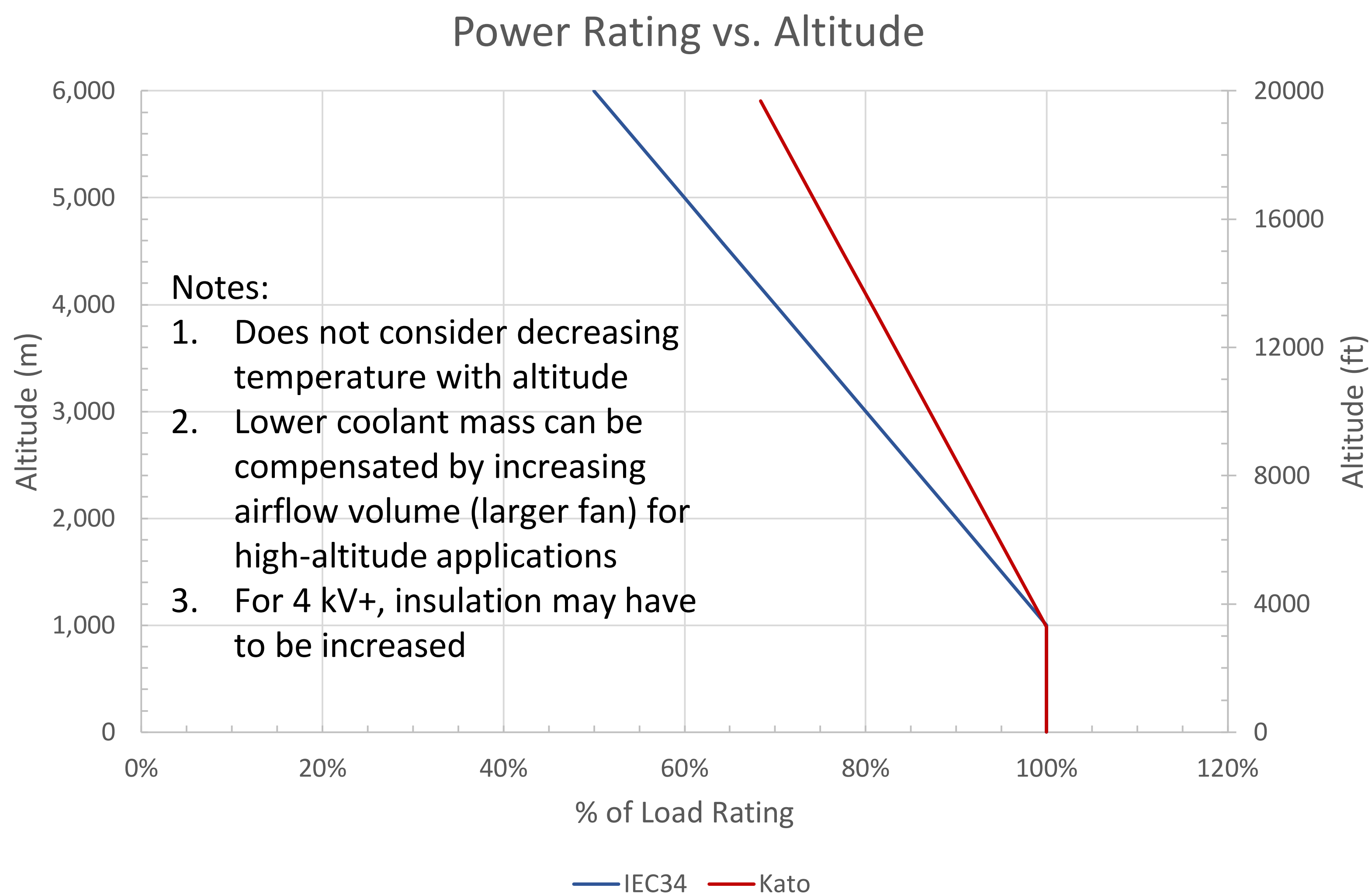
Temperature Rise

- Conditions that impact temperature rise:
  - Altitude
  - Overloads and duty cycle
  - Current unbalance
  - Harmonics
  - Low power factor
  - Airflow restrictions
  - Dust and other debris in air passages

Temperature Rise

- Airflow required for cooling is determined by the machine losses and allowable air temperature increase
  - For 18ºC air temperature rise, 100 cu. ft. per minute (about 170 m^3/hour or 2800 liters/min) is required for every kW of loss
- For ducted air, the fan must be able to produce enough pressure to maintain required flow – special fan may be needed

Altitude Effect on Temperature Rise



Altitude

- IEC 60034-1 Table 10 suggests assumption that the ambient temperature decreases with altitude, at a rate that may be sufficient to make generator derating with altitude unnecessary below 4000 m (use at own risk)

Table 11 – Assumed maximum ambient temperature

Altitude m	Thermal class			
	130 (B)	155 (F)	180 (H)	200 (N)
	Temperature °C			
1 000	40	40	40	40
2 000	32	30	28	26
3 000	24	19	15	12
4 000	16	9	3	0

Overloads and Duty Cycle

- The materials that make up a generator have a certain amount of heat capacity or “thermal inertia”. If the machine is overloaded, the temperature will take a while to reach the limits of the insulation. And insulation can operate safely above its rated temperature for short periods, provided the average “aging rate” is low enough to give adequate lifetime.
- Calculations may done by treating the machine as a “thermal R-C network” with losses as input, aging rate per Arrhenius eqn
- Need accurate estimate of duty cycle profile

Overloads and Duty Cycle

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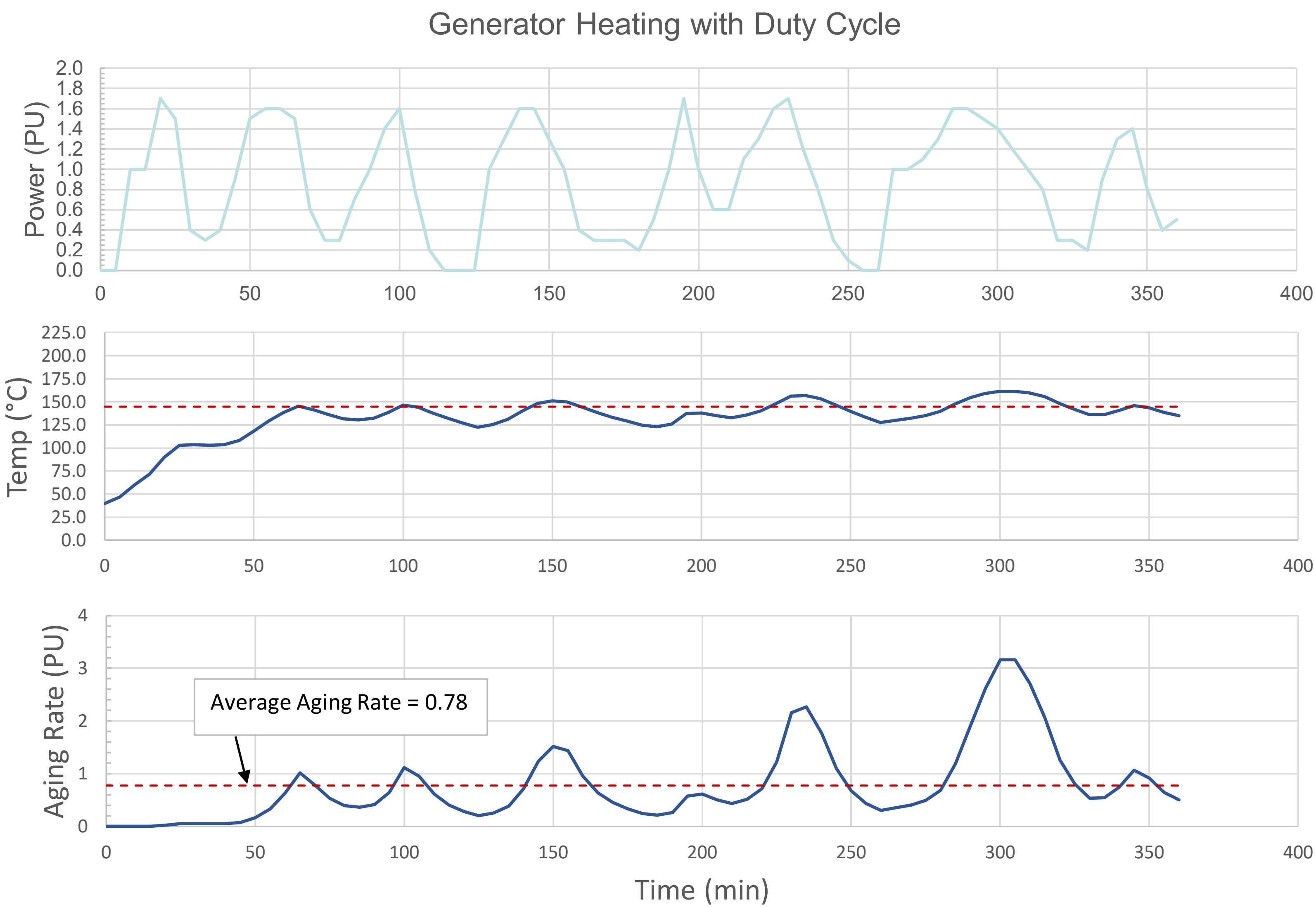


Overloads and Duty Cycle

- What do the different classes of rating mean?
  - ISO 8523-1 defines four load categories:
    - Continuous power (COP) – runs at full rating 24/7, e.g. cogeneration. Most data sheets will be for this rating unless otherwise stated.
    - Prime power (PRP) – runs at full rating some of the time but average power is limited to 70% of rating in a 24-hour period. 10% overload for 1 hour out of 24 is allowed. Backup power.
    - Limited time power (LTP) – continuous but limited to 500 hours/year, e.g. peaking
    - Emergency standby (ESP) – same as PRP but 200 hours/year (may allow add’l 25ºC rise?)

Overloads and Duty Cycle

- What do the different classes of rating mean?
  - IEC 60034-1 duty types S1-S10. These are intended mostly for motors, but if specified for a generator:
    - Duty Type S1 – eq. to continuous power
    - Duty Type S2 – eq. to limited time power, but specific durations must be given in specification
    - Duty Type S9 – similar to prime power, but cyclic operation must be given explicitly
    - Others should be negotiated with the vendor on a case-by-case basis. Thermal analysis will probably be needed.

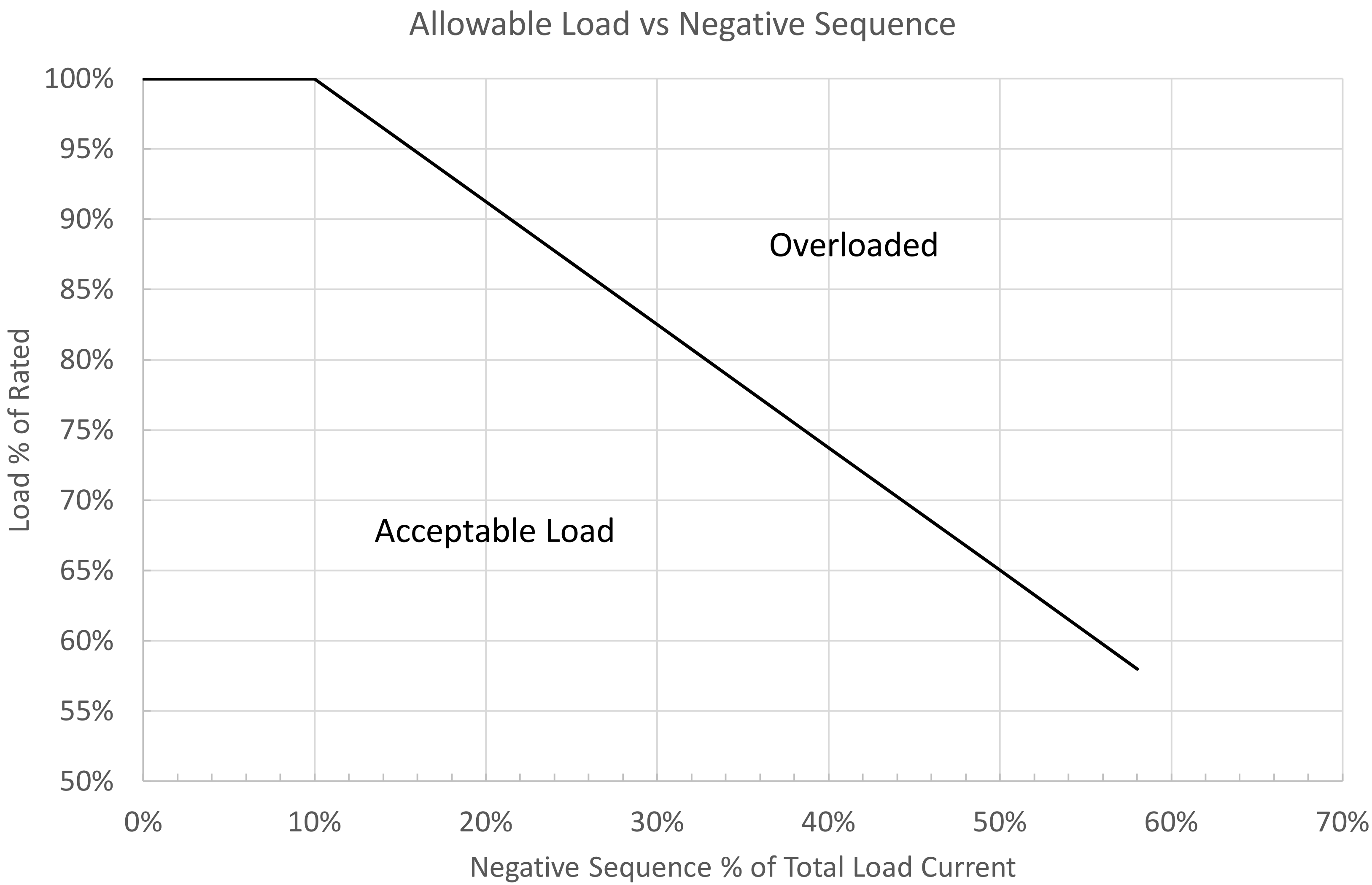
Current Unbalance

- Unbalanced load causes extra heating in rotor due to negative-sequence currents in stator
  - The stator magnetic field due to negative-sequence current rotates opposite of that caused by normal load current
  - Induce current in rotor bars and winding
  - Increase I^2R loss in rotor
- But as load becomes more unbalanced (with no more than rated current in any phase), the *total* load decreases, compensating to some extent for the increase in rotor loss

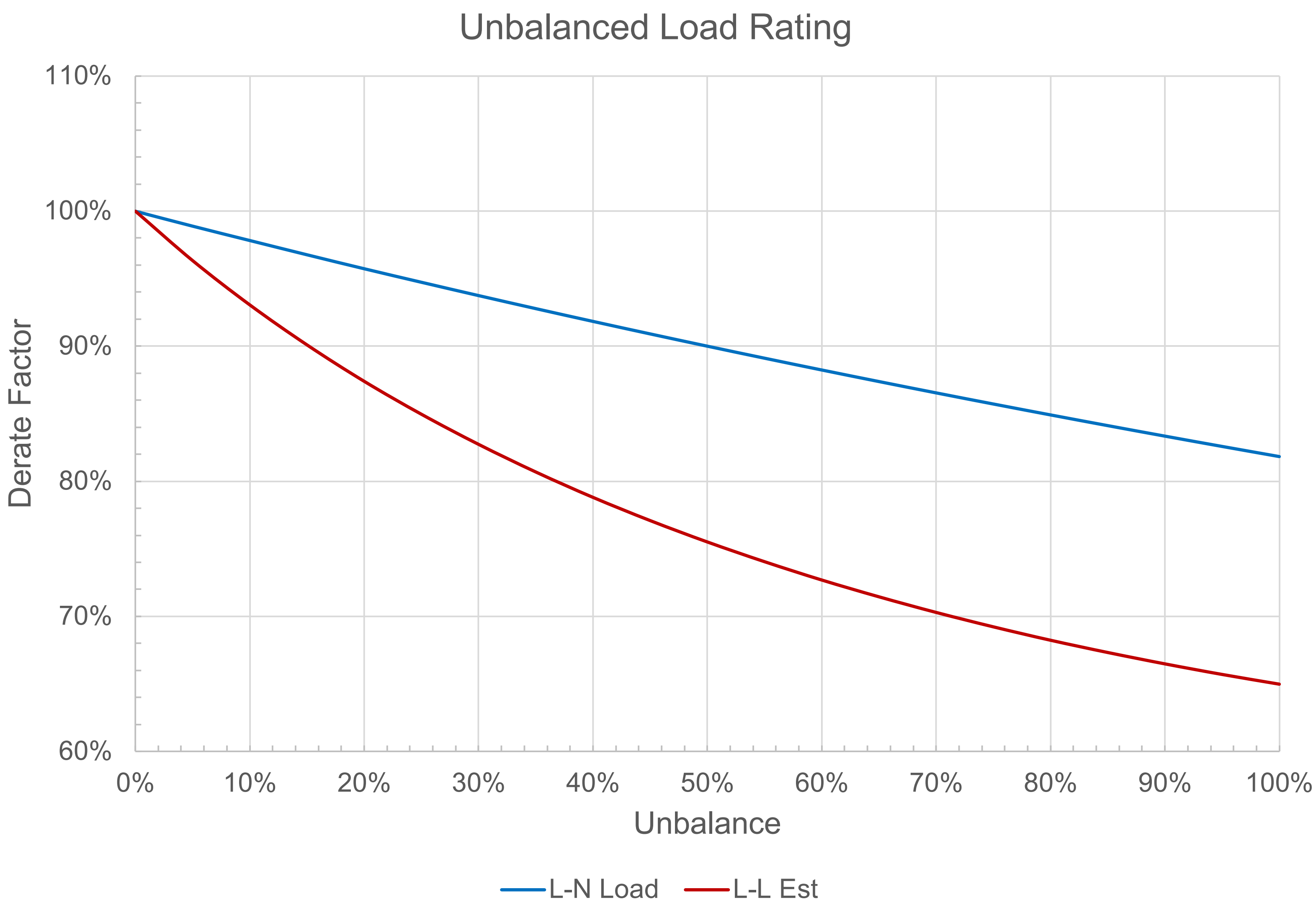
Current Unbalance

- With fully-connected copper cage, 58% of rated kVA single-phase may be available under these conditions (full rated current)
- Special windings like dogleg or double-delta help to balance stator currents and may allow up to 66% of three-phase rating (but these do nothing for rotor heating)
- Some machines are wound specifically for single-phase operation and have only one phase winding (ditto)

Current Unbalance



Current Unbalance



Harmonic Loads

- High harmonic load currents produce rotating magnetic fields that are not synchronous with the rotor, so they induce current in the rotor
  - Mostly in the damper cage, if there is one
  - Causing additional rotor heating
  - This is similar to the extra heating caused by unbalanced loading, and is treated in a similar manner to calculate heating
  - Effective harmonic "negative sequence current" I_{2E} used for calculation (weighted sum of harmonics – see paper by Rice, cited later, for details)

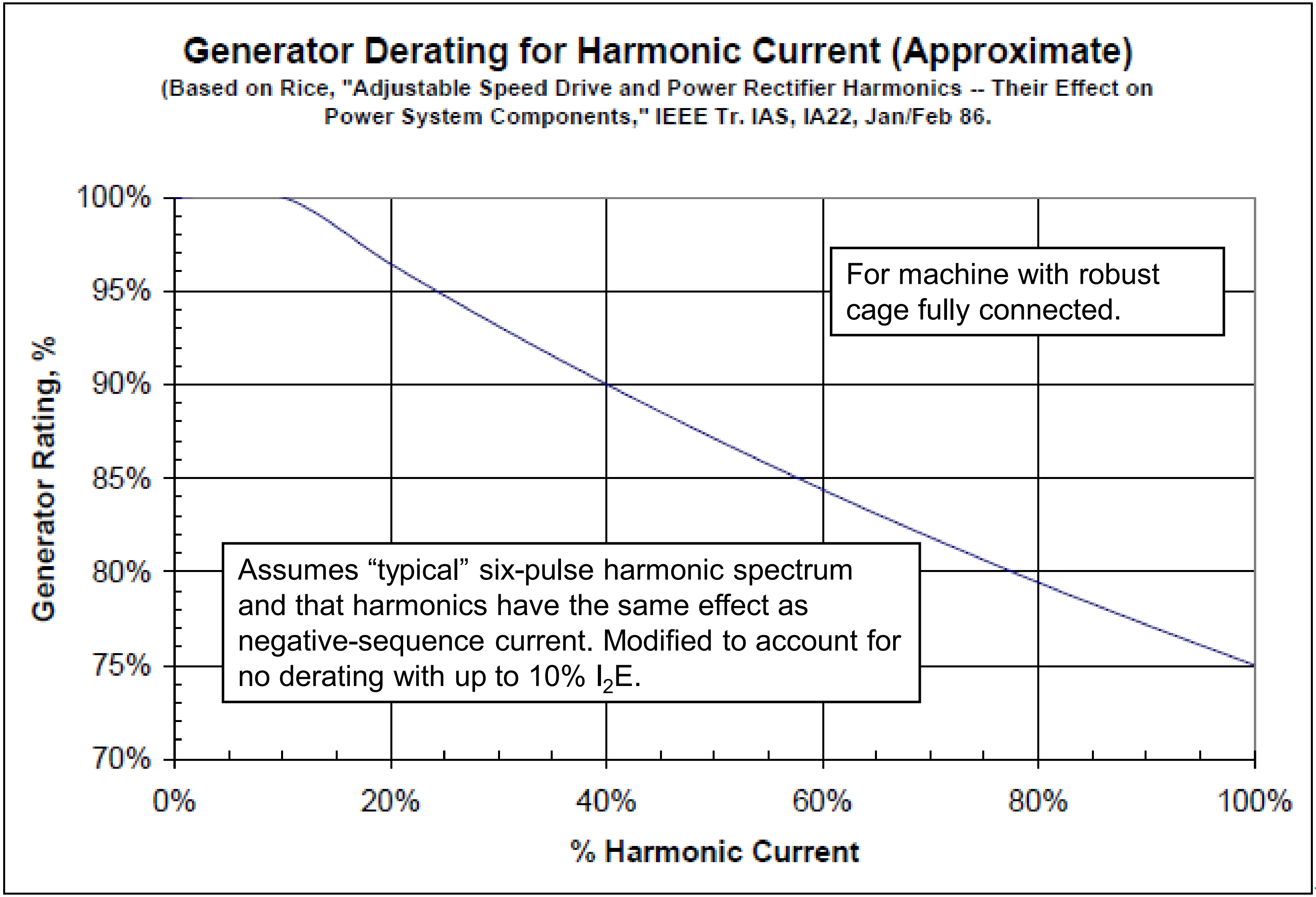
Harmonic Loads

- Some sources propose extreme oversizing (like 250%) as a precaution against high load harmonics – this is usually not necessary and may lead to other problems
- If no unbalance, 10% I_{2E} should be *thermally* tolerable without increasing the size, if the load is well-balanced (10% I_2 is the limit for load unbalance, which has the same effect)
- Up to 30% (normal six-pulse rectifier) harmonics requires no more than 10% derate (see following graph)

Harmonic Loads

- Properly sizing a generator for harmonic load requires knowledge of the harmonic frequencies and the current at each frequency (spectrum), at the worst-case combination of all harmonic loads
- Rather than oversizing the generator to control harmonics, other methods may be more effective or economical:
  - Using lower-harmonic equipment (e.g. 12- or 18-pulse rectification)
  - Applying phase-shift transformers to cancel lower harmonics, or using harmonic filters

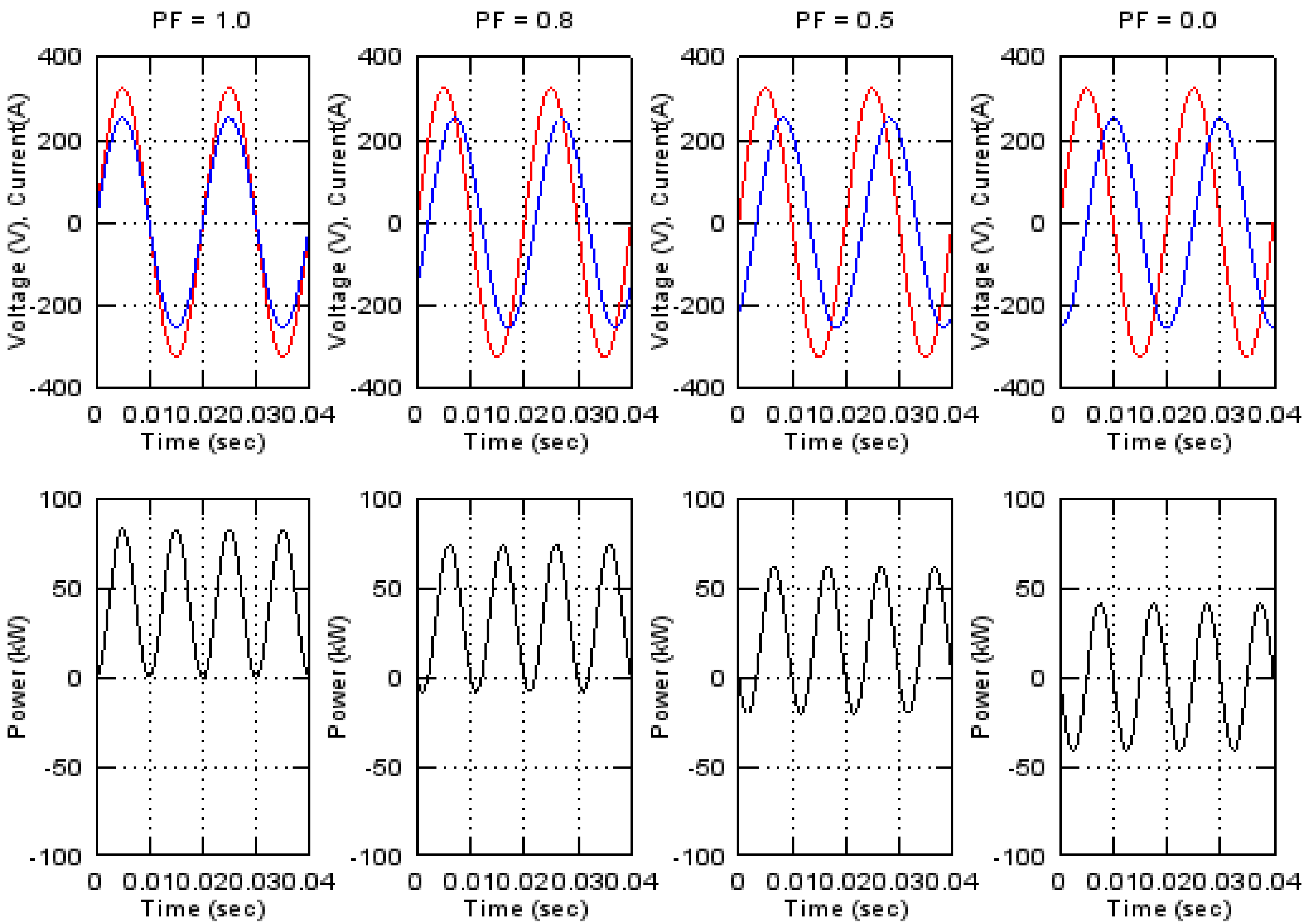
Harmonic Loads (cont.)



Power Factor (review)

- In a power system carrying sinusoidal AC voltages and currents, the voltage on each wire may not be “in phase” with the current
- The instantaneous power carried by that wire is the product of the voltage and current at that instant. If the peak of the voltage and current don’t occur at the same time, the amount of power carried by the wire is reduced. The fraction to which it is reduced is called the power factor (PF).
- The PF is equal to the cosine of the electrical phase angle between voltage and current

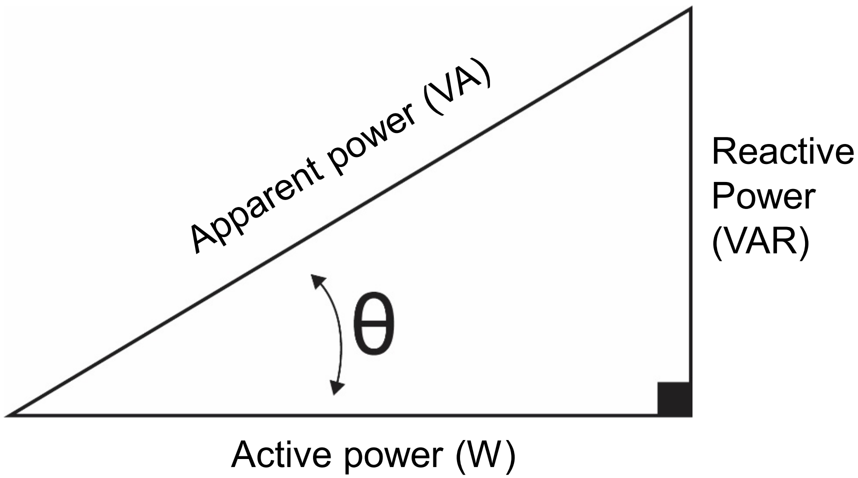
Power Factor



Red – voltage, blue – current. Current *lags* voltage.

Power Factor

- Active (real) power (W) -. Eventually produces a tangible result like heat or light (= I^2R).
- Reactive power (VAR) - Surges back and forth between the source and load (zero average value). This power produces alternating magnetic fields in devices (= I^2X).
- Apparent power (VA) - Is the vector sum of active and reactive, the total needed (= I^2Z).



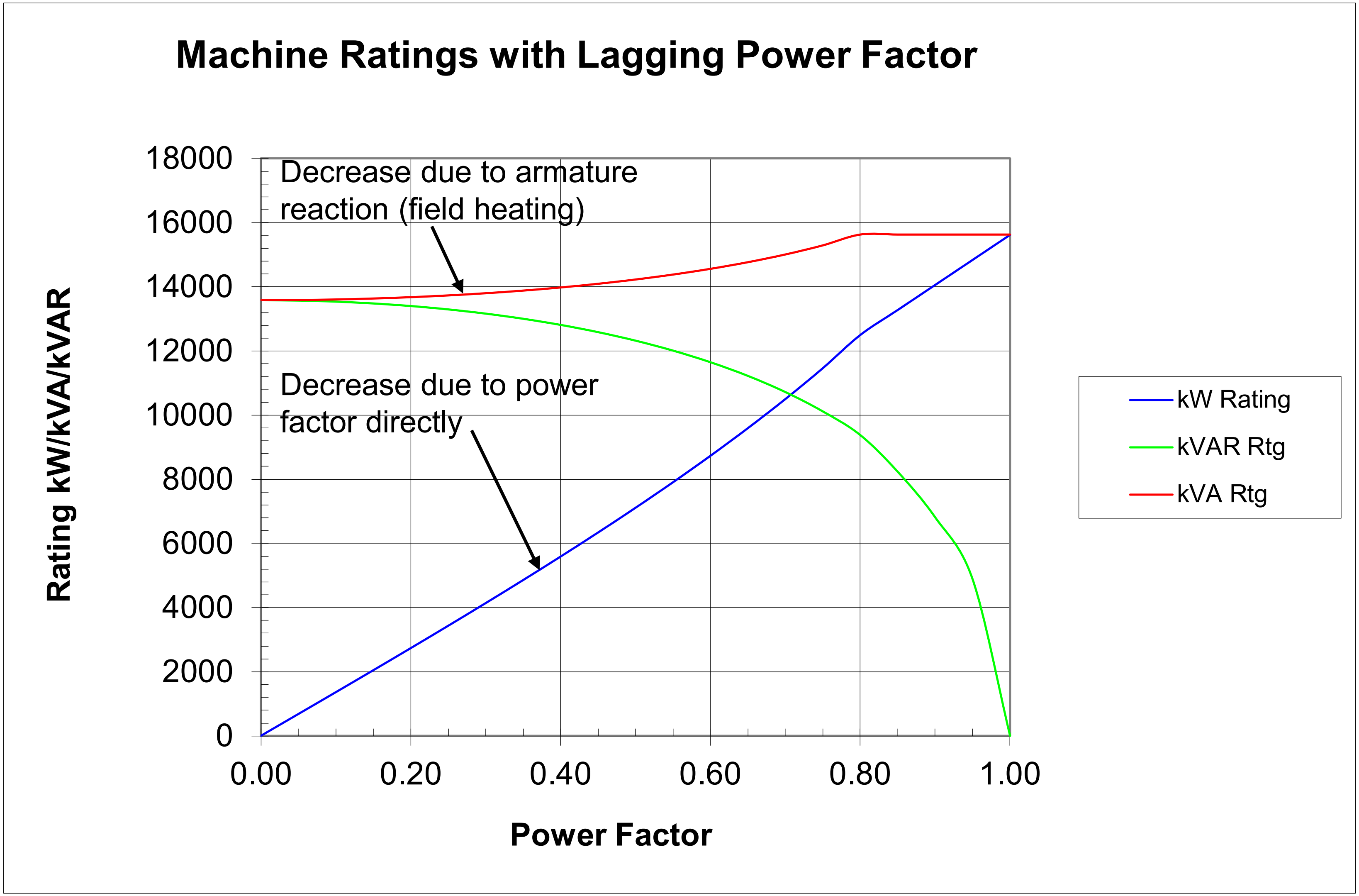
Power Factor

- In synchronous generators a stator (armature) winding produces voltage in response to a magnetic field produced when a rotor winding is “excited” by field current.
- Increasing field current increases the magnetic field resulting in increased voltage.
- Adding load to the generator changes the amount of field current required to maintain the voltage setpoint.
- Lagging power factor load *increases* the required field current; Leading power factor load *decreases* the required field current.
- Leading power factor loads will be discussed in more depth later

Power Factor

- NEMA, IEEE, IEC use 0.8 (overexcited, i.e. lagging load) as nominal power factor
- Lower lagging power factor requires oversizing due to two factors:
  – For a given *kW* rating, the *kVA* will increase at lower power factor, requiring more stator current (larger machine)
  – For a given *kVA* rating, the *rotor current* increases as power factor decreases, due to stator reaction flux. A larger machine is needed to prevent rotor overheating.

Power Factor



Reactive Capability Curve

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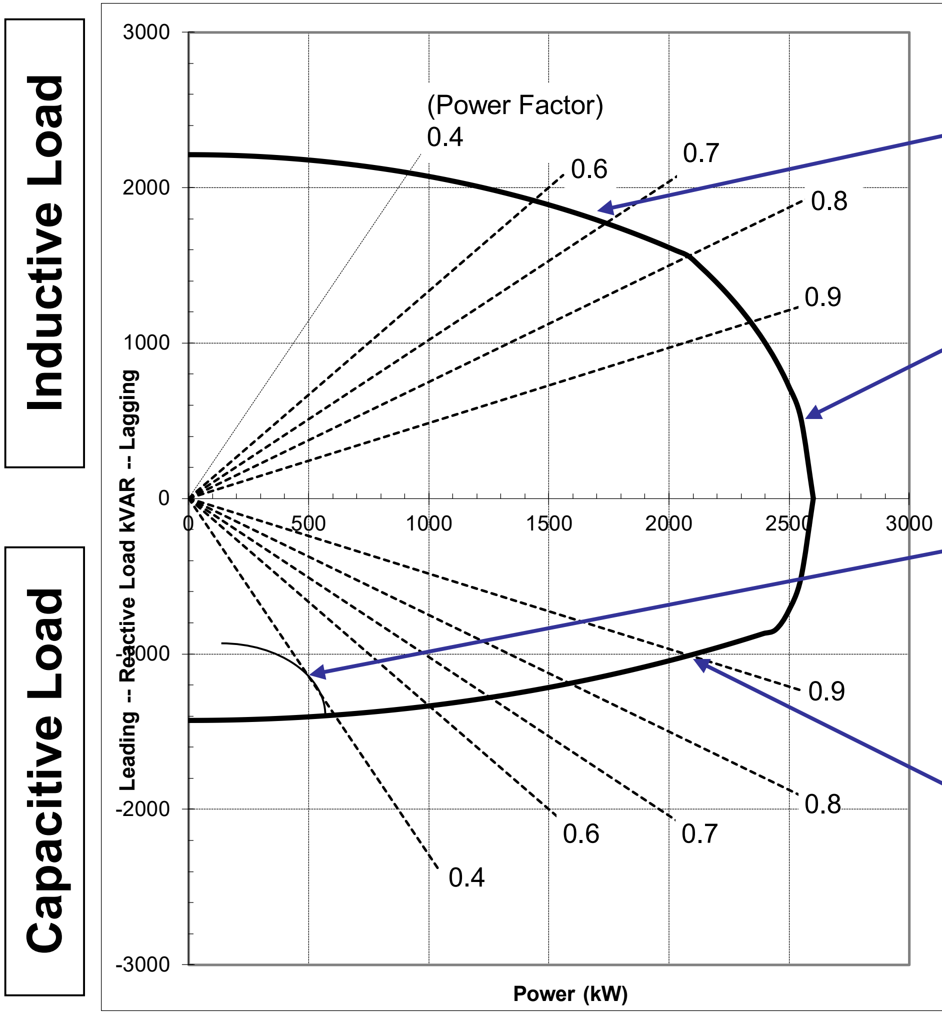

(Lagging) Limited by rotor heating

(Either) Limited by stator heating

Limited by control stability

(Leading) Limited by dynamic stability

Different view, same data

Power Factor Nomograph

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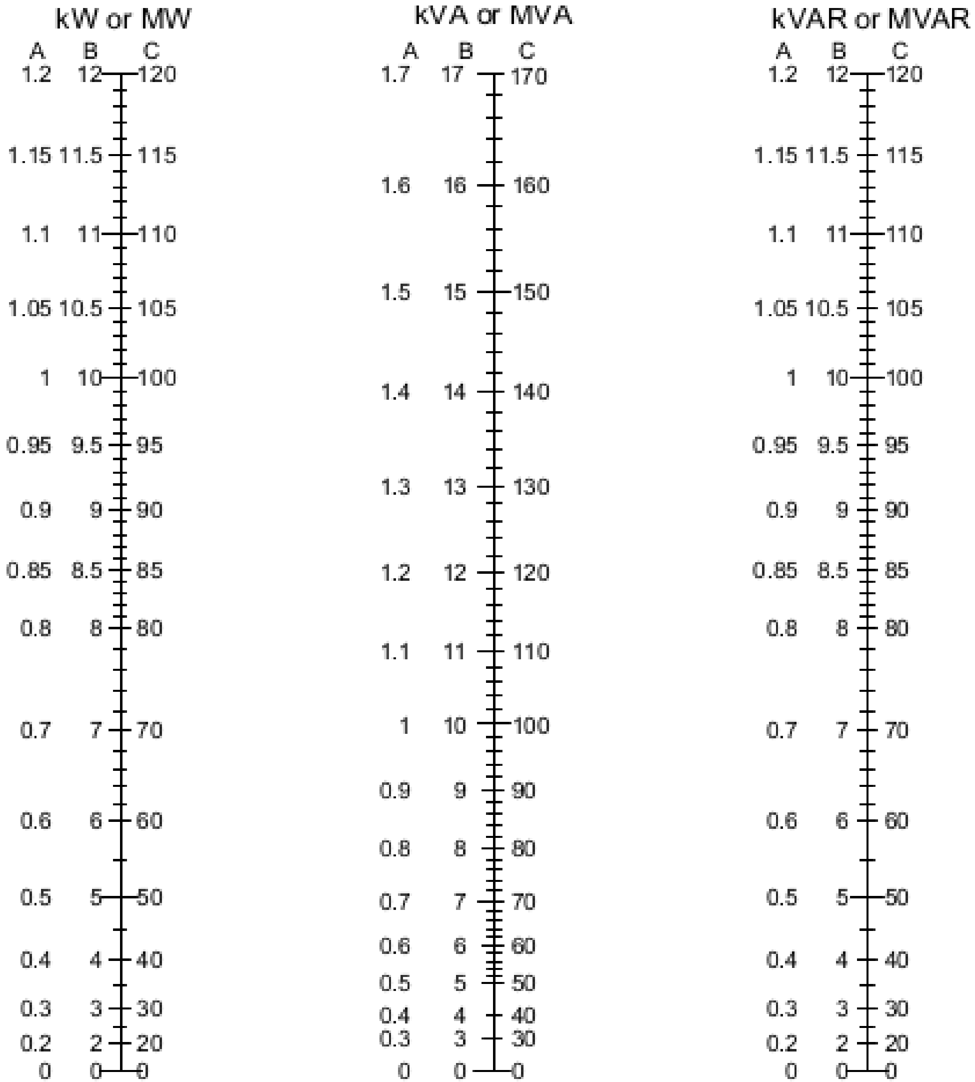

Use same units and scale (A, B, or C) for all power values.

Email allen.windhorn@mail.nidec.com or a.windhorn@ieee.org for electronic copy.

Leading Power Factor

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- Operation with load at a more leading power factor (less inductive, or more capacitive) *reduces* the required field current, so reduces the rotor temperature rise. If the rotor temperature is the limiting factor, the machine could be operated at a higher kVA rating with this load. But engine limits kW anyway.
- But normally, we say the kVA rating is limited by stator current, so it is constant at lagging power factors greater than 0.8.
- Leading power factor load is usually stability limited, and will be discussed more later.

Airflow Restrictions

- Some cooling systems and enclosure types (for example, filters, or the multi-bend ductwork for WP-II enclosure) can restrict the flow of cooling air, so cause derating of the generator. We will cover this when we talk about enclosures and cooling systems.
- Inadvertent restrictions, like long narrow ducts, air intakes or outlets too close to obstructions, lack of room air provisions, or debris collected in air passages or on generator surfaces, can cause generator overheating.

