SOVN – ny markedssimulator

Stokastisk
Optimaliseringsmodell for Norden med individuelle
Vannverdier og
Nettrestriksjoner

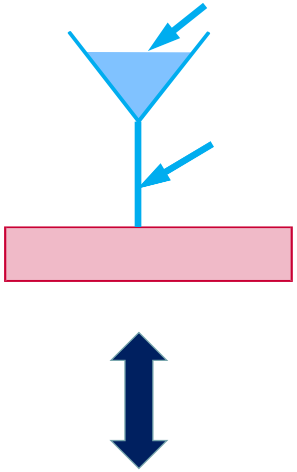
The aim is to develop a computer program suitable for simulating the Northern European power supply market using individual water values in Scandinavia and power flow constraints.

Market Model Challenges

Current models (EMPS and others):

Simplifies the problem by heuristics

- Use *aggregate* hydropower representations when establishing a strategy (water values)
- Use *detailed* hydropower representations when simulating the system

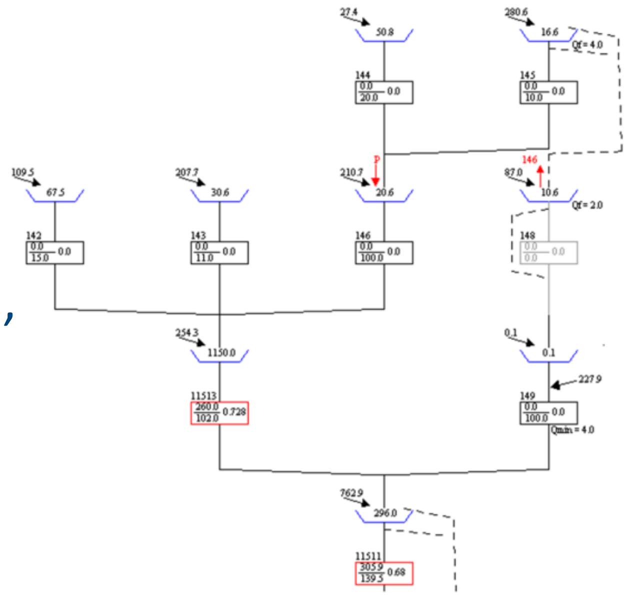


Increasing volatility in hydropower production patterns

→ Hydro constraints become more binding

→ Harder to establish precise approximations of the aggregate system

→ Harder to provide robust and consistent decision aid, e.g. in investment decisions



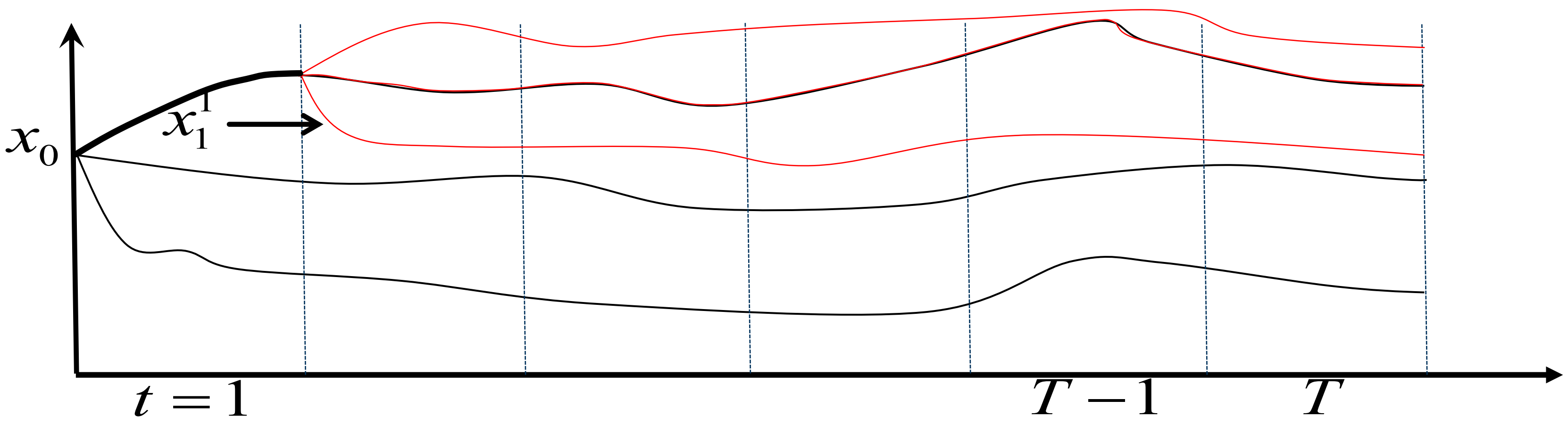
Model users: "Aggregate models not precise enough"

