Frequency control and Inertia in the future Nordic power system

Kjetil Uhlen
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Outline

• Background – motivation
• Some frequency control issues
• Modelling and analysis
  – Slow frequency variations (FCR and FRR)
  – Turbine and Governor responses (FCR)
  – Inertia
• Synthetic inertia -Laboratory demo.
• Possibilities with Advanced control?
• Concluding remarks
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Frequency is a global measure on (scheduled) power balance in an ac grid.
Trend: Frequency deviations in the Nordic synchronous zone

Minutes outside the frequency band 49,9 – 50,1 Hz

Source: Statnett
Frequency «fluctuations» with period 60-90 sec.
Frequency «fluctuations» with period 60-90 sec.
The future challenge:
- More variability, more extremes..
More Wind power and variable RES:
-Possible shut-down of Nuclear plants
More interconnectors: Norwegian hydro as the European energy battery – potential and challenges
Main challenges

- Increased number of interconnections
- Higher demand for balancing services
- Higher ramp rates
- Uncertainty about available reserves (FCR and FRR)
- Lack of inertia in periods with high import and high wind
- Uncertainty about the actual response and capability of hydro plants
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Tasks and time-scales in operation (in keeping the balance)

Increasingly market based

- Long term markets and contracts
- Day-ahead markets

- Intra-day markets
- Real-time balancing markets (tertiary control)
- AGC (secondary control)

- Primary frequency control
- Inertia

Degree of automation

-sec. - min. - hour - day - year
ENTSO-E definitions

Network Code on Load-Frequency Control and Reserves (28 June 2013):

- **Frequency Containment Reserves (FCR)**
  - shall aim at containing the System Frequency deviation after an incident within a pre-defined range.

- **Frequency Restoration Reserves (FRR)**
  - means the Active Power Reserves activated to restore System Frequency to the Nominal Frequency and for Synchronous Area consisting of more than one LFC Area power balance to the scheduled value.

- **Replacement Reserves (RR)**
  - means the reserves used to restore/support the required level of FRR to be prepared for additional system imbalances. This category includes operating reserves with activation time from “Time to Restore Frequency” up to hours;
System frequency response

Frequency [Hz]

Reserves activated [MW]

Inertia – Rate of change of frequency

Frequency «nadir»

Primary (FCR)  Secondary (FRR)  Tertiary (RR)

$\Delta f$  $\Delta P$

“$R$” = System frequency response $= \frac{\Delta P}{\Delta f}$ [MW/Hz]
Frequency transient in Nordic system
(caused by trip of large power plant)

$\Delta f = 0.5 \text{ Hz}$

$\Delta t = 8 \text{ sec}$

$\Delta t = 30 \text{ sec}$
Expanded view..
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Simplified model of the Nordic power system (23 gen.)
Model tuning...

### Table

<table>
<thead>
<tr>
<th>HYGOV</th>
<th>Initial Case (blue)</th>
<th>Case N (red)</th>
<th>Best Fit Case (to 11.06.2011) (green)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permanent droop, $R_p$, Norway</td>
<td>0.06</td>
<td>0.08</td>
<td>0.08</td>
</tr>
<tr>
<td>Permanent droop, $R_p$, Sweden</td>
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<td>0.1</td>
<td>0.1</td>
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<tr>
<td>Transient droop, $R_t$</td>
<td>0.4</td>
<td>0.6</td>
<td>1.35</td>
</tr>
<tr>
<td>Governor time constant, $T_r$</td>
<td>5</td>
<td>3</td>
<td>2.6</td>
</tr>
</tbody>
</table>
Simulation result:

- Applying random load variations
- Looking at impact of governor tuning
Hydraulic system and turbine models
“Classical model”

Simple linearized model

\[ T_m = \frac{1 - T_w s}{1 + \frac{1}{2} T_w s} g \]
Hydraulic system and turbine models
“IEEE model with surge tank”
Comparison of the turbine models

Magnitude response

Phase response

Classical model
IEEE model
Comparison of the turbine models

Dynamic response to loss of production

Classical
IEEE
Comparison of the turbine models (eigenvalues)

<table>
<thead>
<tr>
<th>Number</th>
<th>Eigenvalue [1/s], [Hz])</th>
<th>Damping ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Classical; 1</td>
<td>-0.446730 j0.029693</td>
<td>0.9978</td>
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<tr>
<td>Classical; 2</td>
<td>-0.025646 j0.006039</td>
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<tr>
<td>IEEE; 1</td>
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<tr>
<td>IEEE; 3</td>
<td>-0.002898 j0.010318</td>
<td>0.2704</td>
</tr>
</tbody>
</table>
“Classical” hydro governor model

\[
\Delta P_L = \frac{1}{R_p}
\]
PID-type governor

\[ \omega_{\text{ref}} \rightarrow \Sigma \rightarrow \Sigma \rightarrow \text{KP} \rightarrow \text{KI} \rightarrow \Sigma \rightarrow \text{KD} \rightarrow \text{Pilot servo} \rightarrow \text{Gate servo} \rightarrow \text{Gate} \]

\[ \omega_r \rightarrow + \rightarrow \Delta \omega \rightarrow + \rightarrow \Sigma \rightarrow + \rightarrow \Sigma \rightarrow + \rightarrow \omega_{\text{ref}} \rightarrow - \rightarrow \omega_r \rightarrow - \rightarrow \Sigma \rightarrow - \rightarrow \Sigma \rightarrow - \rightarrow \text{ KP } \rightarrow \text{ KI } \rightarrow \text{ KD } \rightarrow \text{ Pilot servo } \rightarrow \text{ Gate servo } \rightarrow \text{ Gate } \]
Comparison of governors