Power Rating

- Thermal capacity factors:
  - Ambient temperature
  - Temperature rise/Load factors:
    - Altitude
    - Duty cycle
    - Power factor
    - Unbalanced load
    - Harmonic load
    - Airflow
  - Cooling method (discussed later)
- Electrical capacity factors:
  - Available fault current
  - Ride-through
  - Load factors:
    - Harmonic voltages
    - Voltage unbalance
    - Leading PF load
  - Motor starting and voltage dip
  - (Above all related to reactances of machine)
  - Efficiency

Cooling Method

- Cooling methods that restrict airflow, or result in higher-temperature coolant, require derating of the generator
- We will discuss derating factors for different cooling methods further on in the program, when we talk about enclosures

Power Rating

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Electrical Capacity Factors

- Often it is necessary to oversize a generator for reasons not connected with temperature
- Some of these require controlling generator reactance or impedance:
  - To increase or reduce available fault current (e.g. for breaker coordination)
  - To reduce harmonic voltages or voltage unbalance
  - To meet a grid code ride-through spec
- Meeting grid codes may also require increased inertia (hence a larger rotor)

Electrical Capacity Factors -- Reactance

- Reactance is controlled by the same factors that control voltage and power ratings
- Reactance is normally given in per-unit or percent of a base impedance so that it is independent of voltage and power rating
- Lower reactance requires fewer turns, fewer slots, or lower pitch, which all reduce voltage
  – So additional magnetic material has to be added to bring the voltage back to rated
  – Makes for a larger machine, higher cost

Electrical Capacity Factors -- Reactance

- Higher reactance requires more turns, more slots, or higher pitch (1st 2 of which reduce the area available for copper), or else added lamination stack
  - So a larger lamination may be needed to allow the extra room for the windings
  - Or the added stack also increases size
- Lower reactance improves voltage dip, but increases fault current, and vice-versa
- Lower reactance reduces voltage unbalance and harmonic voltages

Unbalanced Voltage

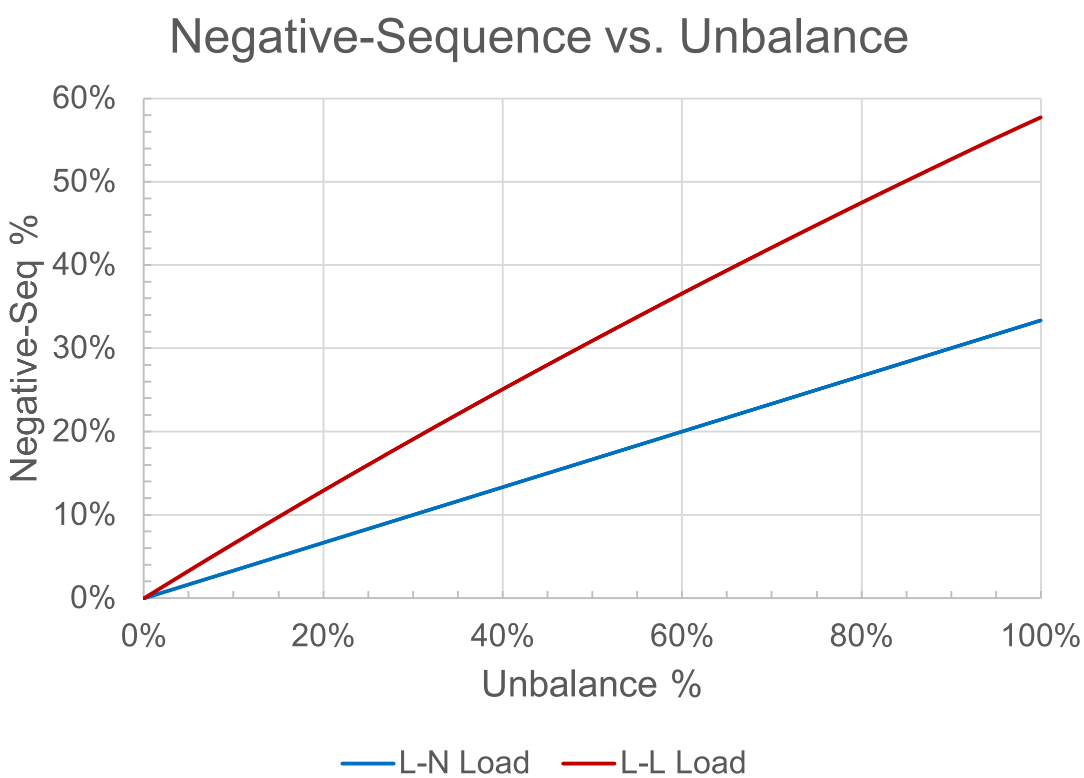
- The impedance of a generator to unbalanced load current is primarily negative-sequence reactance X_2 (with a small R_2 component)
  - Controlled mostly by damper cage design
- Voltage unbalance is calculated by means of symmetrical components
  - Use known current amplitudes and phases to calculate negative-sequence current I_2
  - Multiply I_2 by X_2 to get negative-seq voltage
  - Add to positive-sequence voltage to obtain unbalanced voltage vector set

Unbalanced Voltage

- Voltage drop in generator is mostly inductive
- Lagging load power factor (more inductive) means voltage drop is more “in-phase” with respect to line voltage.
- So lagging power factor load increases the negative-sequence voltage across the generator reactance, so increases unbalance

Unbalanced Voltage

- Rough rule of thumb: 20% current unbalance (between minimum and maximum currents) gives about 10% negative-sequence current



Definition: Worst-case X% unbalance is 100% current in two phases and X% less in the third.

Assumes equal power factor (120º current angles) for L-N load.

Assumes no neutral current for L-L load

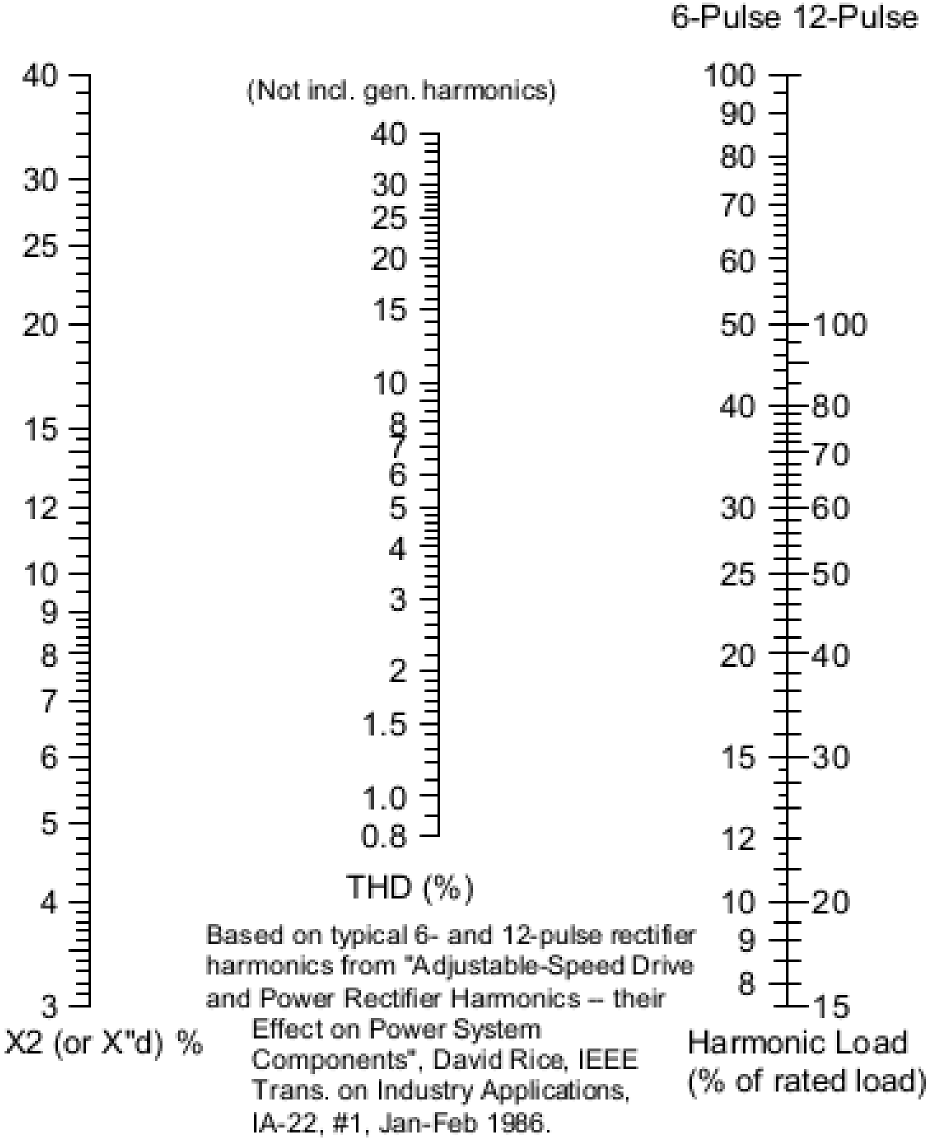
Harmonic Voltage

- High harmonic load currents also interact with the generator impedance to produce harmonic voltages. These can cause excess heating of motors and transformers, as well as failures of sensitive equipment. IEEE Std 519 recommends maximum harmonic levels for power systems.
  - The effective impedance for harmonics is the negative-sequence reactance, X_2, multiplied by the harmonic order
  - X_2 should be close to the subtransient reactance, if the machine has a fully connected damper cage

Harmonic Voltage

- Harmonic voltage of a particular harmonic is equal to harmonic current at that frequency times reactance at that frequency
- Root of the sum of the squared individual harmonic voltages gives the effective RMS harmonic voltage – divide by the fundamental to get total harmonic distortion (THD)

Harmonic Loads (cont.)



Notes:

- Six- and twelve-pulse load values are the fraction of the load that is harmonic-generating, in per cent
- Align X_2 and % of load values with a straightedge, and read voltage THD from middle scale, or align % of load and THD to get the maximum value for X_2
- Estimate only, since THD depends on system factors other than the generator impedance

Operation at Leading Power Factor

Excitation of Synchronous Machines

- Remember leading power factor load *decreases* field current. At some value of leading power factor load, the field current required to maintain voltage decreases to zero. At this point, there is no ability to control voltage and the generator voltage will increase until saturation stops it.
- If the generator is paralleled with a grid, the effect is different. Since voltage is controlled by the grid, it doesn't increase. But without field current, the generator can't accept the torque delivered by the engine, so will become unstable and slip poles. "Pole slipping" causes severe voltage disturbances and pulsating torque, and results in rapid heating of the generator.

Excitation of Synchronous Machines

- Leading power factor is sometimes referred to as "reverse VARs" or "negative VARs"
- This is *not* the same thing as "negative power factor" or "reverse power", which is *real* power flow *into* the set, and is controlled by the engine, not the generator.
- Power factor is *positive* for either leading or lagging condition. As long as power is being delivered, the PF is greater than zero. A different quantity, usually called reactance factor (RF), becomes negative when the power factor is leading.

  $|RF| = \sqrt{1 - PF^2}$ (Pythagoras)

Reactive Capability Curves

- The interaction between field current and output voltage and current is complex, especially when saliency and saturation of the magnetic material are considered, so usually simplified (but conservative) rules are used to determine generator sizing.
- The tool most commonly used to determine excitation limits is the reactive capability curve, which is derived from these simplified rules. We saw this earlier – let's take a closer look.
- Kato uses the method from IEEE Std 67-1971 for lagging power factor load, and Rubenstein and Temoshok, AIEE Trans. Dec.1954, V73-III-B, p. 1434 for leading power factor load. Just so you know.

Reactive Capability Curves

- The generator parameters that control this are saturated short-circuit ratio (SCR or, in Europe, Kcc) and saturated synchronous impedance Xds. These both represent the same quantity and are reciprocals of each other.
- High SCR and low Xds make the machine more stable. To a first approximation, if Xds is less than 1, or SCR greater than 1, the machine will be stable with *any* leading power factor down to zero.
- To achieve this usually requires a considerably oversized machine.

Reactive Capability Curves

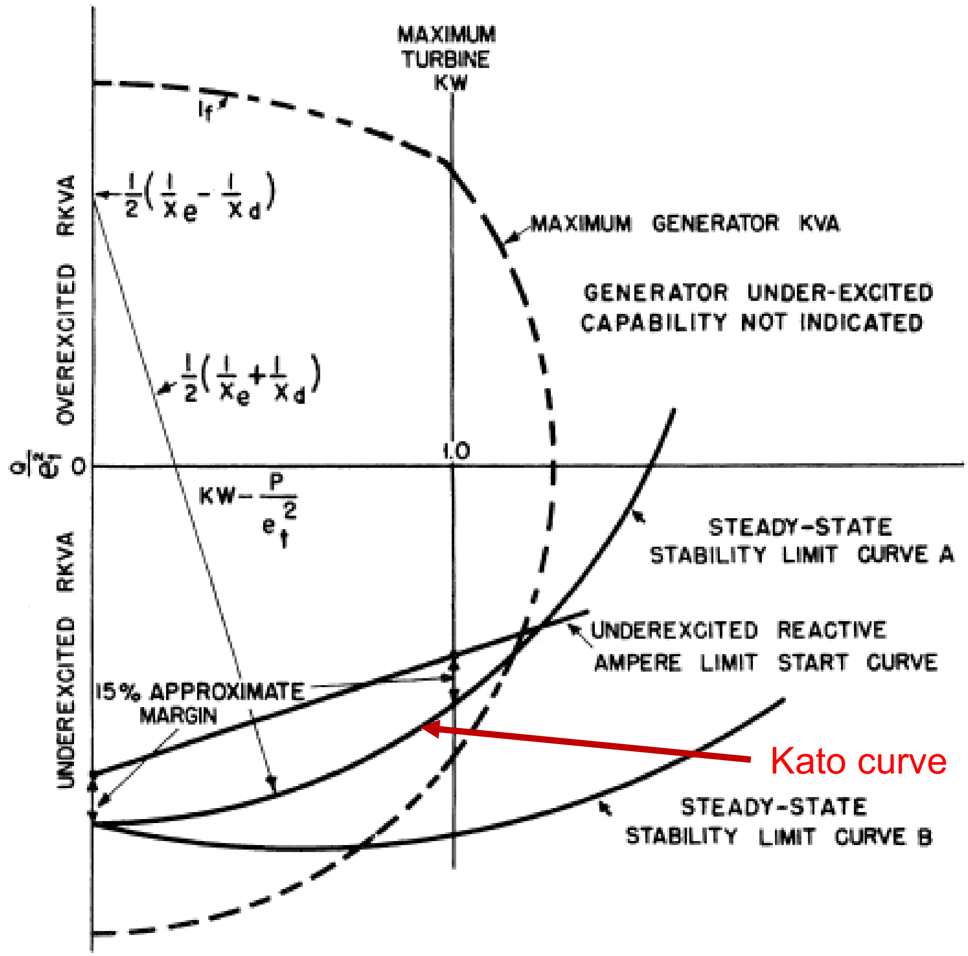


Fig. 1. Steam turbine generator characteristics with steady-state stability limit curves and underexcited reactive ampere limit setting

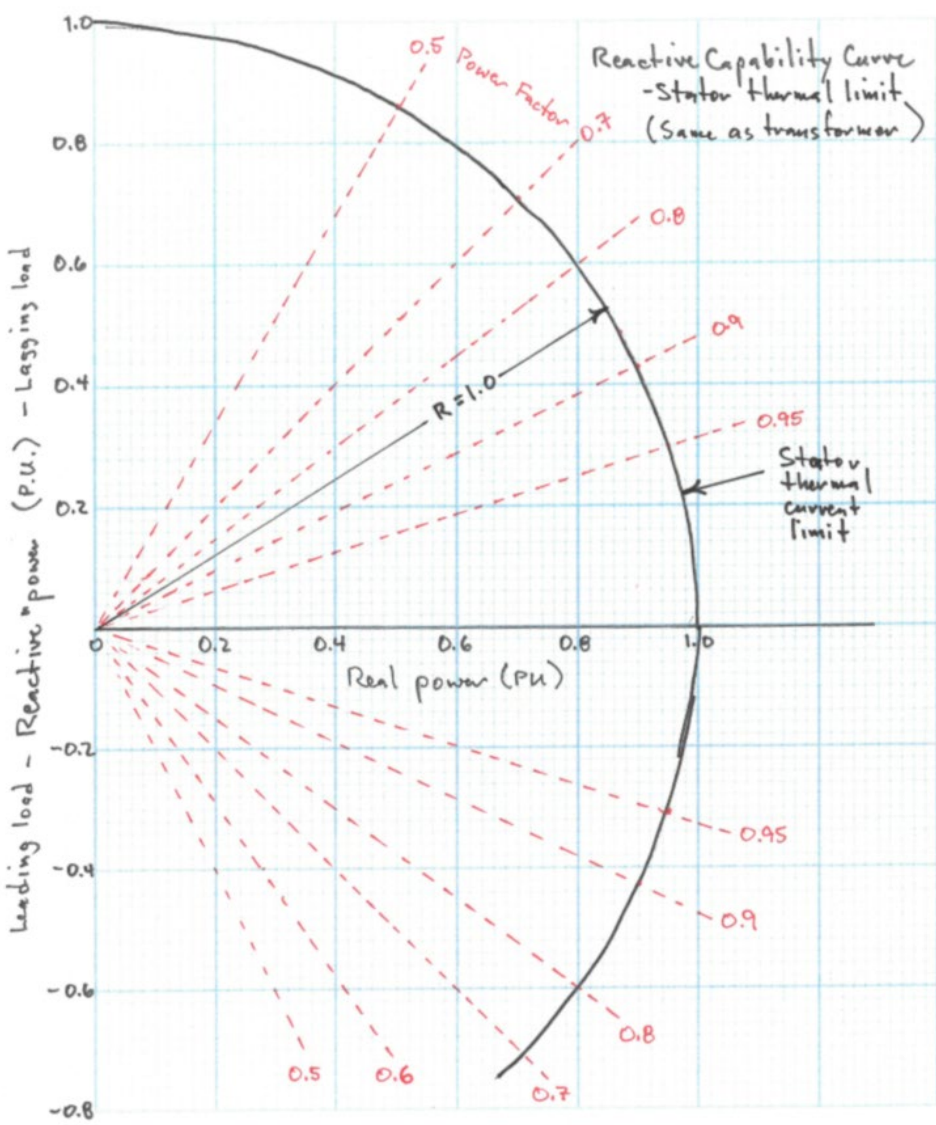
Curve A—Steady-state stability limit with noncontinuously acting regulator or close manual control

Curve B—Steady-state limit with continuously acting buck-boost amplidyne regulator

This shows the reactive capability curve from Rubenstein and Temoshuk.

Xe is system reactance for grid paralleled machine. Smaller Xe makes the curve flatter – limit with Xe equal to zero is horizontal line (zero torque angle δ). Kato uses curve A for Xe = 0.4, which is very conservative for salient-pole machines.

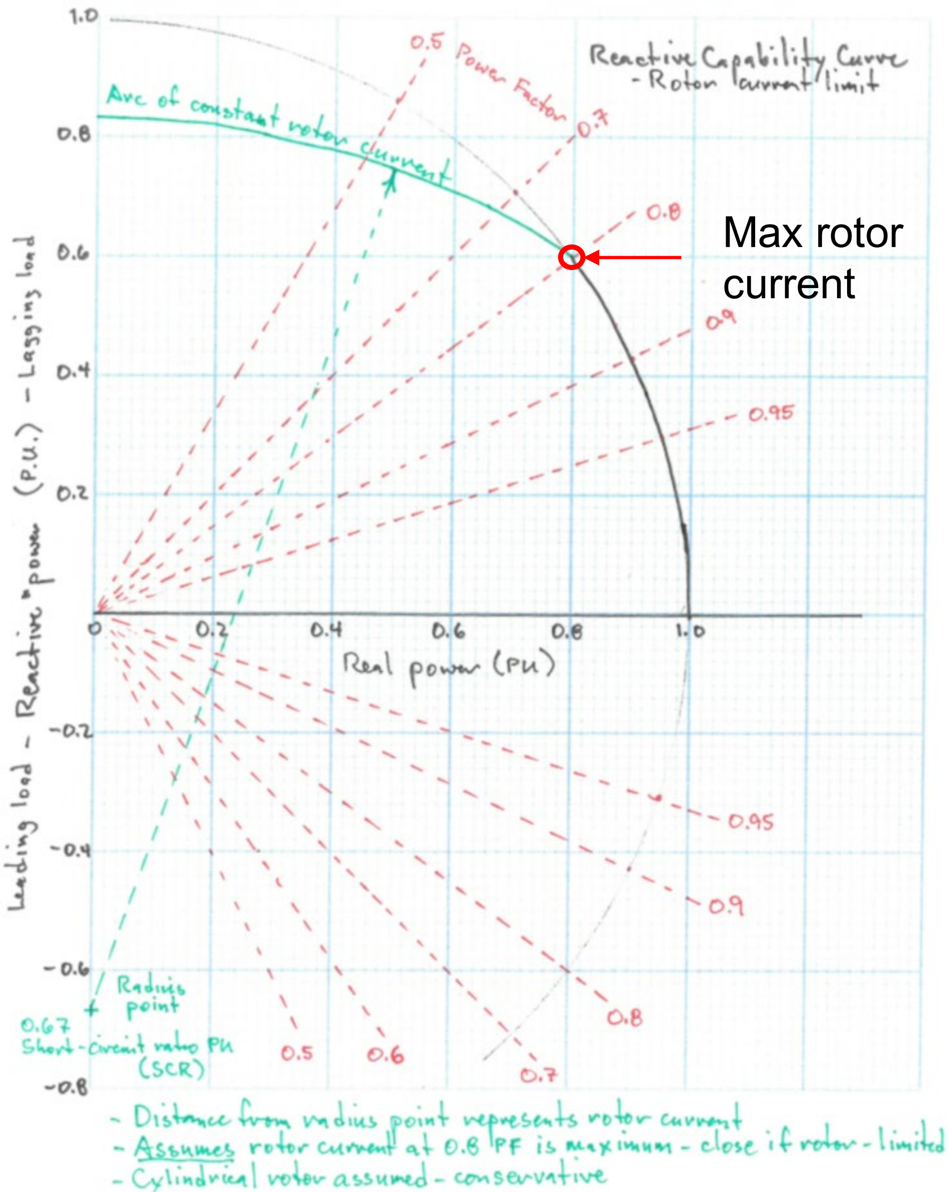
Reactive Capability Curves



We will build the full reactive capability curve in pieces.

This curve assumes that the machine is thermally limited to 1.0 per unit current. In reality, there is usually some margin, so the curve is for a nominal arbitrary current limit rather than the actual machine capability. This saves bother and allows the curves to be drawn automatically.
Distance from (0,0) is load current in PU.

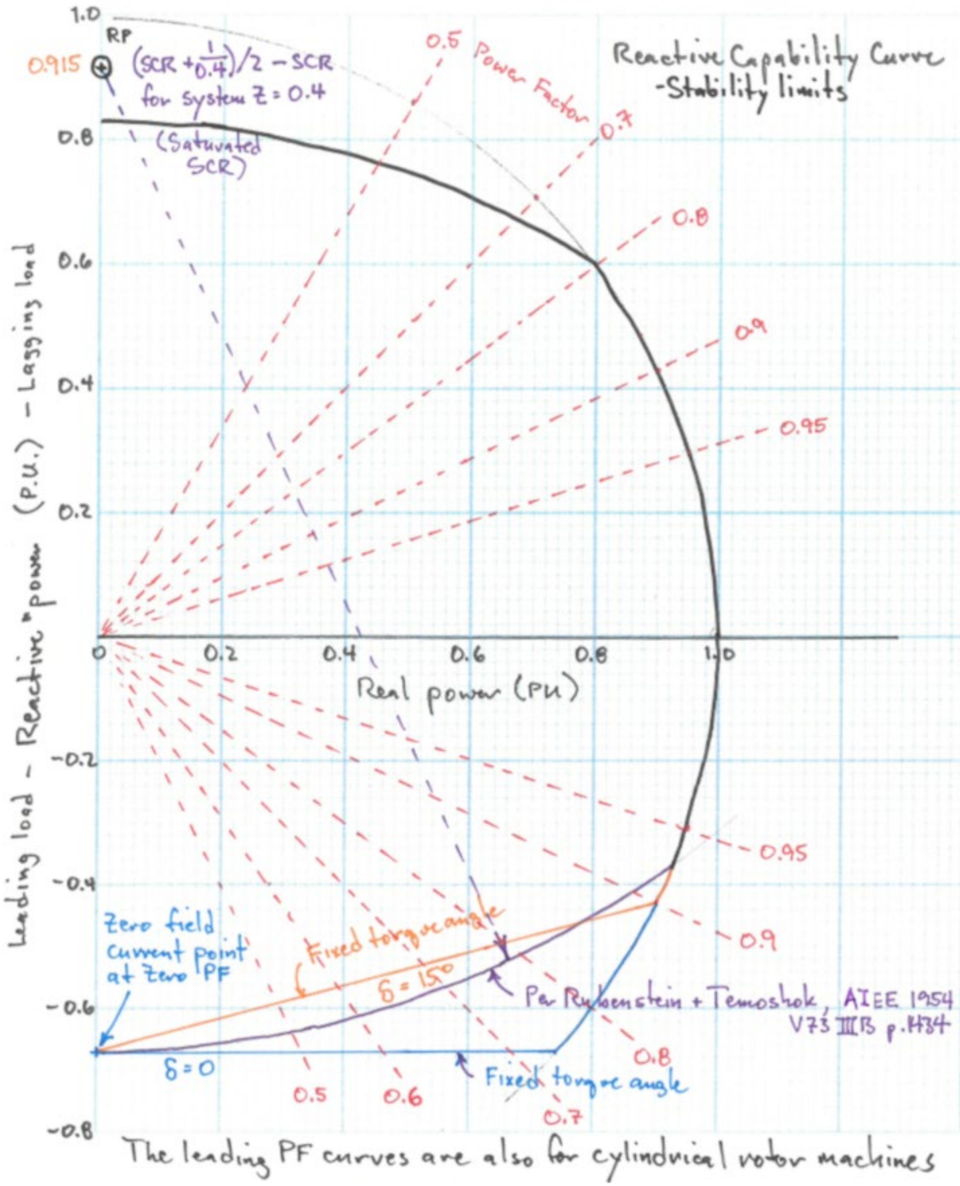
Reactive Capability Curves



Distance from center point represents approximate value of excitation (saturated). Assumes that the machine is perfectly thermally balanced at 0.8 PF, and becomes rotor-limited below 0.8 PF. This is not generally true, so this curve represents what we will guarantee the machine to do, not what it is actually capable of doing.

Per IEEE Std 67-1971 Assumes cylindrical rotor, which is not true for our sets, but is conservative

Reactive Capability Curves



Blue curve is the theoretical torque limit for a round-rotor machine (δ = 0).

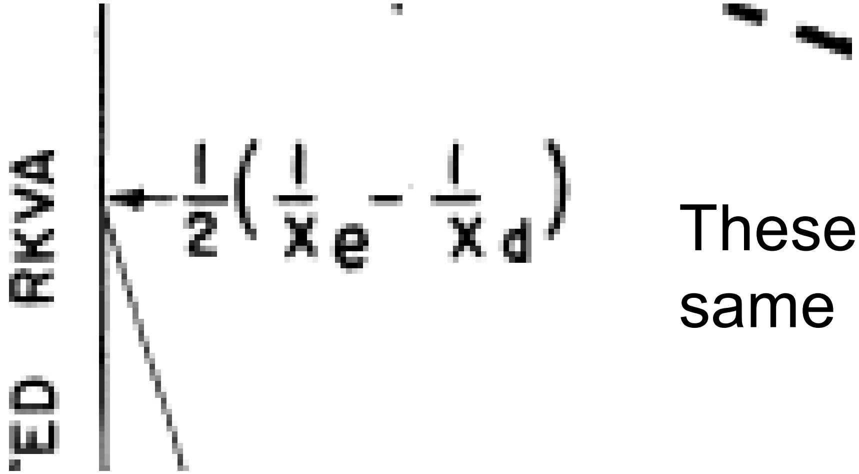
Orange curve is for a more reasonable δ limit of 15º.

Purple curve is for the limit from the Rubenstein and Temoshuk paper, also for round-rotor machine.

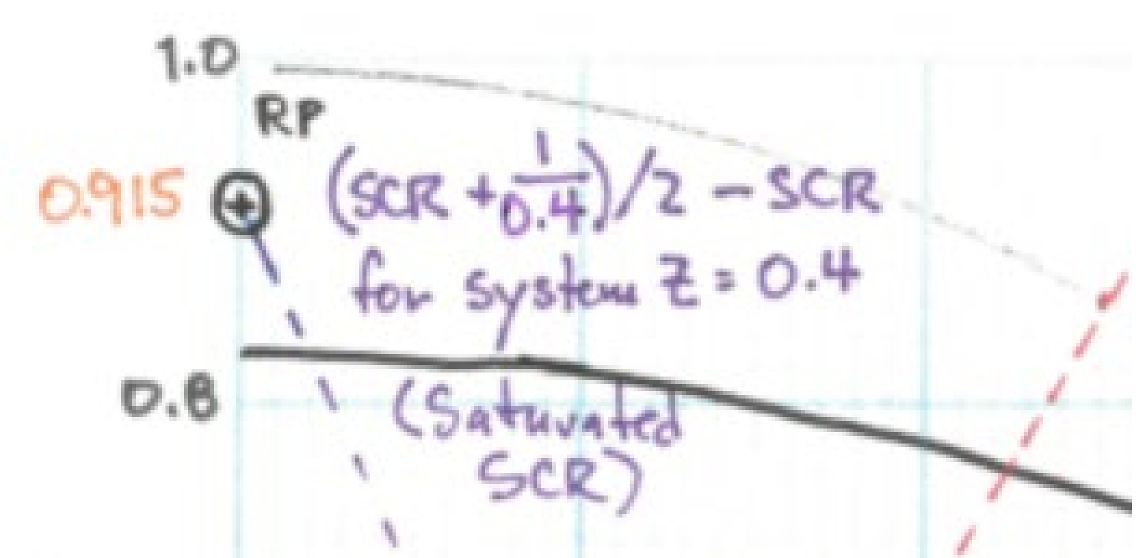
These are conservative for salient-pole, because they ignore saliency torque, which improves stability.

Limits for paralleled machines, same for islanded machines, but for different reasons.

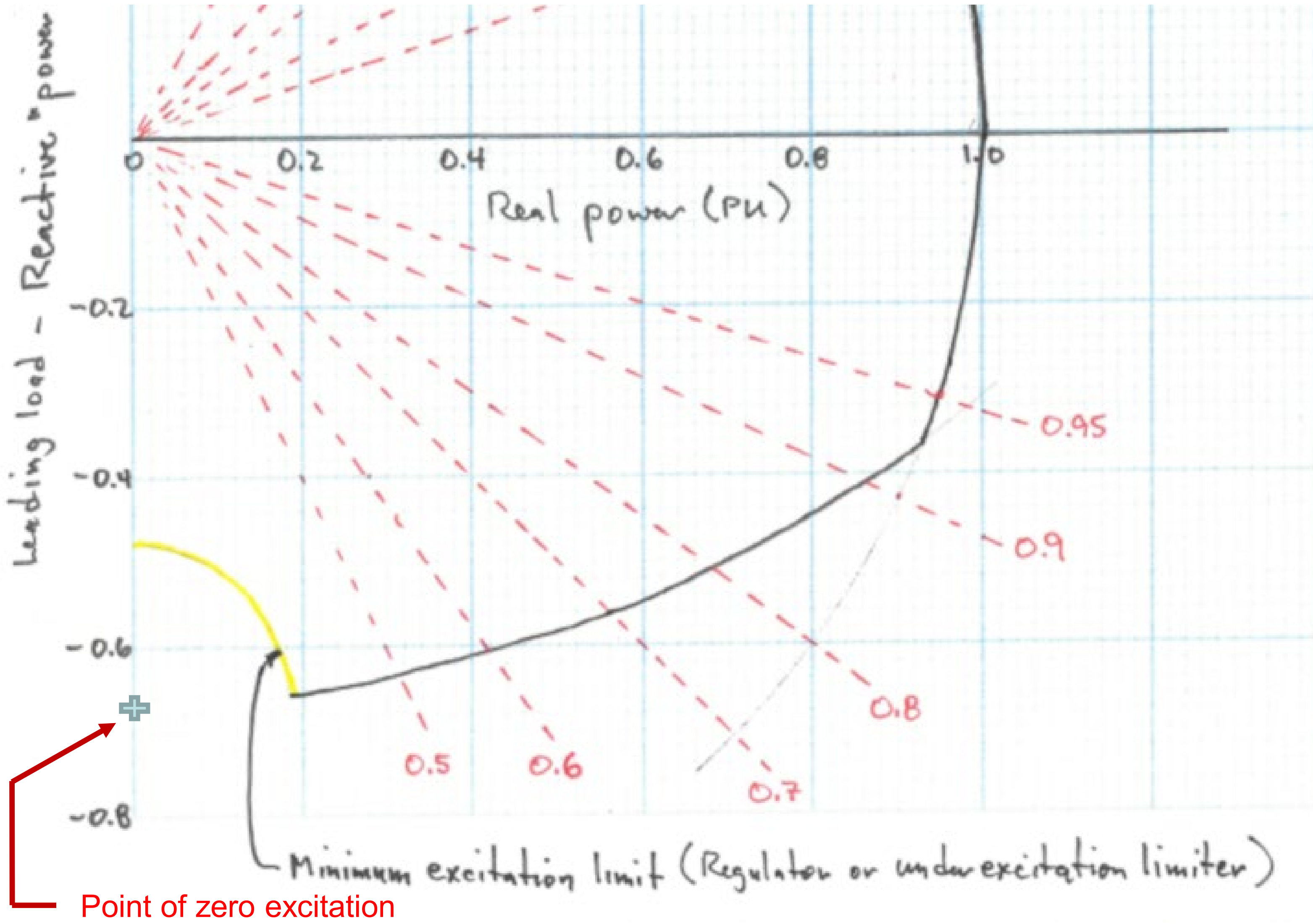
Reactive Capability Curves



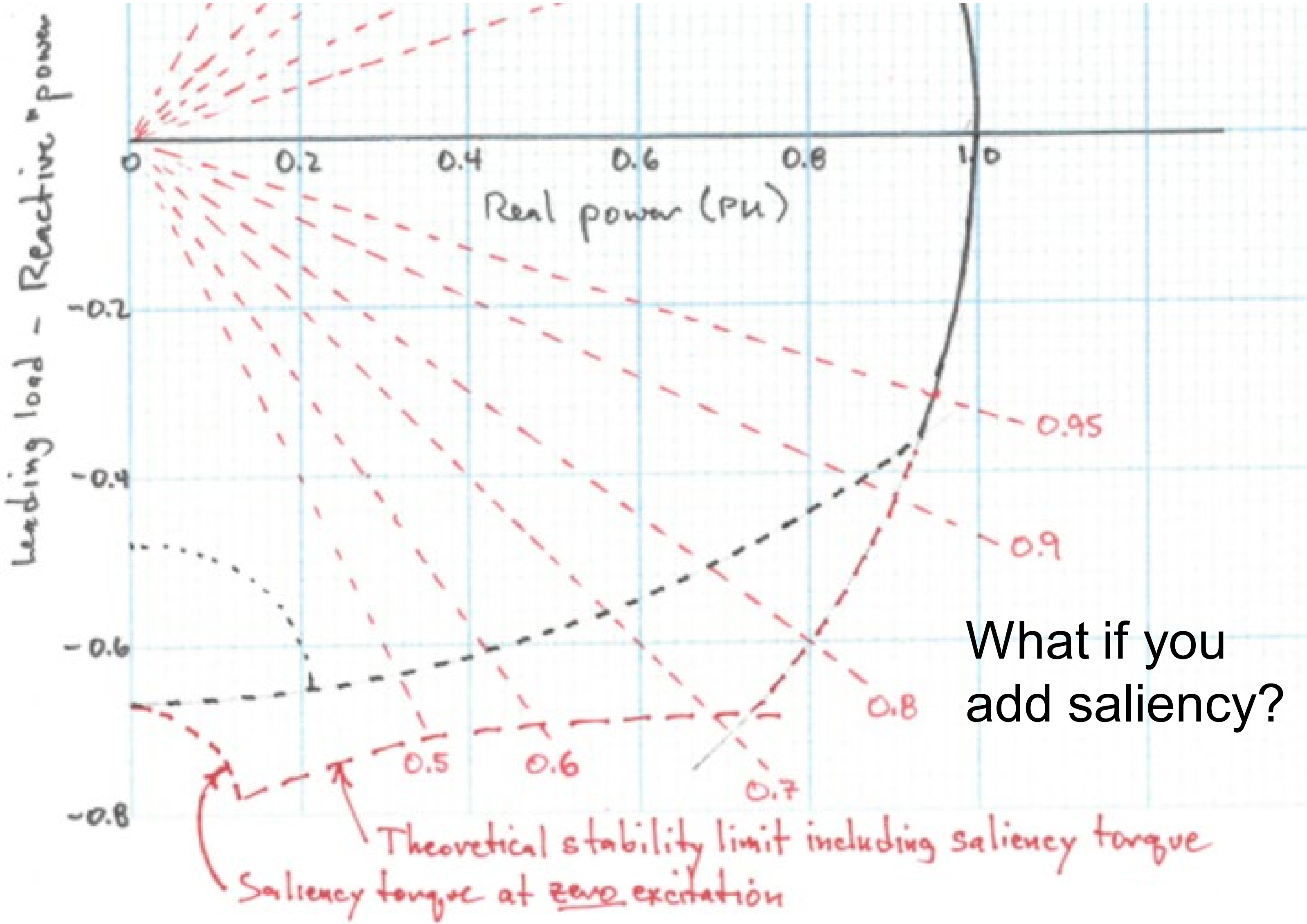
These two equations are the same



Reactive Capability Curves



Reactive Capability Curves



What if you add saliency?

Reactive Capability Curves

- With lagging power factor, the limits on generator output are caused by heating. At leading power factor, on the other hand, the limits are concerned with the stability of the machine, meaning its ability to supply power at a steady rate at constant speed and voltage.
- For large or high-speed machines there may be a limit on leading power factor due to heating of the end regions of the rotor. We have never observed this in the kind of machines we build, but it should be kept in mind as we build larger machines.

How to Specify Generators for Leading PF

Preferably, the generator OEM and the user (or site engineer) should work together to select a generator design that will meet the requirements of the site. In addition to the normal rating data, the manufacturer will benefit from the following information:

- Whether the site will run in island or grid-connected mode, or both.
- In island mode, what sort of capacitive load will be connected, and how it will be coordinated with other loading.
- In grid-connected mode, the maximum leading VARs or minimum leading power factor required

How to Specify Generators for Leading PF

- For example, large UPS sets will generally have a fixed capacitive reactance on the input due to the input filters, but these UPS sets will have variable real power load depending on how their output is loaded. Other loads on the circuit (e.g. chillers) may provide lagging load to counterbalance the leading load, but if they are started *after* the leading load, the system must be stable without them.

How to Specify Generators for Leading PF

- In grid-connected mode, the user has control over the VAR loading, but if leading power factor operation is required (possibly for local voltage control at light load), the generator manufacturer needs to know the possible range of real and reactive loading.
- Recent grid codes require operation at least at 0.95 PF leading, possibly 0.9 PF leading.
- Also required is operation at 90-95% reduced voltage (increased current), increasing the per-unit reactance and decreasing stability limits.

How to Specify Generators for Leading PF

To meet the site requirements, we may:

- Propose an oversize generator in order to keep the synchronous reactance low.
- Use a special design that is more saturated than normal for the same reason.
- Include special testing to insure that the generator will meet requirements.
- Propose additional protective relaying and controls to detect or prevent unstable conditions.

How to Specify Generators for Leading PF

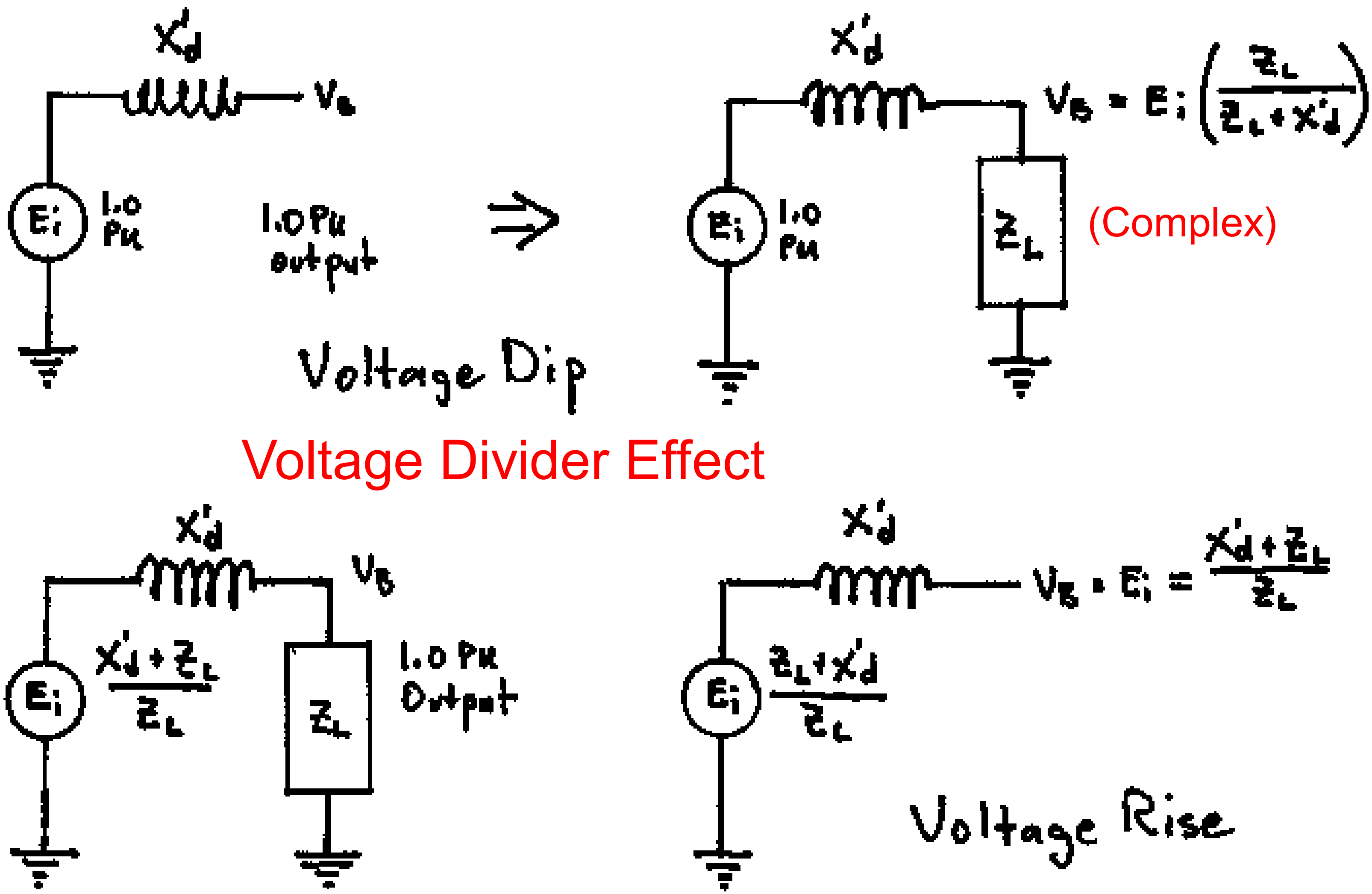
- At a minimum, a reactive capability curve as well as saturation curves and V-curves should be requested for the proposed generator before ordering, and carefully examined by the site engineer to make certain the generator will always operate within the safe region.
- Because the leading power factor capability depends strongly on factors that vary by manufacturer, frame size, pole count, and model, it is not possible to use a “rule of thumb” for sizing the generator.