Objective and challenges

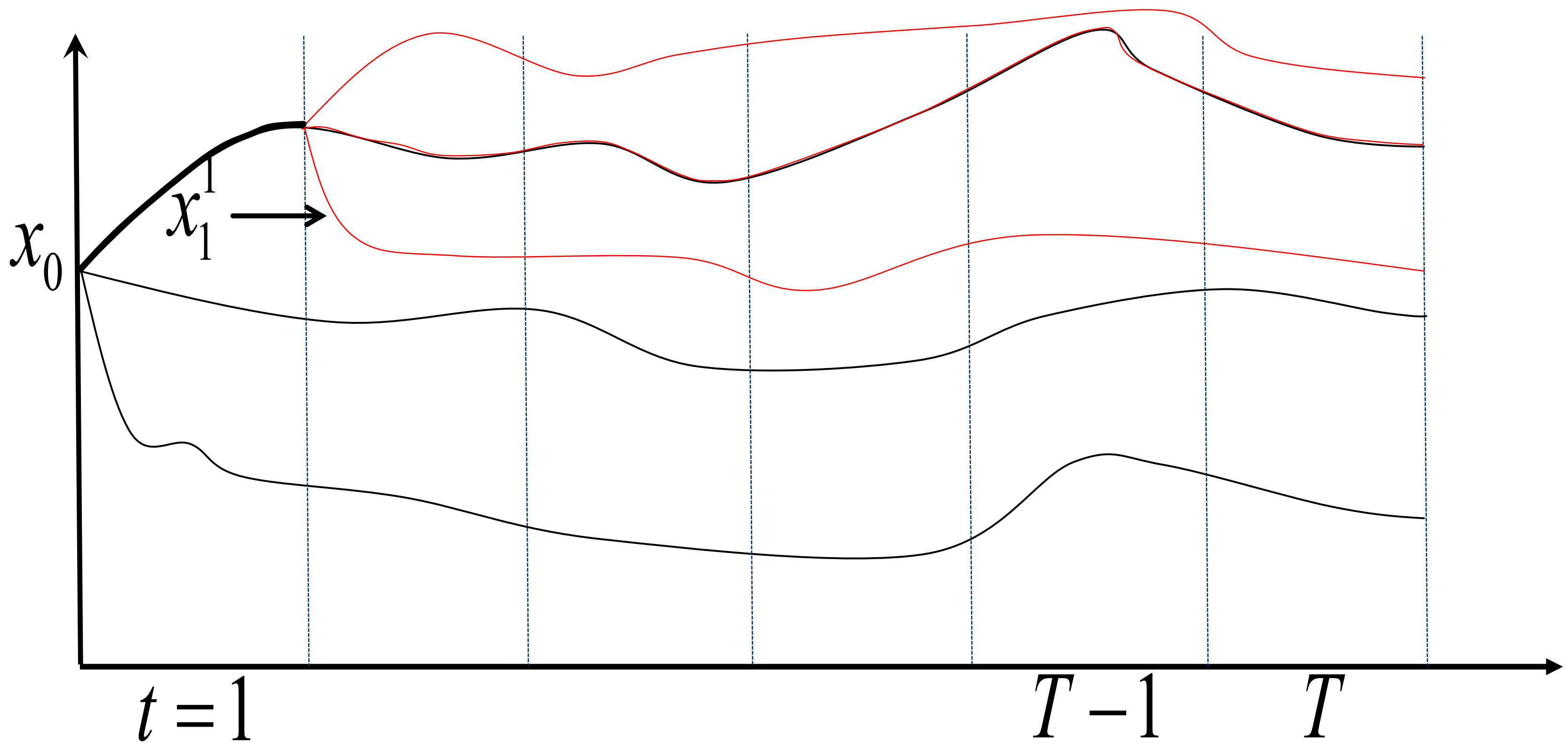
- Fundamental based market model including all relevant physical constraints (demand transmission and production)
  - Stochastic dynamic optimization formulation
  - Perfect market assumption
- Challenges problem size:
  - About 1000-1500 states (reservoirs)
  - Typically 100 -200 different stochastic inputs
    - Inflows to reservoirs
    - Temperatures
    - Wind and solar power production
    - Exogenous prices
  - Multiperiod planning problem (3-5 years ahead , down to hourly resolution)
  - Statistical properties in time and space is important, especially for inflows (simulation using weather years)

