Hydro Scheduling Powered by Derivatives

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Summary

- An empirical analysis of how commodity storage is operated for 13 hydropower producers
- Testing different hypotheses on inventory and operational policies
- Our results indicate:
  - A simple regression model can explain a significant part of the variation in the scheduling policies
  - Electricity forward prices are used in the optimization of hydro scheduling
  - Real option theory applies: The higher the price volatility, the lower the production
Outline

- Related literature
- Nordic electricity market
- Hydropower scheduling
- Empirical analysis
Related literature

- Hydropower scheduling
  - Many OR and engineering papers on methods, including stochastic programming: Wallace & Fleten (SP handbook, 2003)
  - Some econ papers, e.g., Førsund (2007)
  - Only few empirical studies. For instance, Tipping (2006) and Nasakkala & Keppo (2007)
- Related OR papers: Ding, Dong & Kouvelis (OR 2007), Caldentey & Haugh (MOR 2006), Birge (2006)
  - Imply that financial information should be used
  - Nonfinancial firms don’t trade much derivatives
Nordic electricity market

- All the time supply equals demand
  - National grid companies manage short term imbalances
- Spot market
  - Daily submission of supply and demand bids for the next 12-36 hours
- Forwards and futures
  - Traded on Nord Pool (exchange) and OTC/bilaterally
Electricity derivatives market

- **Underlying asset**
  - Elspot system price which is the average price of physical electricity in the whole Nord Pool area over the next 12-36 hours and calculated assuming no transmission bottlenecks

- **Futures**
  - Exchange-traded contract for delivery in a specified future time interval at an agreed price
  - Financially settled mark-to-market, week and month maturity lengths

- **Forwards**
  - Financially settled during maturity period, quarters and years maturity lengths, up to five years into the future
Nord Pool prices

- Descriptive statistics for spot prices, weekly futures, seasonal forwards, and spot price relative to the futures prices. All prices are in Euro/MWh. ADF is the Augmented-Dickey-Fuller stationary test statistic which has a critical value of -2.87 at a 5% significance level.
- An average of 0.96 indicates that forward prices above the spot price, i.e., risk premium

<table>
<thead>
<tr>
<th></th>
<th>Mean</th>
<th>Min</th>
<th>Max</th>
<th>Std. dev</th>
<th>ADF</th>
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<tbody>
<tr>
<td>Spot Price</td>
<td>29.63</td>
<td>4.78</td>
<td>103.65</td>
<td>14.01</td>
<td>-2.928</td>
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<tr>
<td>Weekly futures</td>
<td>30.44</td>
<td>5.70</td>
<td>114.56</td>
<td>14.89</td>
<td>-3.446</td>
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<tr>
<td>Seasonal forwards</td>
<td>31.16</td>
<td>10.48</td>
<td>83.25</td>
<td>13.56</td>
<td>-2.890</td>
</tr>
<tr>
<td>Spot relative to futures prices</td>
<td>0.958</td>
<td>0.435</td>
<td>1.71</td>
<td>0.136</td>
<td></td>
</tr>
</tbody>
</table>
Nord Pool prices, Cont’d

- Spot and selected futures and forward prices between February 2000 and December 2006.
- Timing matters!
Supply curve

Annual Nordic consumption

Gas turbines

Condensing, oil

Condensing, coal

Combined heat and power

Nuclear

CHP industry

Hydro (average)

Average price

Production cost

100
200
300
400 TWh

Annual Nordic consumption
Key characteristic: Inflow uncertainty

Spot price *) [€cent/kWh]

Inflow **) [TWh]

*) Average spot price in 1999-prices

**) Annual inflow Norway and Sweden
Inflow and hydro scheduling

How to optimise reservoirs with
- stochastic inflow
- stochastic spot- and forward prices
- multi-year storage capacity?
Power station and reservoir
Scheduling problem

- "Marginal costs" are opportunity costs of discharging water
- Avoid spilling, discharge when prices are high
Scheduling problem

\[
\max E_{\pi,p} \left[ \sum_{t=1}^{T} \frac{\pi_t p_t}{(1+k)^t} + \frac{V(l_T, \pi_T)}{(1+k)^T} \right]
\]

subject to
hydro balance
lower and upper bounds on reservoir and discharge

Notation:
\(\pi = \text{price}\)
\(p = \text{generation}\)
\(k = \text{discount interest rate}\)
\(V = \text{value at end of horizon}\)
\(l = \text{reservoir volume}\)