** End of Detour **

Motor Starting and Voltage Dip

- For generators rated ~50 MW or less with electronic voltage regulators, the transient reactance X'd controls the voltage dip or rise due to short-term load transients
- On load application, generator reactance forms a voltage divider circuit with the load impedance, reducing the voltage until the regulator can respond and increase the internal excitation voltage to compensate
- Similarly on load rejection, when the load is removed, voltage rises to value of (increased) internal excitation voltage

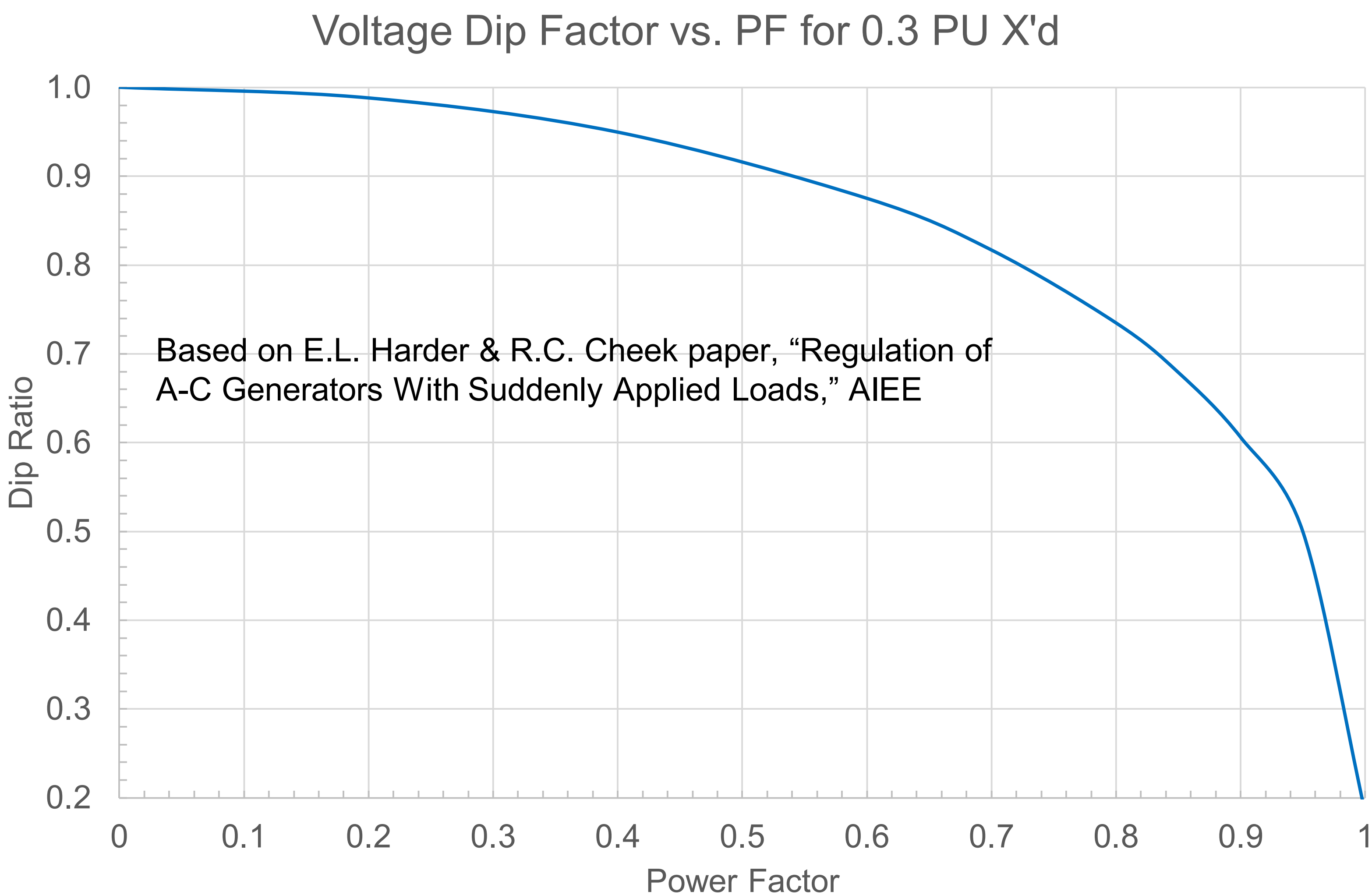
Motor Starting and Voltage Dip



Motor Starting and Voltage Dip

- For low power factor load (esp. motor starting, typically 0.2-0.4 PF), Z_L and X'd are both mostly inductive, and voltage dip can be calculated using the magnitudes of the impedances
- For higher power factor (> 0.4), complex or vector calculation must be used
- To simplify, an approximate power factor "dip factor" can be used (see following slide)

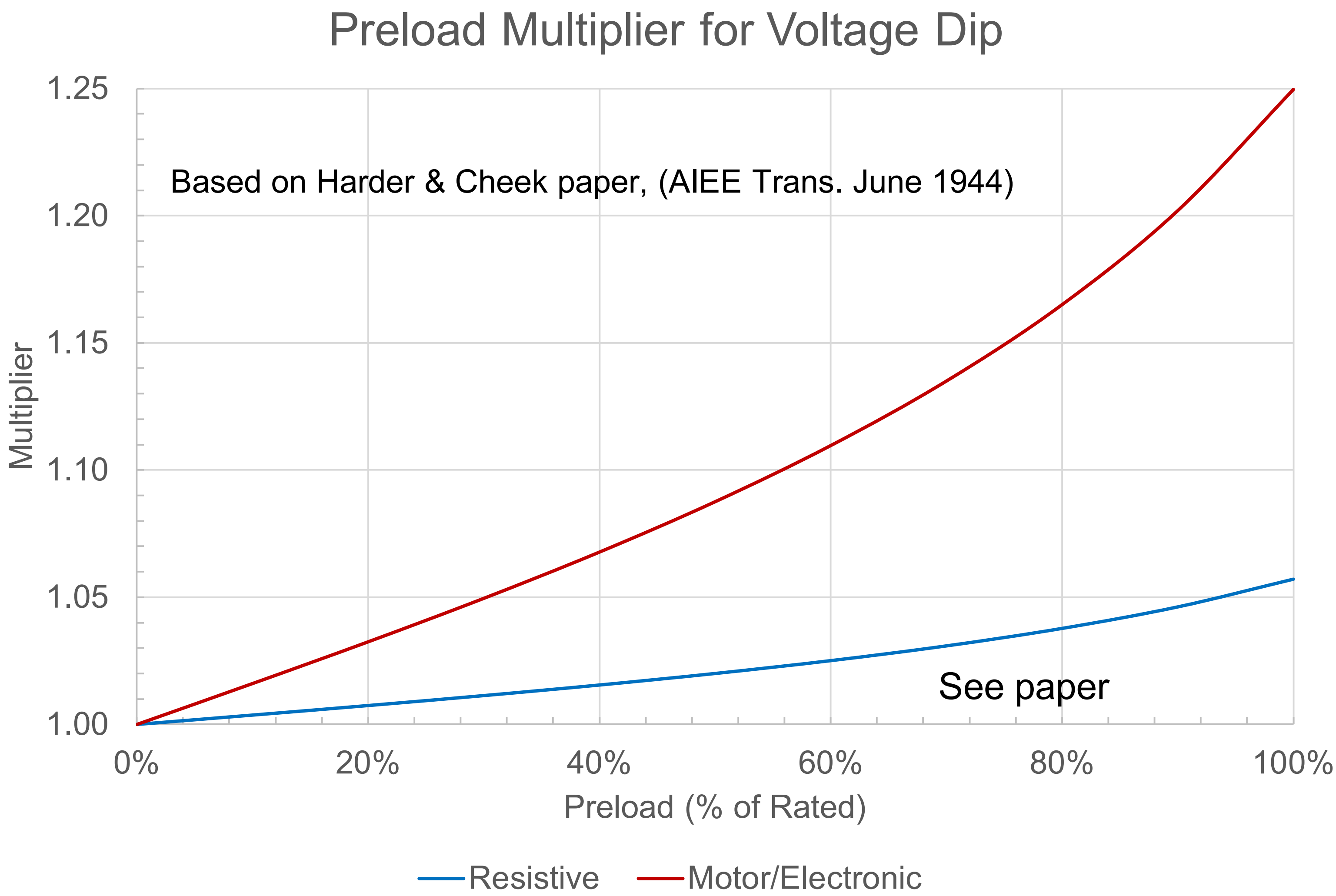
Motor Starting and Voltage Dip



Motor Starting and Voltage Dip

- Preload of the generator affects the voltage dip, and more so if it is motor load or other constant-power load
- Resistive load like heaters or incandescent lighting will draw *reduced* current during a voltage dip (still, the dip increases – why?)
- Motors or electronic load maintain constant power draw, so if the voltage decreases, the current will *increase*, worsening the dip
- An approximate preload "dip factor" is used to estimate the increase in the voltage dip

Motor Starting and Voltage Dip



Motor Starting: Examples

- NEMA MG1 32.18.5.3 Motor starting equation

$$\mathrm{D} = \frac{X'd}{X'd + \frac{BKVA}{SKVA}}$$

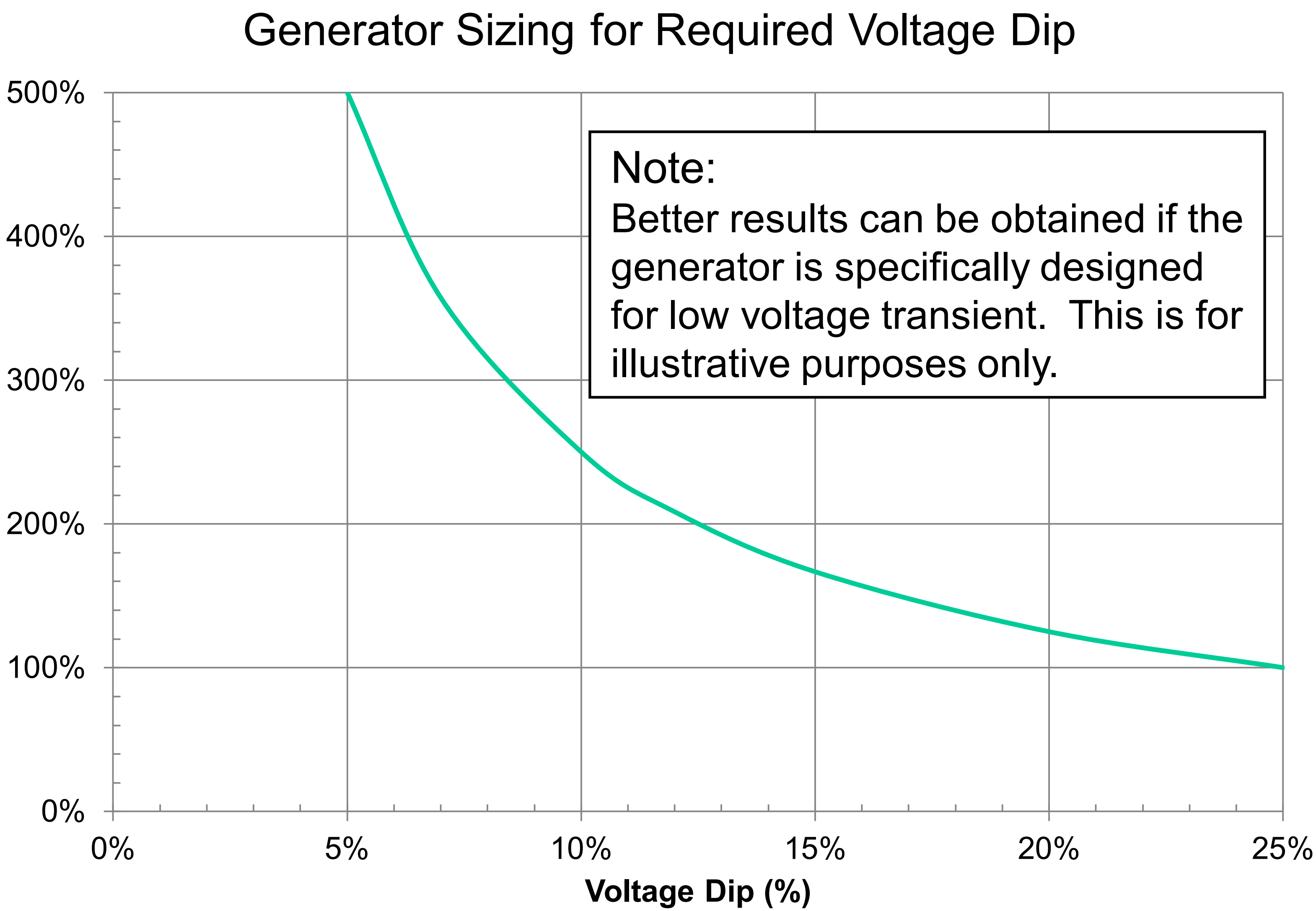
Where D is PU dip, X'd is in per unit of the KVA base, BKVA is base kVA, SKVA is motor starting kVA

Example: 2000 kW @ 0.8 PF with X'D = 18.2% starts a 750 HP code F motor – What is the approximate voltage dip?

- Base kVA = 2000 kW / 0.8 PF = 2500
- Starting kVA = 750 HP × 5.6 kVA / HP = 4200
- $\%\mathrm{Dip} = 100\% \times \frac{0.182}{0.182 + \frac{2500}{4200}}$ = 23.4%

- Note: To reduce the dip, reduced voltage starters can be used. Engine transient response will increase dip, but the engine response is usually much slower than the generator. This assumes a very low starting power factor.

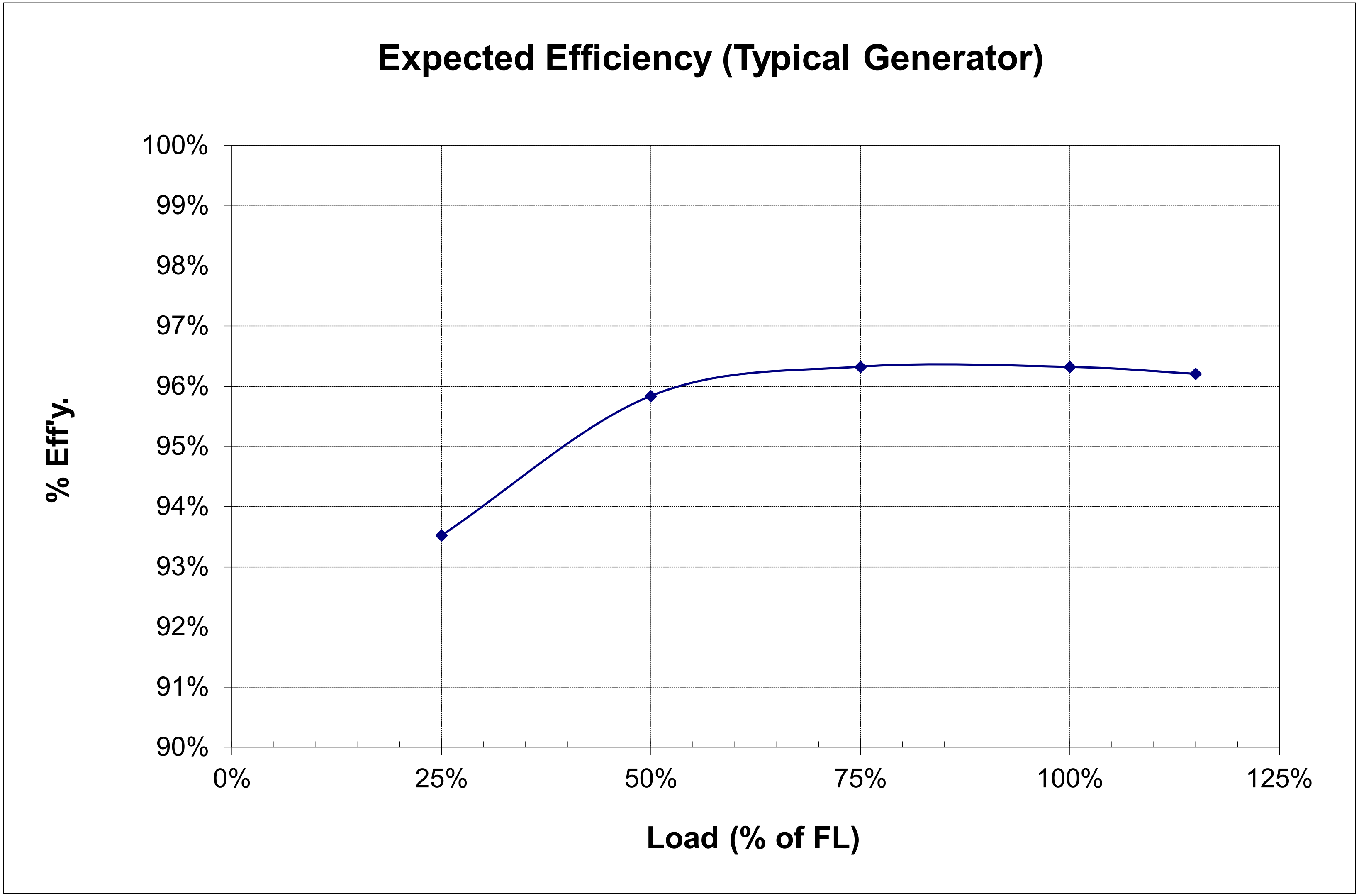
Motor Starting and Voltage Dip



Electrical Capacity Factors -- Efficiency

- Increasing the size of a generator allows reduction of the number of coil turns or slots, so the winding resistance can be reduced
  - This reduces winding losses, improving efficiency
  - It also increases core and other fixed losses, so a balance must be achieved between the losses to obtain best efficiency.
- Highest efficiency is usually achieved at or slightly below full load for normal generator

Electrical Capacity Factors -- Efficiency



Electrical Capacity Factors -- Efficiency

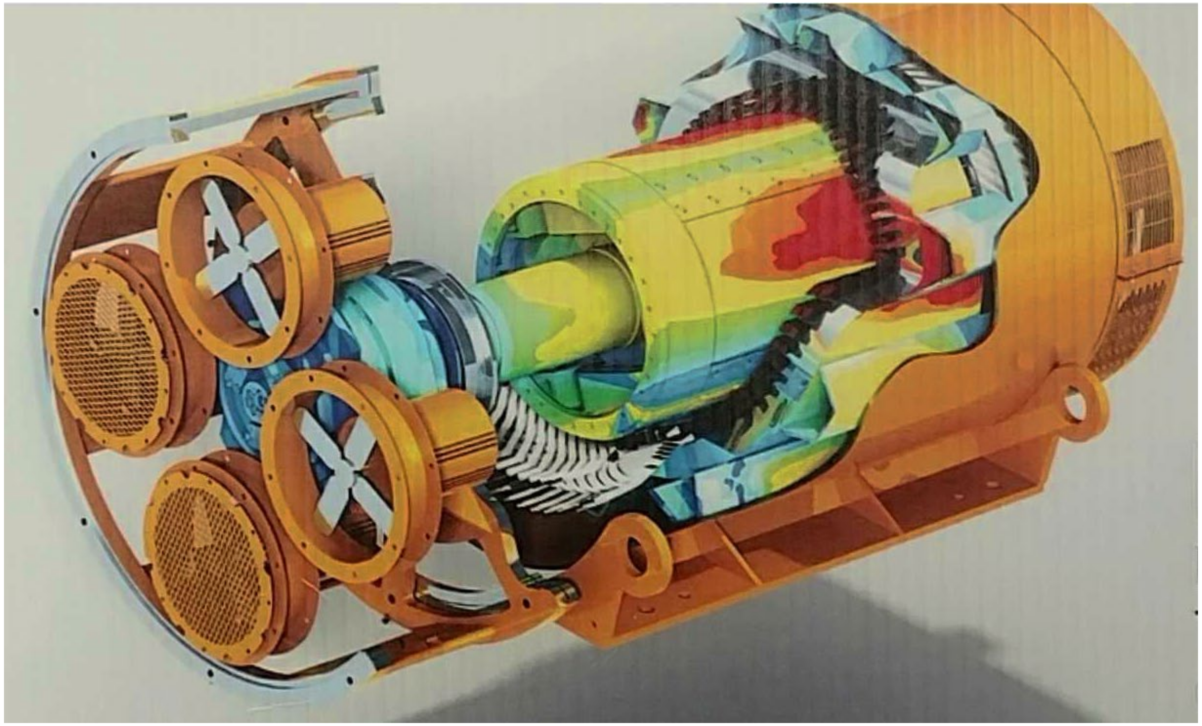
- The first step to increasing the efficiency of a generator is usually to reduce the core loss
  - Change stator steel to lower-loss material (more expensive)
  - Change rotor steel to electrical steel, or core-plate, to reduce pole-face loss
- Second, increase the machine size to allow larger conductors/fewer turns for lower resistive (I^2R) loss in stator and (indirectly) in rotor windings

Electrical Capacity Factors -- Efficiency

- Since losses are now lower, a smaller fan may be used to reduce friction and windage
- The machine will also run cooler, reducing the resistance and hence resistive loss
- Double-end-vent construction also allows use of smaller and more efficient fans (but not as suitable for reciprocating engine application)
- All other things being equal, *slower* and *larger* generators generally have higher efficiency

Electrical Capacity Factors -- Efficiency

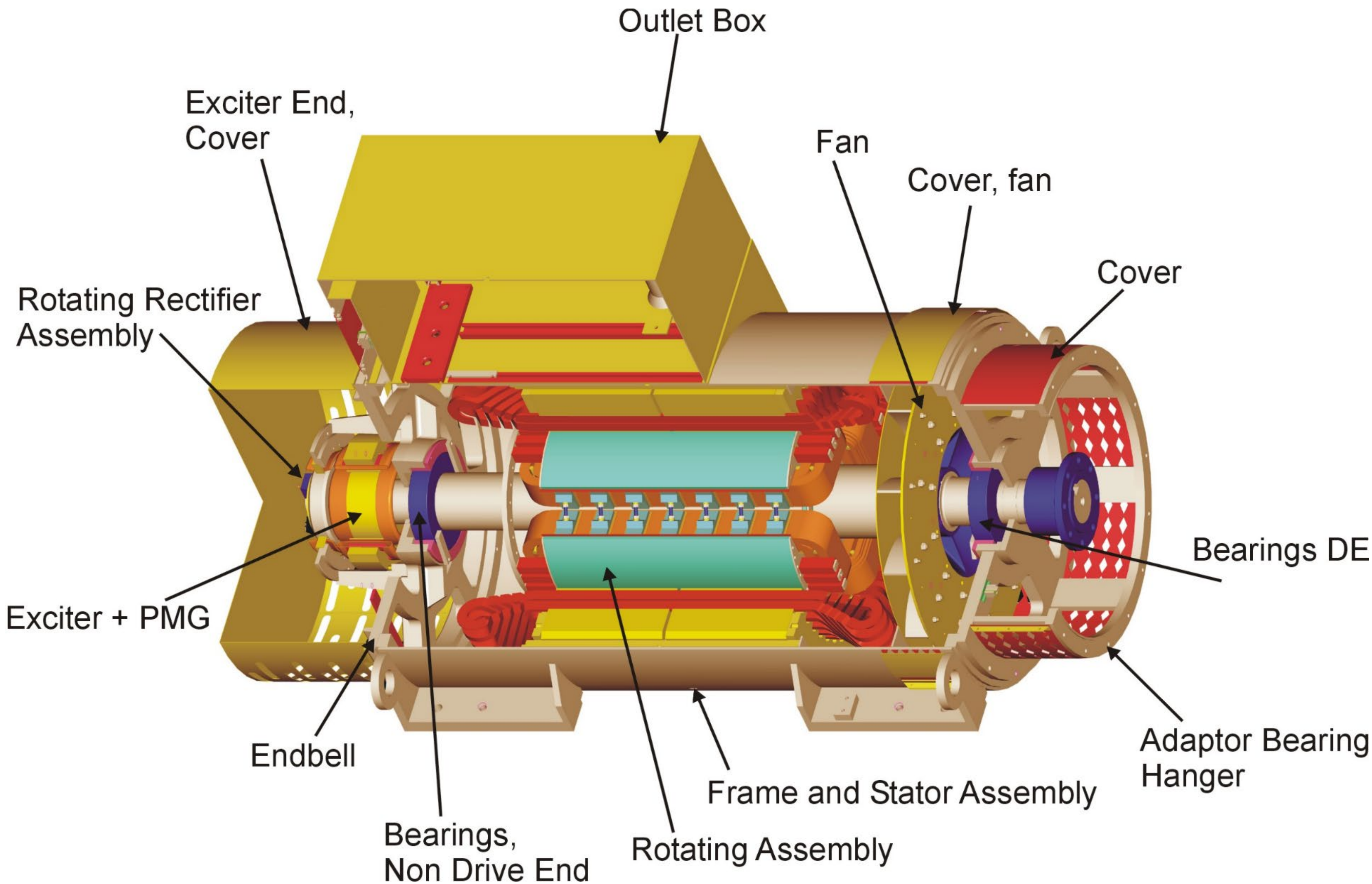
- Applying advanced techniques like variable electric blowers, rotor shrouds, optimization techniques, and special aerodynamic design, can reduce loss still further



98% eff'y!

2. Generator Construction

Generator Construction



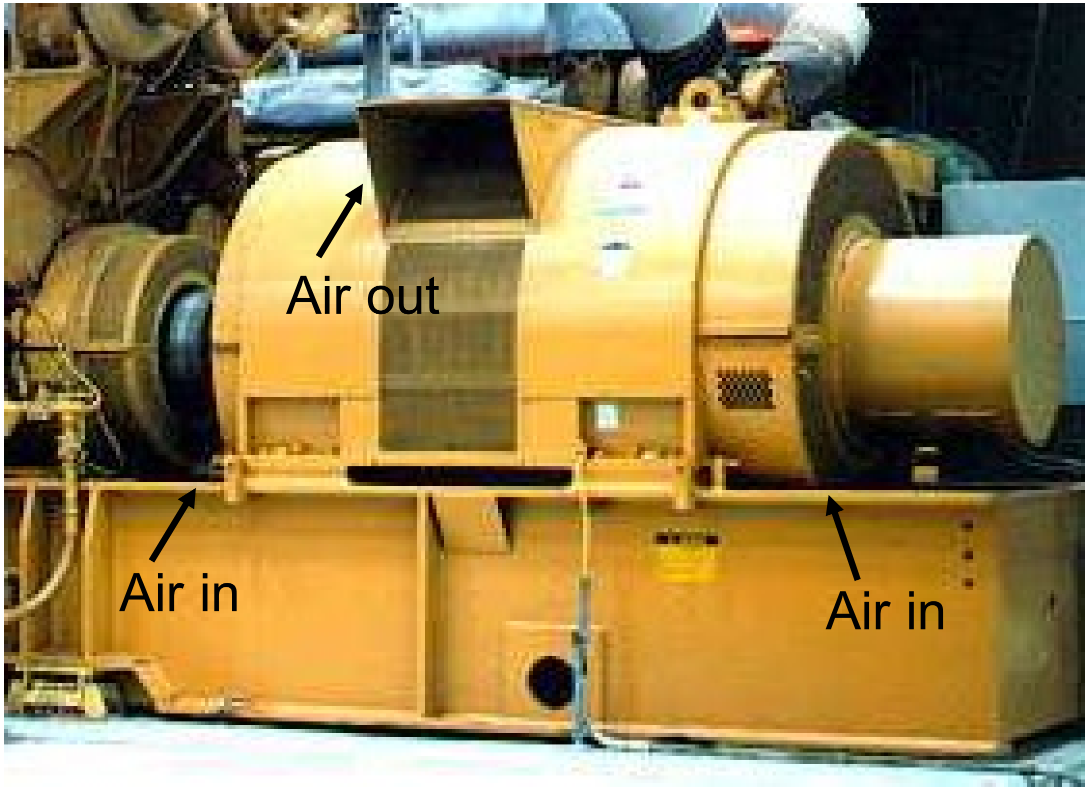
Generator Construction

Nidec
All for dreams

- Types of enclosure
  - Open drip-proof (ODP)
  - Totally enclosed air-to-air (TEAAC or CACA)
  - Totally enclosed water cooled (TEWAC or CACW)
  - Water Protected II (WP-II)
- IC cooling codes
- IP protection codes
- Double- vs single-end ventilation

Generator Construction

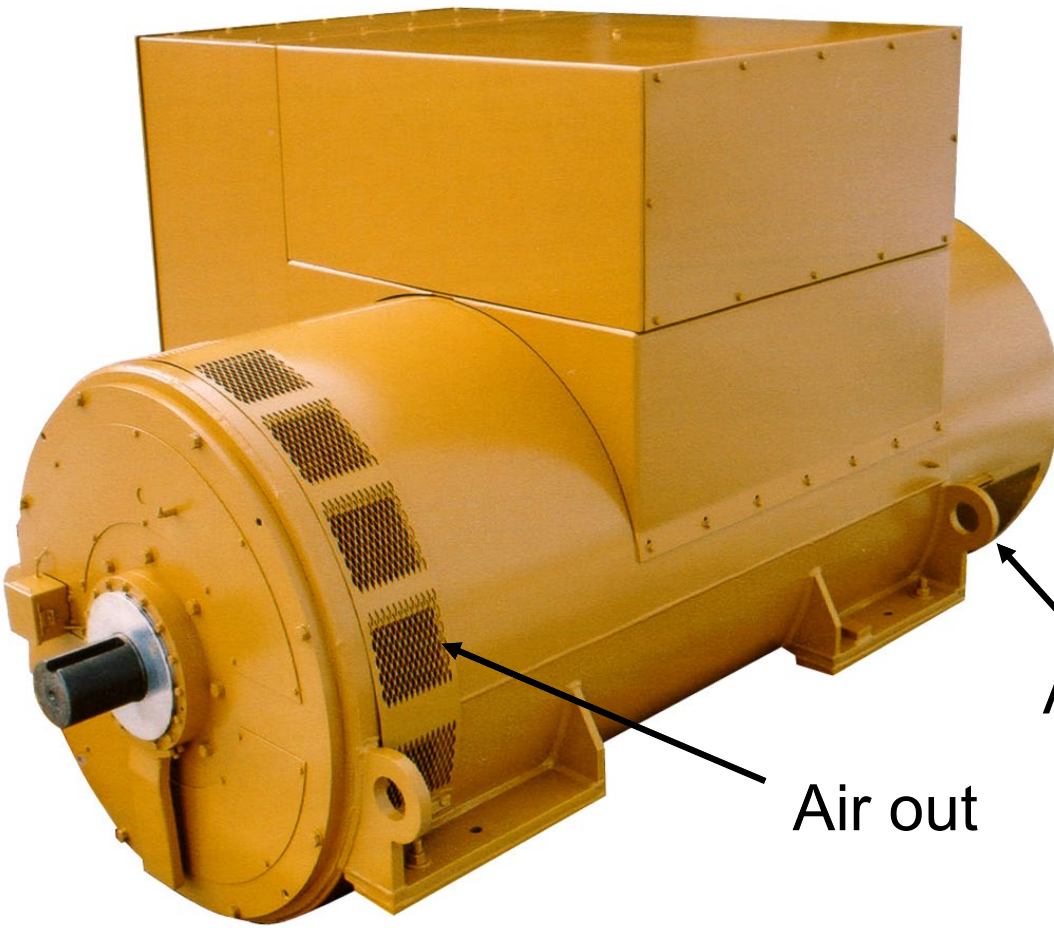
- Open drip-proof:
  - Most common type of construction
  - Protects against water from above



Double-end ventilation (draws air from both ends and exhausts in middle)

Generator Construction

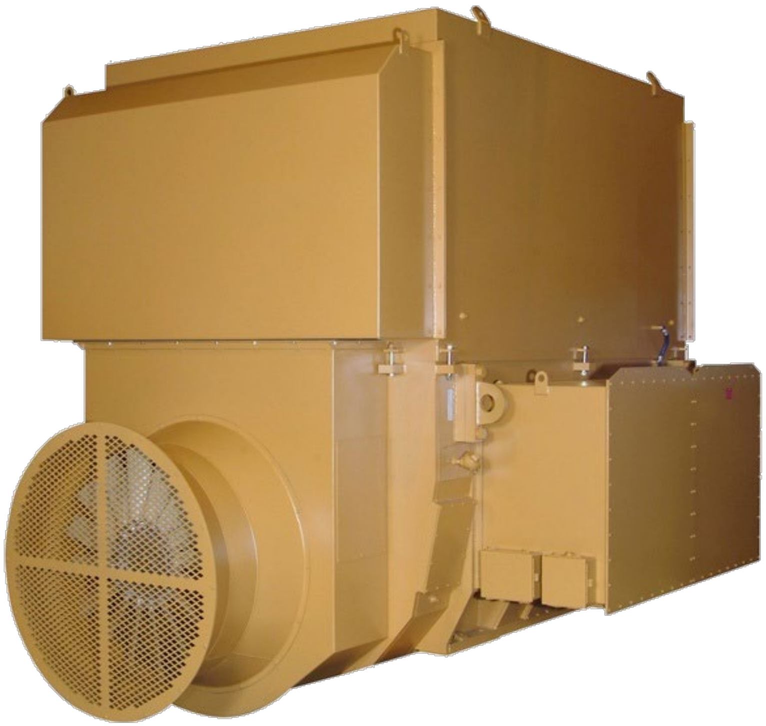
- Open drip-proof:



Single-end ventilation (draws air from one end and exhausts at other)

Generator Construction

- Totally-Enclosed Air-to-Air (or TEFC)
  - – Larger machines have top heat exchanger
  - – Smaller may just have fins
  - – Water or dust ingress is restricted



May be single- or double-end vent internally

Generator Construction

Nidec
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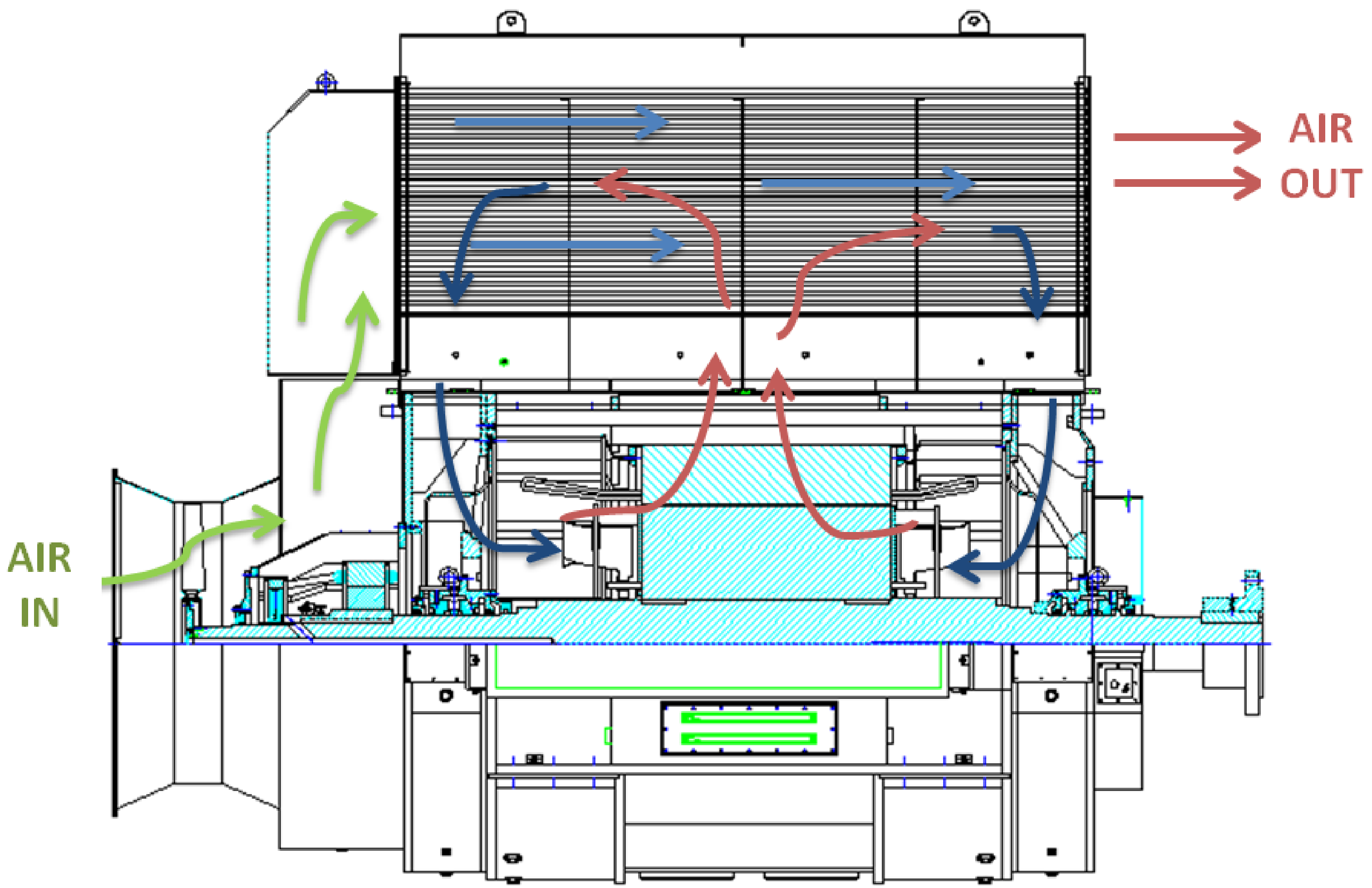
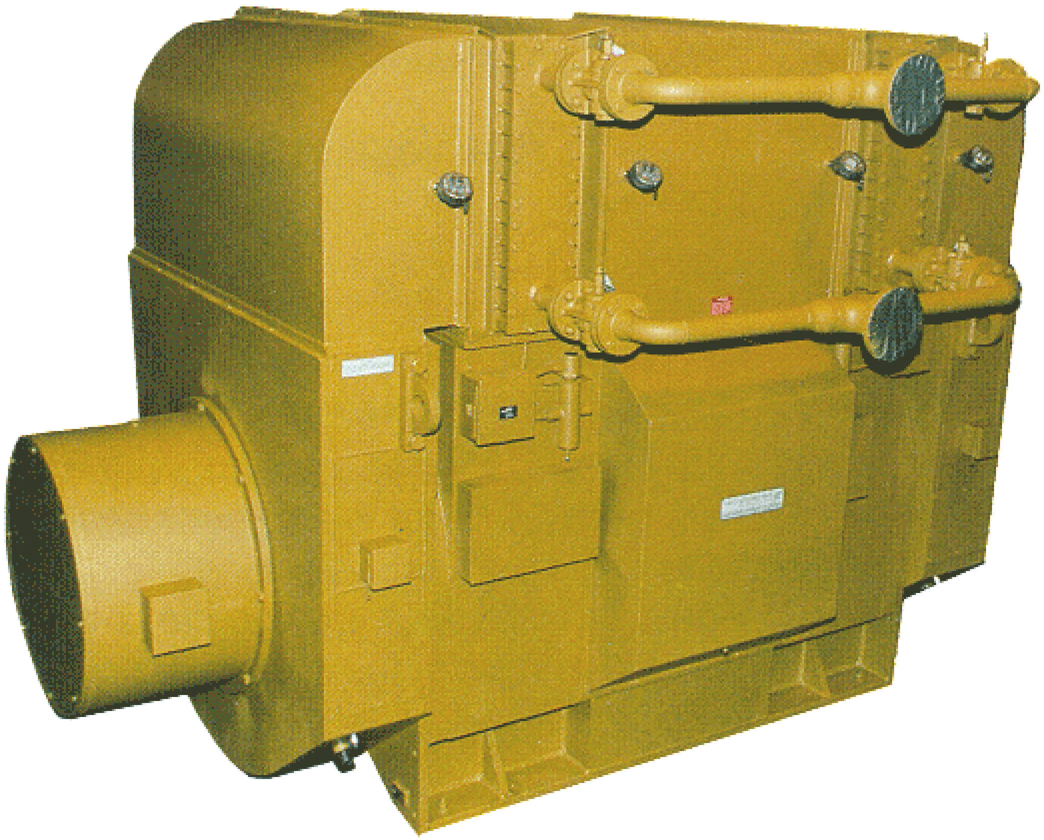


Generator Construction

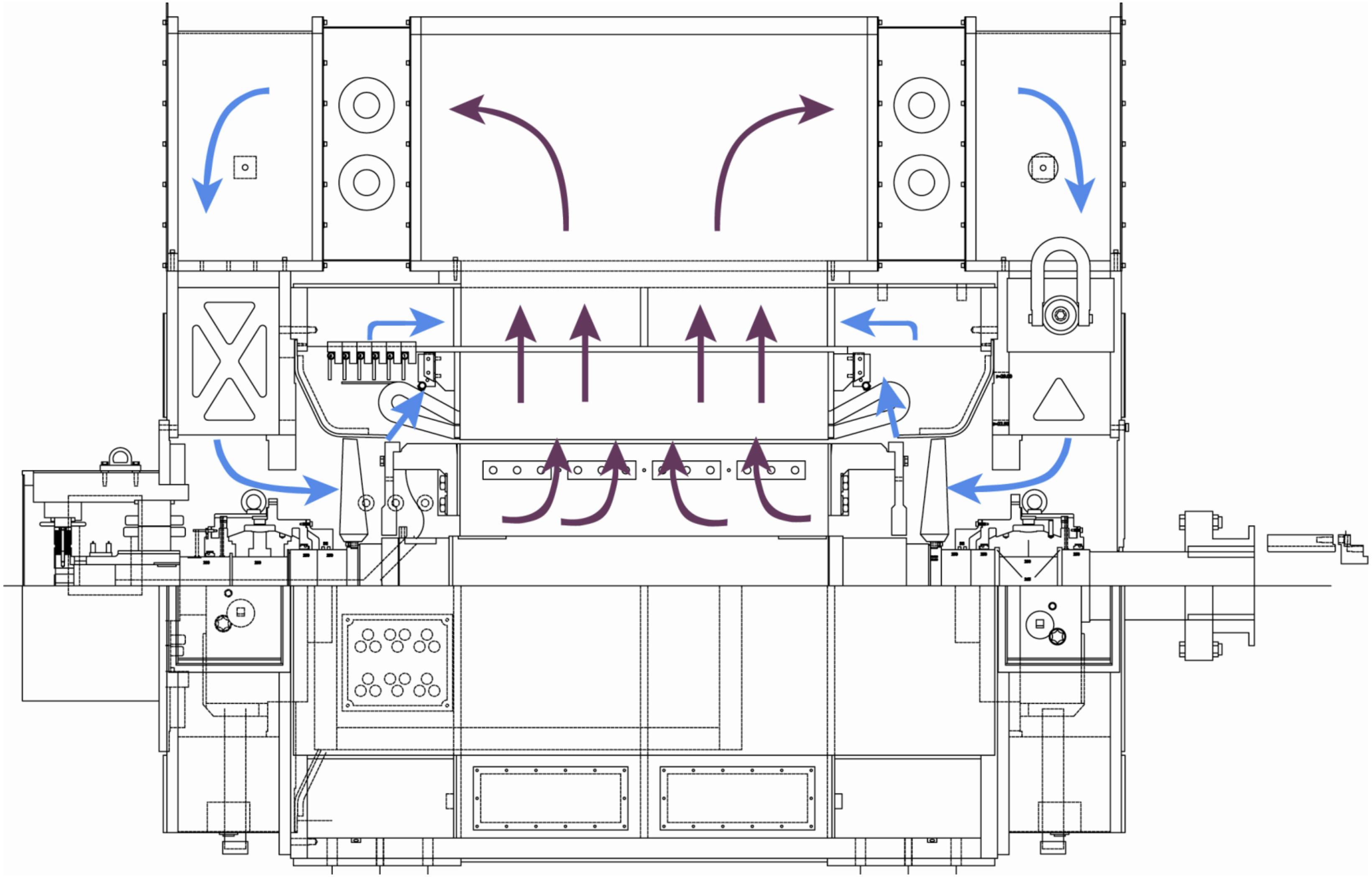
- Totally-Enclosed Air-to-Air (or TEFC)
  - Cooling air temperature is increased because of the heat exchanger – internal air may be up to 25ºC warmer than outside
  - Rating is reduced on account of this (about 25% reduction for Class B rise)