Simulator Scheme

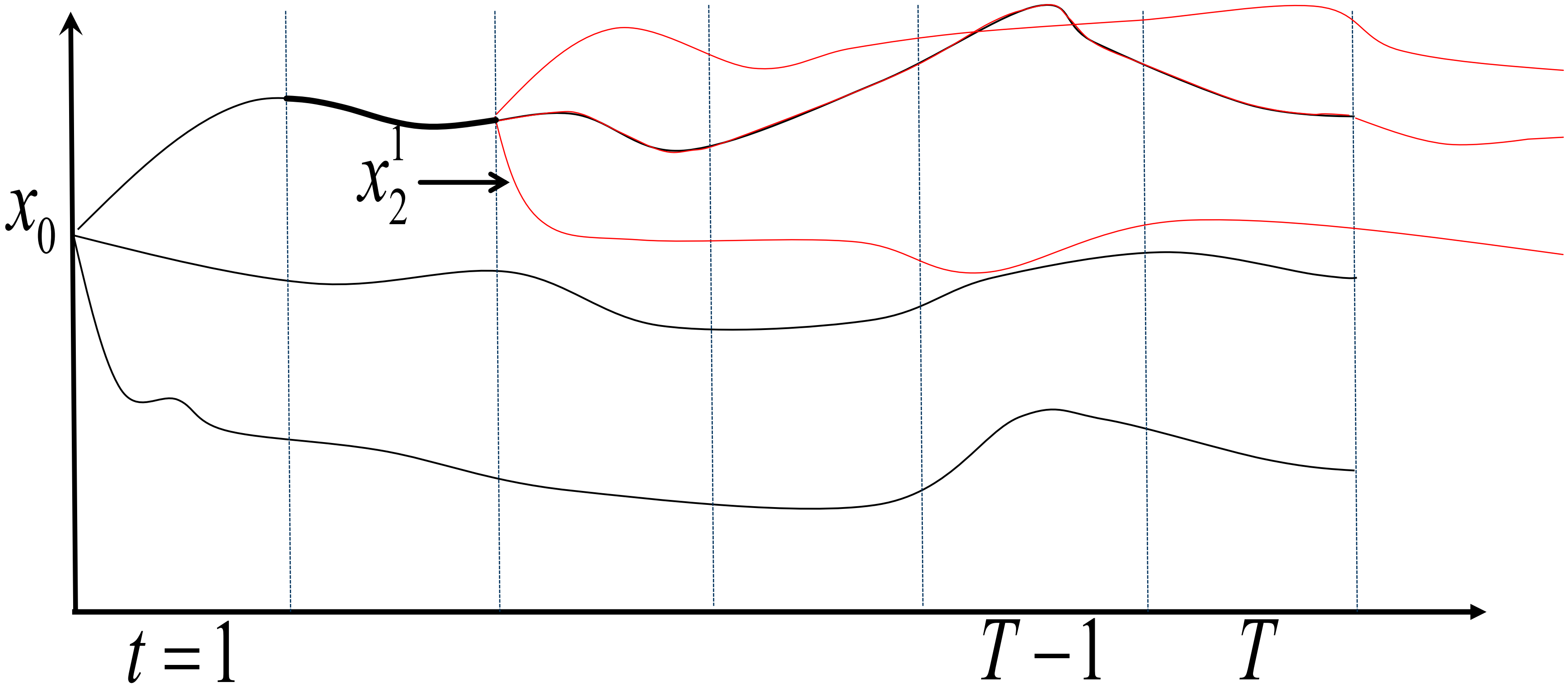
- Simulation along observed *weather scenarios* by solving a sequence of stochastic optimization problems
  - Two-stage stochastic problems
  - Inflows known in the first-stage (week)
  - All uncertainty is resolved in the second stage
  - First-stage decision is implemented and state variables are updated
  - Rolling horizon, fixed problem size