How to calculate the expectations? Forecasts or forward curve?
Hydro scheduling – hierarchy
(Fosso et al., 1999)

- **Reservoir management**
  - Horizon: 2-3 years
  - Time step: 1 week
  - Scheduling discharges
  - The horizon depends on the size of the reservoir compared to the annual inflow
  - There may also be a medium term model

- **Short term planning**
  - Horizon: 24-168 h
  - Time step: 1 h
  - Detailed generation allocation with signals from the long term models
  - Bidding into the physical day-ahead market
Production and information

- Hydropower producer should consider
  (i) current spot price and expected future prices
  (ii) water reservoir level and expected inflow
  (iii) production constraints

- For instance,
  - The higher the forward prices the more should be produced later
  - The higher the water level the more should be produced now

- Producers have continuous access to spot and forward price information
  - Inflow forecasts are not reliable beyond one week ahead
  - Daily inflow forecasting, price forecasting, bidding
Empirical questions

- Is derivative price information used in hydropower scheduling?
  - Do forward prices explain realized production schedules?
  - Does it help to use forward prices?

- Which factors drive generation scheduling?
  - Prices, inflow, reservoir levels, …
Data

- 13 Norwegian plants, having one main reservoir
  - 9 producers say that they use forward information
  - 4 producers use their own forecasts
- The largest producers (Statkraft, Hydro) are not represented
  - We consider only price takers
- Weekly data 2000-2006: generation, reservoir level, inflow
- Nord Pool prices
  - Elspot (day ahead) and Eltermin (futures and forwards)
### Producers

<table>
<thead>
<tr>
<th>Producers</th>
<th>Capacity MW</th>
<th>kWh/m³</th>
<th>Reservoir GWh</th>
<th>Inflow GWh/y</th>
<th>Relative reservoir</th>
<th>Capacity factor %</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>128</td>
<td>1.16</td>
<td>228.1</td>
<td>641.2</td>
<td>0.356</td>
<td>57.2</td>
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<tr>
<td>2</td>
<td>120</td>
<td>1.32</td>
<td>624.4</td>
<td>380.8</td>
<td>1.64</td>
<td>36.2</td>
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<tr>
<td>3</td>
<td>30</td>
<td>1.15</td>
<td>47.1</td>
<td>106.6</td>
<td>0.442</td>
<td>40.5</td>
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<tr>
<td>4</td>
<td>40</td>
<td>1.27</td>
<td>51.8</td>
<td>139.9</td>
<td>0.37</td>
<td>39.9</td>
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<tr>
<td>5</td>
<td>28</td>
<td>0.67</td>
<td>118.9</td>
<td>87.8</td>
<td>1.35</td>
<td>35.8</td>
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<tr>
<td>6</td>
<td>23</td>
<td>0.16</td>
<td>14</td>
<td>153</td>
<td>0.092</td>
<td>76</td>
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<tr>
<td>7</td>
<td>68</td>
<td>1.25</td>
<td>255</td>
<td>272.3</td>
<td>0.937</td>
<td>45.7</td>
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<tr>
<td>8</td>
<td>167</td>
<td>1.09</td>
<td>272.5</td>
<td>414.4</td>
<td>0.642</td>
<td>28.3</td>
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<tr>
<td>9</td>
<td>210</td>
<td>1.46</td>
<td>1270</td>
<td>1250.5</td>
<td>1.015</td>
<td>68</td>
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<tr>
<td>10</td>
<td>62.1</td>
<td>1.5</td>
<td>142</td>
<td>231.8</td>
<td>0.613</td>
<td>42.6</td>
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<tr>
<td>11</td>
<td>41</td>
<td>0.95</td>
<td>42.6</td>
<td>81.3</td>
<td>0.953</td>
<td>22.6</td>
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<tr>
<td>12</td>
<td>29</td>
<td>0.91</td>
<td>12.4</td>
<td>147.2</td>
<td>0.084</td>
<td>57.9</td>
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<tr>
<td>13</td>
<td>140</td>
<td>1.36</td>
<td>380.8</td>
<td>662.9</td>
<td>0.574</td>
<td>54</td>
</tr>
</tbody>
</table>
Regression model variables