Generator Construction

- Totally-Enclosed Water Cooled
  - Usual for marine applications
  - Heat exchanger on top



Generator Construction



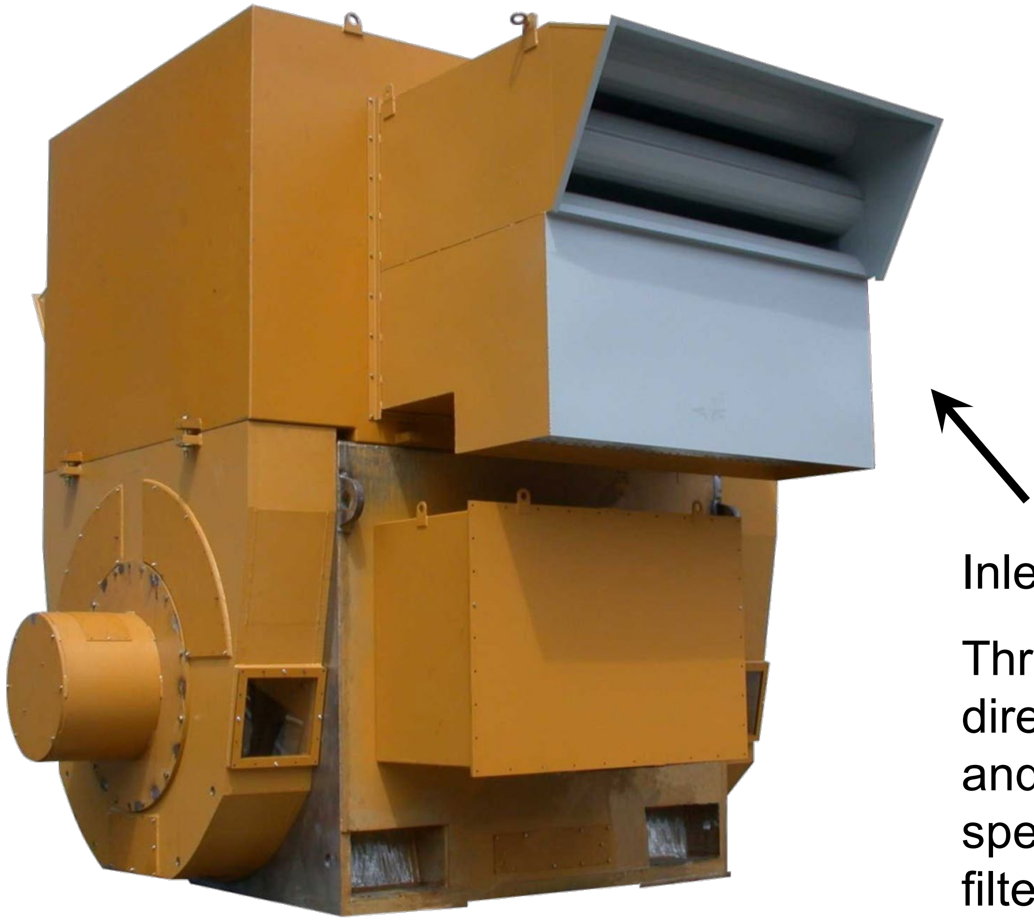
Generator Construction

- Totally-Enclosed Water Cooled
  - Internal cooling air will be about 8ºC warmer than the incoming water (18ºC for double-tube, required for seawater cooling)
  - Typical water temperature is 32ºC, so air is at around 40ºC, or 50ºC for double-tube
  - Some derating is required from the 40ºC rating for double-tube heat exchanger

Generator Construction

- WP-II (Weather-Protected)
  - Uses large ducts for low-velocity air
  - Uses right-angle bends to deter water from entering and divert any that does enter
  - About 5% derate required due to restricted airflow

Weather Protected II (WPII)



Inlet Air

Three 90 degree direction changes and <600 fpm air speed. Optional air filters

Other Ambient Conditions

- Humidity:
  - “Coastal” overcoating for moist locations
  - Use space heaters to keep temperature above condensation point
  - API-546 construction (double VPI plus overcoat, windings immersed in water for dielectric test)
  - Totally-enclosed (fan or water cooled)
- Outdoor installations:
  - WP-II IEC IP-44 construction

Other Ambient Conditions

- Dust and debris:
  - Inlet air filters keep dust out
  - Filter back pressure detectors to indicate that filters need to be changed
  - Increase size by about 5%

Air Filtered Unit

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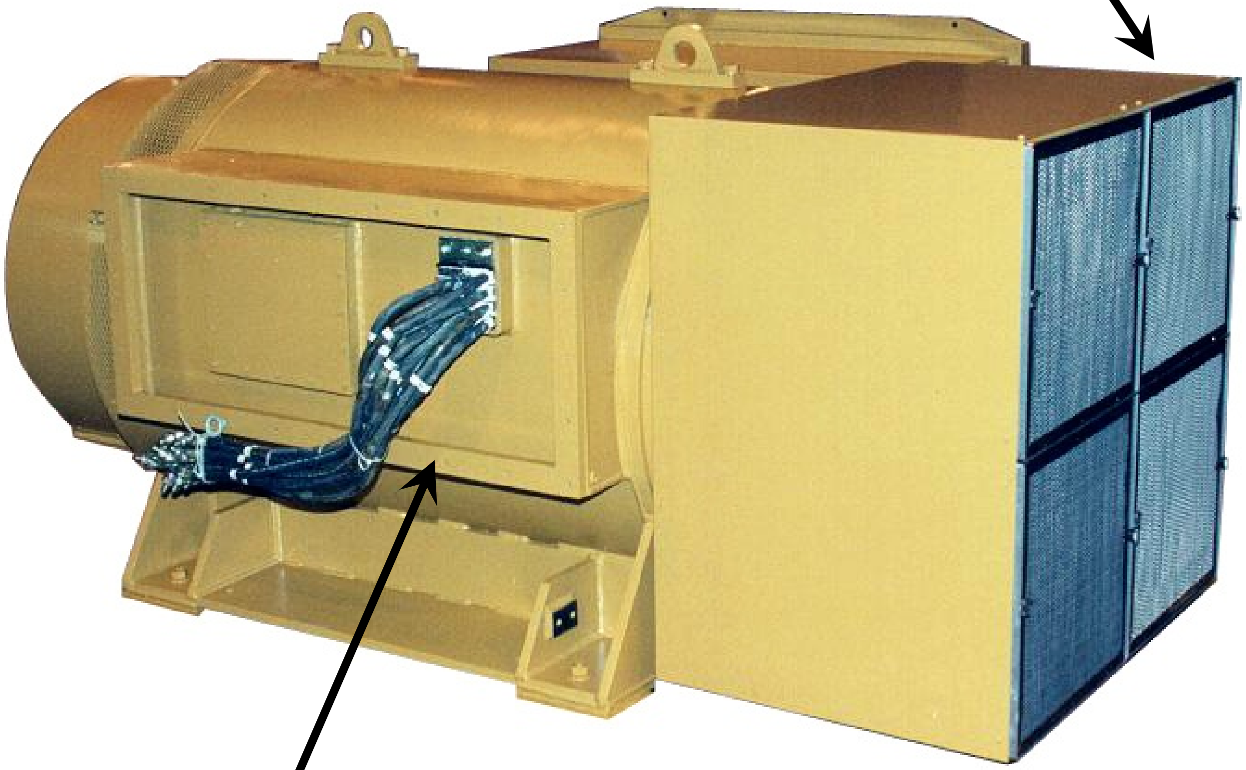
Filtered Air Inlet



Optional IP44 Sealed Outlet Box Construction

IEC 60529-02 IP Codes (Sim to IEC 60034-5)

- Protection of persons against contact with hazards
- Protection of machine against ingress of solid objects
- Protection of machine against harmful effects due to ingress of water

IEC 60529-02 IP Codes

1st digit –

2) Protected against 12 mm objects
4) Protected against 1 mm objects
5) Dust protected
6) Dust tight

2nd digit –

1) Protected against dripping water
2) Protected against 15 deg water spray
3) Protected against 60 deg water spray
4) Protected against splashing water
5) Protected against water jets
6) Protected against powerful water jets (fire hose)

Most Common IP Codes

– IP21 (ODP) IP22 IP23 IP44
  IP54 IP55 IP56

IEC 60034-6 IC Classification

Nidec
All for dreams

- Sequence of numerals and letters to identify the following:
  - cooling type, TEWAC, TEAC
  - cooling medium, air, water, hydrogen

i) A numeral is placed first, indicating the cooling circuit arrangement, being valid for both primary and secondary circuits.

ii) Each circuit is designated by a letter, indicating the coolant, followed by a numeral indicating the method of movement of the coolant.

iii) The letter and numeral for the primary coolant are placed first, then those for the the secondary coolant.

Example: I C 8 A 1 W 7

Arrangement — 8

Primary circuit — A 1

Secondary circuit — W 7

IEC 60034-6 IC Classification

Nidec
All for dreams

Table 1 - Circuit arrangement defines machine construction specifics, ODP, totally enclosed.

Cooling medium routing is also defined for cooling circuits.

Characteristic numeral	Brief description	Definition
0 (see note 1)*	Free circulation	The coolant is freely drawn directly from the surrounding medium, cools the machine, and then freely returns directly to the surrounding medium (open circuit)
1 (see note 1)	Inlet pipe or inlet duct circulated	The coolant is drawn from a medium remote from the machine, is guided to the machine through an inlet pipe or duct, passes through the machine and returns directly to the surrounding medium (open circuit)
2 (see note 1)	Outlet pipe or outlet duct circulated	The coolant is drawn directly from the surrounding medium, passes through the machine and is then discharged from the machine through an outlet pipe or duct to a medium remote from the machine (open circuit)
3 (see note 1)	Inlet and outlet pipe or duct circulated	The coolant is drawn from a medium remote from the machine, is guided to the machine through an inlet pipe or duct, passes through the machine and is then discharged from the machine through an outlet pipe or duct to a medium remote from the machine (open circuit)
4	Frame surface cooled	The primary coolant is circulated in a closed circuit in the machine and gives its heat through the external surface of the machine (in addition to the heat transfer via the stator core and other heat conducting parts) to the final coolant which is the surrounding medium. The surface may be plain or ribbed, with or without an outer shell to improve the heat transfer
5 (see note 2)	Integral heat exchanger (using surrounding medium)	The primary coolant is circulated in a closed circuit and gives its heat via a heat exchanger, which is built into and forms an integral part of the machine, to the final coolant which is the surrounding medium
6 (see note 2)	Machine-mounted heat exchanger (using surrounding medium)	The primary coolant is circulated in a closed circuit and gives its heat via a heat exchanger, which is mounted directly on the machine, to the final coolant which is the surrounding medium
7 (see note 2)	Integral heat exchanger (using remote medium)	The primary coolant is circulated in a closed circuit and gives its heat via a heat exchanger, which is built into and forms an integral part of the machine, to the secondary coolant which is the remote medium
8 (see note 2)	Machine-mounted heat exchanger (using remote medium)	The primary coolant is circulated in a closed circuit and gives its heat via a heat exchanger, which is mounted directly on the machine, to the secondary coolant which is the remote medium
9 (see notes 2 and 3)	Separate heat exchanger (using surrounding or remote medium)	The primary coolant is circulated in a closed circuit and gives its heat via a heat exchanger, which is separate from the machine, to the secondary coolant which is either the surrounding or the remote medium

Table 1 - Numeral for Circuit Arrangement

0) Free Circulation
1) Inlet pipe or inlet duct circulated
2) Outlet pipe or outlet duct circulated
3) Inlet and outlet pipe or duct circulated
4) Frame surface cooled
5) Integral heat exchanger (using surrounding medium)
6) Machine-mounted heat exchanger (using surrounding medium)
7) Integral heat exchanger (using remote medium)
8) Machine-mounted heat exchanger (using remote medium)
9) Separate heat exchanger (using surrounding or remote medium)

IEC 60034-6 Classification

Table 2: Coolant defines coolant type; water, air, oil

TABLE 2	
A	Air
F	Freon
H	Hydrogen
N	Nitrogen
C	CO_2
W	Water
U	Oil
S	Any other
Y	Reserved

IEC 60034-6 Classification

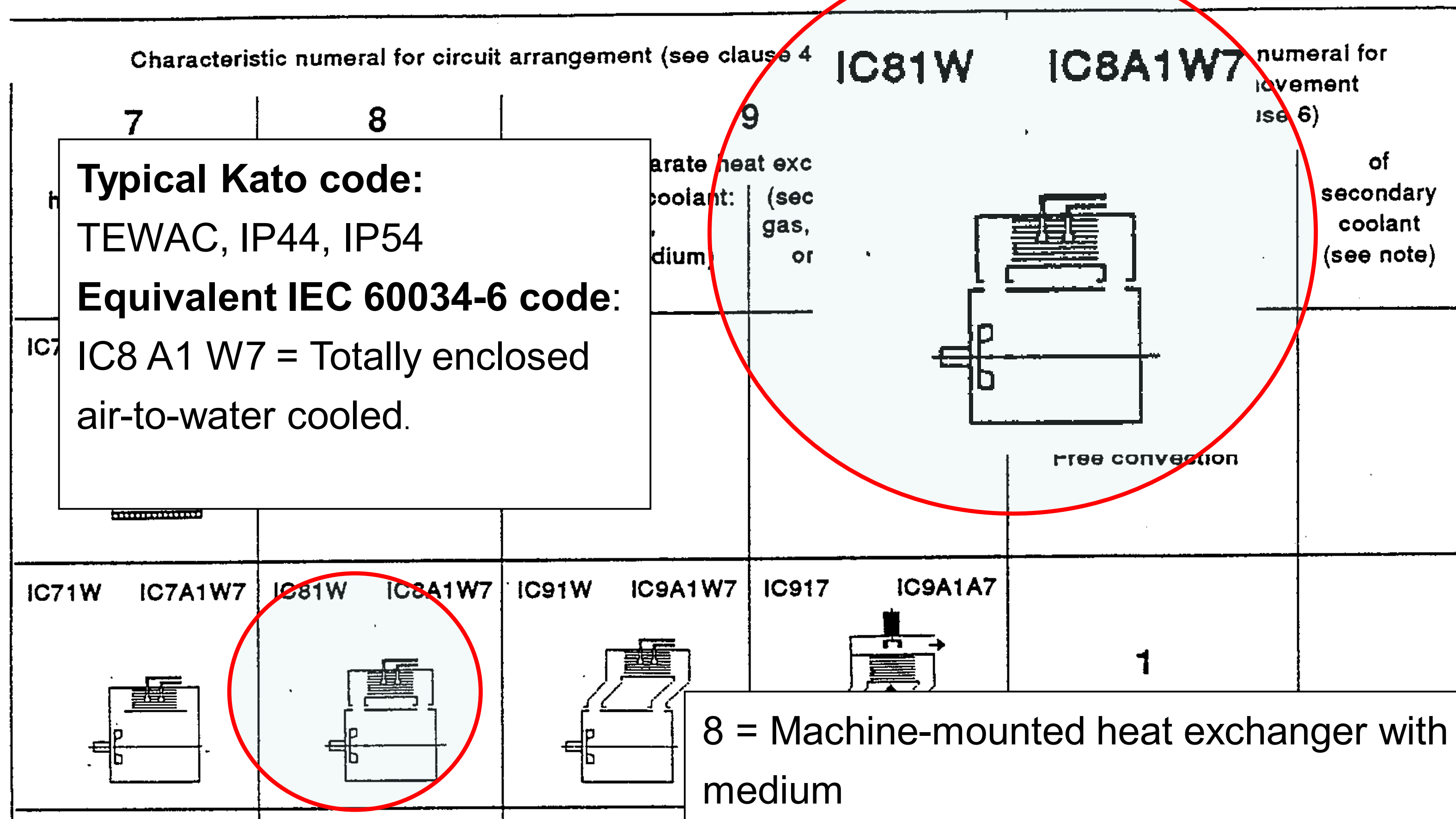
Table 3: Method of Movement defines coolant circulation type, convection, fan drive (internal or external), pumps.

Charac–teristic numeral	Brief description	Definition
0	Free convection	The coolant is moved by temperature differences. The fanning action of the rotor is negligible
1	Self-circulation	The coolant is moved dependent on the rotational speed of the main machine, either by the action of the rotor alone or by means of a component designed for this purpose and mounted directly on the rotor of the main machine, or by a fan or pump unit mechanically driven by the rotor or the main machine
2, 3, 4		Reserved for future use
5 (see note)	Integral independent component	The coolant is moved by an integral component, the power of which is obtained in such a way that it is independent of the rotational speed of the main machine, e.g. an internal fan or pump unit driven by its own electric motor
6 (see note)	Machine-mounted independent component	The coolant is moved by a component mounted on the machine, the power of which is obtained in such a way that it is independent of the rotational speed of the main machine, e.g. a machine-mounted fan unit or pump unit driven by its own electric motor
7 (see note	Separate and independent component or coolant system pressure	The coolant is moved by a separate electrical or mechanical component not mounted on the machine and independent of it or is produced by the pressure in the coolant circulating system, e.g. supplied from a water distribution system, or a gas main under pressure
8 (see note)	Relative displacement	The movement of the coolant results from relative movement between the machine and the coolant, either by moving the machine through the coolant or by flow of the surrounding coolant (air or liquid)
9	All other components	The movement of the coolant is produced by a method other than defined above and shall be fully described

Table 3 - Numeral for Method of Movement

0) Free Convection
1) Self-circulation
2) Reserved for future use
3) Reserved for future use
4) Reserved for future use
5) Integral independent component
6) Machine-mounted independent component
7) Separate and independent component or coolant system pressure
8) Relative displacement
9) All other components

IEC 60034-6 Classification



Typical Kato code:

TEWAC, IP44, IP54

Equivalent IEC 60034-6 code:

IC8 A1 W7 = Totally enclosed air-to-water cooled.

8 = Machine-mounted heat exchanger with remote medium

A = Primary circuit cooling medium, air

1 = Self circulation of medium

W = Secondary cooling medium, water

7 = Separate circulation not mounted to machine.

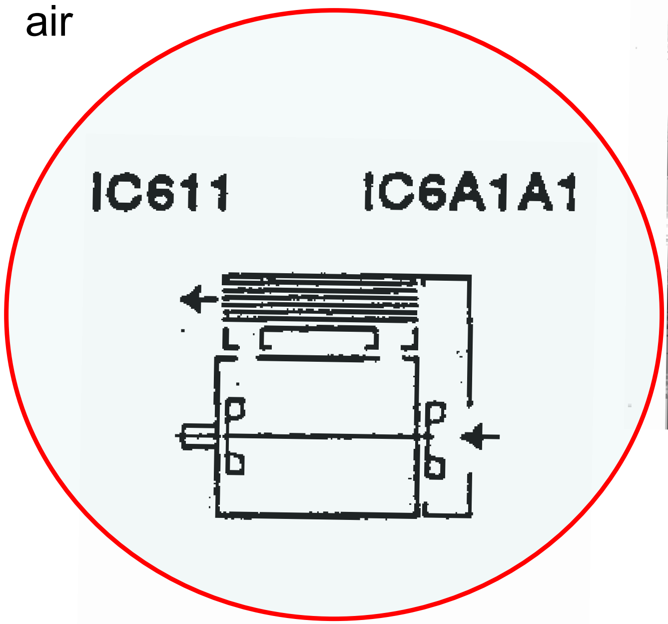
IEC 60034-6 Classification

Typical Kato code:

TEAAC, CACA, IP44, IP54

Equivalent IEC 60034-6 code:

IC6 A1 A1 = Totally enclosed air-to-air cooled with ambient air



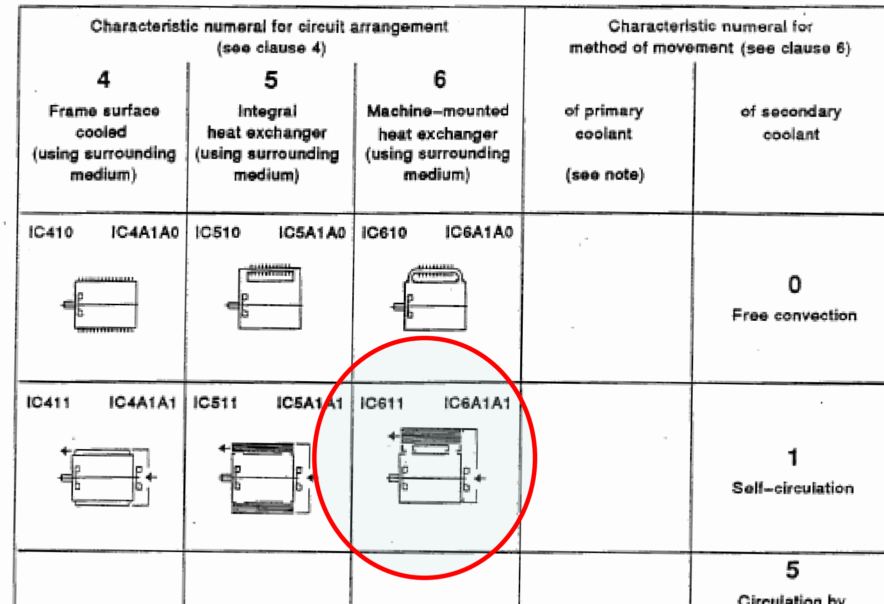


Table A.2 - Examples of primary circuits closed, secondary circuits open using surrounding medium*

Characteristic numeral for circuit arrangement (see clause 4): 4 Frame surface cooled (using surrounding medium)	5 Integral heat exchanger (using surrounding medium)	6 Machine-mounted heat exchanger (using surrounding medium)	Characteristic numeral for method of movement (see clause 6): of primary coolant (see note)	of secondary coolant
IC410 IC4A1A0	IC510 IC5A1A0	IC610 IC6A1A0		0 Free convection
IC411 IC4A1A1	IC511 IC5A1A1	IC611 IC6A1A1		1 Self-circulation
				5 Circulation by

6 = Machine-mounted heat exchanger using surrounding medium

A = Primary circuit cooling medium, air

1 = Self circulation of medium

A = Secondary cooling medium, air

1 = Self circulation of medium

IEC 60034-6 Classification

- IC not used by Kato to describe cooling
- But we can interpret if found in a spec

NEMA MG 1, Section 1, Part 1

- NEMA MG 1, Section 1, Part 1
  - Defines Classification according to environmental protection and methods of cooling
    - Consolidates IP and IC codes (from Parts 5 and 6)
- Classifications
  - Open Machines
    - Drip proof
    - Splash-proof
    - Semi-guarded
    - Guarded
    - Drip proof guarded
    - Open independantly ventilated
    - Open pipe-ventilated
    - Weather Protected Type I / Type II

NEMA MG 1, Section 1, Part 1

- NEMA MG 1, Section 1, Part 1 Classifications (Continued)
  - Totally Enclosed Machines
    - Totally enclosed nonventilated
    - Totally enclosed fan-cooled
    - Totally enclosed fan-cooled guarded
    - Totally enclosed pipe-ventilated
    - Totally enclosed water-cooled
    - Water-proof
    - Totally enclosed air-to-water cooled
    - Totally enclosed air-to-air cooled
    - Totally enclosed air-over machine
    - Explosion-proof machine
    - Dust-Ignition-proof machine

NEMA MG 1, Section 1, Part 1

- NEMA MG 1, Section 1, Part 1 Classifications (Continued)
  - Machines with encapsulated or sealed windings
    - Moisture resistant windings
    - Sealed windings
  - Most common classifications
    - Dripproof guarded machine (ODP)
    - Weather-protected machine: Type I & Type II (WPII)
    - Totally enclosed fan-cooled guarded (TEFC)
    - Totally enclosed air-to-water-cooled (TEWAC, CACW)
    - Totally enclosed air-to-air-cooled (TEAAC, CACA)
    - Machine with sealed windings

Hazardous Location

- Two systems in common use:
  - NEC Article 500 “Class/Division” system (mostly North America)
    - Kato machines normally Class I, Div 2, T3 temperature
  - IEC 60079 “Zone” system (Europe and rest of world)
    - Kato machines normally Zone 2, Ex nA IIB T3 temperature
- Similar (not identical) requirements for both systems

Hazardous Location

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- Require special generator design, construction, and testing – examples:
  – No open conductors or sparking components
  – Maximum temperature limits for machine surfaces and space heaters
  – Voltage limiters on CTs
  – Depending on site requirements, may require totally-enclosed construction with purging facility
  – Manufacturing drawing approval by agency
  – Witnessed type testing by agency including heat runs and possibly enclosure testing
- Needs close coordination with site engineer and engine manufacturer

3. Reactances and Fault Currents

Measurement of reactances

- D-axis synchronous reactance Xd is calculated from the saturation curve
- What is this “D-axis” business?
  - “D” is for “direct”, “Q” for “quadrature”
  - Physically, the D-axis is aligned with the center of the salient pole (or the center of the field winding for cylindrical rotors)
  - D-axis is involved with reactive current – for short-circuits, current is mostly reactive, so D-axis most important for short-circuit
  - More later in reference frame theory

Measurement of reactances

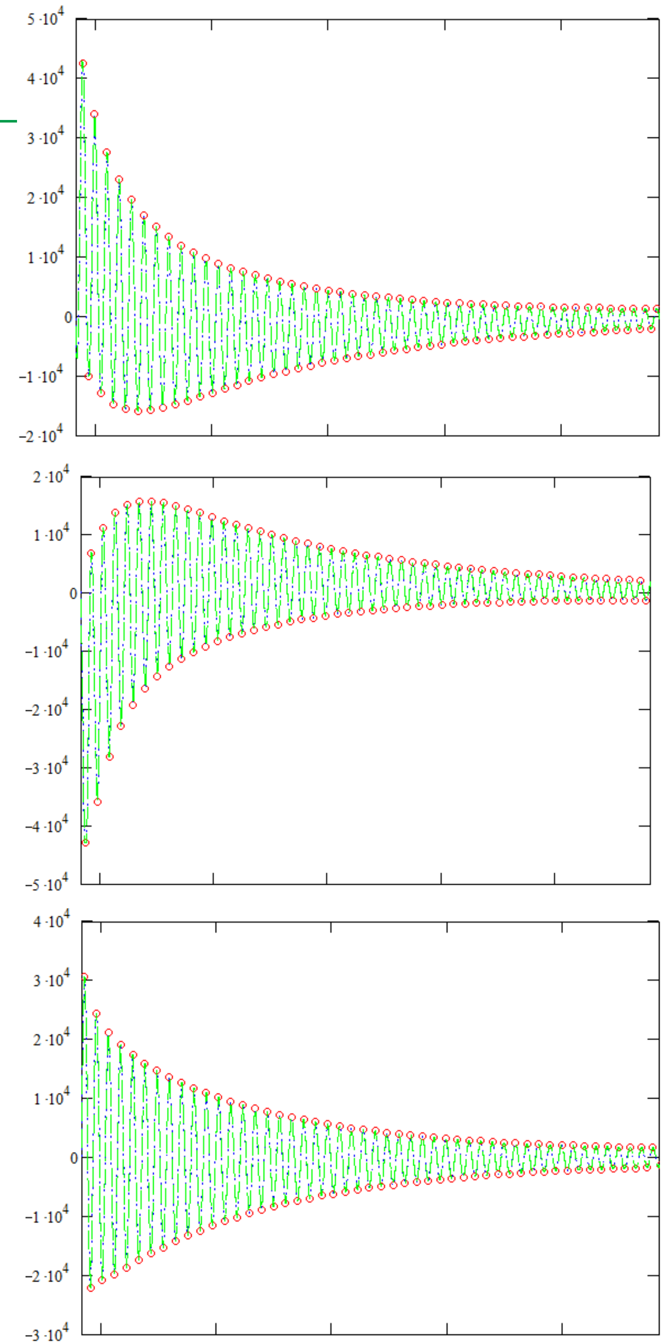
- D-axis synchronous reactance Xd = field current @ rated current SC / rated voltage NL
- The traditional method of measurement for transient reactances is to apply a sudden short-circuit to a generator operating at no load and full voltage (some methods require +5% voltage).
- An oscillograph trace (digital these days) is taken of the current and interpreted to give the D-axis transient (medium-term) and subtransient (short-term) reactances and time constants.

Reactances

- Reactances are used to describe the behavior of a generator during certain operating conditions
- Transient reactance X’d is used in motor starting calculations
  - lower X’d results in better motor starting (i.e. lower voltage dip)
- Subtransient reactance X”d is used in short-circuit current and arc flash calculations
  - lower X”d results in higher short circuit currents.
- There are other reactances for different situations.
  - e.g. direct and quadrature axis, zero and negative sequence, saturated and unsaturated
- The reactances and time constants that are calculated or measured by test determine the generator model parameters

Reactances (Cont.)

- Test method to obtain X’d, X”d:
  - Machine operating at rated voltage, no-load, manual excitation
  - Short circuit is applied across all three phases simultaneously
  - Current envelope in at least one phase is captured over time as it decays



Sample data

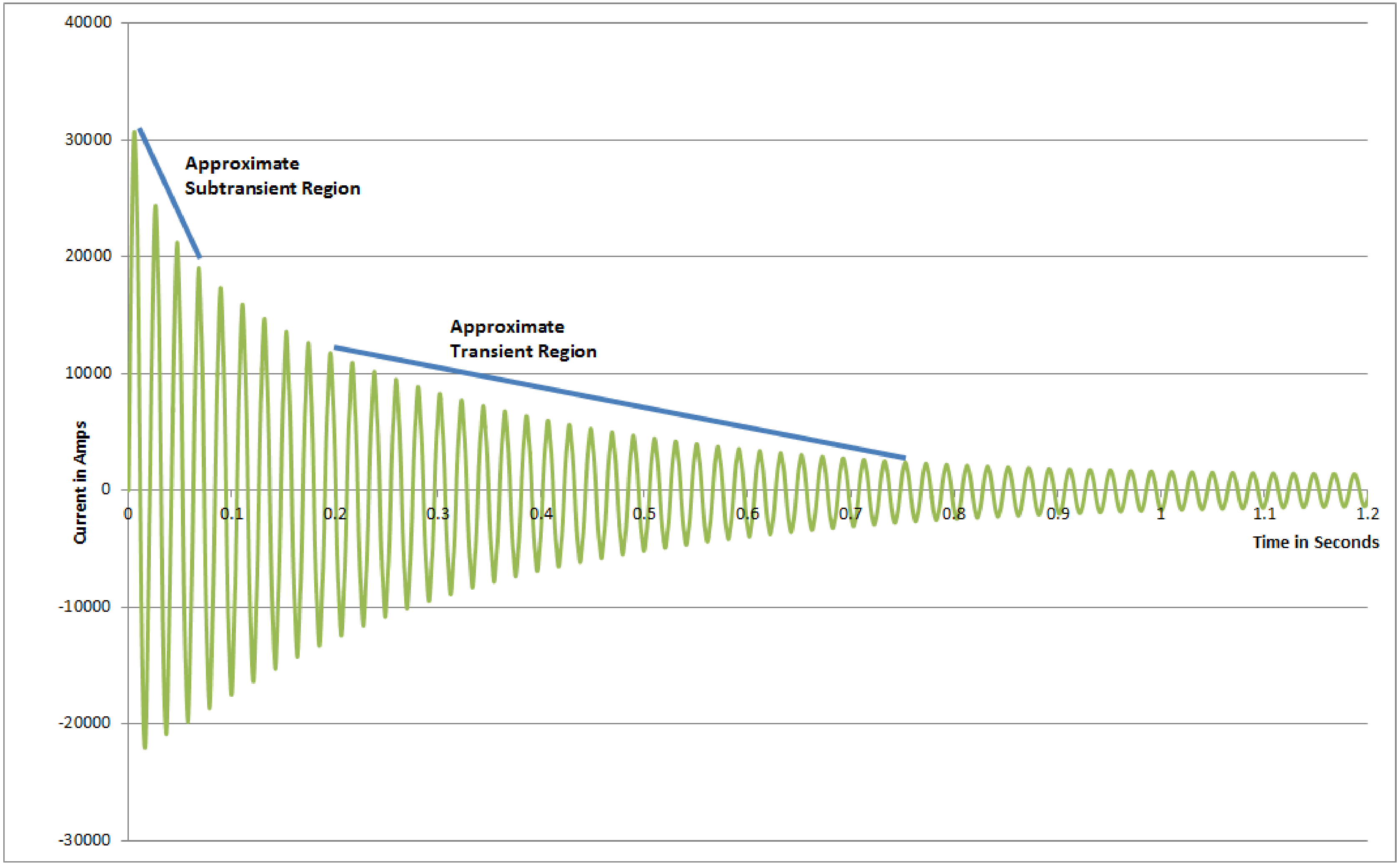
Measurement of reactances

- The (saturated) synchronous D-axis reactance determines the steady-state short-circuit current (it is the reciprocal of the short-circuit ratio). It is taken from short- and open-circuit saturation curves.
- If required, separate tests measure the negative- and zero-sequence reactances, used for unbalanced fault calculations. These are defined in IEEE Std 115.
- Tests for Q-axis quantities are difficult, and not as important, so are usually calculated

Time Constants

- Time constants characterize the rate of decay of the generator fault currents
- The two most common are the subtransient time constant T”d and the transient time constant T’d.
  - These are applied as two exponential decay terms that combine to form the decrement curve
  - Sub-transient time constant T”d determines length of time sub-transient (damper) current flows.
  - Transient time constant T’d determines length of time transient current flows.
- Armature time constant T_A defines the decay of the DC offset term, and is calculated separately, from the curve with AC component removed

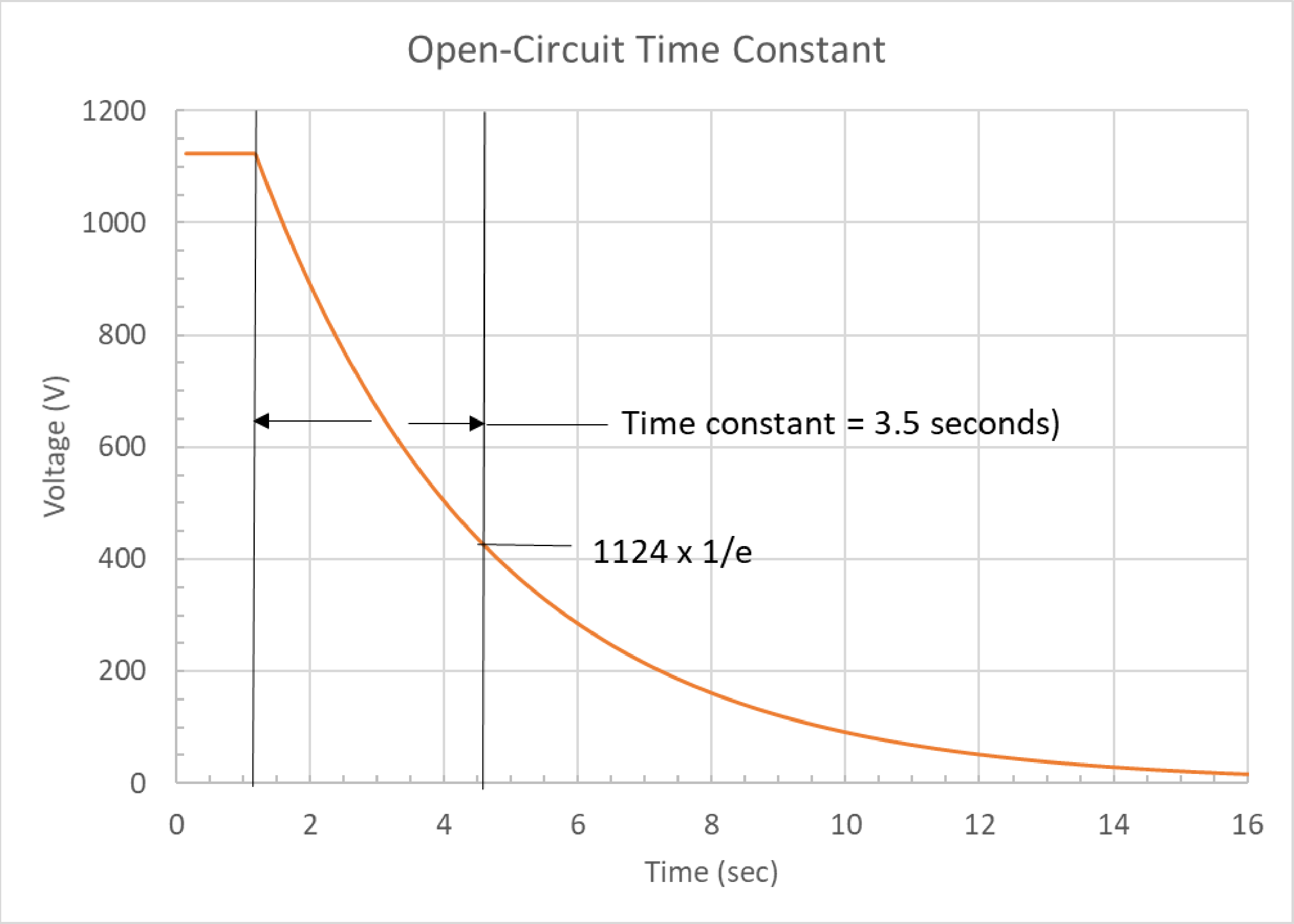
Time Constants



Time Constants (cont.)

- Another time constant example: Open circuit transient T'd0 (related but not equal to T'd).
  - This represents the decay in armature output voltage when main field excitation is removed
  - Test requires slip rings to manually control the main field voltage

Time Constants (cont.)



Reactances, Time Constants: Why are they Important?

- Very useful to predict performance in large system simulations.
- Now, for many users, the reactances and time constants are plugged into simulators used for system modeling and coordination studies.
- Generator manufacturers use this information to produce three curves commonly used for system coordination:
  - Thermal damage curve
  - Short-circuit decrement curve
  - Reactive capability curve

Decrement Curves

- Decrement curves show the fault currents of a synchronous machine under different fault and excitation conditions
- They are used for sizing and coordination of interrupting devices such as circuit breakers and fuses
- Following is a bit more detailed look at how the reactances and time constants combine to produce the estimated fault current curve

Fault Currents of a Synchronous Machine

Fault Currents of a Synchronous Machine

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- IEEE Std 242 provides a simplified method to calculate generator current delivered into a “hard” three-phase fault applied suddenly and with constant excitation.
- *Symmetrical* 3-phase fault is the sum of two sinusoidal decaying exponential functions plus a constant AC term.
- Modifications of this method provide for regulator action that increases excitation following application of the fault. These are not part of any known standard. Basically, we just increase the steady-state excitation relative to the initial value, using an exponential function with short-circuit time constant, whose limit is determined by the exciter ceiling voltage. In the method shown below, this function is represented by e_T, which is constant for fixed excitation.

Fault Currents of a Synchronous Machine

- Equation for symmetrical AC bolted fault current (three terms):

$$i_{ac} = \left(i''_d - i'_d\right)e^{-\frac{t}{T''_d}} + \left(i'_d - i_d\right)e^{-\frac{t}{T'_d}} + i_d e_t$$

Subtransient term (~0-10 cycles)

where:

$$i_d = \frac{e_t \frac{I_F}{I_{Fg}}}{X_d} = \frac{e_i}{X_d} \text{ (constant)}$$

$$i'_d = \frac{e'_i}{X'_d} \text{ (transient)}$$

$$i''_d = \frac{e''_i}{X''_d} \text{ (subtransient)}$$

e_i terms represent excitation to get initial output.

$\frac{I_F}{I_{Fg}}$ is the ratio of loaded field excitation to no-load value e_t.

Fault Currents of a Synchronous Machine

- Equation for AC symmetrical bolted fault current:

$$i_{ac} = \left(i_d^{"} - i_d'\right) e^{-\frac{t}{T_d^{"}}} + \left(i_d' - i_d\right) e^{-\frac{t}{T_d'}} + i_d e_t$$

Transient term (~10-100 cycles)

where:

$$i_d = \frac{e_t \frac{I_F}{I_{Fg}}}{X_d}$$

$$i'_d = \frac{e'_i}{X'_d}$$

$$i"_d = \frac{e"_i}{X"_d}$$

e'_i terms represent initial excitation.

$\frac{I_F}{I_{Fg}}$ is the ratio of loaded field excitation to no-load value e_t.