Simulator Scheme

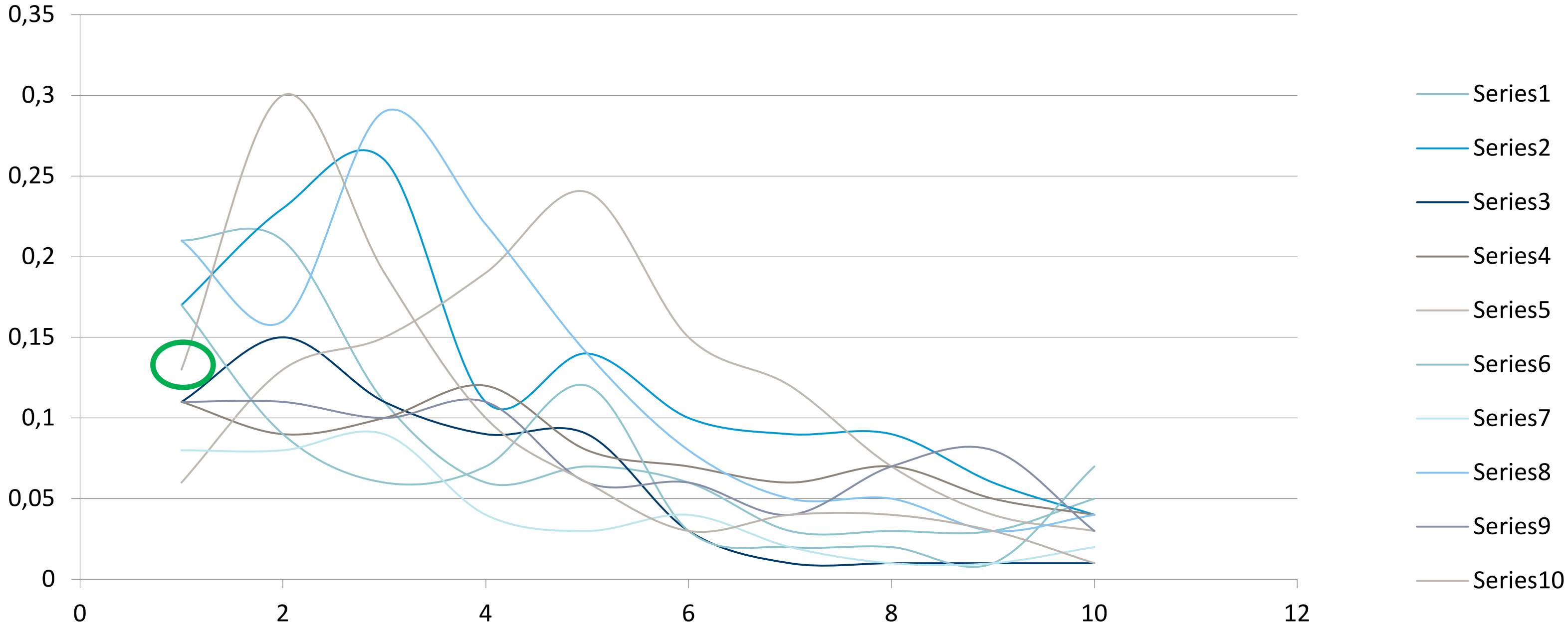


Simulator Scheme



Representation of uncertainties (inflow, wind, prices, etc)

- Historical inflow (wind and exogenous prices)
  for simulated scenario in week 1
- Smooth transition to historical inflow for scenario in scenariofan
  - 1. order auto regressive model using normalized logtransformed data
  - Estimates deviation for scenario using model
  - Add deviation to observed value