- Dependent variable is weekly production relative to the capacity
- Main explanatory variables:
  - Inflow relative to capacity
  - Spot price relative to forward price (nearest season or quarter), we call this as Basis
  - Seasonality dummies: months and filling season (weeks 18-39)
  - Relative production in the previous week
- Additional effects through dummy variables:
  - Reservoir level > average level: Production should be higher.
  - Reservoir level is high or low (over/below 90%/10% of the max level): Production should depend less on the market prices.
  - Reservoir level > 90% of the max level: Production should depend more on inflow.
  - Spot price > 95% of the max price: Production should be high.
  - Spot price volatility > 95% of the max volatility: Production should be low.
  - Producer claims to use forward prices in the scheduling: Production should depend more on the market price.
Regression model

- Granger causality test:
  - Controlling for seasonality
  - Basis Granger causes aggregate production of the 13 power plants
  - The aggregate production does not Granger cause Basis

- OLS estimation procedure
  - Fixed effects: A dummy on the intercept for each producer
  - Lagged production as a covariate, all the other covariates are assumed to be strictly exogenous
  - Each producer in the model is allowed to have its own sensitivity towards inflow, seasonal inflow, and lagged production (only own lagged production)

  - Out-of-sample R² is used as criterion

- Typical model:
  Production week t = constant + dummies + inflow + spot price relative to forward price + lagged production
Best model

- Best out-of-sample model for the relative production (producer $i$ and week $t$):

$$p_{i,t} = \alpha_i + 0.084 \cdot Basis_t + \beta_{1,i} \cdot inflow_{i,t} + \beta_{2,i} \cdot S_t \cdot inflow_{i,t} + \beta_{3,i} \cdot p_{i,t-1}$$

$$+ \sum_{k=2}^{12} \hat{\beta}_k \cdot M_{k,t} + \sum_{k=1}^{6} \tilde{\beta}_k \cdot H_{k,i,t} + \varepsilon_{i,t}$$

where $S_t$, $M_{k,t}$, and $H_{k,t}$ are the filling season, month, and the hypothesis dummies

- Out-of-sample $R^2$ is 78%
Best model, Cont’d

- The higher the spot price relative to the forward prices, the higher the production
- The higher the inflow the higher the production
  - Less so in the filling season (if $S_t=1$)
Additional effects

- A higher reservoir than normal increases production (confirmed)
- When reservoirs are nearly full or nearly empty, market prices are less important (confirmed)
- Inflow is more important when reservoirs are nearly full (confirmed)
- Production is high at the highest prices (opposite is found – they had low reservoir levels)
- Production decreases when spot price volatility is very high (confirmed)
- Producers that claim to use forward price information are more sensitive against market price changes (confirmed)
Production changes

- Best out-of-sample model:
  \[ \Delta p_{i,t} = 6.05 + 0.03 \Delta \text{inflow}_{i,t} + 5152.68 \Delta \text{Basis}_{i,t} \]
  and its R\(^2\) is 3%.

- The R\(^2\) is consistent with the best empirical work in financial time series (see, e.g., Campbell and Thompson (2008))
  - R\(^2\) is lower since we model differences

- The forward price is also in this model
More on the use of forwards

- 4/13 of the producers report that they do not use forward prices to guide scheduling
  - They instead use their own forecasts
- This is confirmed by the data:
  - This difference is significant: The four use significantly less forward information than the nine
- The group which uses forwards have significantly higher production volatility (608% vs. 575%, annualized)
More on the use, Cont’d

- Cash flows normalized wrt production capacity are not significantly different:
  - With forward information: average = 10.78, standard deviation = 10.09
  - Without forward information: average = 12.24, standard deviation = 12.67
  - Performance measures that avoid valuation of water may be hard to come by

- Does it really help using forward price information?
  - Data indicates the case is not clear
Conclusion

- Forward prices are significant in driving production scheduling
  - Our model simplifies hydro scheduling in practice
- 4/13 do not use forward information, the rest say they use
  - Forward prices explain significantly more the production of the nine companies
  - Those using forward info are not performing significantly better than those who use own forecasts
- Large variance in spot prices decreases production
  - This is due to the value of waiting