Fault Currents of a Synchronous Machine

- Equation for AC symmetrical bolted fault current:

$$i_{ac} = (i''_d - i'_d)e^{-\frac{t}{T''_d}} + (i'_d - i_d)e^{-\frac{t}{T'_d}} + i_d e_t$$

Constant term

where:

$$i_d = \frac{e_t \frac{I_F}{I_{Fg}}}{X_d}$$

$$i'_d = \frac{e'_i}{X'_d}$$

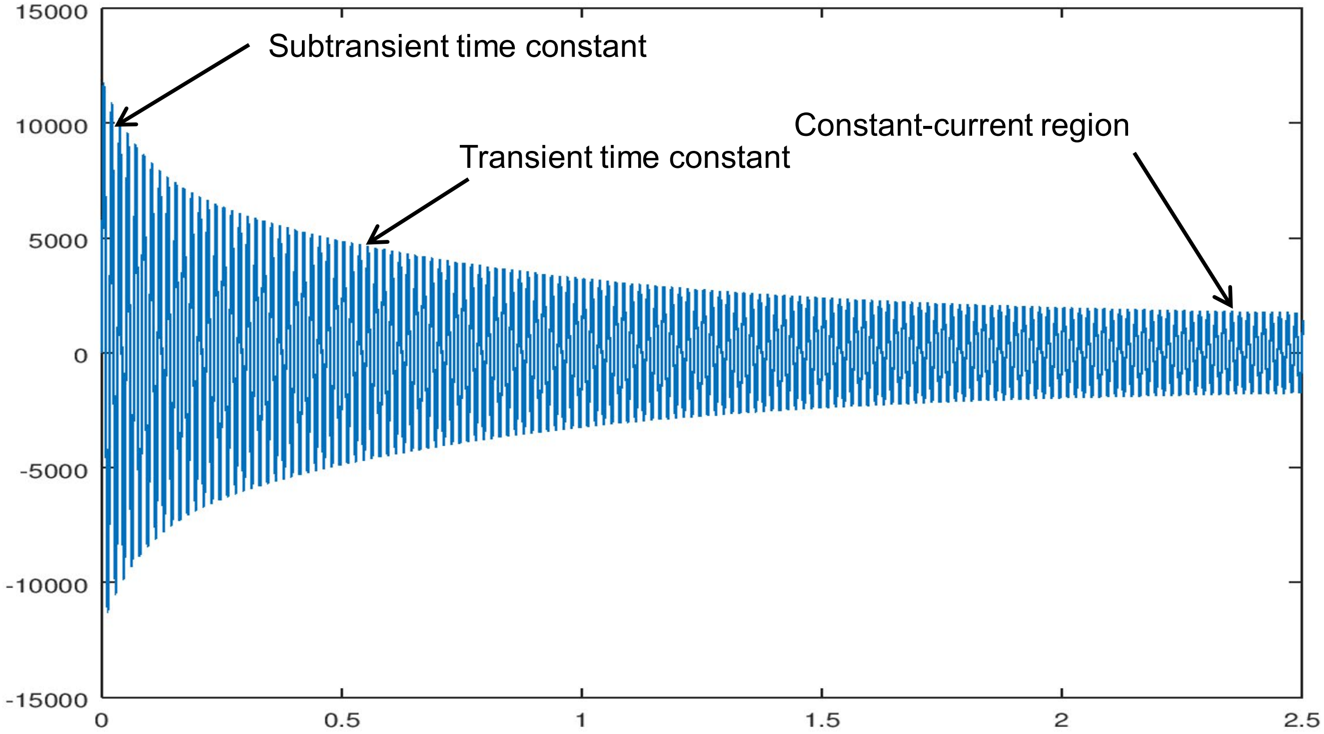
$$i''_d = \frac{e''_i}{X''_d}$$

e'_i terms represent initial excitation.

$\frac{I_F}{I_{Fg}}$ is the ratio of loaded field excitation to no-load value e_t.

Fault Currents of a Synchronous Machine

- The preceding terms are AC, meaning they have a sinusoidal variation at the generator output frequency as shown below.



Fault Currents of a Synchronous Machine

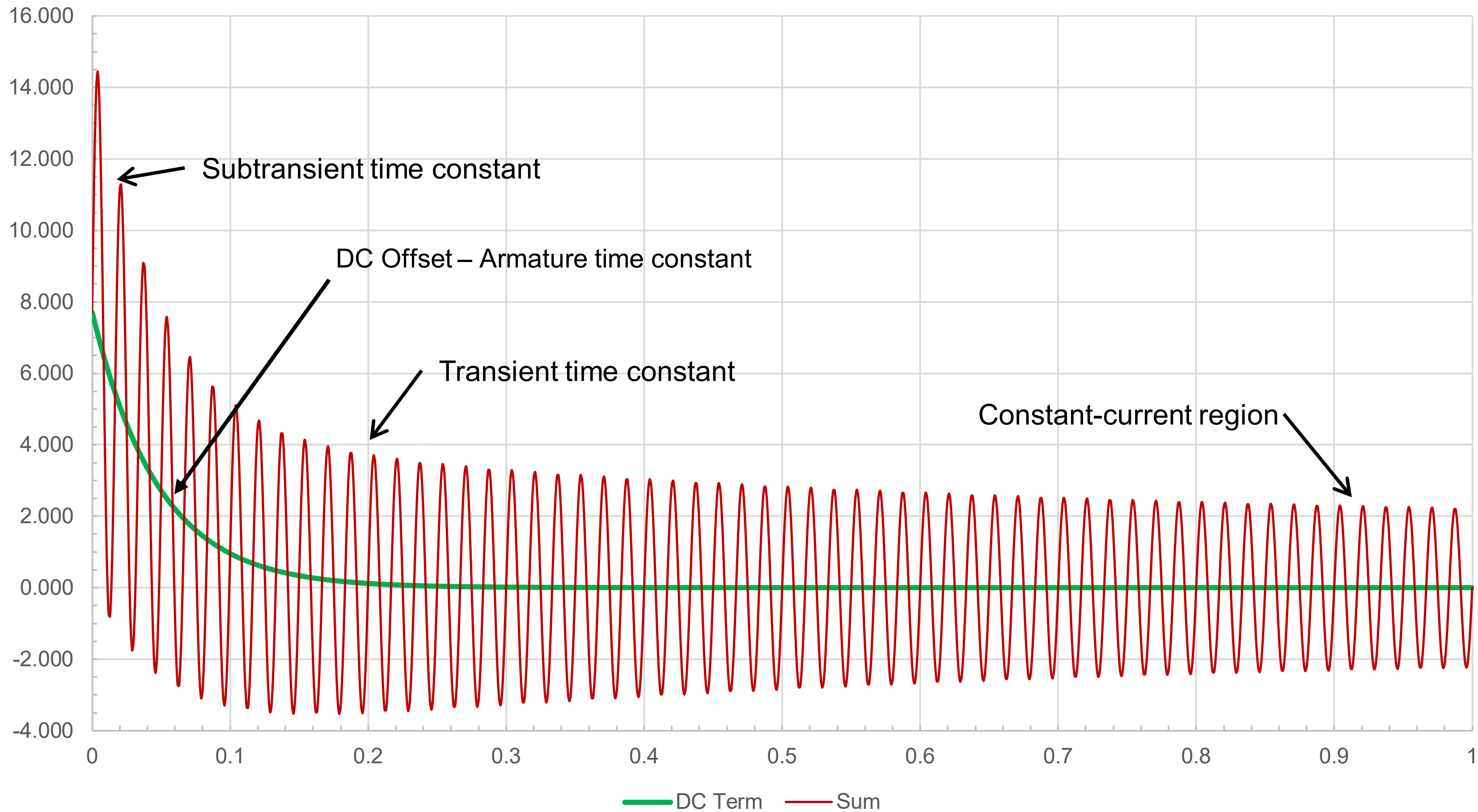
- Asymmetrical fault current adds the DC offset term, which varies depending on the instant of fault initiation and the phase being considered
- For decrement curves, we usually assume the worst case for the DC offset term, which is:

$$i_{dc} = \sqrt{3} i_d'' e^{-\frac{t}{T_A}}$$

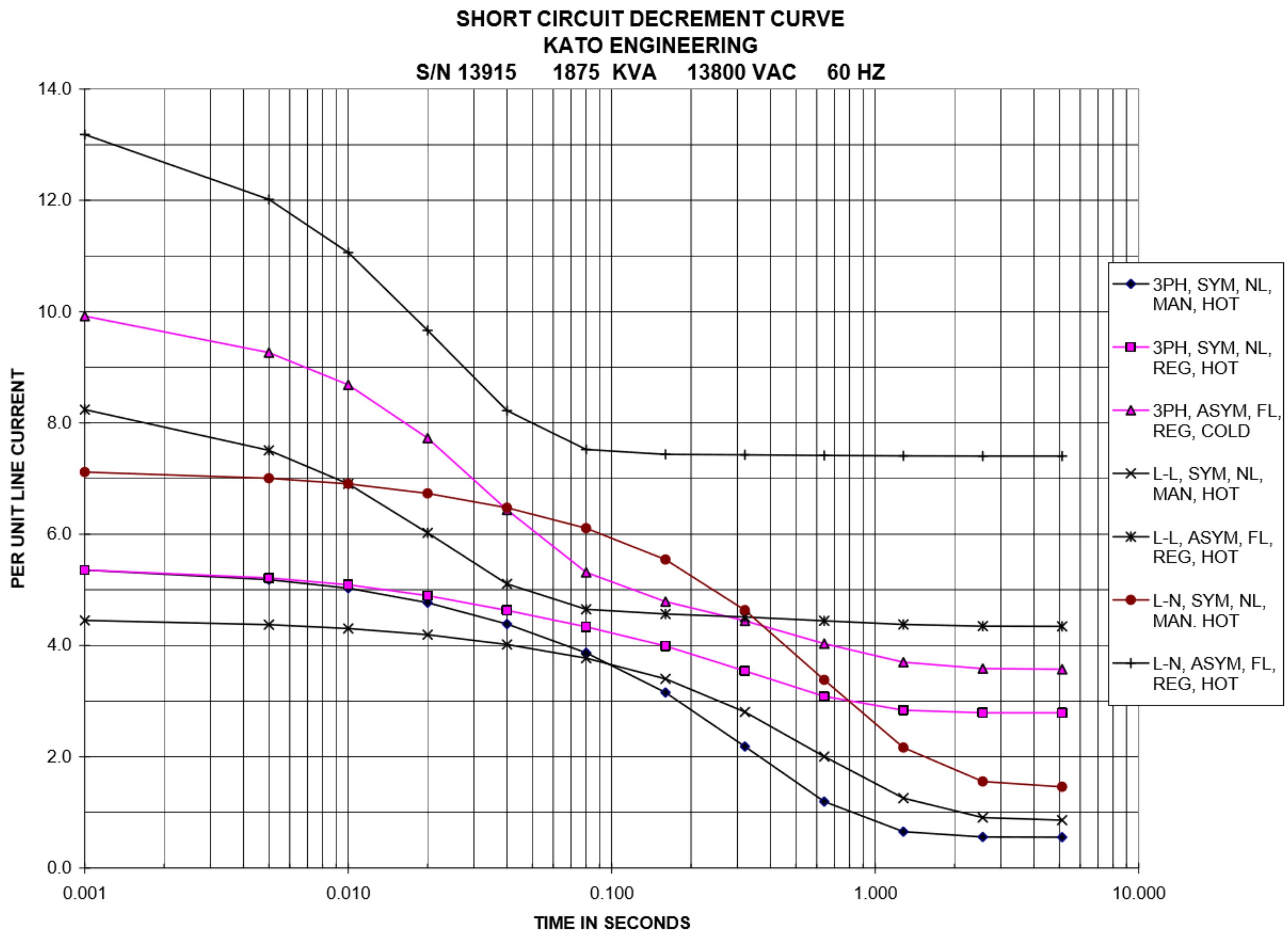
- Note that this is a DC term and has no sinusoidal variation. It produces a decaying offset of the AC waveform that increases the peak fault current
- This offset occurs in differing magnitude and direction in the three phases. Since it sums to zero in the 3 phases, it is often ignored for breaker sizing purposes (depending on the particular standard)

Fault Currents of a Synchronous Machine

- Adding the DC term gives the complete short-circuit current waveform:



Typical Published Decrement Curve



** End of Detour **

4. Grid Codes Effects on Generators

Grid Codes Effects on Generators

- *REPORT ON COORDINATION OF GRID CODES AND GENERATOR STANDARDS: Consequences of Diverse Grid Code Requirements on Synchronous Machine Design and Standards* [GCTF]
  - IEEE Electrical Machinery Committee Task Force on Grid Code Impacts on Generator Standards
    - Chair: Robert Thornton-Jones
    - Members and Contributors: Evert Agneholm, William Bloethe, Edson Bortoni, Kevin Chan, Kay Chen, Bob Cummings, Robert F. Gray, Randall Groves, Les Hajagos, Joe Hurley, Relu Ilie, Chavdar Ivanov, Ana Joswig, Jason Kapelina, Ruediger Kutzner, Jim Lau, Kevin Mayor, Bill Moore, Lon Montgomery, Nils Nilsson, Ryan Quint, Steve Richards, Michel Rioual, Luis Rouco, Mike Sedlak, Uwe Seeger, Nico Smit, Fabian Streiff, Robert Thornton-Jones, John Yagielski, Marc Zeidman, Carsten Zuehlke

Summary

- What is a Grid Code, why new grid codes and consequences ?
- Impact of the Grid Code on sizing:
  - Static
  - Dynamic
  - LS guide lines and basic recommendations
- Fault Ride Through risk and behavior

What is a grid code ?

- A **grid code** is a technical specification which defines the requirements for a generating set to be connected to a public supply network. How it meets, safely, securely and economically a correctly functioning electrical system,
- The grid code is specified by an authority responsible for the system integrity and network operation. This is either a rule, a law or a standard, depending on each country.
- All generators are concerned whatever the driving system and whatever the power rating.

Why is there a new grid code ?

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- The increasing intermittent power generation (due to increasing wind farm installations or photovoltaic plants) and more micro-power plants leads to more instability of the grids,
- Previously, these power suppliers were supposed to protect themselves first in case of fault conditions (short circuit…)
- The grid supervisors demand from power suppliers to remain connected to the grid in case of trouble on the distribution line bus bars and also to contribute to the network stability when there are :
  - Instabilities (regarding voltage & frequency)
  - Voltage sags
  - (Micro) short circuits, etc
- This means that, at least, the Protection strategy & the Genset control sequence must change

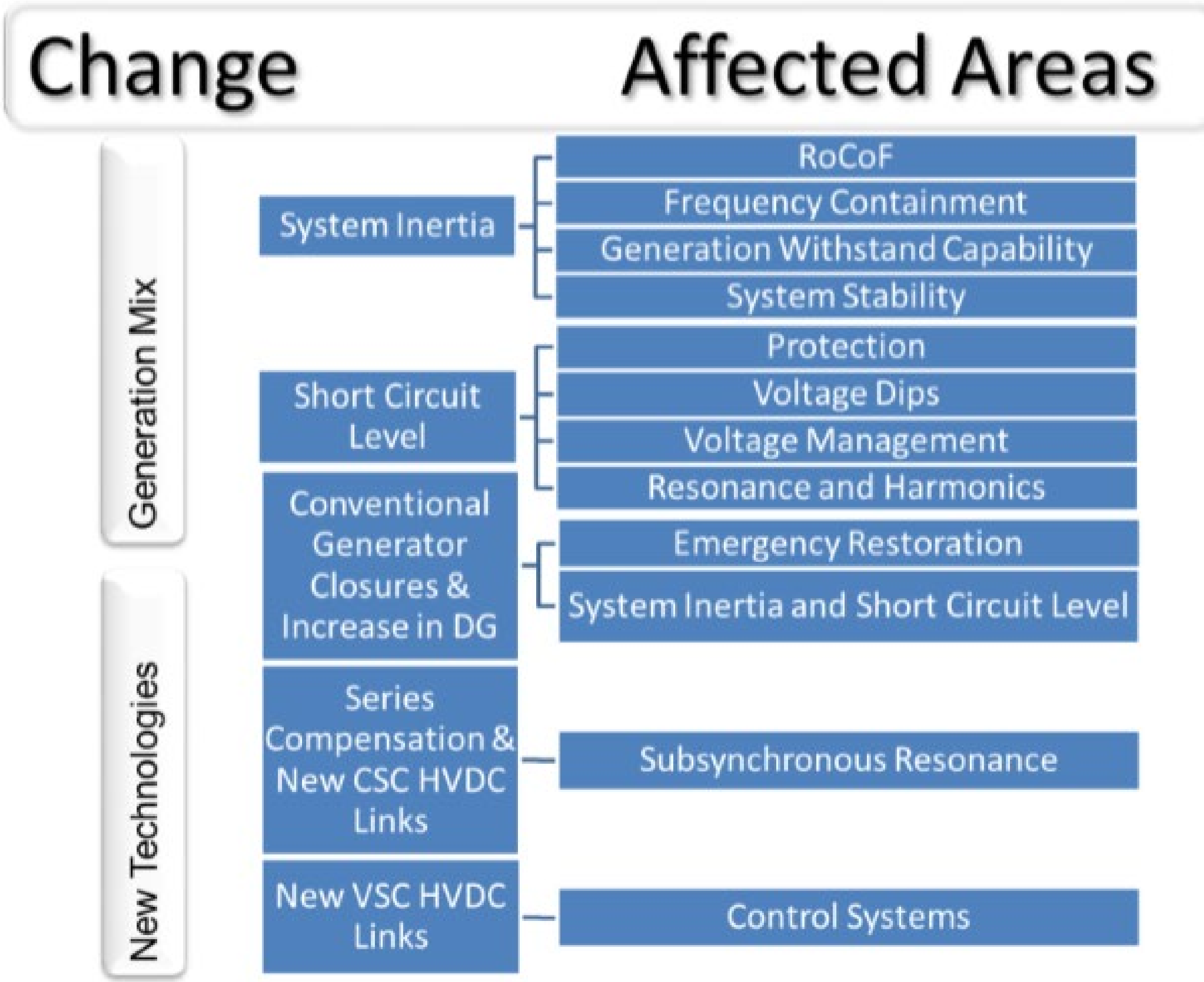
New grid code consequences

- Under the "Grid Code" label, we include all possible requirements related to the constraint of connecting a genset to a public supply network.
- Rules have changed over the past years and will continue to change
- New regulations appear in each country.
- Impact on the genset is related to both running conditions :
  - static : enlarged running condition in steady state
  - dynamic : Fault Ride Through (FRT),

New grid code consequences

- IEEE 1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces
  - And related “dot” standards
    - 1547.1 Test Procedures
    - 1547.2 Application Guide
    - 1547.3 Guide for Monitoring, Information Exchange, & Control
    - 1547.4 Guide for Design, Operation, and Integration
    - 1547.6 Recommended Practice for Interconnecting DR
    - 1547.7 Guide for Conducting Distribution Impact Studies
    - 1547.9 Interconnection of Energy Storage

Grid Code Impact on Generator Design



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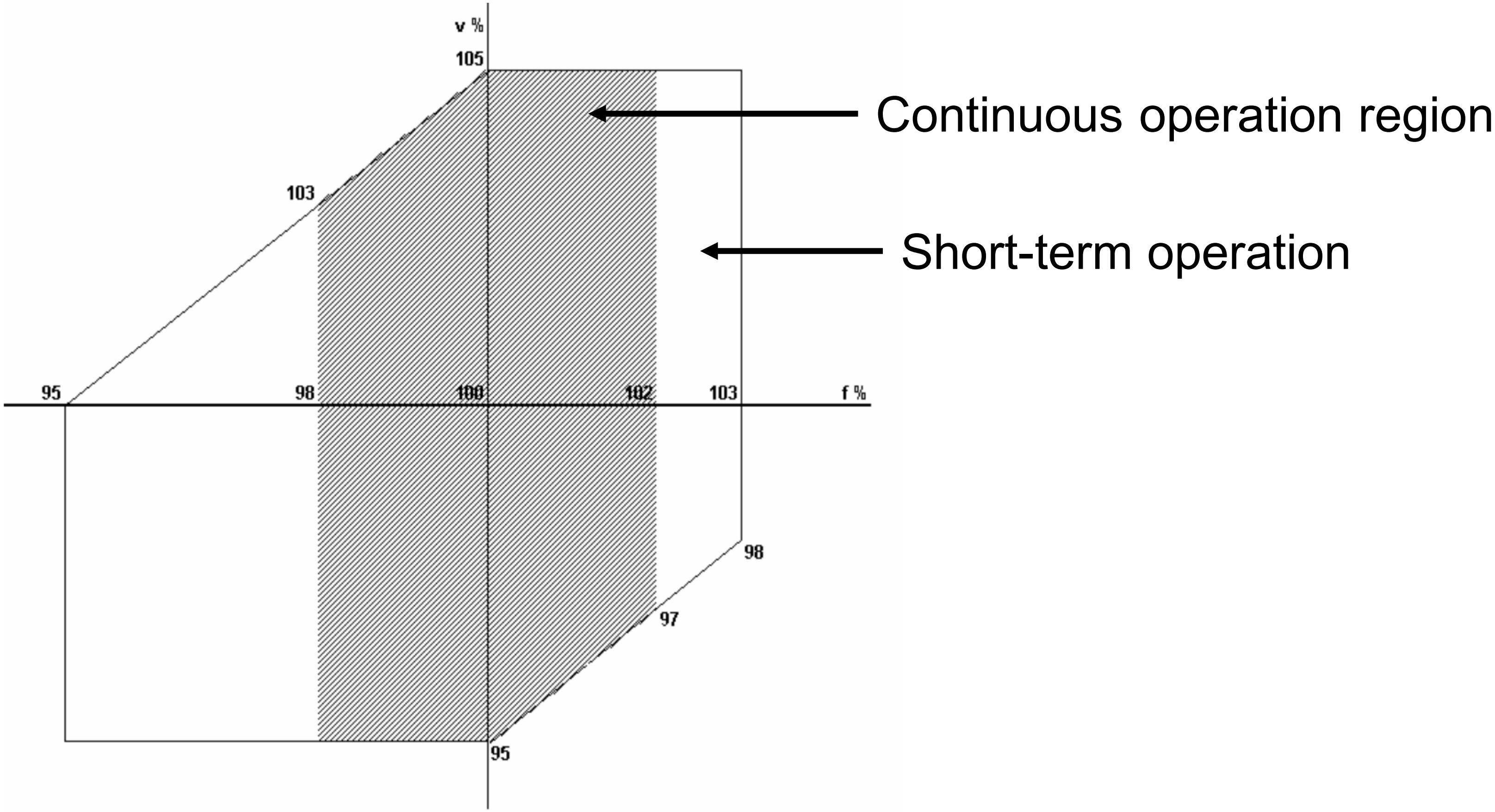
Grid Code Impact on Generator Design



- IEC 60034/IEEE Std C50.12/13 voltage and frequency operating range

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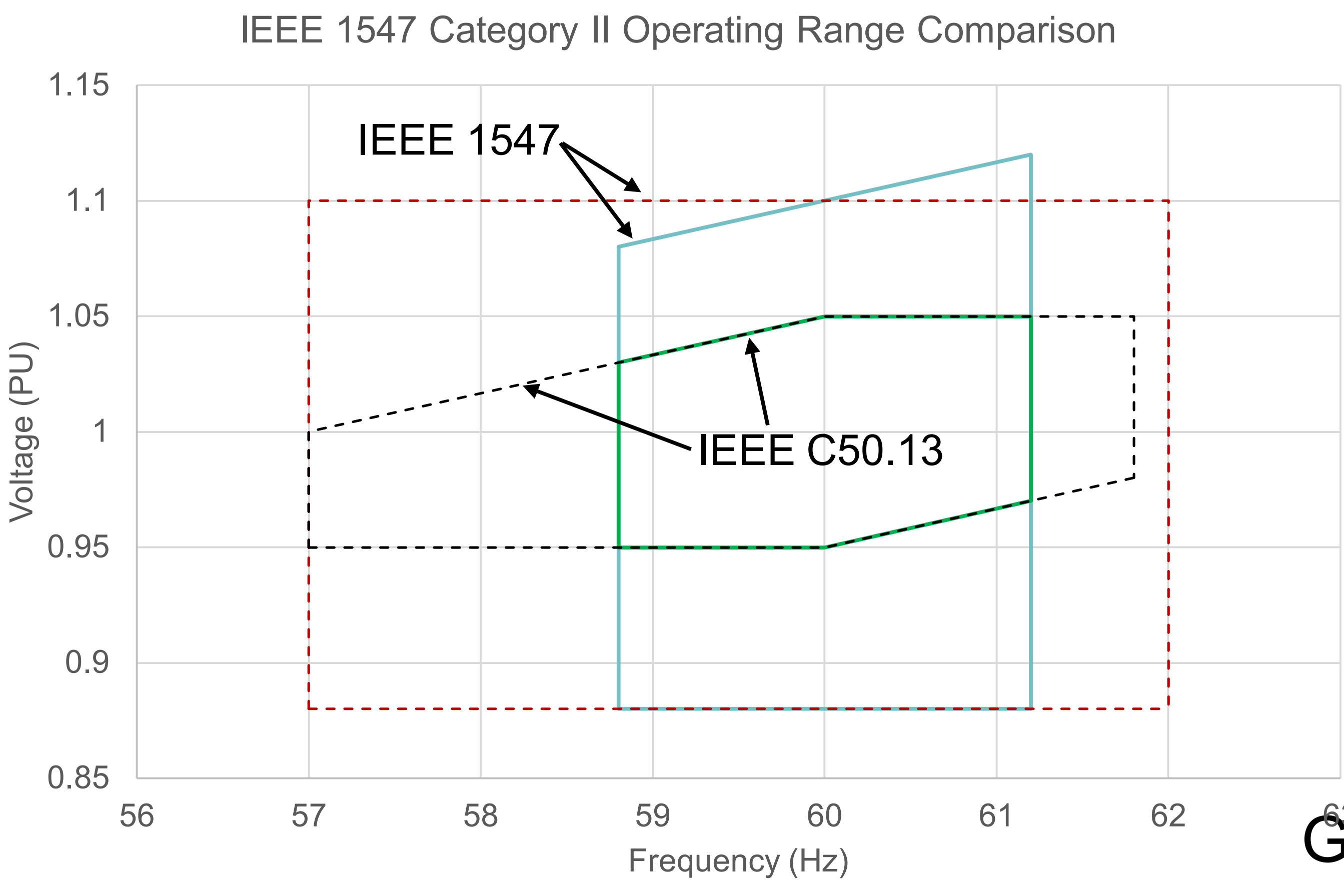
Grid Code Impact on Generator Design

- Grid codes call for wider operating ranges
  - Increased size leads to higher cost



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Grid Code Impact…: Power requirement

New Grid Code imposes new operating limits…

- Regarding reactive power production and absorption,
- Lagging & leading power factor requirement respectively…

Direct impact on alternator sizing… meaning :

- Xd max value criteria

or

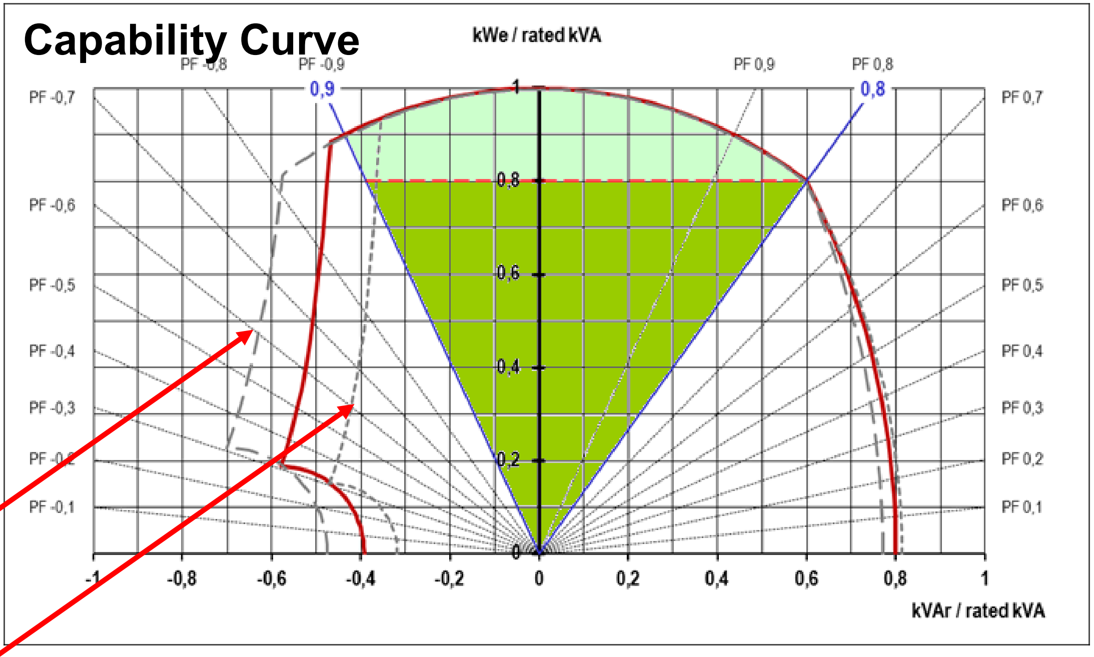
- Kcc min value criteria

More on this later…

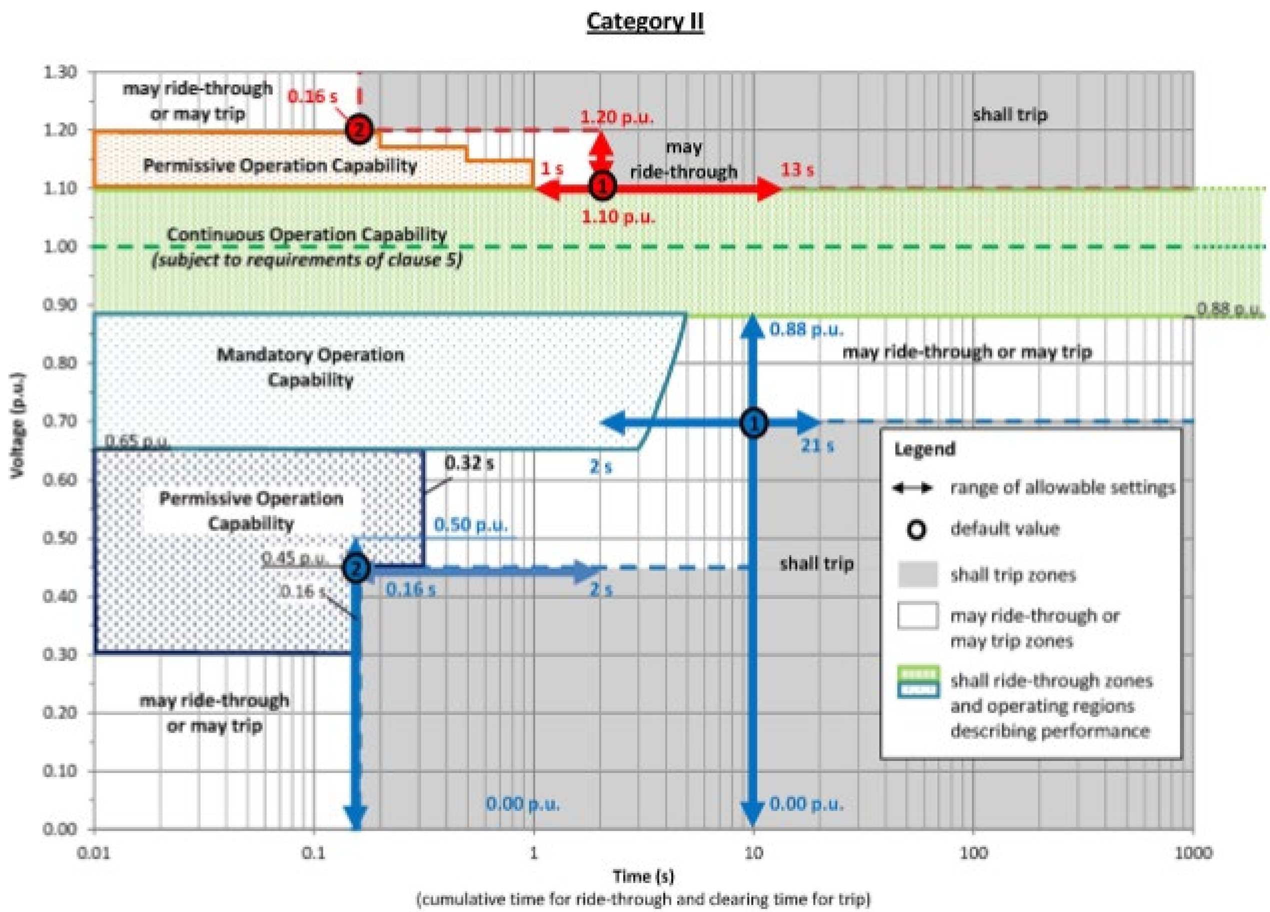
Reminder: Xd = 1/Kcc

Maximum voltage

Minimum voltage



Grid Code Impact on Generator Design



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- IEEE Std 1547-2018 voltage vs. time operating range for Category II systems – more complex

Grid Code Impact on Generator Design

- Limits apply at grid connection point, *not* at generator terminals
  - Line and transformer drops may expand required voltage operating range
- Grid codes are not harmonized (not even within Europe) – each must be dealt with on a case-by-case basis
- Even IEEE 1547, targeting North American grid, is not uniform
  - Three categories, negotiable between end user and system operator

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Grid Code Impact on Generator Design

- Power factor:
  - May be required to supply 0.9 lagging through 0.9 leading power factor – 0.85 lagging on generator side of transformer
  - *Less* strict VAR requirement than normally called for in island mode (0.8 PF lagging)
  - May apply over voltage range (unrealistic)
- Short-circuit ratio:
  - Requirement for (e.g.) 0.5 minimum may lead to oversized machine, increasing cost

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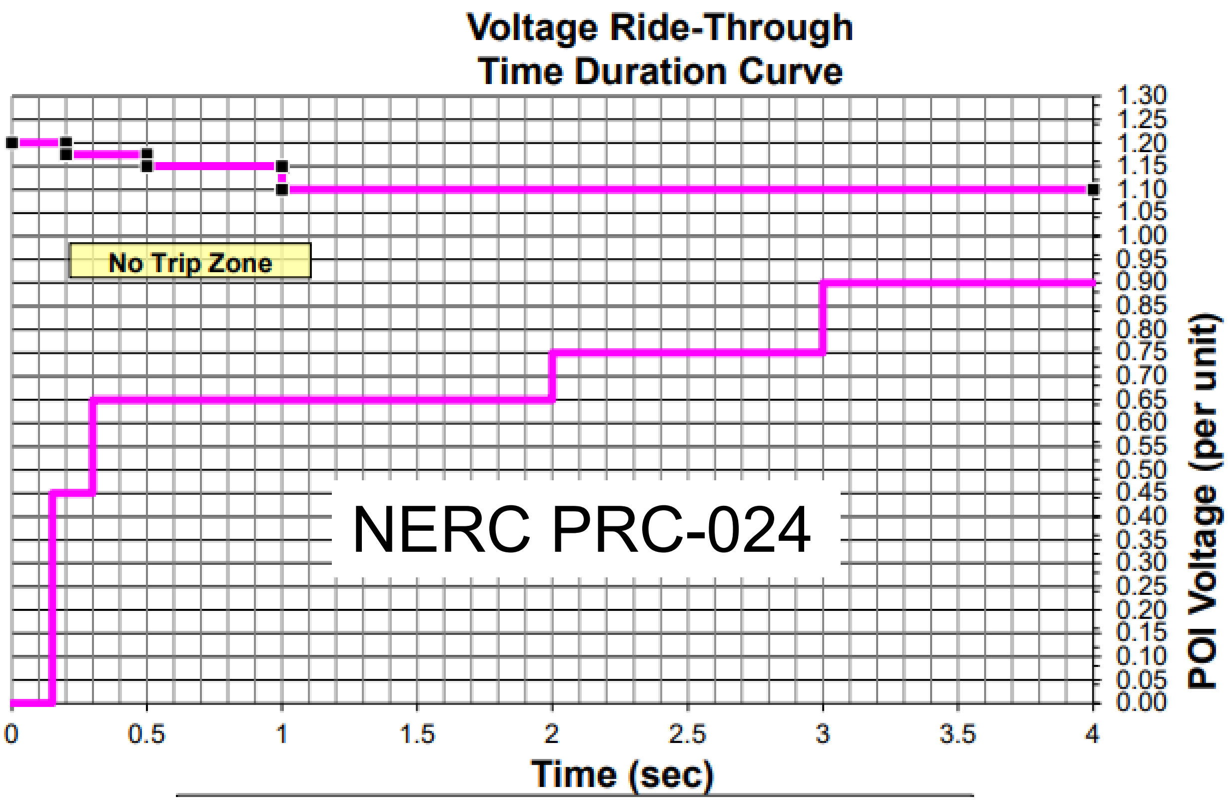
Grid Code Impact on Generator Design

- Ride-through requirements:
  - Voltage vs. time profile for remaining connected



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Grid Code Impact on Generator Design

- What happens?
  - During a fault, not much power is being delivered by the generator (low voltage)
  - The prime mover can't react, continues to supply power at the same rate
  - Extra energy goes to *speed up* the generator at a rate determined by inertia
  - Generator voltage gets out of sync with the grid. If not too far out, it will slow down once the grid comes back. If not, it may continue to accelerate and slip poles.

Grid Code Impact on Generator Design

- Must remain connected and in synchronism during and after fault
  - May require higher inertia (to reduce speed variation), lower reactance (= higher short-circuit ratio SCR, to help pull back into sync on recovery), or both
  - Causes high stresses on windings and shaft, may require stronger construction
  - High-response excitation will improve ability to resynchronize

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Grid Code Impact on Generator Design

- Generators providing grid support may encounter new service factor requirements:
  - More frequent stopping and starting
  - More load variability while running (both MW and MVAR)
- Make sure generator vendor is aware of all the requirements – simply calling out the grid code is not sufficient
- Helpful to involve generator manufacturer in negotiation with power company

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5. Synchronization and Paralleling

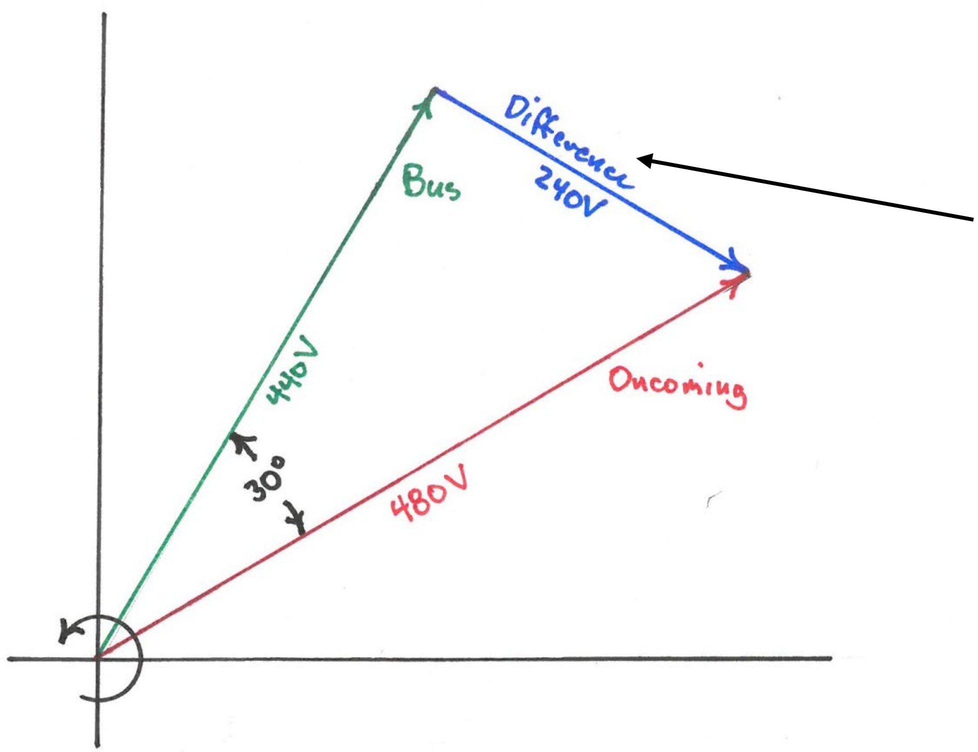
Synchronization and Paralleling

- Why operate generators in parallel?
  - Add capacity:
    - Limitations on engine/generator size
    - Modularity for expansion, flexibility of operations
    - Multiple locations
  - Redundancy
    - N+1 allows one set to fail or be maintained while others deliver required load power
    - Improves reliability from 98% to 99.96% (typical system)
  - Efficiency
    - During light load conditions, sets can be shut down so remaining ones operate closer to full load
    - Prevent "wet-stacking" and engine damage

Synchronization

- Involves preparation of two power buses for being connected together. One is usually just called the “bus” and the other, “oncoming”, is the machine or set of machines being added to the bus
- Transient currents and torques occur that depend on the instantaneous voltage difference between the two buses at the moment of connection, and the impedance of the two buses
- Voltage and phase angle contribute to this voltage difference
- Speed (i.e. frequency) difference is also important

Synchronization and Paralleling



- Difference is due to combination of angle and voltage.
- 240V difference is about half of rated voltage, so will produce about half of normal short-circuit current and torque.
- 10-15º and 5% voltage difference are typical generator requirements for synchronization – if system will exceed this, extra bracing needed

Parallel Operation

- When a generator is operating in parallel with a bus (or another generator), it must be controlled in order to balance both reactive (VAR) and real (power) load.
- Real power is controlled entirely by the engine or prime mover via the governor. The generator itself has no control over power.
- Reactive load is controlled by the generator excitation alone. The prime mover can't control the VARs (much).

Parallel Operation – Droop Mode

- Droop mode is the simplest method of parallel operation.
- For control of VARs, the voltage regulator is set so that as the voltage decreases, it applies more excitation (attempting to increase the voltage), but allows the voltage to decrease slightly in proportion to the VARs being drawn by the load. Requires a current transformer to sense the reactive current.
- The voltage serves as the signal that controls the generator excitation, and varies with reactive load.

Parallel Operation – Droop Mode

- Similarly, for the engine, if the speed decreases, the governor applies more fuel (attempting to increase the speed), but allows the speed to decrease slightly in proportion to the power being drawn by the load.
- The speed serves as the signal that controls the engine, and it varies with power load.
- Droop mode is best for systems with widespread or diverse generation, or paralleled with the grid.

Parallel Operation – Cross-Current Mode

- Cross-current mode is more complex and requires a separate channel of communication between generators.
- For control of VARs, the voltage regulators are cross-connected to that as the reactive current becomes unbalanced, more excitation is applied to the machine producing fewer VARs and less to the machine producing more, rebalancing the currents. The voltage remains constant.
- The signal that controls the generator excitation is carried on a separate pair of wires.

Parallel Operation – Isochronous Mode

- For the engine, this mode is known as isochronous or constant-speed. If the power becomes unbalanced, the governor applies more signal to the lower-power machine, and decreases the power to the higher power machine. Speed does not vary.
- The signal that controls the engine is carried on a separate channel between the governors.
- As far as I know, nothing prevents these two types of control from being mixed (e.g. droop voltage and isochronous speed).
- Isochronous/cross current modes are best for systems of like machines in close proximity.

Synchronization and Paralleling

- Paralleling of generators with different third harmonic may require special attention as explained elsewhere.
- Accidentally synchronizing generators with phase angle or voltage difference beyond the recommended range may cause internal damage to the generators due to high currents, or to the shaft or engine due to high torques.
- A method of synchronizing several generators exists where the generators are connected to the (dead) bus and excitation is applied before the engines are started. As the engines come up to speed, the generators are drawn naturally into synchronism.