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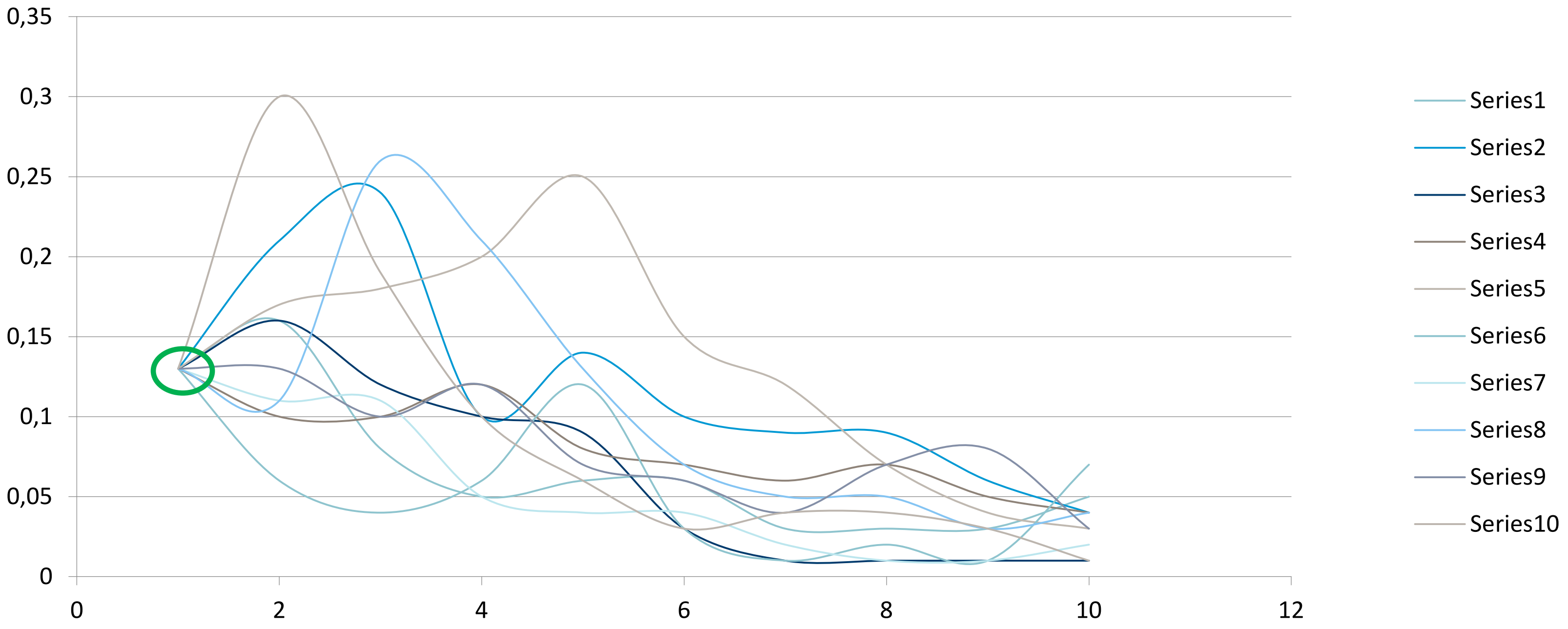
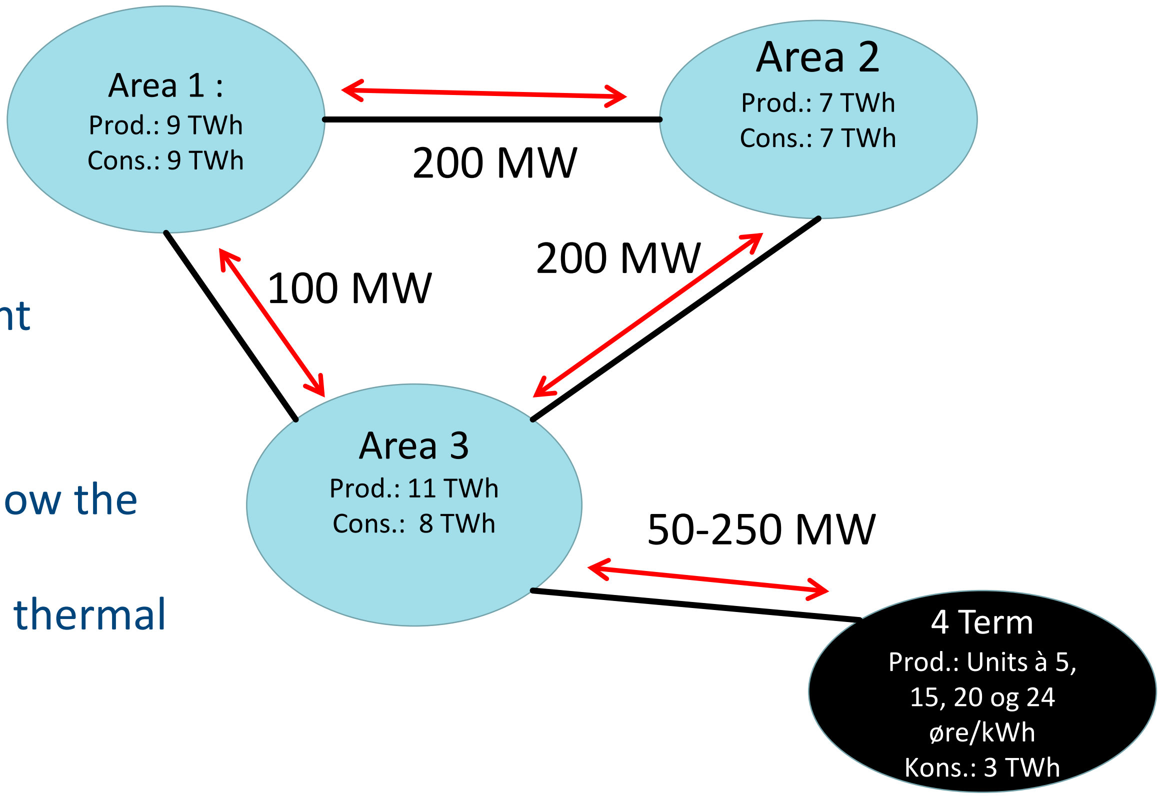


Simulator – pros and cons

- Pros
  - Direct use of historical "weather scenarios" in second-stage forecast
  - Resembles (to some extent) operational planning practice
  - Easy to build, extend and parallelize
    - Efficient use of computational resources
- Cons
  - Model users wants results quickly but this model has long computational times
  - Examples:
    - 950 modules, 52 week scenariofan, 4 load steps:
      - Observed: appr. 17 minutes per weekly decision problem (CPLEX)
      - Estimate 260 week simulation horizon: 74 hours (~3 days)
    - Small test dataset (see next slide)