**Magnitude response**

**Phase response**

- **Frequency [Hz]**
- **Gate/Speed [dB]**
- **Gate/Speed [Degrees]**

- **Kundur**
- **PID**
Impact of *low inertia* and *syntetic inertia* in the Nordic power system

Silje Mork Hamre
Kjetil Uhlen
Event and scenarios:

Event simulated:
- Sudden outage of nuclear plant in Sweden. Loss of approx. 1100 MW

3 scenarios:
1. Reference scenario 05.03.2015
   - Measured verses simulated response in frequency
2. Low load summer scenario with unchanged governor settings
   - Compared to reference scenario
3. Low load, high wind and high import future scenario:
   - With and without synthetic inertia from wind plants
1. Reference scenario (model tuning)

\[
R = \frac{1100}{0.13} = 8500 \text{ MW/Hz}
\]
2. Low load scenario versus reference

Scenario 1 vs. Scenario 2

Scenario 1 - Nordic44 response
Scenario 2 - Low load summer day - 23.06.2013
Unchanged droop settings

\[ R = \frac{1100}{0.43} = 2600 \text{ MW}/\text{Hz} \]

Need to avoid UFLS..
3. High import and high wind with and without synthetic inertia
3. Response from wind plants

Response from wind turbine SE3

- Scenario 3 - 2020 - High import - 20% wind
- Scenario 3 - 2020 - High import - 20% wind with synthetic inertia, $K_{wi}=10$
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Providing inertial response from VSC-HVDC connected wind farms

Laboratory scale implementation and demonstration

Hanne Støylen - Atle Rygg Årdal – Kjetil Uhlen

Norwegian University of Science and Technology
Department of Electrical Engineering
Department of Engineering Cybernetics
Frequency transient in Nordic countries
(caused by trip of large power plant)

$\Delta f = 0.5\, \text{Hz}$

$\Delta t = 8\, \text{sec}$

$\Delta t = 30\, \text{sec}$
1. Drop in onshore grid frequency $f_{\text{grid}}$
2. $VSC_{\text{grid}}$ reduces $V_{dc}$ in proportion to $df_{\text{grid}}/dt$
3. $VSC_{\text{owf}}$ reduces $f_{\text{owf}}$ in proportion to $\Delta V_{dc}$
4. Turbines provide inertial response to offshore AC-grid

Main challenges: *Dynamic response, choice of parameter values, signal processing delays*
Laboratory implementation overview
Laboratory implementation overview

- Rating of units: $\approx 50$ kVA
- Converter control: Custom built FPGA + LabVIEW
Benchmark scenario

- Sudden connection of large load ≈ 0.25 p.u.

- Synchronous generator seeks to restore power balance
  - **BUT**: Governor response is slow and inertia is low

- Impact of wind farm frequency support is investigated ->
Results(1): Choice of parameter values

- Significant improvement in frequency low-point (nadir), also shifted in time

- System becomes oscillatory for larger inertia support gains

- NB: Time-delay of ≈ 400 ms. before support reaches weak grid
  - Frequency measurement processing
  - $VSC_{\text{grid}}$ control response time
  - $VSC_{\text{WF}}$ control response time
  - DC grid dynamics

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### Wind farm equivalent

- $IM$ (Inertia Machine)
- $IG$ (Inertial Generator)

### Weak grid equivalent

- $SG$ (Synchronous Generator)
- $IM$ (Inertia Machine)

**Weak grid frequency $\Delta f_{\text{grid}}$ [Hz]**

![Graph showing frequency changes with increasing inertia support]
Conclusions

• Successful laboratory-scale implementation of inertial support from VSC-connected offshore wind farm

• Challenging control system design due to:
  – Two stages of frequency conversion
  – Multiple dynamic responses and possible interactions
  – Requirement of fast and accurate measurements

• Present work: Extending laboratory model to include turbine frequency converter
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MPC for Frequency Control

- Model predictive control (MPC) for FRR control
  - Applies model of system to predict future behavior.
  - Optimizes governor setpoints at each time step with respect to an objective function.
- Use larger model for «real world» and simplified model in MPC.
- MPC decides total change in governors setpoints as well as participation factors for each generator.
- MPC takes into account limitations on
  - Generation capacity.
  - Generation rate of change.
  - Power transfer capacity on transmission lines.
Anne Mai Ersdal, Lars Imsland and Kjetil Uhlen
«Model Predictive Load-Frequency, Control»
IEEE TRANSACTIONS ON POWER SYSTEMS (available IEEE Explore)
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Concluding remarks

• Renewed interest in frequency control
• Uncertainties about the performance of hydro turbine/governors
• New requirements for frequency control performance are coming..
  – Inertia, FCR, FRR,..
  – New market design..
Thank you!
ENTSO-E definitions

Network Code on Load-Frequency Control and Reserves (28 June 2013):

- **Frequency Containment Process (FCP)**
  - means a process that aims at stabilizing the System Frequency by compensating imbalances by means of appropriate reserves;
  - 1. The control target of FCP is to stabilize the System Frequency by activation of FCR.
  - 2. The overall characteristic for FCR activation in a Synchronous Area shall reflect a *monotonically decrease of the FCR activation as a function of the Frequency Deviation.* (frequency droop)

- **FCP → Primary control**