Grounding Methods (Short Diversion)

- Grounding affects circulating currents
- IEEE Std 142, “Recommended Practice for Grounding of Industrial and Commercial Power Systems” (“Green Book”) shows several methods for grounding power systems
  - Ungrounded (no intentional ground)
  - High- or low-resistance grounding
  - Reactance grounding
  - Ground-fault neutralizer (resonant ground)
  - Solid grounding
- Each of these has advantages and detriments

Grounding Methods

- Ungrounded (no intentional ground)
  - Allows operation with a single ground fault
  - Simple and inexpensive
  - No 3rd harmonic circulating current
  - Used on Navy ships for LV power system
  - May lead to overvoltages with arcing faults
  - Uncontrolled neutral voltage

Grounding Methods

- Low-resistance grounded
  - Limits ground fault current to no more than three-phase fault current (protects generator from physical stresses due to high current)
  - Ground fault cleared by coordinated breaker
  - Prevents transient overvoltages
  - Multiple sources multiply available ground fault current unless switched grounds used
  - Reduces third-harmonic current – but grounding resistor must be sized for steady-state 3rd harmonic current if present (standard requires 15% continuous)

Grounding Methods

- High-resistance grounded
  - Has same benefits as low-resistance
  - Also allows operation for limited time with one ground fault present
  - Limits current in generator internal fault, reducing damage
  - Reduced continuous 3rd harmonic current (reduces power dissipation)
  - Multiple grounds usually are no problem
  - Requires separate ground-fault detection means (resistor voltage or current will do)

Grounding Methods

- Reactance grounded
  - Similar to resistance grounded, lower loss
- Ground-fault neutralizer
  - Mainly on systems above 15 kV, excluding most generators
- Solidly grounded
  - May allow very high fault current to flow in the generator windings in case of a single-phase-to-ground fault – possibly causing generator damage (NEMA MG-1 says windings braced for 3-phase fault only)

Grounding Methods

- Hybrid grounded (recent introduction)
  - External or switched low-resistance ground combined with high-resistance generator neutral ground
  - Combines benefits of both systems
  - Requires careful design

Grounding Methods -- IEC

- IEC 60364 Grounding Arrangements
  - First letter: T for “earthed”, I for “isolated”
  - Second letter: T for directly earthed, N for connected to the earthed neutral at origin
  - TN-C: Combined ground and neutral, like old-style dryer hookup
  - TN-S: Separate ground and neutral wires connected together at source, similar to normal NA practice
  - TT: Like TN-S but not requiring bonding neutral to common ground, using GFCI for protection
  - IT: Isolated from ground with ground fault detector

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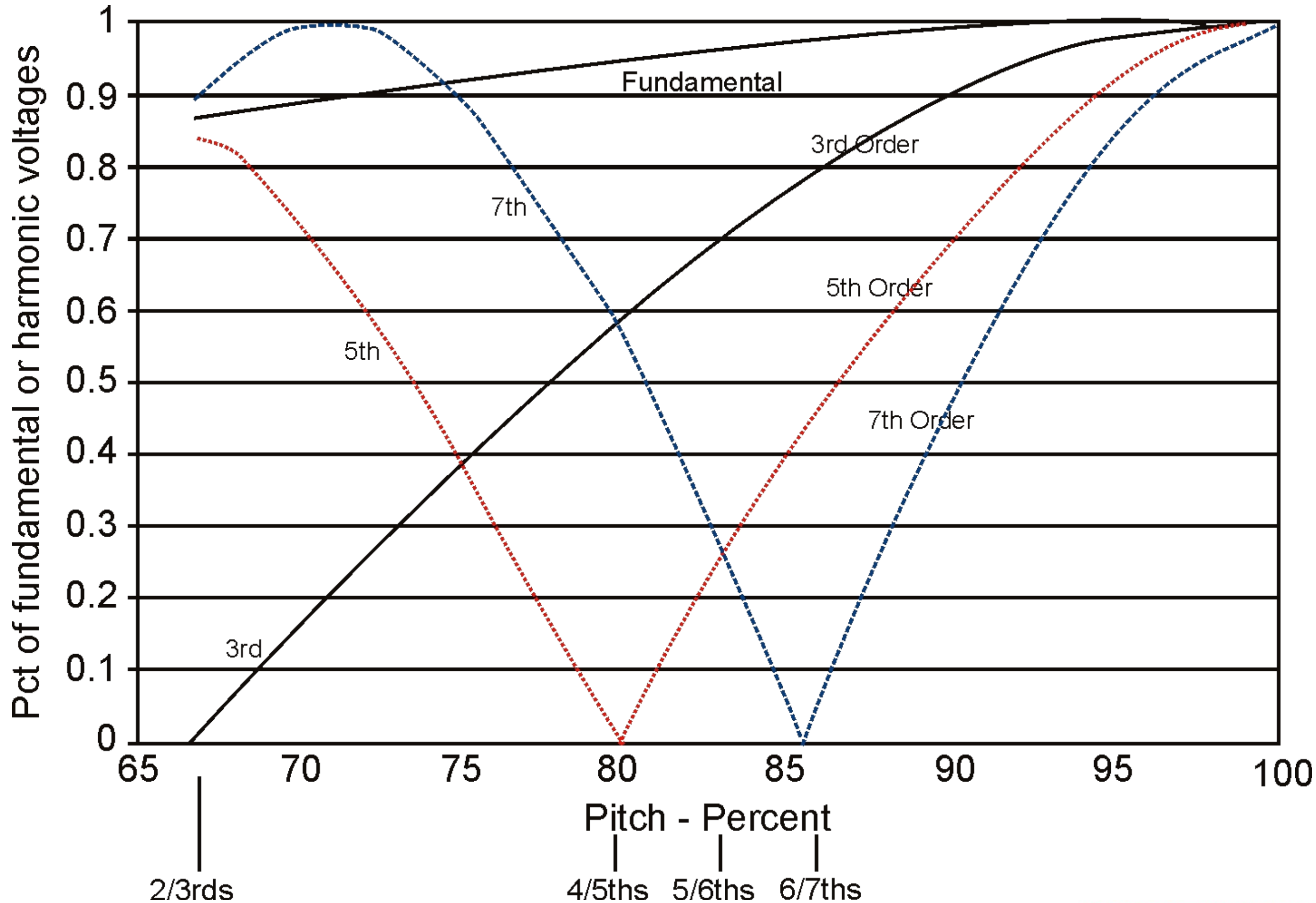
Fundamental & Harmonic Voltages vs. Pitch (Knoltons Handbook)



Effects of Generator Pitch

- Pitch factors for *reduction* of various harmonics:

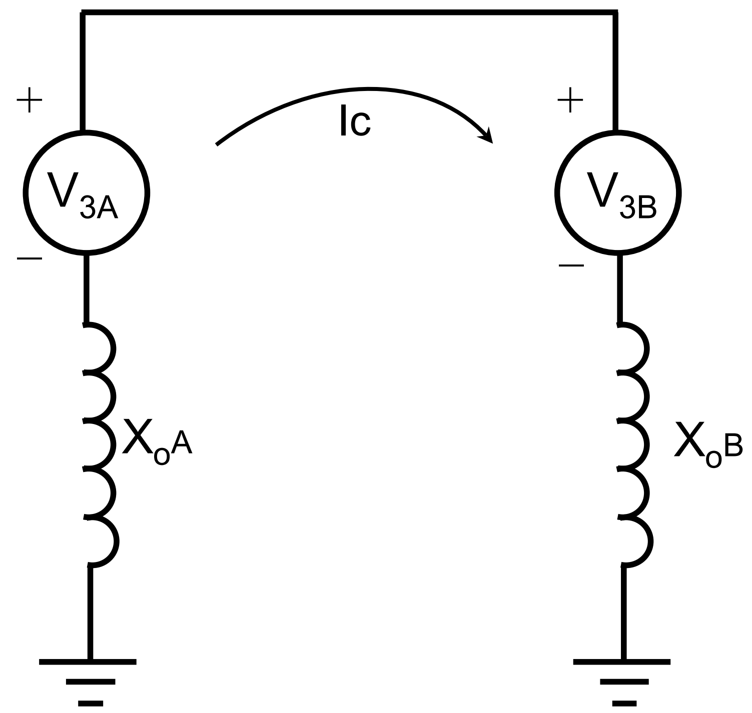
	Harmonic Number						
Pitch	**Fund**	**3**	**5**	**7**	**9**	**11**	**13**
2/3	0.866	0.000	-0.866	0.866	0.000	-0.866	0.866
11/15	0.914	-0.309	-0.500	0.978	-0.809	0.105	0.669
3/4	0.924	-0.383	-0.383	0.924	-0.924	0.383	0.383
7/9	0.940	-0.500	-0.174	0.766	-1.000	0.766	-0.174
4/5	0.951	-0.588	0.000	0.588	-0.951	0.951	-0.588
5/6	0.966	-0.707	0.259	0.259	-0.707	0.966	-0.966
6/7	0.975	-0.782	0.434	0.000	-0.434	0.782	-0.975
7/8	0.981	-0.831	0.556	-0.195	-0.195	0.556	-0.831
Full	1.000	1.000	1.000	1.000	1.000	1.000	1.000

(Harmonic in flux wave is multiplied by reduction factor.)
(Also reduced by distribution, skew)

Circulating Harmonic Currents

- Circulating current: When two generators (or generator and utility) are connected in parallel and third harmonic current flows between them depending on zero-sequence impedance and difference of 3rd harmonic voltages. Per phase:

$$I_C = \frac{V_{3A} - V_{3B}}{3 \bullet (X_{0A} + X_{0B})}$$

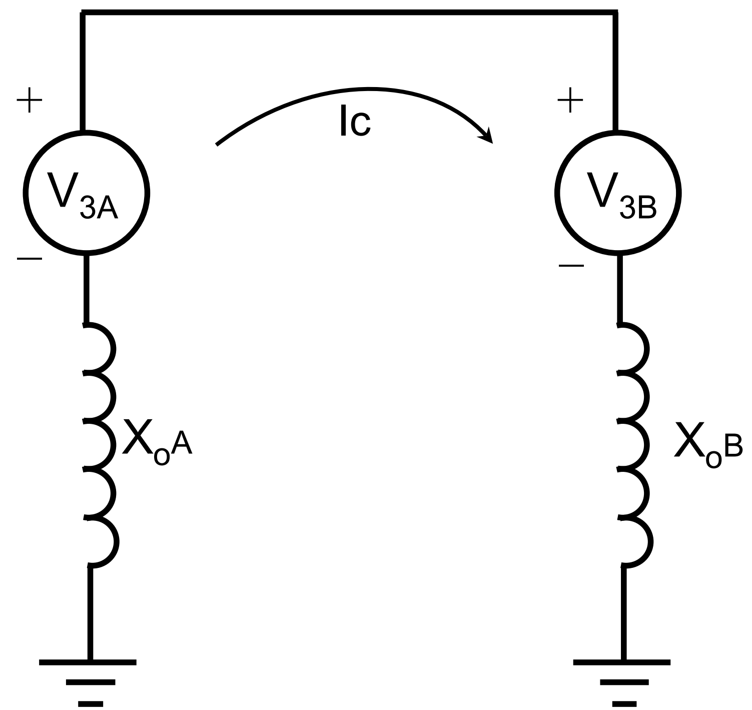


Where:

- V_3 is L-N third harmonic voltage.
- X_0 is zero-sequence reactance of each source (including external grounding reactance).

Circulating Harmonic Currents

- Higher harmonics (5th and up) are not usually significant:
  - 5th, 7th, etc. don't flow in neutral lead.
  - Higher impedance at higher frequencies means harmonic current is lower.
- Third, 9th, etc. harmonic flows in neutral.
- May cause overheating of neutral lead or grounding resistor, false tripping of differential protection relay and other problems.



Circulating Harmonic Currents

- What to do about this?
  - It may not be a problem
  - Neutral current splits three ways, so 100A in neutral is only 33A in phase leads
  - Adds as RMS, so 10% extra phase current only adds 2% to heating
  - Neutral grounding device will reduce current
    - Must be rated for continuous 3rd harmonic ~15%
  - Otherwise, *third harmonic voltages, not pitch*, should be matched to reduce circulating current – consult manufacturer

Selection of Correct Pitch (cont.)

- Why not just use 2/3 pitch?
  - Low zero-sequence impedance will cause generator to attempt to absorb any third-harmonic current on bus from other sources. Must balance third harmonic voltage to prevent circulating current.
- Why do other manufacturers have a different recommendation?
  - If building mainly low-voltage machines, these are usually solidly grounded and will more likely require 2/3 pitch for utility paralleling.
  - May have made design decision to allow high third harmonic in flux wave, and reduce by making all units 2/3 pitch.

Selection of Correct Pitch (cont.)

Nidec
All for dreams

2/3 Pitch

- Kato generators are designed for optimum pitch unless otherwise specified
- Pole pitch is the angle between adjacent poles, i.e. 4 pole = 90º mechanical
- Winding pitch is the coil span divided by the pole pitch, i.e. 60º / 90º = 2/3
- Optimum pitch balances generator performance while effectively utilizing generator active materials
- 2/3 pitch used when paralleling different generators and in conjunction with nonlinear L-N loads. May require derating.

Selection of Correct Pitch (cont.)

- **Paralleling directly with utility bus, solid ground, 480V up:**
  - Normally no line-neutral loads, no load third harmonic generated locally.
  - No third harmonic from utility due to transformer connection.
  - *Use 2/3 pitch* to minimize circulating current with utility.

Selection of Correct Pitch (cont.)

- **Paralleling with utility, high impedance grounding:**
  - Third harmonic circulating current cannot flow through neutral.
  - *Use optimum pitch* to minimize cost.
  - In most cases systems with high-impedance ground will not require 2/3 pitch. Consulting engineer for project should determine allowable neutral voltage. Adjust pitch to reduce 5th and 7th harmonics.

Selection of Correct Pitch (cont.)

- **Paralleling with other generators, same type:**
  - Since all generators matched, no circulating current.
  - *Use optimum pitch* to minimize cost.
  - Note: if also paralleling with external grid through grounded primary transformer, 2/3 pitch may be required.

Selection of Correct Pitch (cont.)

- **Paralleling with other generators, different type, solidly grounded:**
  - Must know third harmonic voltage on bus.
  - *Select pitch and slots* to match third harmonic voltage, minimize circulating current.
  - *May not* be same pitch as other generators on bus. Depends on pole shape, saturation, other factors.
  - Must involve manufacturer and end user in design.
  - Possibly use switchable grounds, or grounding transformer

Selection of Correct Pitch (cont.)

- **Not paralleled, but high harmonic line-neutral load:**
  - Normally 120/208 volt or possibly 277/480V systems.
  - *Use 2/3 pitch* to minimize zero-sequence reactance, to reduce third harmonic L-N voltage.
- **Not paralleled, but only line to line loading:**
  - Many industrial 480V systems and almost all medium- and high-voltage systems.
  - *Use optimum pitch* to minimize cost.

6. Reference Frame Theory

Nidec
All for dreams

- Three phase balanced set of AC currents creates approximately a moving wave of sinusoidal flux which travels around the stator at a rate determined by the frequency.
- In a synchronous machine, the rotor rotates at the same (average) speed as this flux wave. If it lags behind, it is pulled by the flux and acts as a motor. If it is pushed out ahead of the flux, it delivers power as a generator.

Imagine you are on a new theme park ride ("The Synchronous Generator! Amazing!")

- You take your seat on the rotor of the generator and put on your magic 3D glasses which allow you to see the magnetic lines of force, and the currents.
- The machine starts and comes up to 1800 RPM…*

*Only 1500 in Europe, which is why EuroDisney is boring.

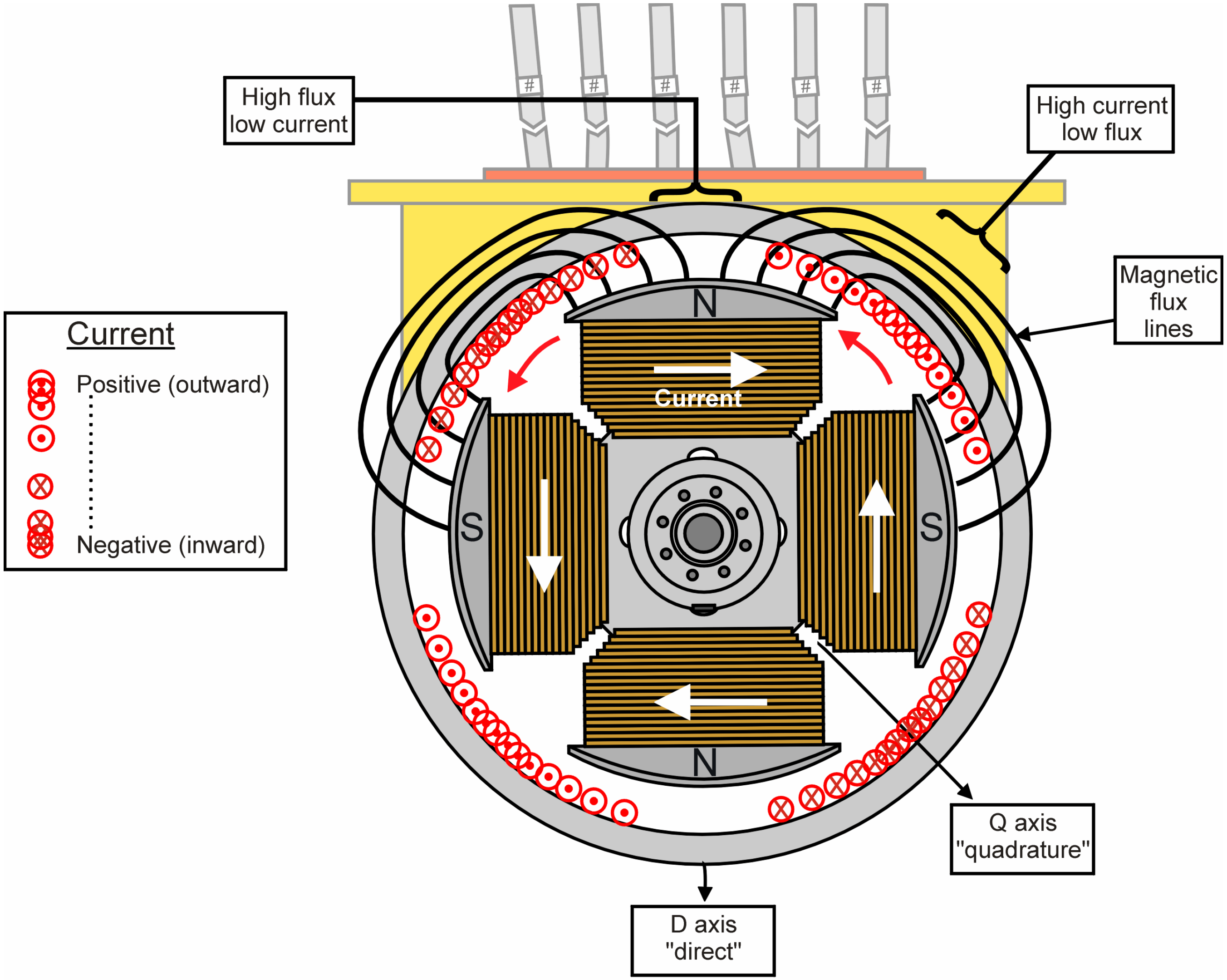
When excitation is applied to the generator with no load you see lines of flux going straight up from the rotor to the stator.

- They are most concentrated at the center of the rotor.
- There are few between the poles.
- On the adjacent poles they go from the stator to the rotor.
- There is no current in the stator.

- If a lagging zero-power-factor load* is applied.
  - You see stator current ahead of you, going to the right, and behind you going to the left, but none near the center of the pole.
  - The location of the current is steady from your point of view, even though the surface of the stator is passing by at high speed.
  - The lines of flux are reduced, because the stator current is in the opposite direction from the rotor current.

* Lagging power factor means that the peak of the current occurs after the peak of the voltage. Leading power factor means the peak of the current occurs before the peak of the voltage.

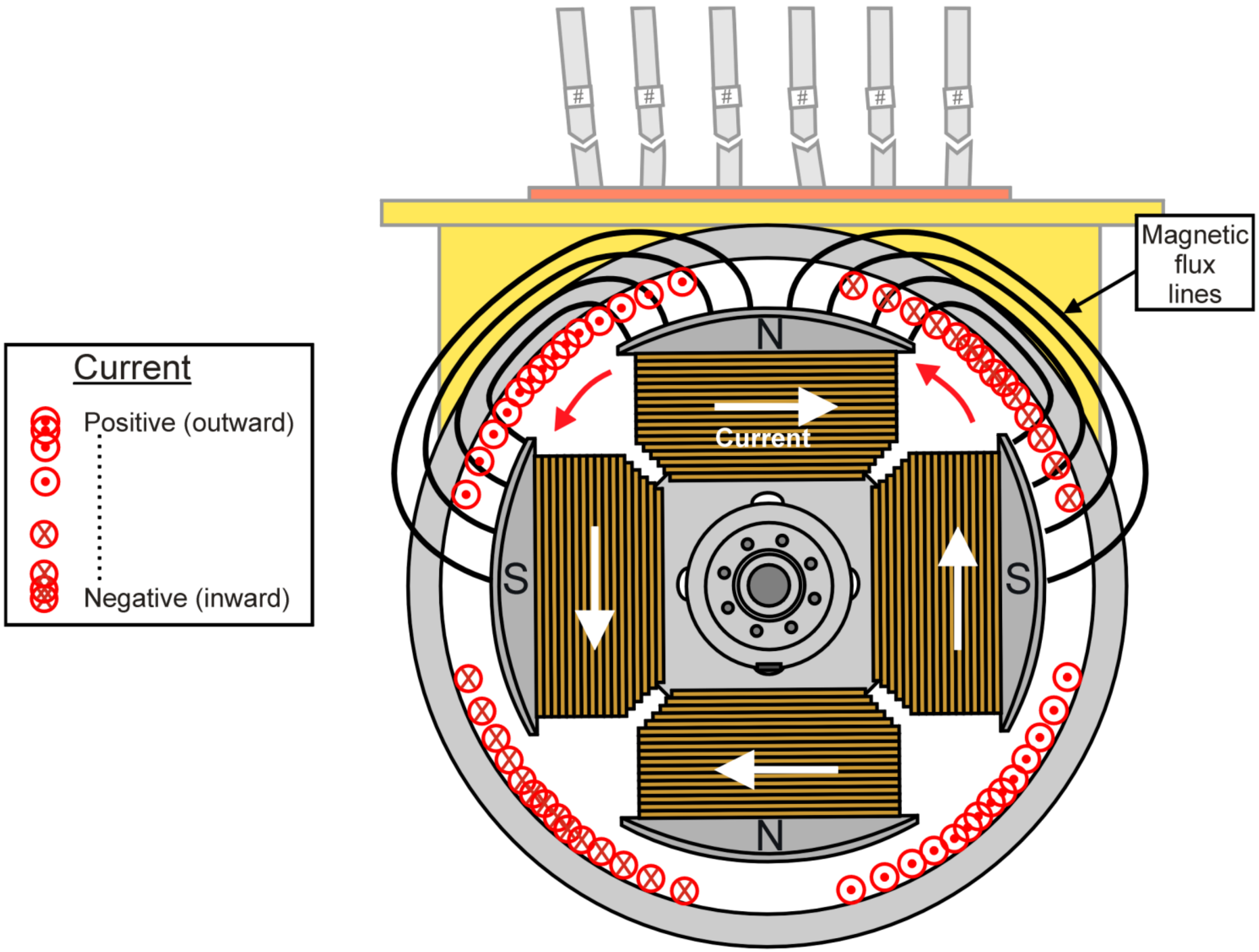
Intro to Reference Frame Theory
Short Version



Lagging Zero Power Factor Load

- If a leading zero power factor load is applied:
  - You see stator current ahead of you, going to the *left,* and behind you going to the *right,* but none near the center of the pole.
  - The location of the current is still steady from your point of view.
  - The stator current flows the opposite direction, and the flux is strengthened.
- In both cases, flux is high where the current is low, and vice versa, so no torque developed.

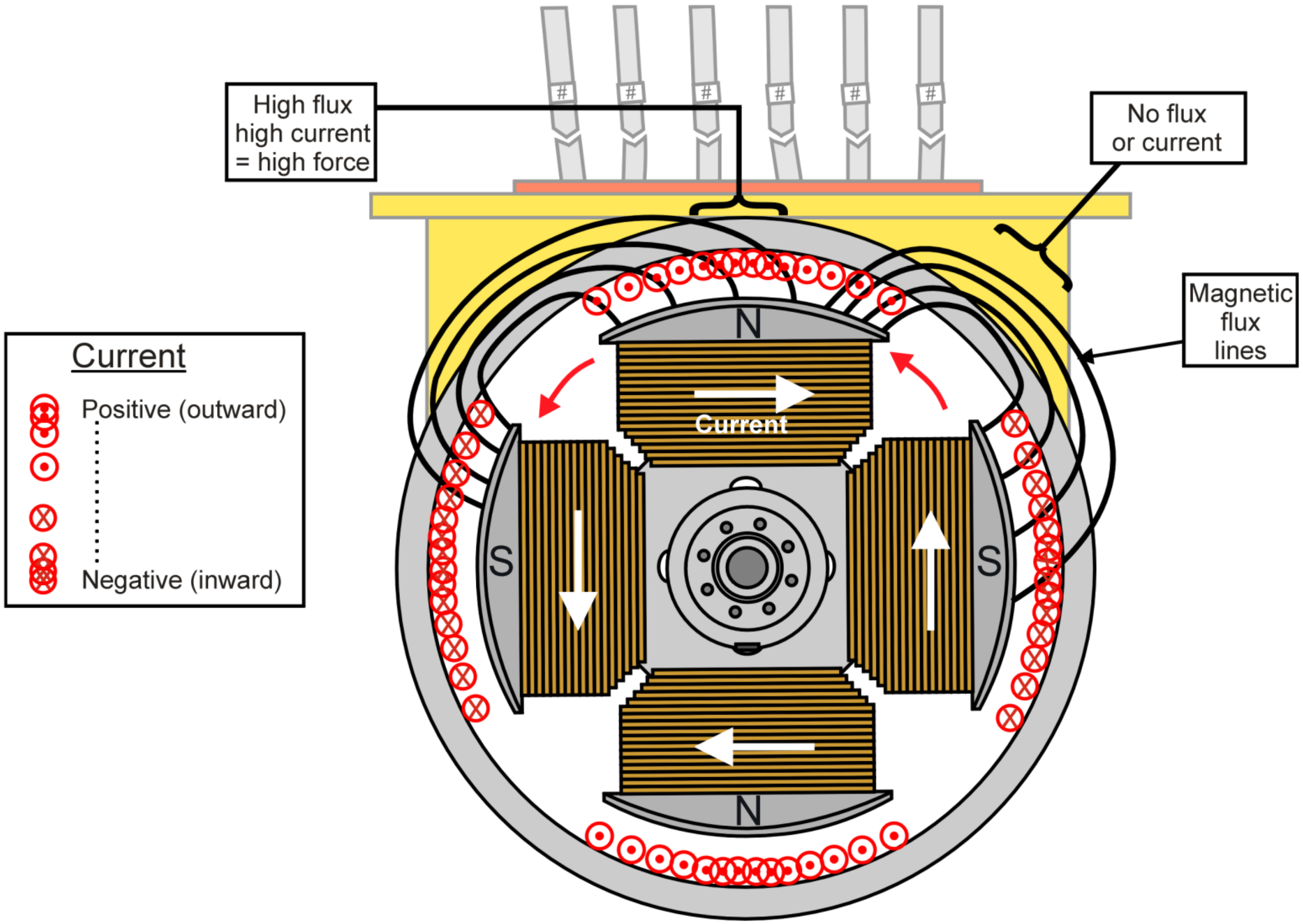
Intro to Reference Frame Theory
Short Version



Leading Zero Power Factor Load

- If a real (unity power factor) load is applied:
  - You see current from left to right over the center of the pole head -- where there is high flux -- and low current between poles. Current x flux generates force (power).
  - The current in the stator pulls the lines of flux backward, crowding them into the trailing edge of the pole head.
  - Unity power factor load does not have a big effect on the total flux.

Intro to Reference Frame Theory
Short Version

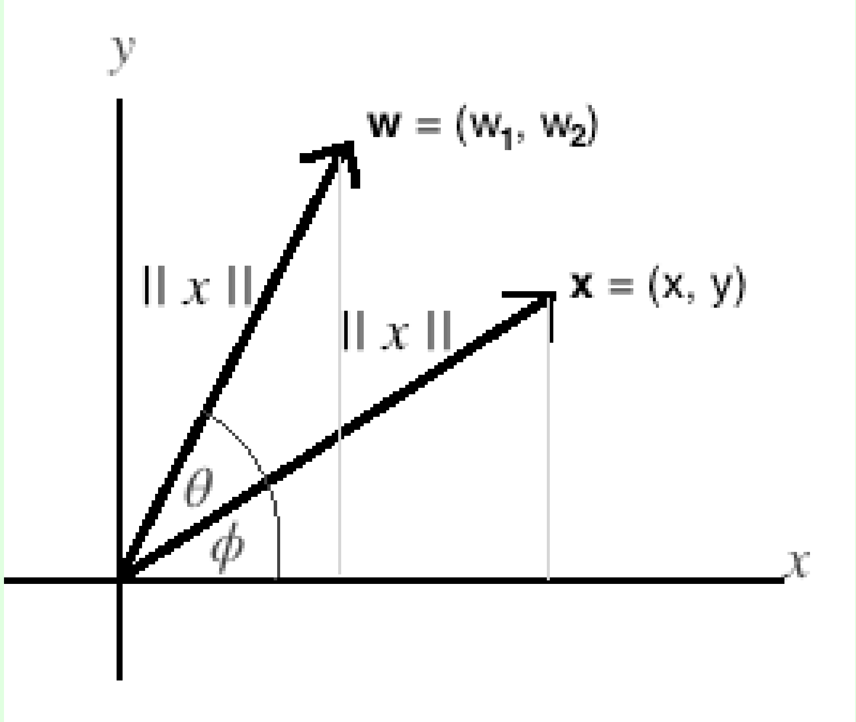


Unity Power Factor Load

- Summary of generator loading:
  - Lagging power factor (inductive) current demagnetizes the rotor, requiring higher field current to maintain flux and voltage. It does not produce torque or power.
  - Leading power factor (capacitive) current aids the magnetization of the rotor. So less field current is required. It does not produce any torque or power.
  - Unity power factor (resistive) current neither magnetizes not demagnetizes the rotor, so field current is not affected (much). The retarding torque produced uses mechanical power and produces electrical power.

Rotational Transformations in 2-Space

Let $\vec{x} \in R2$. We will need to find equations relating $\vec{x} = (x,y)$ to its image $\vec{w} = (w1,w2)$ under the a rotational transformation T. Let ϕ be the angle between the positive x-axis and $\vec{x}$, and let θ be the angle between $\vec{x}$ and $\vec{w}$. The length of both vectors is R.



Skip ahead ->

Intro to Reference Frame Theory

Note that we can calculate the components of our vector $\vec{x} = (x, y)$ with the polar equations
$x = R\cos\phi$ and $y = R\sin\phi$ (where R = ||X||) - both of which were derived by basic trigonometry. We can also calculate the components of $\vec{w} = (w1, w2)$ from these equations:
$w1 = R\cos(\theta+\phi)$ and $w2 = R\sin(\theta+\phi)$.

Using the following trigonometric identities:
(1) $\cos(\alpha+\beta) = \cos\alpha\cos\beta - \sin\alpha\sin\beta$
(2) $\sin(\alpha+\beta) = \sin\alpha\cos\beta + \cos\alpha\sin\beta$
we can write $w1$ and $w2$ as follows:
$w1 = R\cos\theta\cos\phi - R\sin\theta\sin\phi$
$w2 = R\sin\theta\cos\phi + R\cos\theta\sin\phi$

Intro to Reference Frame Theory

Lastly we substitute x=Rcosϕ and y=Rsinϕ to get:
$w1 = x\cos\theta - y\sin\theta$
$w2 = x\sin\theta + y\cos\theta$

It thus follows that if $w=Ax$, then our standard matrix A = $\begin{bmatrix} \cos\theta & -\sin\theta \\ \sin\theta & \cos\theta \end{bmatrix}$, and transformation in matrix form is:

W = Ax or $\begin{bmatrix} w_1 \\ w_2 \end{bmatrix} = \begin{bmatrix} \cos\theta & -\sin\theta \\ \sin\theta & \cos\theta \end{bmatrix} \begin{bmatrix} x_1 \\ x_2 \end{bmatrix}$

The zero-axis terms don't rotate, so don't have to be transformed.

Intro to Reference Frame Theory

Use the Clarke transform to convert to direct/ quadrature/zero axes:

The Clarke transform (named after Edith Clarke) converts vectors in the ABC reference frame to the XYZ (often αβz) reference frame. The primary value of the Clarke transform is isolating that part of the ABC-referenced vector which is common to all three components of the vector; it isolates the common-mode component (i.e., the Z component). The power-invariant, right-handed, uniformly-scaled Clarke transformation matrix is [from Wikipedia]:

Intro to Reference Frame Theory

$$K_C = \sqrt{\frac{2}{3}} \cdot \begin{bmatrix} 1 & -\frac{1}{2} & -\frac{1}{2} \\ 0 & \frac{\sqrt{3}}{2} & -\frac{\sqrt{3}}{2} \\ \frac{1}{\sqrt{2}} & \frac{1}{\sqrt{2}} & \frac{1}{\sqrt{2}} \end{bmatrix}$$

$u_{xyz} = K_c u_{abc}$ so u_{abc} (three-phase) becomes u_{xyz} (orthogonal).

The non-power-invariant form is more common in older texts, it just removes the square root sign, and preserves voltages or currents instead of power. Note the quantities are amplitudes, not RMS values, in fundamental system (dimensionless in per-unit system).

This is a similar process with *vectors* to what we do with *phasors* in symmetrical components. Or is it the other way round? Anyway…

Intro to Reference Frame Theory

Then we change all stator quantities to rotor reference frame (stop the rotation).

This is the Park transformation. It multiplies the instantaneous vector quantities by reference vectors rotating (normally) at the same speed as the rotating MMF from the field winding:

$$K_P = \begin{bmatrix} \cos(\theta) & \sin(\theta) & 0 \\ -\sin(\theta) & \cos(\theta) & 0 \\ 0 & 0 & 1 \end{bmatrix}.$$

So u_{xyz} (rotating) becomes u_{dqz} (stationary).

Intro to Reference Frame Theory

- When $\theta = \omega t$, the reference frame is rotating at ω radians/sec. If this is the rotor speed, the new reference frame is stationary with respect to the rotor, and all steady-state stator quantities become DC.
- This is similar to the way traditional DC motors actually work: the field is stationary, and the commutator effectively performs a transform on the rotating armature currents so that they become stationary as well.
- There are a lot of good articles online for further reading (including Park's original 1926 article).

Intro to Reference Frame Theory

- By making orthogonal D and Q axes stationary with respect to the rotor, we get rid of all of the time-varying inductances and align the analysis with the physical structure
- Note that we can rotate the reference frame at any speed we want, and declare any axes we want – but for synchronous machines only the rotor reference frame and D-Q axes allow us to save labor.
- With high-speed computing power available, it is possible to analyze a synchronous machine in the stator reference frame, with all three phases, but it’s still a pain.

Reference Frame Theory – the Details

- Winding distribution in ideal machine
  - *Current* in a conductor creates magneto-motive force (MMF, or magnetic *field* H), which is the driving force for magnetic *flux*
  - Units of MMF are ampere-turns, i.e. multiple turns with current in each behave as the sum of the individual currents.
  - MMF at a location equals the net current enclosing that location
  - Winding distribution defines a *winding function* giving MMF over a path (gap)

Intro to Reference Frame Theory

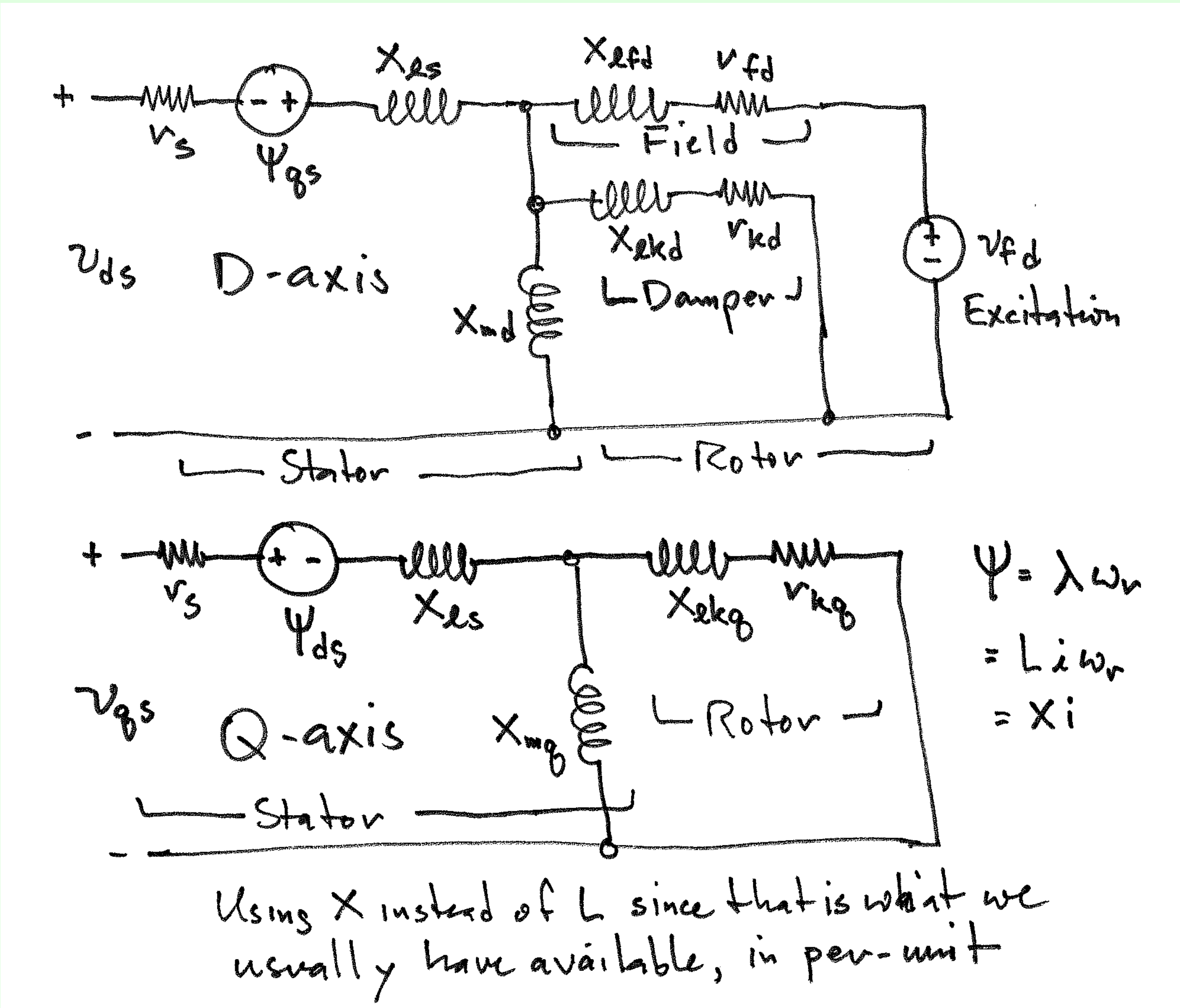
- Here we will skip over a lot of important material including:
  - Turns and winding functions, winding factor (for harmonics and fundamental), MMF
  - Winding distributions and pitches
  - Inductances of cylindrical machine
  - Effective gap, flux distribution, and how to deal with shape of salient pole
  - Leakage inductance calculations
- These are properly covered in a semester class

Generator Equivalent Circuits

- The Clarke and Park transforms can be applied to *any* kind of electrical circuit – including passive networks – but provide the most benefit with synchronous machines.
- Equivalent circuits for the *transformed* synchronous machine have been developed
- These are *models* of the machine – the elements of the model don't exist inside the machine as discrete entities. There are many circuits that can be used to model a particular machine. Some may provide a better fit than others. All have their uses.

Generator Equivalent Circuits

Traditional model for a salient pole machine:



We can write this circuit as a set of differential equations, then solve them to find the response of the circuit.

Riaz (UofM) uses Spice to simulate the circuit.

Generator Equivalent Circuits

- Equations of this model:

$$v'^{r}_{qs} = -r_s i'^{r}_{qs} + \frac{\omega_r}{\omega_b}\psi'^{r}_{ds} + \frac{p}{\omega_b}\psi'^{r}_{qs}$$

$$v'^{r}_{ds} = -r_s i'^{r}_{ds} - \frac{\omega_r}{\omega_b}\psi'^{r}_{qs} + \frac{p}{\omega_b}\psi'^{r}_{ds}$$

$$v_{0s} = -r_s i_{0s} + \frac{p}{\omega_b}\psi_{0s}$$

$$v'^{r}_{kq1} = r'_{kq1} i'^{r}_{kq1} + \frac{p}{\omega_b}\psi'^{r}_{kq1}$$

$$v'^{r}_{kq2} = r'_{kq2} i'^{r}_{kq2} + \frac{p}{\omega_b}\psi'^{r}_{kq2}$$ (solid only)

$$v'^{r}_{fd} = r'_{fd} i'^{r}_{fd} + \frac{p}{\omega_b}\psi'^{r}_{fd}$$

$$v'^{r}_{kd} = r'_{kd} i'^{r}_{kd} + \frac{p}{\omega_b}\psi'^{r}_{kd}$$

From Krause, Analysis of Electric Machinery

Ψ values are "flux linkages per second" (~voltages)

The "r" subscript means rotor reference frame, the prime ("'") means transformed to stator base. In per-unit, as we normally use, this is always the case, so I leave them off.

"p" is differential operator (solve for those terms).

Generator Equivalent Circuits

- Equations of this model (psi equivalences):

$$
\begin{aligned}
\psi^r_{qs} &= -X_{ls} i^r_{qs} + X_{mq}(-i^r_{qs} + i'^r_{kq1} + i'^r_{kq2}) \\
\psi^r_{ds} &= -X_{ls} i^r_{ds} + X_{md}(-i^r_{ds} + i'^r_{fd} + i'^r_{kd}) \\
\psi_{0s} &= -X_{ls} i_{0s} \\
\psi'^r_{kq1} &= X'_{lkq1} i'^r_{kq1} + X_{mq}(-i^r_{qs} + i'^r_{kq1} + i'^r_{kq2}) \\
\psi'^r_{kq2} &= X'_{lkq2} i'^r_{kq2} + X_{mq}(-i^r_{qs} + i'^r_{kq1} + i'^r_{kq2}) \\
\psi'^r_{fd} &= X'_{lfd} i'^r_{fd} + X_{md}(-i^r_{ds} + i'^r_{fd} + i'^r_{kd}) \\
\psi'^r_{kd} &= X'_{lkd} i'^r_{kd} + X_{md}(-i^r_{ds} + i'^r_{fd} + i'^r_{kd})
\end{aligned}
$$

Normally we solve the differential equations for the "psi" quantities, then calculate the currents. This means you have to invert the inductance matrix used to calculate ψ

(Disregard "kq2" quantities for laminated rotor)

λ is flux linkage, which is inductance times current, Li. Ψ is flux linkage per second, ωLi. Since ωL is X, and Xi is voltage, these are effectively voltages.