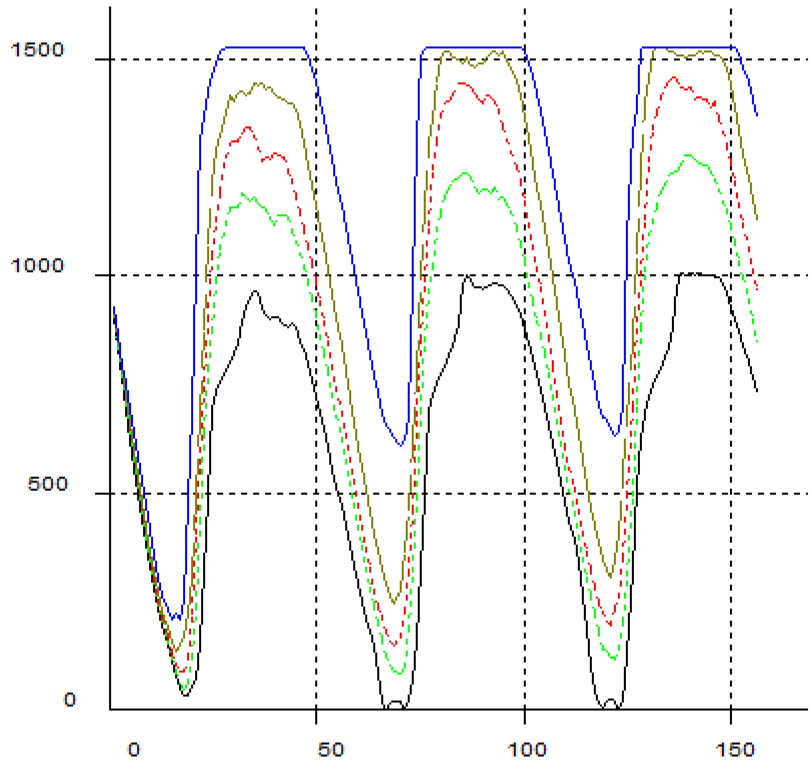
Test case: SOVN vs EMPS

- Four areas: 3 with hydro and one with only thermal units
- 38 years, 4 time steps a week
- Parallel simulation with 156 weeks
- Calc. time EMPS: 1 min
  Calc. time SOVN: 1 hour
  with 52 weeks scenario horisont
  using 79 cores
- Increased capacity between Area 3 and TERM to evaluate how the model simulates the impact of interconnecting a hydro and thermal system together

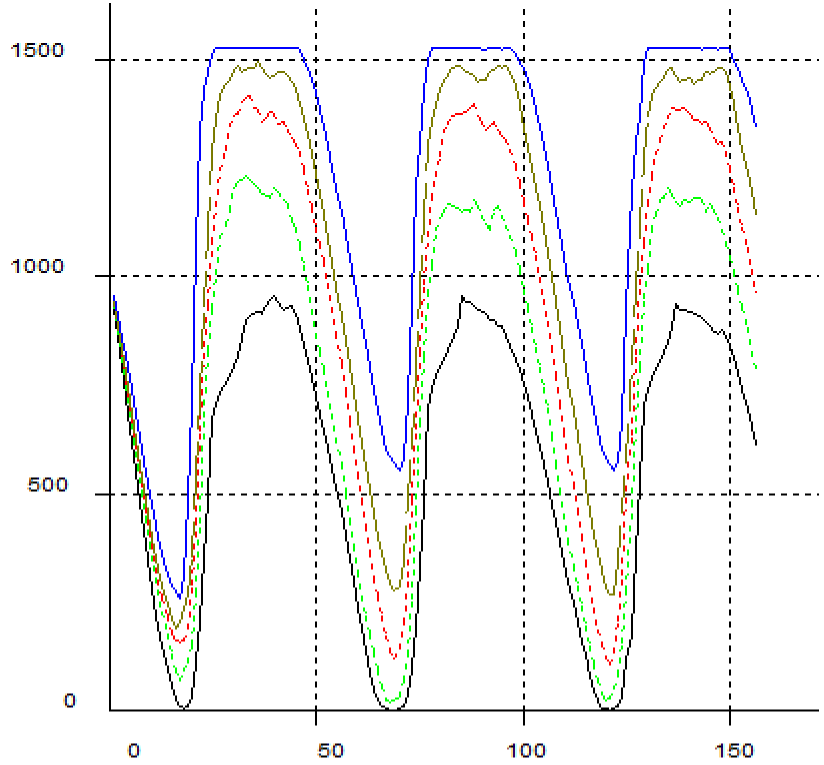


Results: Reservoir handling area 1 (0 – 100 % percentile)