Generator Equivalent Circuits

- Let's look at one of the equations:

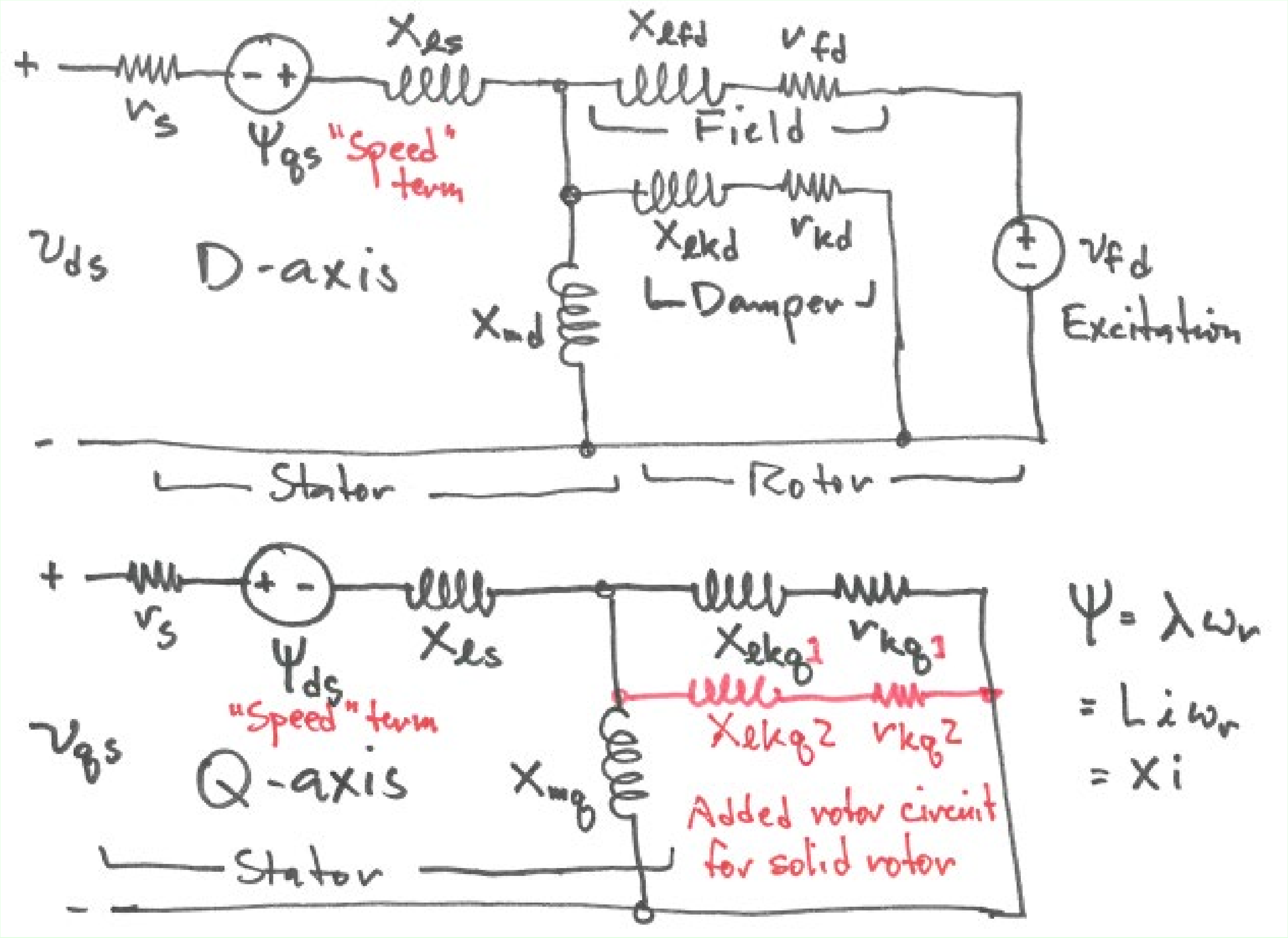
$$v_{ds}^{r} = -r_s i_{ds}^{r} - \frac{\omega_r}{\omega_b}\psi_{qs}^{r} + \frac{p}{\omega_b}\psi_{ds}^{r}$$

The last term represents the transient behavior of the d-axis flux linkage – a change in either the inductance or the current will result in transient voltage (product rule). The previous term is called a "speed" voltage, because it is proportional to speed. It represents the generator output due to the rotation of the rotor. The first term is just the voltage drop in the resistance.

Notice that Q-axis flux results in (negative) D-axis voltage, and D-axis flux results in Q-axis voltage. The flux is changing fastest when its value is zero.

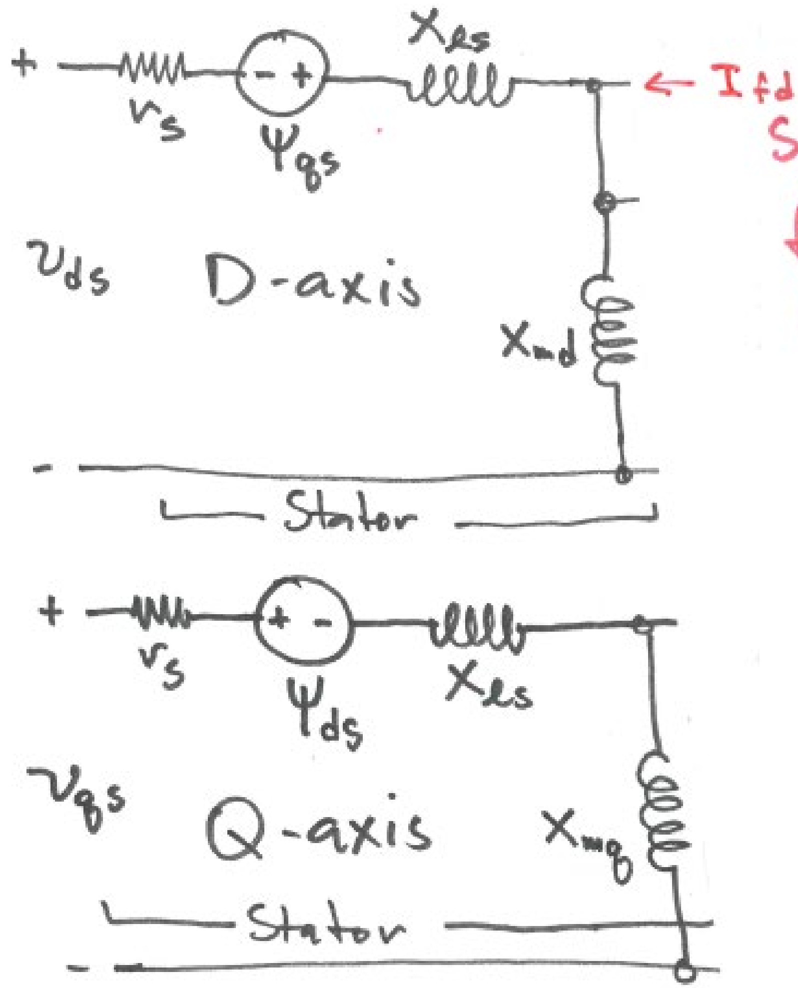
Generator Equivalent Circuits

- Showing added rotor circuit for solid pole



Generator Equivalent Circuits

Steady-state (synchronous) terms:



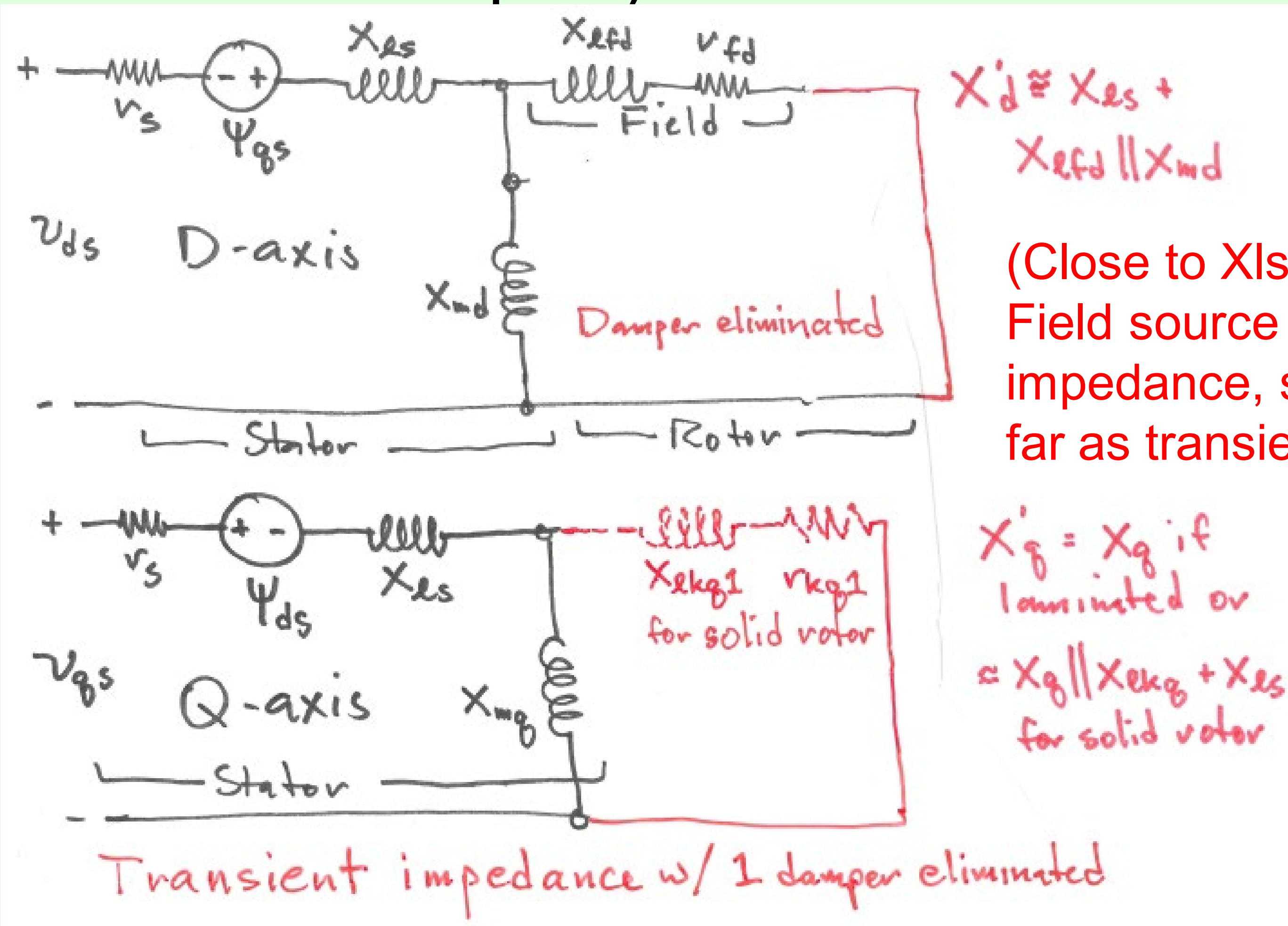
Synchronous impedance for steady-state - all rotor circuits are "shorted out" by the X_{md} / X_{mq}

$$X_{ds} = X_{ls} + X_{md}$$

$$X_{qs} = X_{ls} + X_{mq}$$

Generator Equivalent Circuits

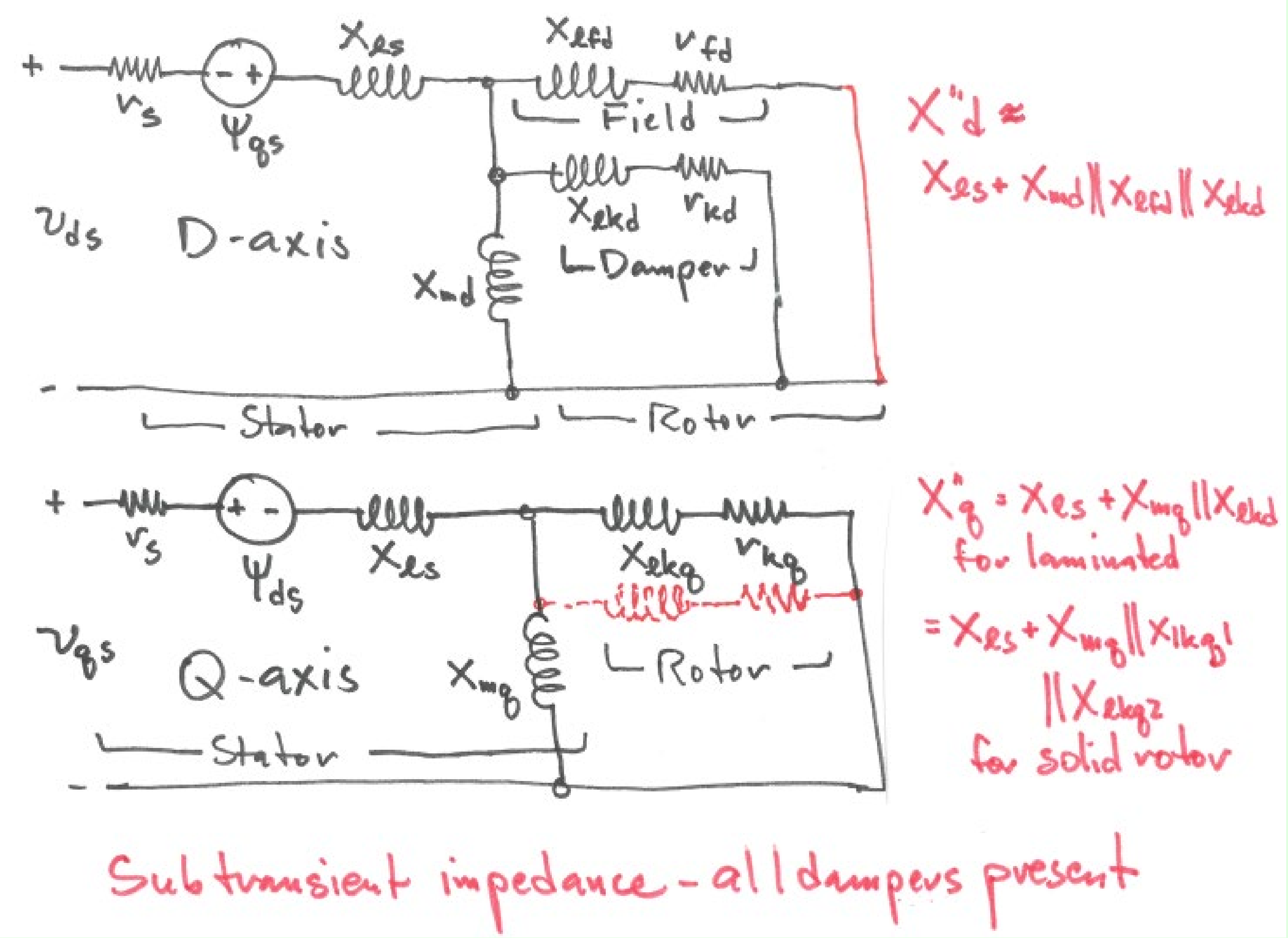
Transient terms add field circuit (and one rotor circuit for solid pole)



(Close to Xls + Xlfd)
Field source is low impedance, so "shorted" as far as transient goes

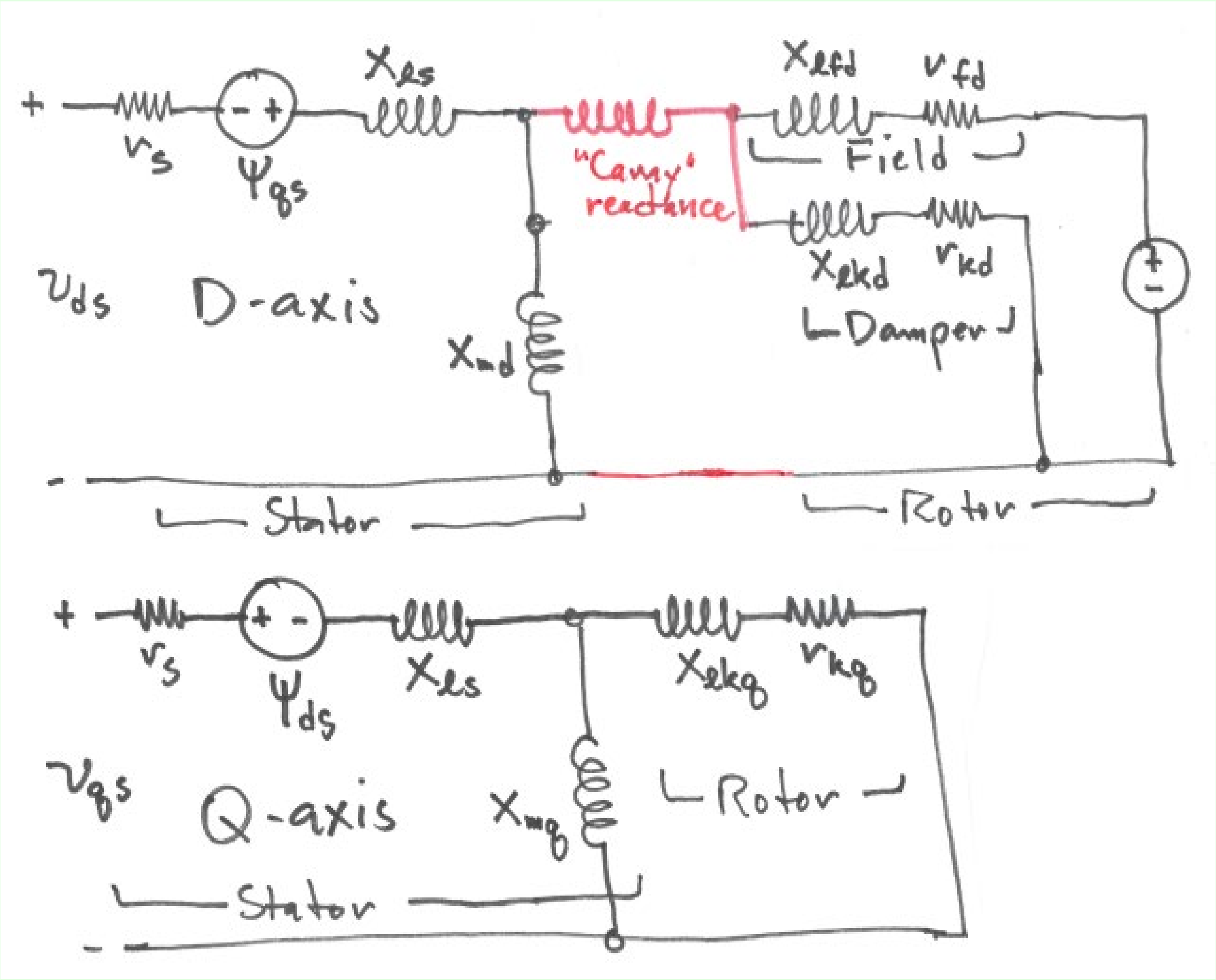
Generator Equivalent Circuits

Subtransient is result of all windings:



Generator Equivalent Circuits

Adding "Canay" reactance:



Better prediction of rotor field currents.
Represents the flux that links cage, but not winding, and vice-versa.
Can't be measured accurately using short-circuit test.

The model is not the machine!

Solving the model equations:

- First rearrange them so the derivative term is on the left hand side.

$$p\psi_{qs} = \omega_b(v_{qs} + r_s i_{qs}) - \omega_r \psi_{ds}$$

$$p\psi_{ds} = \omega_b(v_{ds} + r_s i_{ds}) + \omega_r \psi_{qs}$$

$$p\psi_{fd} = \omega_b(v_{fd} - r_{fd} i_{fd})$$

$$p\psi_{kq} = \omega_b(-r_{kq} i_{kq})$$

$$p\psi_{kd} = \omega_b(-r_{kd} i_{kd})$$

Solving the model equations:

- Then change to matrix form:

$$\vec{\Psi} = \begin{bmatrix} \Psi_{qs} \\ \Psi_{ds} \\ \Psi_{fd} \\ \Psi_{kq} \\ \Psi_{kd} \end{bmatrix} \qquad [R] = \begin{bmatrix} r_s & 0 & 0 & 0 & 0 \\ 0 & r_s & 0 & 0 & 0 \\ 0 & 0 & -r_{fd} & 0 & 0 \\ 0 & 0 & 0 & -r_{kq} & 0 \\ 0 & 0 & 0 & 0 & -r_{kd} \end{bmatrix} \qquad \vec{i} = \begin{bmatrix} i_{qs} \\ i_{ds} \\ i_{fd} \\ i_{kq} \\ i_{kd} \end{bmatrix}$$

$$[S] = \begin{bmatrix} 0 & -1 & 0 & 0 & 0 \\ 1 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix}$$

Equations in matrix form

$$p\Psi = \omega_b [R] \vec{i} + \omega_b [S] + \vec{v}$$

$$\vec{v} = \begin{bmatrix} v_{qs} \\ v_{ds} \\ v_{fd} \\ 0 \\ 0 \end{bmatrix}$$

You can use currents directly as state variables. The equations get more complicated, and the solution is slower, but you don't have to do the current conversion.

Solving the model equations:

- A similar treatment is used to obtain the transforms between flux linkages and currents in matrix form
- These equations may be made into a function that takes the V (input) and Ψ (state) vectors as inputs, and produces the derivatives of Ψ as outputs
- If voltage (V) vector is not known, it must be determined by iterative methods (if load is known, it may be incorporated into the model and V set to 0)
- The initial values are determined from steady-state conditions, by setting the derivative terms to zero and solving for state variables
- A numerical differential equation solver can be used to solve these equations (Matlab/Octave/Numpy)

Solving the model equations: Saturation

- Saturation of the magnetic circuit has a very significant effect on the behavior of the machine
- Basic models only consider D-axis saturation, by changing the value of the magnetizing reactance as a function of the excitation
- More elaborate models consider effect of D-axis saturation on the Q-axis reactance
- Different fitting functions are used for saturation curve
  - The best one is $\mathrm{E_i} = AV\left(1 + \alpha e^{\beta V}\right)$ where A is the slope of the air-gap line, α and β are fitting constants, and V is the terminal voltage

Solving the model equations: Saturation

- You will see requirements for NERC code names:

"The GENROU, GENSAL, GENTPF, and GENTPJ models represent round rotor and salient pole synchronous machines. The predominant difference between the GENROU/GENSAL and GENTPF/GENTPJ models is how they account for saturation.

• The GENSAL model uses simplifying approximations that significantly compromise treatment of magnetic saturation. The GENSAL model ignores saturation on the q-axis completely. In both the GENROU and GENSAL models, saturation is a single additive terms. The GENROE and GENSAE models use the same treatments of saturation as GENROU and GENSAL; the only difference is that they fit saturation with an exponential rather than quadratic curve.

• The GENTPJ and GENTPF models use approximations in their treatments of saturation, but are more accurate than GENSAL and GENROU. In these models, saturation is multiplicative on all inductance terms. GENROU and GENTPF do not fully recognize the effect of stator current on saturation.

• The GENTPJ1 model recognizes the effect of stator current on saturation by including an additional parameter, Kis, which appears in the saturation function as shown in [3] and [5]."

Solving the model equations

- Refer to IEEE Std 1110 and the NERC documents for more details on these models
- Different power system analysis packages have different requirements for entry of generator parameters. We aren't intimately familiar with any of them, so can't always advise as to the correct value to put in a particular field.
- Fortunately, many of the more obscure ones don't make a lot of difference to the response

Simulink simulation of model:

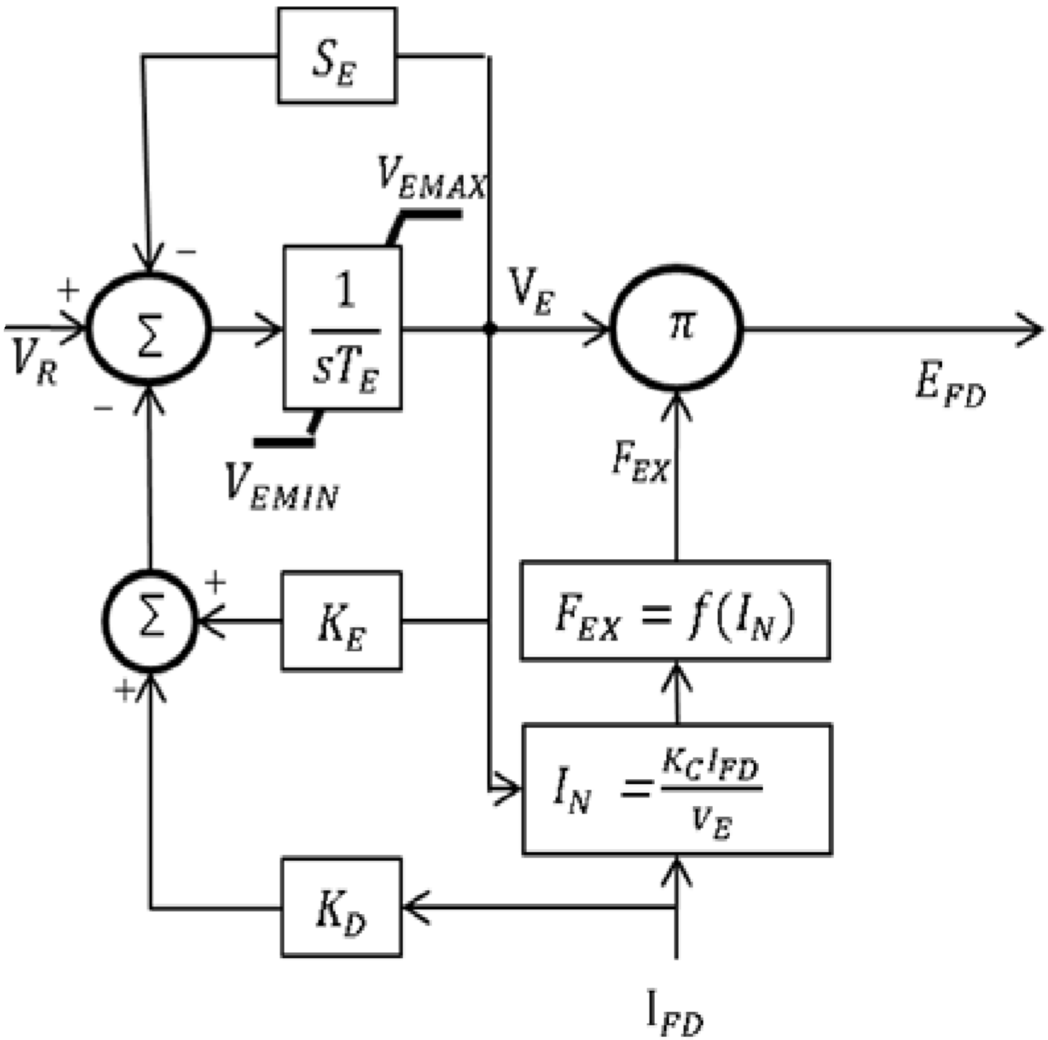
- Matlab/Simulink allows you to build a model by graphically connecting function blocks. Other software packages (Labview, Simula, Scilab) have similar capability).
- The software does the job of assembling the differential equations and solving them "behind the scenes" for you
- Simulink has an extension "Simscape" and further, "Simscape Electrical" that contain pre-assembled model blocks for synchronous and other electrical machine types. These also take care of the Park/Clarke transforms, loads, etc..

7. Excitation System Models, IEEE Std 421.x, and Exciter Response

Exciter AC8C Model

- The models of excitation systems defined in IEEE Std 421.5 (most recent 2016) are appropriate to different kinds of exciters and regulators. The AC8C (latest) model is becoming popular for PID regulators used with synchronous brushless exciters such as are normally used on Kato generators. It represents the exciter adequately for system modeling purposes.
- The exciter model is common to all the AC(N) models, so the following is applicable to any of these.
- The definition of exciter constants in the Standard is left to the manufacturer of the exciter. Unfortunately, no guidance is given for how to calculate those constants. Correspondence with the Working Group for this standard has yielded no further clues, so we are apparently on our own as regards the interpretation of the standard.

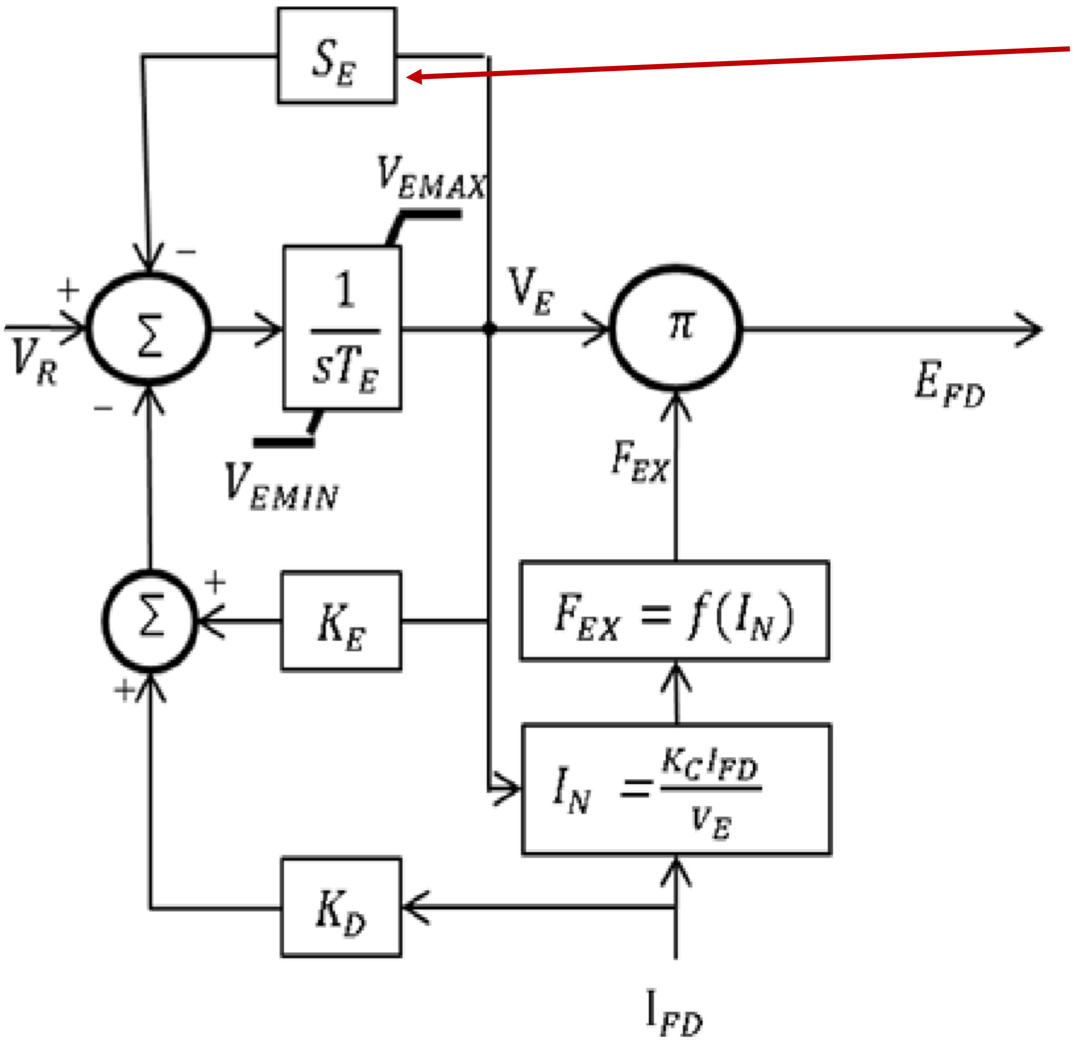
Exciter AC(N)(X) Model



Exciter model from the AC series of excitation system models, IEEE Std 421.5

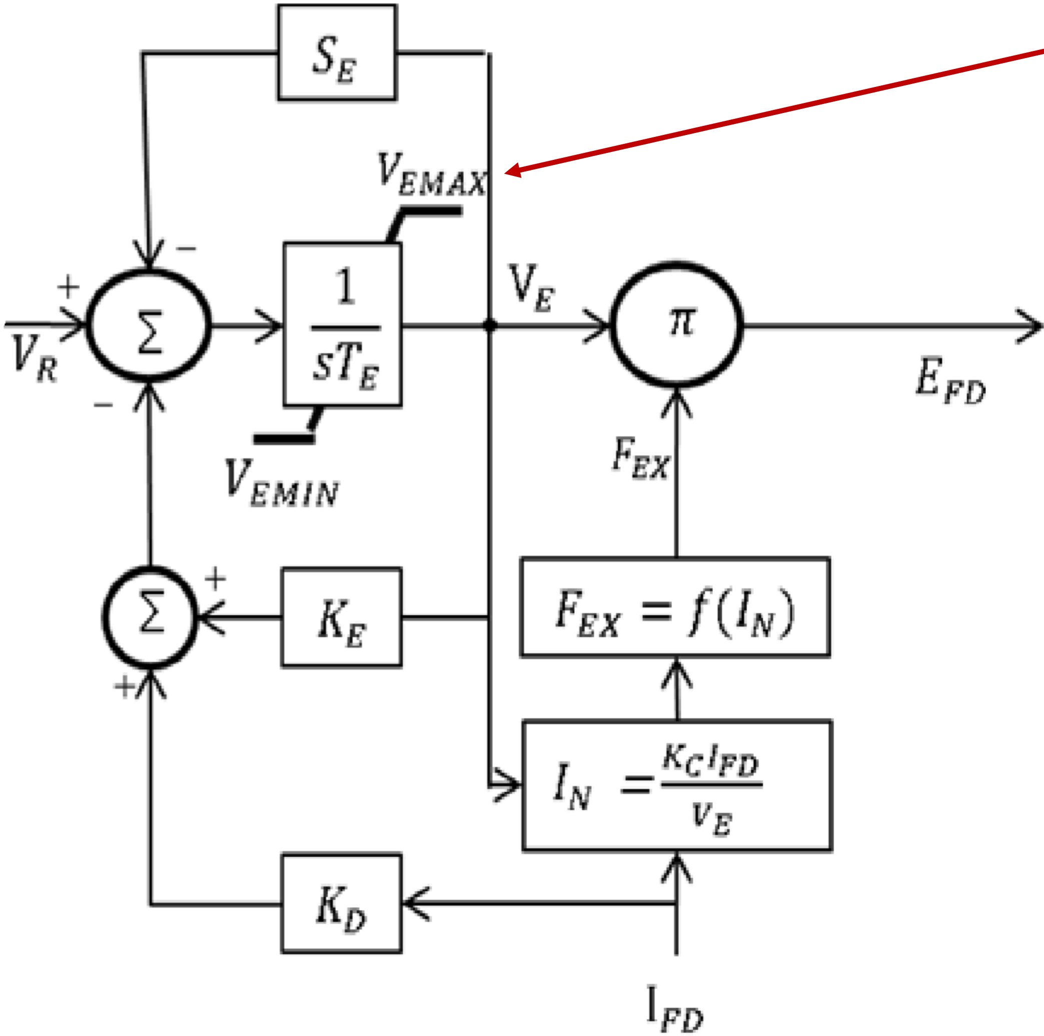
Vr is the regulator output voltage, Ifd is the main field current, Efd is the exciter output voltage to the main field (all in PU)

Exciter AC(N)(X) Model



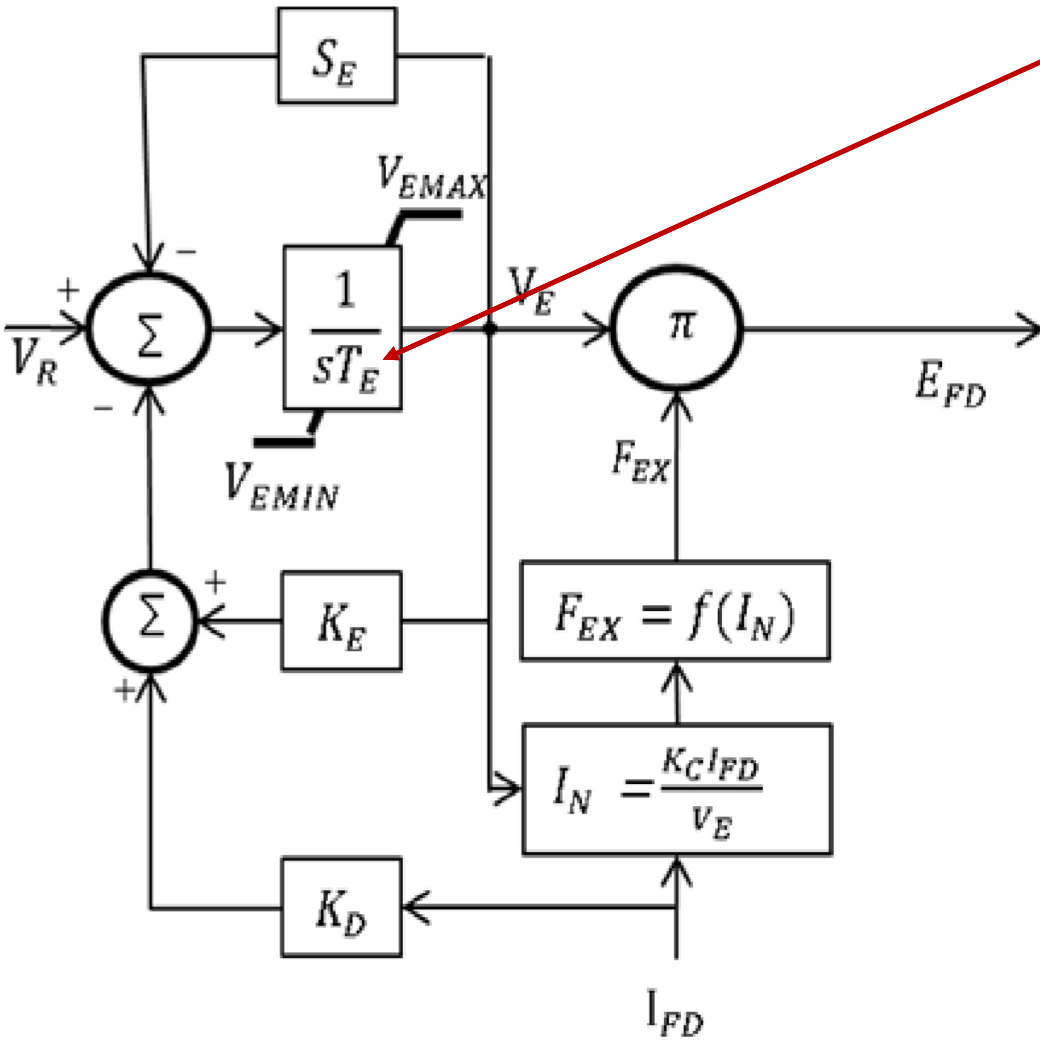
S_E is the exciter saturation function. We use an exponential function if it is needed, but most of our exciters have such low saturation under normal conditions, that it can be ignored (set to zero).

Exciter AC(N)(X) Model



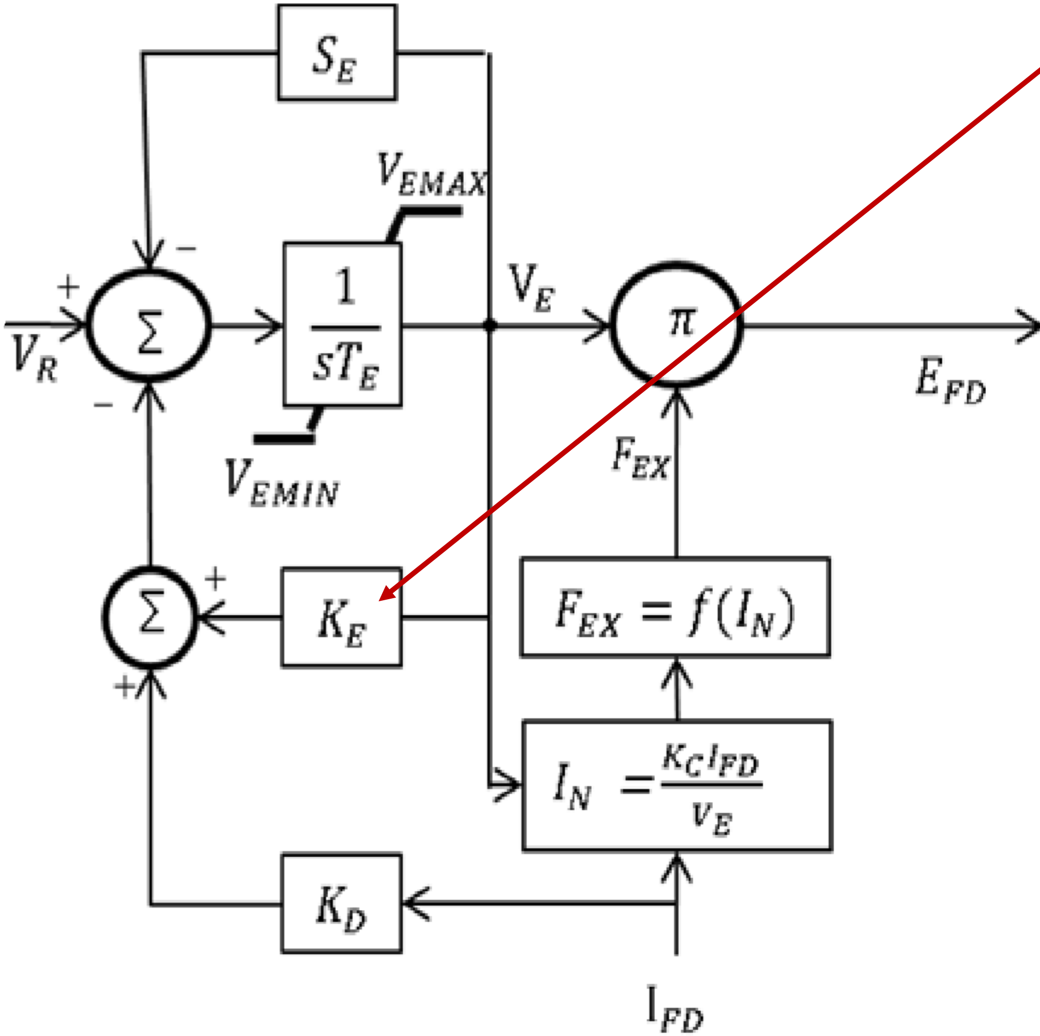
V_{EMAX} is the exciter voltage limit. This is already defined by the saturation function (if used), and anyway, the regulator usually saturates before the exciter, so this is usually set to a high value like 99.