EMPS_100 MW



SOVN_100 MW

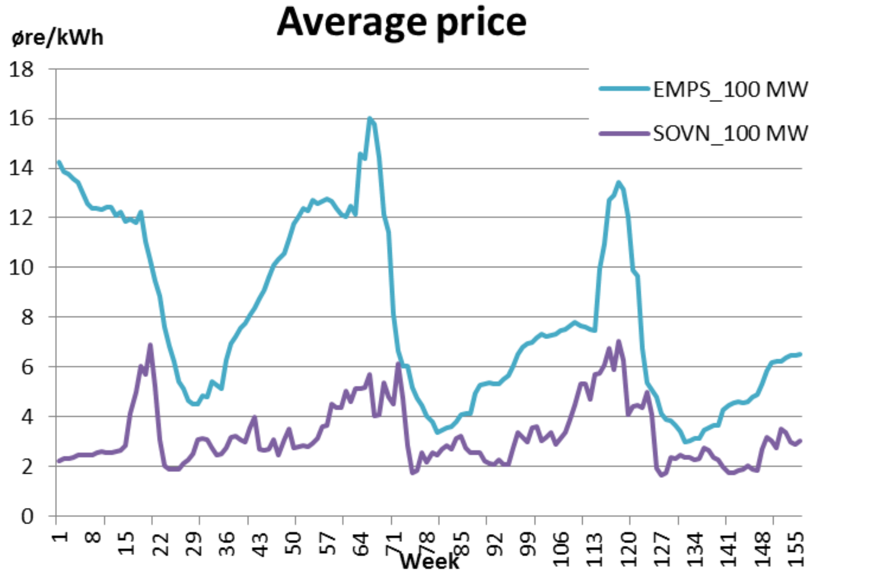


The SOVN model gives less flooding and lower prices

- More optimal use of the water in the reservoirs gives less flooding
- Higher hydro production replaces some of the thermal production in TERM

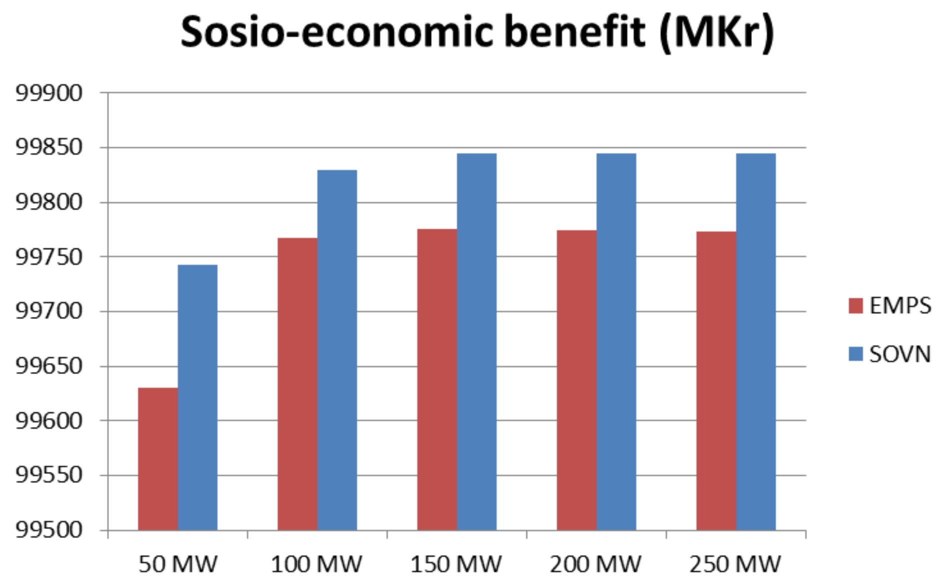
- This gives lower prices (since the price is set by the thermal units in TERM)
- Production surplus goes down, while consumer surplus goes up → in total a net benefit

Difference between SOVN and EMPS (100 MW capacity Otra-Term)						
SOVN-EMPS	Hydro	Flood	Thermal	PO	KO	S.E.B
Area	GWh	GWh	GWh	MKr	MKr	MKr
1 -Numedal	134	-120	-14	-426	459	24
2 - TEV	195	-320	0	-416	384	-39
3 - Otra	458	-165	-4	-493	509	10
4 - TERM	0	0	-654	-37	91	66
Total	**787**	**-605**	**-672**	**-1 372**	**1 443**	**63**



Sosio-economic benefit is higher in SOVN for all cases

- An increased capacity between OTRA and TERM from 50 to 250 MW yields higher SEB* in both SOVN and EMPS
- The SOVN model has in general a higher SEB regardless of capacity
- The SEB of the EMPS model actually decreases (marginally) from 150 to 250 MW
    - This is not the case for the SOVN model



* In a parallel simulation it is important to use the same water values when compairing socio-economic benefit to avoid that reservoir change between the start and the end of the simulation period is valued differently.

Further tests

- Increase complexity of the test data set including wind power, external prices and start and stop costs
- Investigating differences in pumping pattern
- Testing the SOVN model on a real Nordic dataset

Current status for model development

- Basic model developed and running. Model being tested.