Exciter AC(N)(X) Model



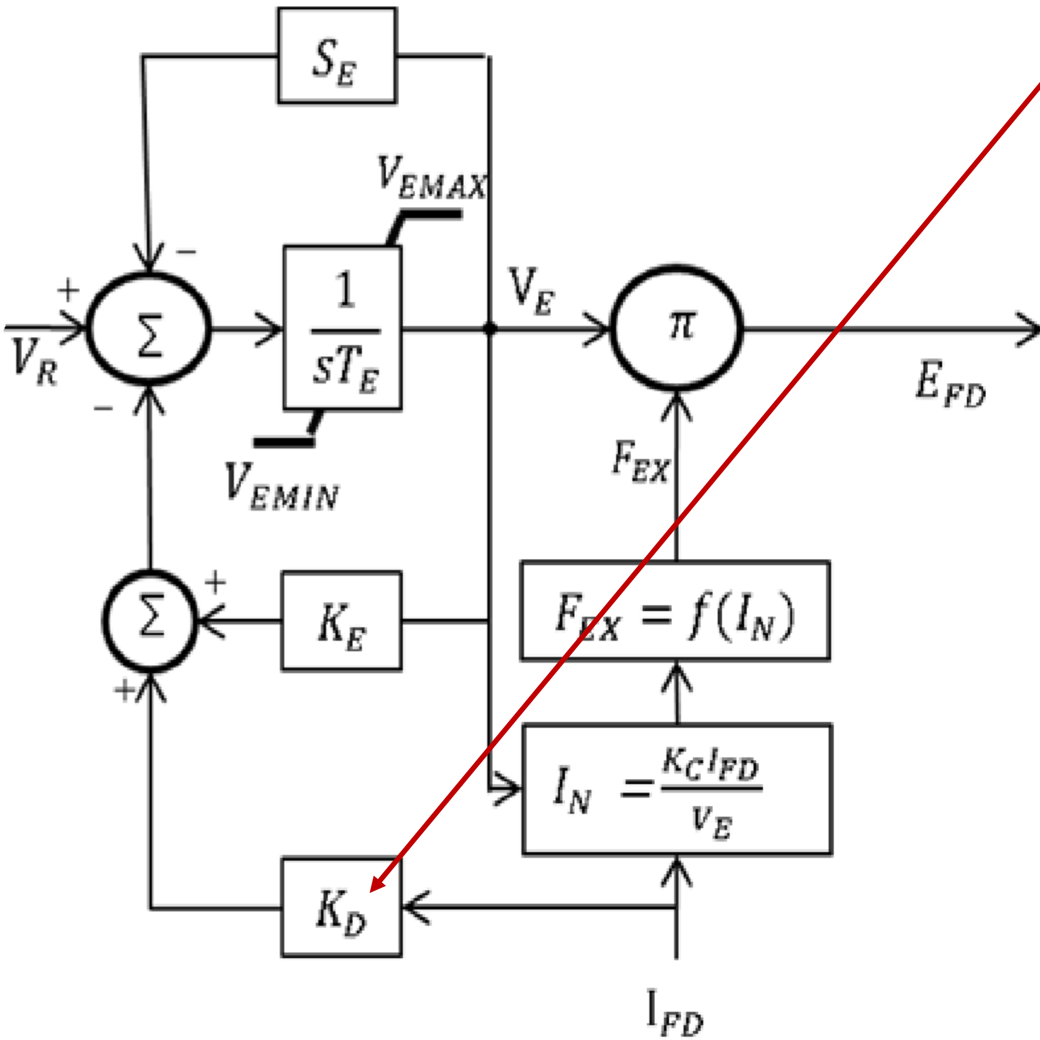
T_E is the exciter time constant. We use the open-circuit value, to be conservative. It is typically 0.1-0.5 seconds depending on the size of the exciter.

Exciter AC(N)(X) Model



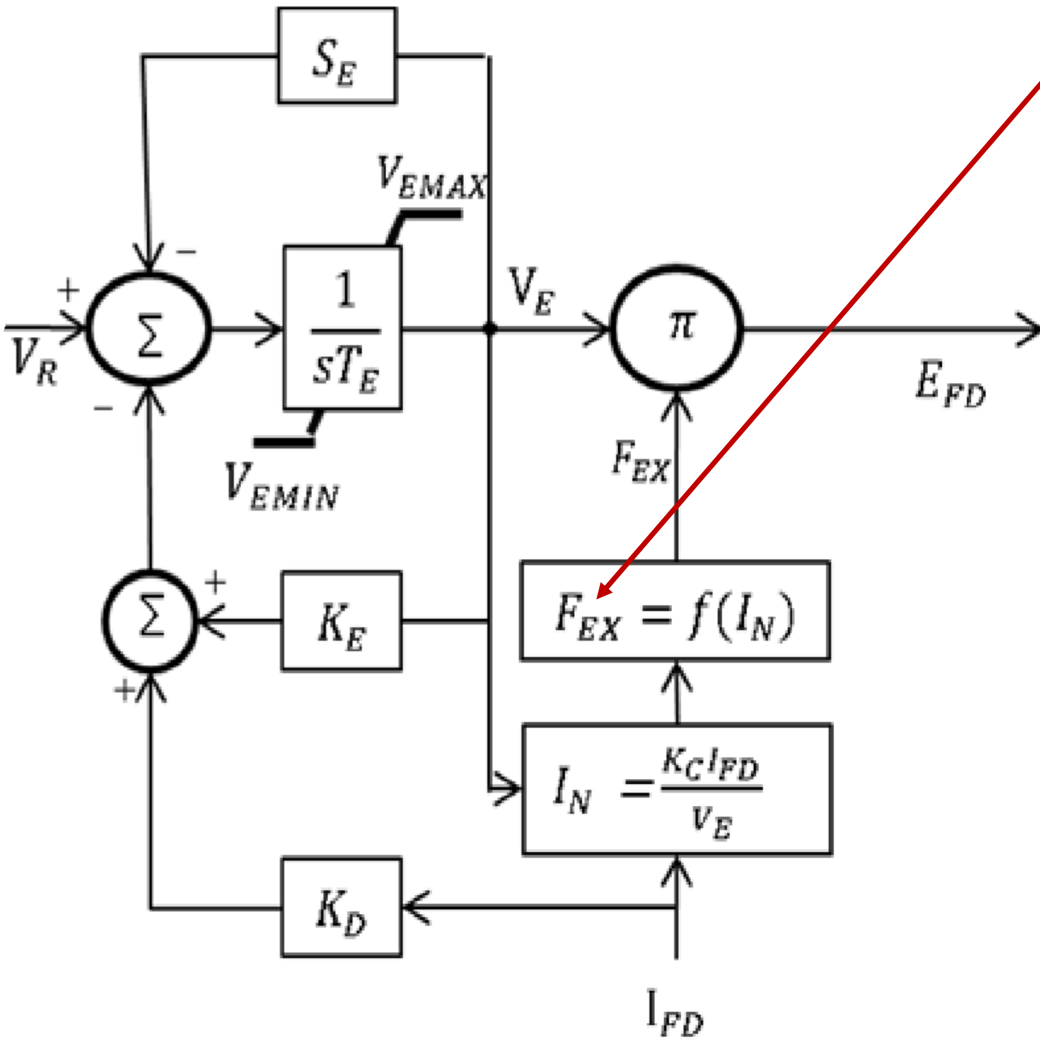
K_E is the exciter (feedback) gain constant.

Exciter AC(N)(X) Model



K_D is the exciter droop constant. This is a nonlinear term, but the model uses a linear approximation.

Exciter AC(N)(X) Model



F_{EX} is the rectifier commutation function. It is ~ constant for a given frequency and value of main field resistance. We don't use this function at the moment (we set K_C equal to 0.0), but we include the effect in the K_D constant.

Exciter AC(N)(X) Model Parameters

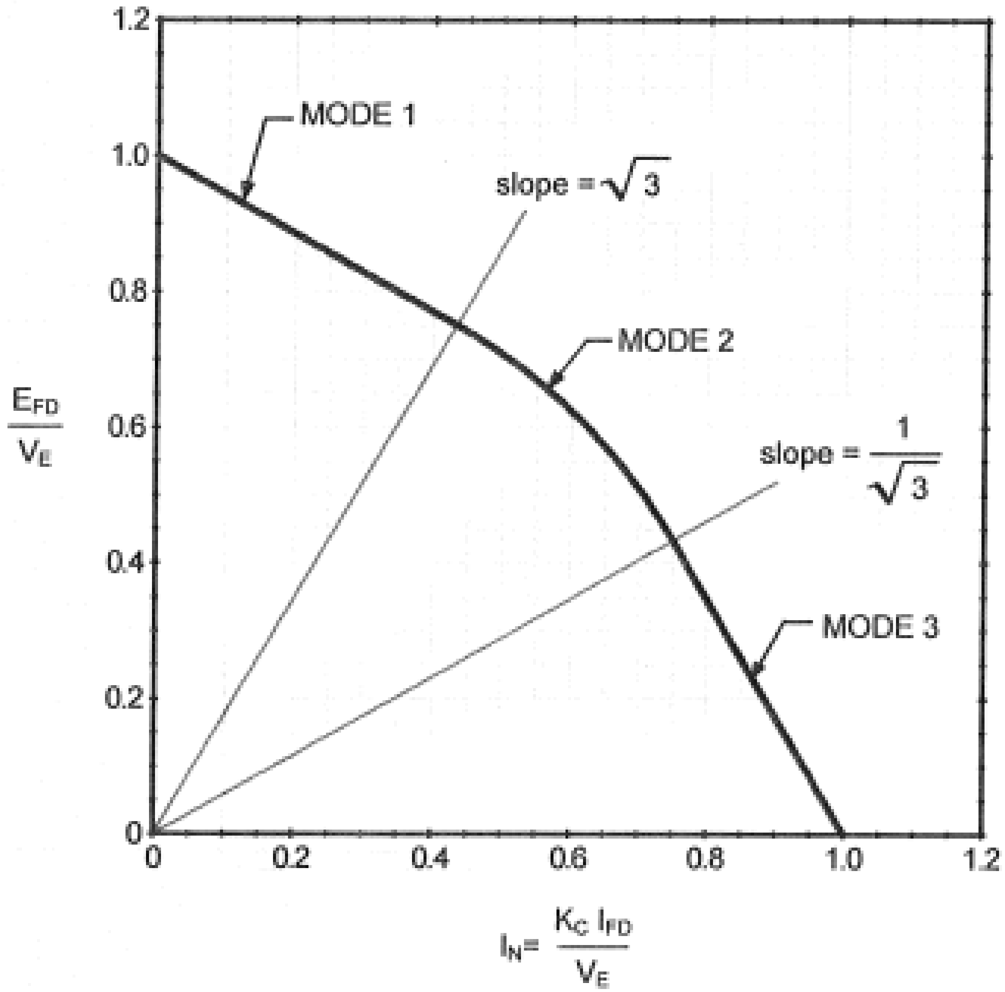


Figure D.1—Rectifier regulation characteristic

Three regions of operation, depending on X/R ratio

Most Kato exciters operate in or near MODE 1, where the effect can be (mostly) subsumed into K_D

Exciter AC(N)(X) Model Parameters

- Real rectifier function equations:

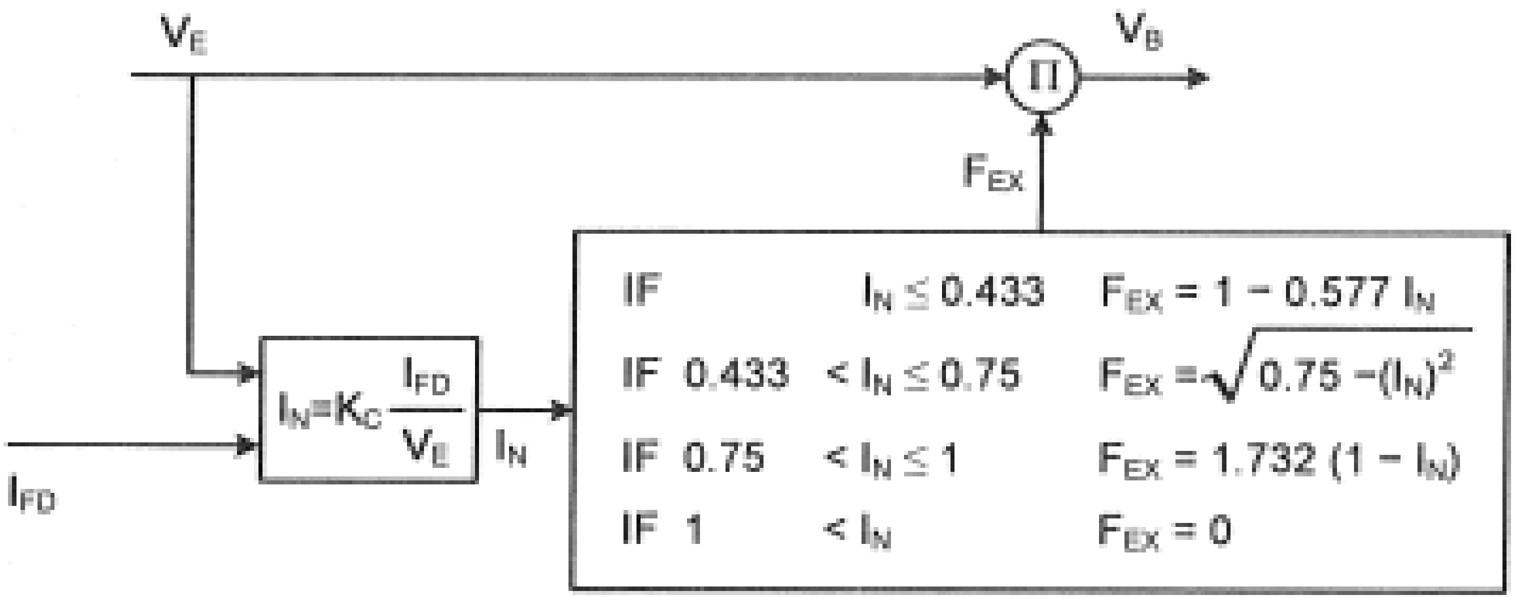
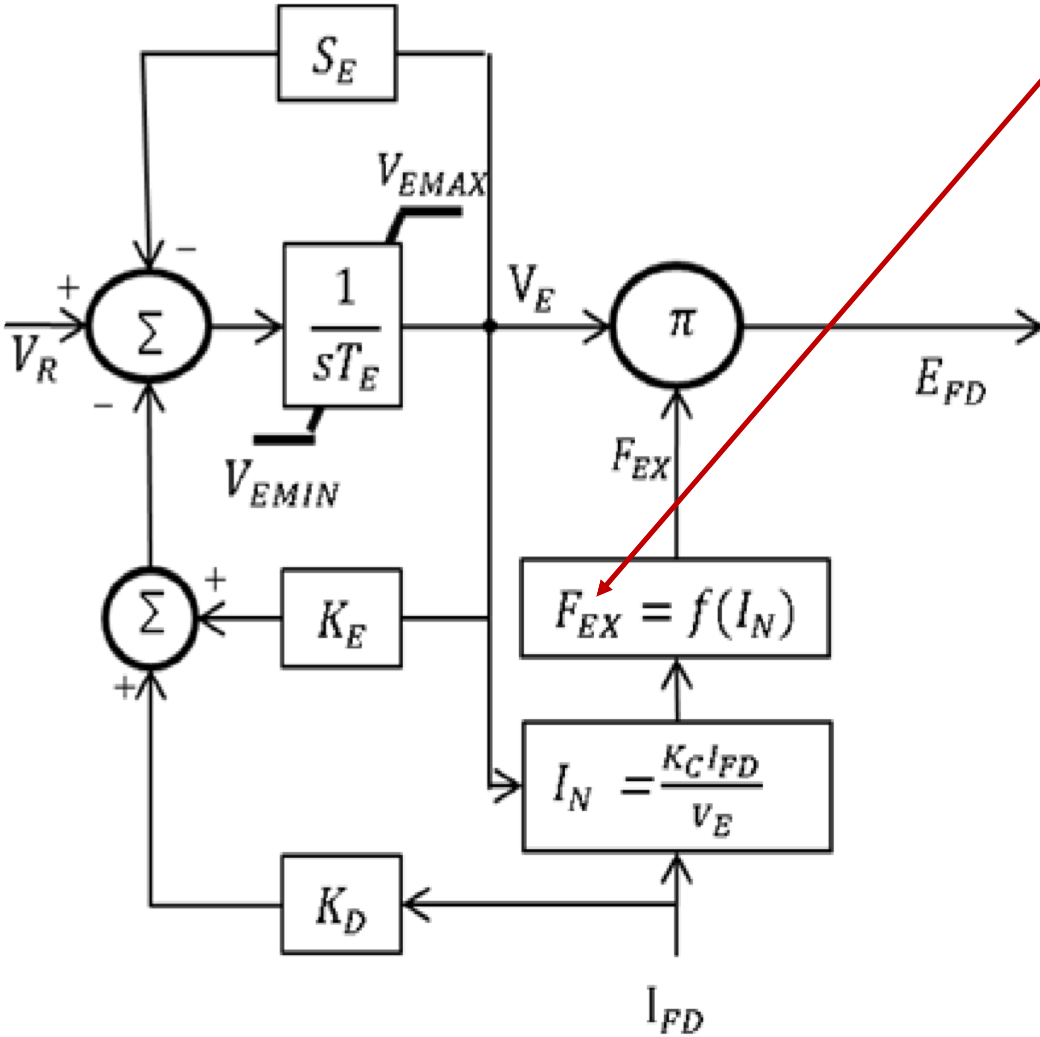


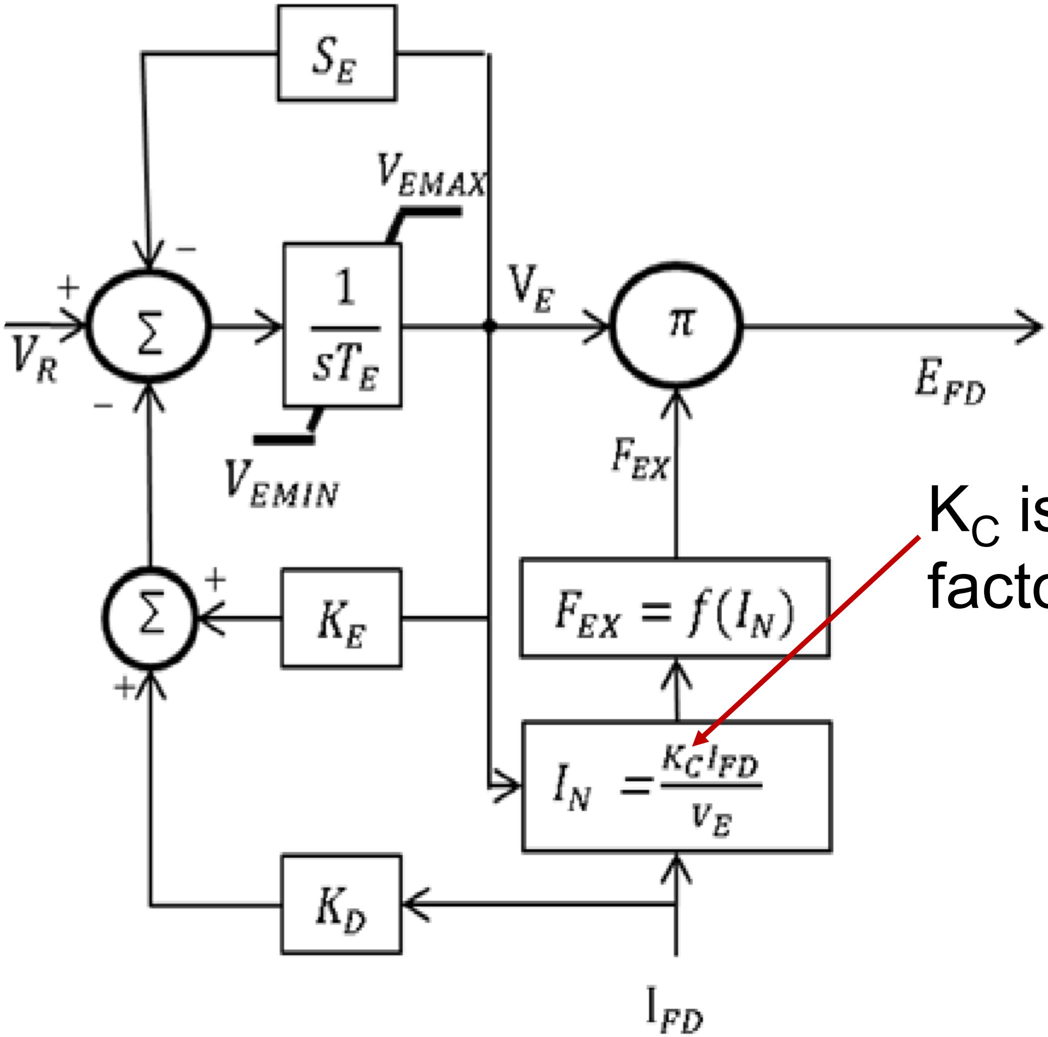
Figure D.2—Rectifier regulation equations (function F_{EX})

Exciter AC(N)(X) Model



For convenience I use Fex ~ $\left(\frac{1-I_N}{1-uI_N}\right)$, where u ~ 0.563 (fitted curve)

Exciter AC(N)(X) Model



K_C is the rectifier loading factor

Exciter AC(N)(X) Model Parameters

- The standard defines 1.0 PU *input* (V_R) *as* the input voltage required to produce 1.0 PU *output* on the *unloaded air gap line* of the exciter saturation curve.
  - *This means that under normal conditions, 1.0 PU input does not produce 1.0 PU output from the exciter!*
  - A per-unit conversion is needed to make this come out right.
  - This definition is equivalent to requiring the constant K_E to be equal to 1.0, assuming the value of S_E tends to zero at low values of excitation (which it should).
- S_E is the saturation function for the exciter (different programs use different saturation functions, and IEEE 421.5 doesn't prescribe a particular function)
- Best S_E formula we have found is $S_E = \alpha e^{\beta E_{FD}}$, which fits tested curves very well

Exciter AC(N)(X) Model Parameters

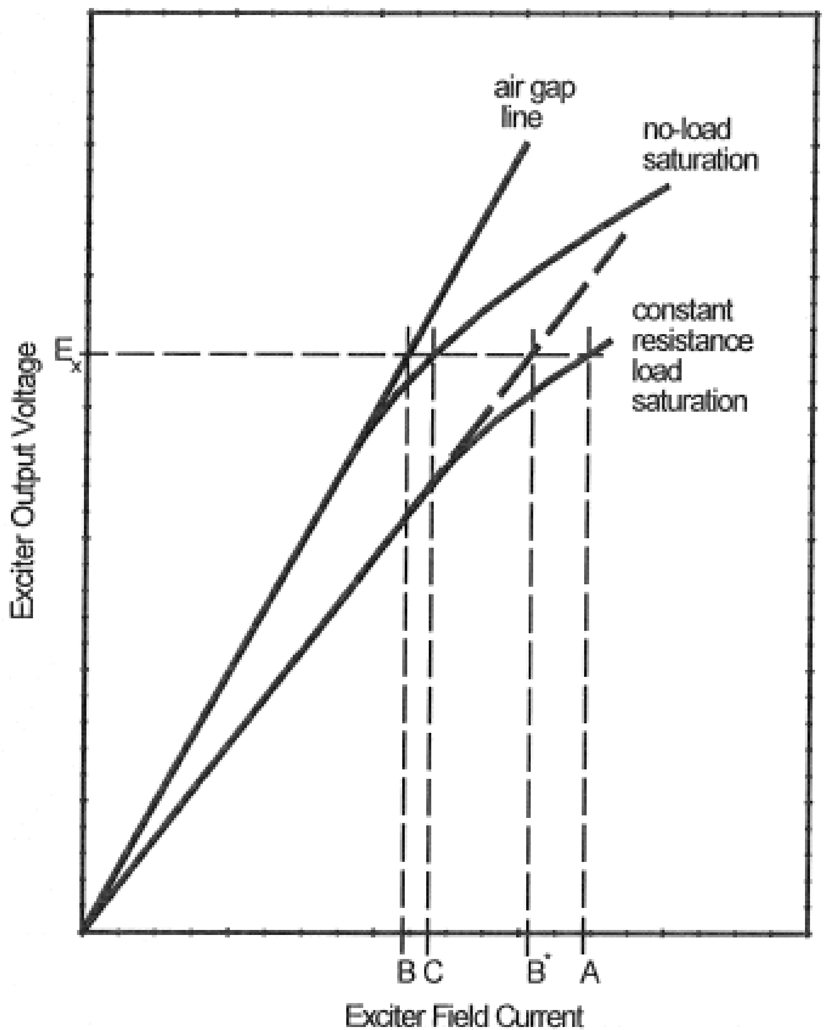


Figure C.2—Exciter saturation characteristics

$$S_E(V_E) = S_E(E_{FD}, I_{FD} = 0) = \frac{C - B}{B}$$

S_E represents the PU *increase* in exciter input voltage to produce a particular no-load output, above the value on the air gap line.

(from IEEE Std 421.5-2016)

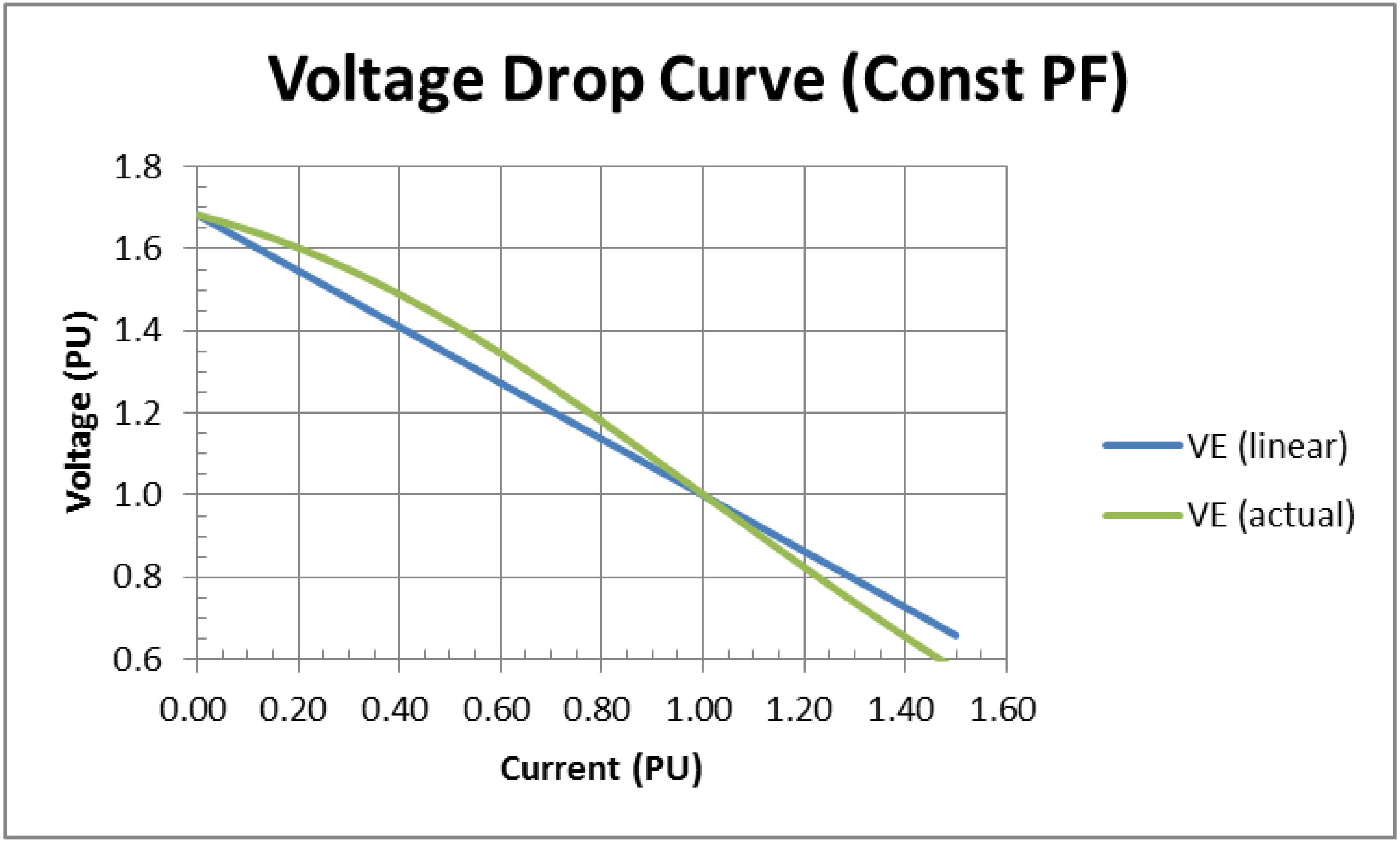
Shown as function of E_{FD}, it must be inverted numerically

If the exciter is not very saturated at the regulator ceiling voltage, S_E can be disregarded (set to zero)

Exciter AC(N)(X) Model

- Kd in the AC models appears as a linear term, whereas in the actual exciter it produces a curve depending on the effective field impedance and the effective displacement power factor of the rectifier (which are variable in the transient condition).
- We assume if we match the exciter performance when it is unloaded and fully-loaded the errors in-between won't matter much.
- Using K_C for part of the feedback will put some "bend" in the curve.

Exciter AC(N)(X) Model



Exciter AC(N)(X) Model

- We believe that normally the exciter constants should be calculated *hot* as this is the usual operating condition.

Exciter AC(N)(X) Model

- With ceiling voltage input, call output on *air gap line* = Eocu, and on unloaded saturation curve = Eoc. If they differ by more than (say) 5%, then the exciter is saturated at normal operating conditions and Kd and Ke calculations may have to consider saturation (this is a judgement call depending on how critical the requirement for accuracy of the model is).
- Calculations: From the exciter saturation curves, determine the exciter field current values for:
  - Ceiling voltage unloaded (in case the regulator is not known, use the standard values).
  - From the unloaded ceiling voltage, determine Se(max) *unloaded.*
  - From 75% of the unloaded ceiling, determine Se(0.75 max)

Exciter AC(N)(X) Model

- Calculations:
  - K_D may be calculated from steady-state saturation curves:
  - Since at steady-state the integrator gain is infinite, and its input will be zero,
  - $V_R - S_E V_E - K_E V_E - K_D I_{FD} = 0$ from the model diagram
  - $I_{FD} = E_{FD}$ at steady state, and F_{EX} is constant, so $I_{FD} = E_{FD} = V_E F_{EX}$ and $V_E = \frac{E_{FD}}{F_{EX}}$
  - $V_R - (S_E + K_E + K_D F_{EX})V_E = 0$ so $\frac{V_R}{V_E} = (S_E + K_E + K_D F_{EX})$
  - $\frac{V_R}{E_{FD}} = \frac{(S_E+K_E+K_D F_{EX})}{F_{EX}} = \frac{(1+K_D F_{EX})}{F_{EX}}$ if $S_E = 0$ and $K_E = 1$
  - $K_D = \frac{V_R}{E_{FD}} - \frac{1}{F_{EX}}$
  - $\frac{V_R}{E_{FD}}$ can be determined from points on the unsaturated part of the unloaded vs. loaded saturation curves

Exciter AC(N)(X) Model

- Calculations:
  - K_C and hence F_{EX} is a function of the X/R ratio of the exciter ($K_C \sim X_L/R_{LOAD}$), and $F_{EX}(SS) \sim e^{-0.504K_C}$ for reasonable values of K_C (<=1)
  - If result gives a negative value for K_D, you need to decrease K_C
  - T_E will be the exciter value of T'do during transients only when the exciter output current is close to zero, but will be somewhat lower otherwise. For conservative estimation of recovery time etc., we recommend using T'do for transient response calculations.

Exciter Response Ratio

- Exciter response ratio is a measure of how much output is available from the exciter after half a second under forcing conditions, compared to its normal output.
- Based on 1959 AIEE article by V.C. Strode. Now embodied in IEEE Std 421.2-2014.
- Meant as a metric for comparison of excitation systems.
- 0.5 second is a long time for a modern excitation system, except maybe for power-plant size machines.
- Can't really be calculated accurately without a full magnetic model of generator and exciter, including rotating rectifier.
- Measuring response ratio requires a fairly elaborate setup
- Some *useful approximations* can be made.

Exciter Response Ratio

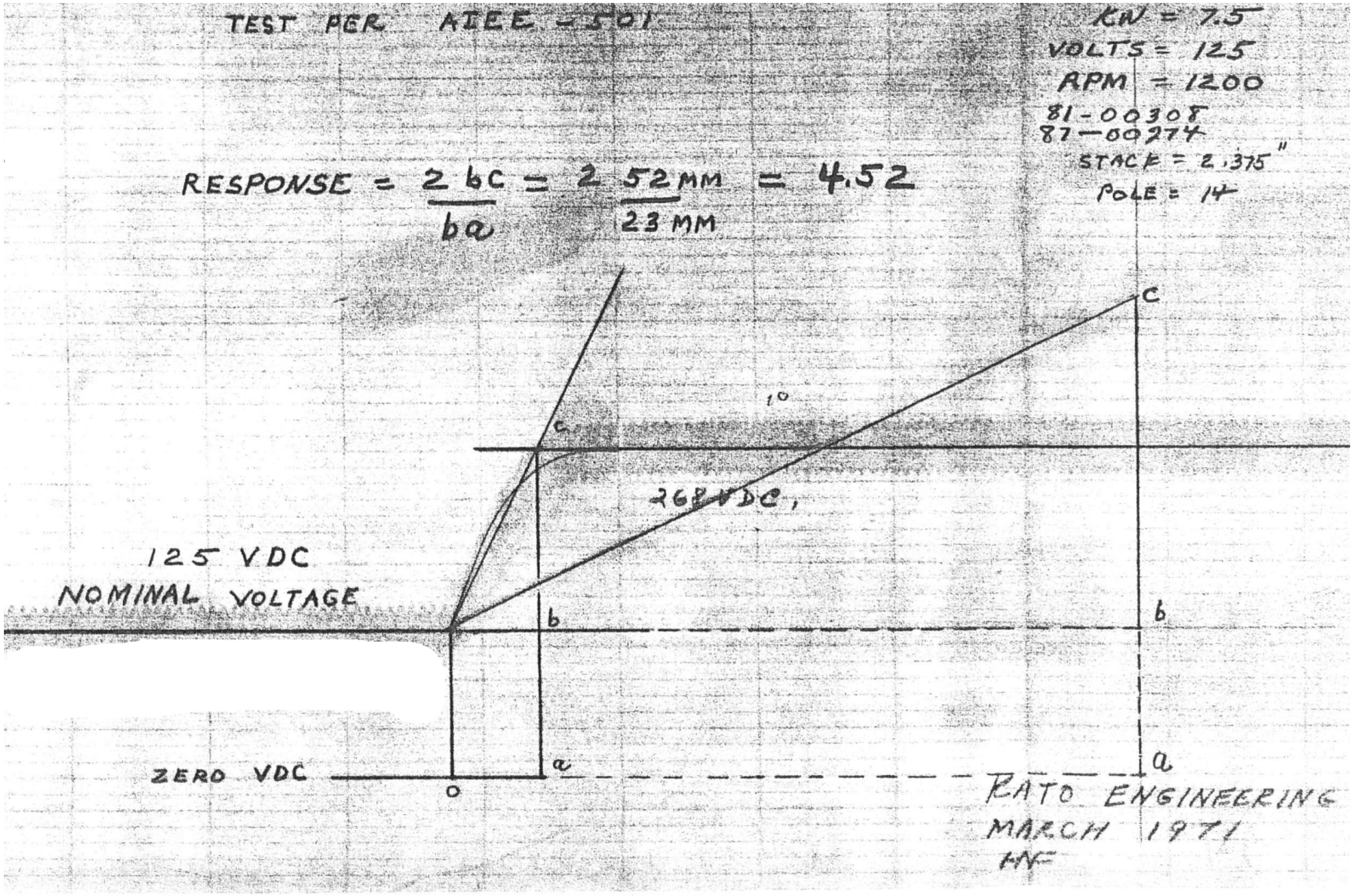
1. We assume that the exciter is not highly saturated. This is a good approximation for most Kato exciters, and is conservative if the exciter is saturated.
2. We assume that the generator field is purely resistive. This is definitely not the case, but that is the way the exciter is tested on its own, and the actual field inductance will result in higher response ratio, so it is conservative.
3. Absent any better value, we use the exciter T'do as the exciter time constant. The loaded time constant will be shorter so the response will be faster. This is also conservative.

Exciter Response Ratio

Nidec
All for dreams

- Procedure: operate the exciter (usually with resistive load) at its nominal full-load point, then suddenly increase the exciter field voltage to the regulator ceiling value.
- Take a recording of the exciter output voltage under these conditions, for at least half a second.
- Draw a straight line from the initial point such that the area under the line, between time = 0 and time = 0.5 second, is the same as the area under the exciter response curve (in the past this was generally an “eyeball” estimation). The value of voltage at the end point of the line, divided by the full-load starting voltage, less one, times 2, is the response ratio (second^{-1}).

Exciter Response Ratio

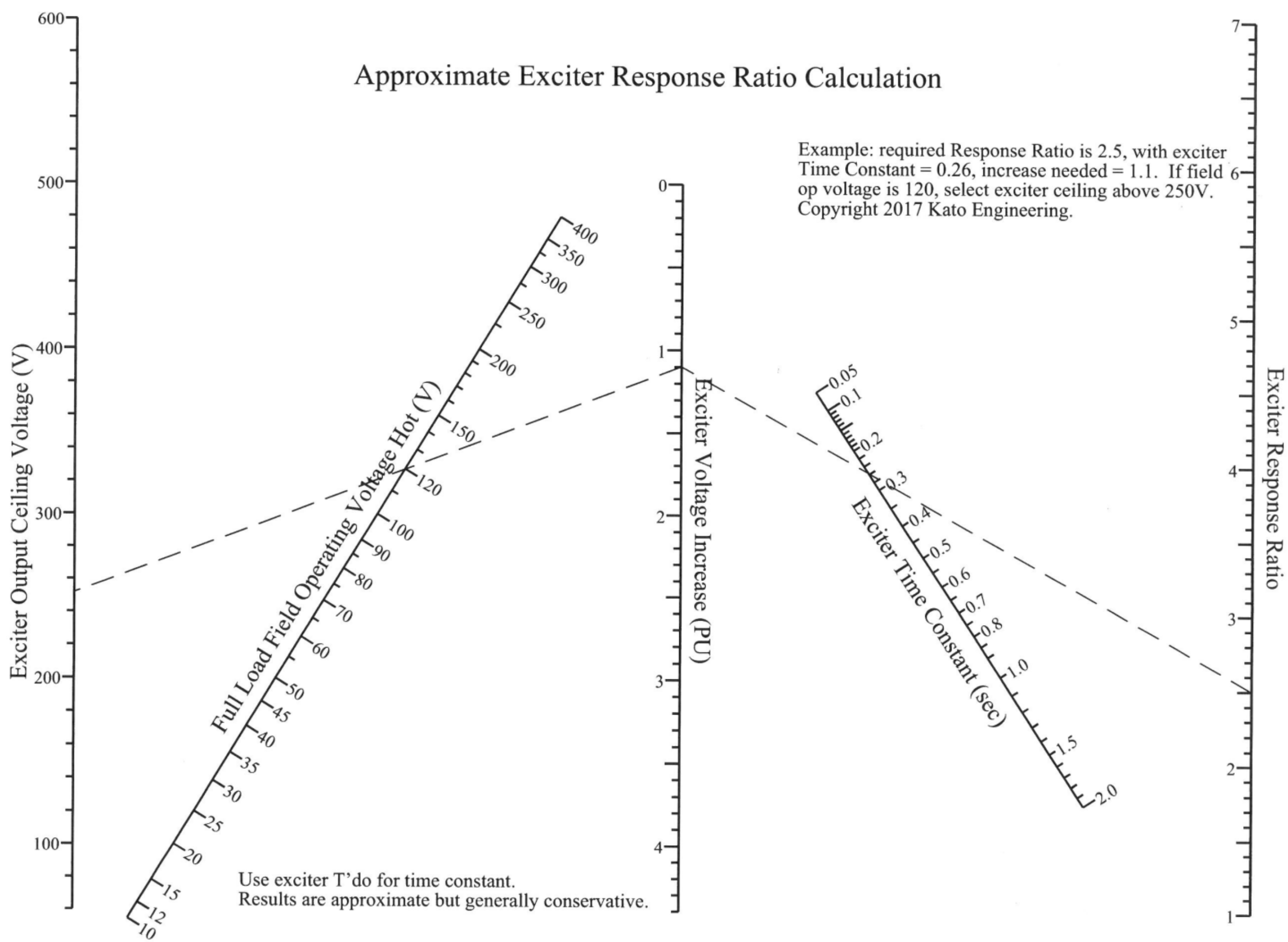


Typical Response Ratio Test

Exciter Response Ratio

- Nowadays we would do a numerical integration based on data acquisition output to determine the test result.
- Normally we do not perform this test (it requires slip rings and is expensive). We can get a good approximation of the result by calculation based on exciter data sheet. A spreadsheet can be used to perform this calculation.
- Alternatively, a nomograph is available to calculate response ratio.

Exciter Response Ratio



8. Synchronous Condensers (or Compensators)

Synchronous Condensers (Compensators)

- What is a synchronous condenser?
  - Nothing more or less than a synchronous motor or generator (NB: they are the same thing), when operated without a prime mover in order to deliver (or absorb) reactive “power” (volt-amperes)
  - May be optimized for low losses and zero power factor operation
  - Surplus generators are often pressed into service as synchronous condensers
  - Probably need some changes in protection and controls
  - Will need some kind of starting system

Synchronous Condensers (Compensators)

- Purpose of synchronous condensers
  - Distributed generation using inverters, which until recently have had difficulty supplying VARs (volt-amperes reactive) at the level required
  - Providing line “stiffness” for momentary overloads and fault support
  - Providing inertia, which is lacking in most distributed resources
  - Solid-state devices such as System VAR Controllers (SVCs) and Static Compensators (StatComs) can provide or sink VARs but do not provide inertia or fault current, and are often more expensive
  - Recent changes in “grid codes” mandate ability to supply *and absorb* VARs to stabilize the grid

Synchronous Condensers (Compensators)

- Starting methods (see also M-G sets)
  - Asynchronous starting, using cage or solid rotor to start as induction motor
    - Across-the-line or reduced-voltage start
    - Energize field at around 95% speed to pull machine into synchronism
  - Variable-frequency drive
    - Low starting current and fast starting time
    - Most expensive option, but drive sized for partial rating can be used
  - Pony-motor start
    - Low starting current, may run on auxiliary source
    - Drive sized for pony motor rating so can be economical

Synchronous Condensers (Compensators)

- Design and construction
  - Because the synchronous condenser is simply a generator, often a surplus machine repurposed from a power plant, the design process is very similar to a generator design. For a purpose-built condenser, there are opportunities for optimization. In particular, losses should be minimized, and ability to accept VARS may be useful.

Comparison of Synchronous Condenser with FACTS

Characteristic	Synchronous Condenser	Fixed Reactance	Static VAR Compensator	STATCOM
Cost	Moderate	Inexpensive	Moderate	Expensive
Speed	Moderate	Slow	Fast	Fast
Reliability	High	High	Moderate	Low-Moderate
Durability	High	Moderate	Moderate	Low
Longevity	Very high	High	Moderate	Low
Size	Large	Small	Moderate	Moderate
Inertia	Moderate (lg w/ flywheel)	None	None	None
Lagging Cap'y	Low	As required	High	High
Controllability	High	Low	High	High
Efficiency	Moderate	High	High	High

Questions?

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