- Functionality implemented:
  - "Basic EMPS" – functionality included, e.g.
    - Startup costs
    - Wind energy
  - CPLEX & COIN
  - Parallel version available
  - Flexible time resolution

Next step

- Some additional functionality (e.g. dynamic end-user elasticity)
- Prototype ready for testing by medio June 2015
- Current model uses flow constraints.
  Detailed transmission constraints will be implemented using PTDF's.
- Project finished 2016

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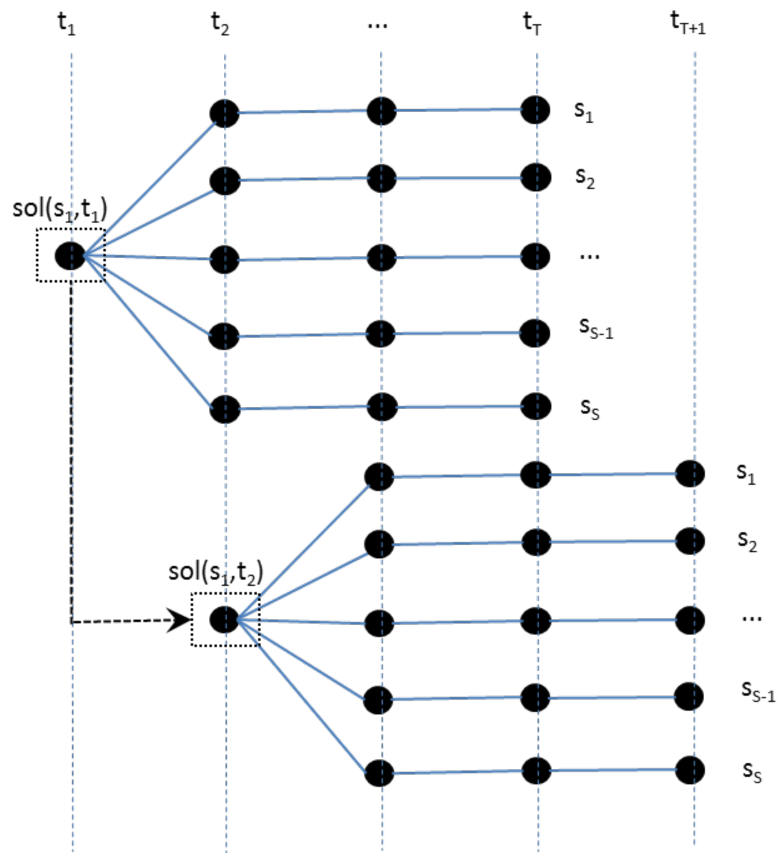
Method

- Two possible methods:
  - Alternative 1: Scenario Fan Simulator
  - Alternative 2: SDDP (Stochastic Dual Dynamic Programming)
- 1: Scenario Fan Simulator (chosen approach)
  - Two stage formulation (simpler stochastic modelling)
  - Second stage scenarios based on historical weather years
- 2: SDDP
  - Regarded as state of the art for such problems
  - Long experience
  - Testing show poor results when many uncertain variables

Scenario scheme: LP-structure



Prerequisites – The Long-Term Scheduling Problem

- A large-scale multi-stage stochastic optimization problem
- The problem is characterized by:
  - A large number of state variables (> 1000 hydro reservoirs)
  - Time horizon of 3-5 years
  - Weekly stochastic time-resolution
  - Down to hourly time resolution within the week

- Inflow is the most important stochastic variable, and is correlated in time and space

- The strategy will be simulated using historical inflow scenarios (de facto standard among players in the Nordic Power market).

Prerequisites – The Weekly Decision Problem

- The overall problem decomposed to weekly decision problems
- Formulated as an LP problem:
    - Minimize system cost (maximize welfare)
    - Subject to:
        - Power balance
        - Reservoir balances
        - Power flow constraints
        - *(Start-up costs, ramping, etc.)*

Valuation of water at end of scenariofan

- Water value from aggregate reservoir

- Based on EMPS-logic for target reservoirs (siktemagasin) for indiviual reservoirs
  - Goes through all reservoirs from empty to full
  - Finds target value for given reservoir level
  - Sets water value (from aggregate reservoir)

- Individual decoupled water value for all reservoirs at end of scenariofan

Simulator – Challenges

- Model users wants results quickly…

- Efficient use of computational resources
  - Large-scale parallel processing, but adapted to the available resources
  - Optimal use of information from previously solved problems

- Optimization problem approximations are needed
  - Each second-stage scenario with >> 1 M variables and > 1 M constraints
  - Approximate problem by:
    - Aggregation of time periods far ahead
    - Shorten forecasting horizon; end-value set by another program
    - Scenario bundling/reduction